Distribution Annual Planning Report

2019-20 to 2023-24

ERGON. ENERGY

NETWORK

Version Control

Version	Date	Description
1.0	24/12/2019	Final for Publication
1.1	4/09/2023	Update new website links

Further Information

Further information on Ergon Energy's network management is available on our website:

https://www.ergon.com.au/network/our-network

Disclaimer

Ergon Energy's Distribution Annual Planning Report (DAPR) is prepared and made available solely for information purposes. While care was taken in the preparation of the information in the DAPR, and it is provided in good faith, Ergon Energy accepts no responsibility or liability for any loss or damage that may be incurred by any person acting in reliance on this information or assumptions drawn from it, except to the extent that liability under any applicable Queensland or Commonwealth of Australia statute cannot be excluded (including without limitation, liability to any person by reason of negligence or negligent mis-statement).

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

All financials presented in the DAPR are correct at the time of writing (Dec 2019) and represent the existing organisational accounting treatment, which may be subject to change. The information contained in the DAPR is subject to annual review. Ergon Energy is obligated to publish future editions by 31st December, in accordance with the National Electricity Rules.

Contents

Figures

Tables

Executive Summary

Ergon Energy's Distribution Annual Planning Report 2019-20 to 2023-24 (DAPR) details the corporation's future direction and intentions for the next five years in an energy environment characterised by rapid technological change and high penetrations of renewable energy resources. These factors are driving the transformation of our ageing network that connects and distributes electricity to over 760,000 residential, commercial and industrial customers spanning 97% of the state of Queensland and will see a return to steady growth over the forecast horizon.

The DAPR provides the community and stakeholders with an insight into the key challenges we face and our responses to them. Many solutions seek customer and industry participation in resolving. In addition, the online network interactive map increases the transparency of our network planning, asset management and investment decision making processes, providing guidance to stakeholders for solutions.

Community and Customer Engagement

Ergon Energy's vision as part of the Energy Queensland Limited Group is 'Energising Queensland communities', with our purpose of 'Providing Safe, Secure, Affordable and Sustainable energy solutions for our customers and communities'.

To ensure we are meeting the unique and diverse needs of our communities and customers, in a period where our industry is undergoing rapid transformation, we operate a coordinated, multi-channel community and customer engagement and performance measurement program. This program of engagement has had a strong influence in shaping our Regulatory Proposal for 2020-25, our network tariff reform program and investment plans.

Ergon Energy is one of more than 20 energy businesses that has committed to the Energy Charter which established in January 2019 to deliver electricity aligned to customer and community expectations.

The Charter sets out five principles:

- We will put the customers at the centre of our business and the energy system
- We will improve energy affordability for customers
- We will provide energy safely, sustainably and reliably
- We will improve the customer experience
- We will support customers facing vulnerable circumstances

As a signatory participating in the Energy Charter, Ergon Energy will report to an independent Accountability Panel who will evaluate our disclosures and provide recommendations of improvements to assist further customer outcomes.

These efforts are intended to align our future thinking with the long-term interests of our customers and communities.

Safety

Safety is considered of the utmost importance by Ergon Energy and the community. As our networks age and the risk of equipment failure towards end of life increases, our focus on maintaining safety outcomes for our staff, customers and communities is paramount. We are taking a no compromise approach to community and staff safety, leveraging innovative solutions that enable continuous improvement. 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.

Affordability

Our customers have told us that affordability is their primary concern – for both cost of living and business competitiveness. Affordability is more than part of our purpose statement; it is a fundamental consideration in how we manage our network. We have implemented a number of savings as part of the merger of Ergon Energy and Energex as part of Energy Queensland. To date these savings across both businesses is expected to be over $510 million which results in lower network prices to Queensland customers. Our forward investment program, reaching into the next regulatory control period has been focused on minimising costs to customers, whilst still ensuring that we meet the outcomes that our customers expect. Our Asset Management strategies balance between customers' need for an affordable, secure, safe, reliable, and high quality electricity supply, and their desire for this service to be provided at minimal cost. A key part of that process is to optimise the economic benefits of network improvement, considering actions beyond the boundaries of the network, such as demand management, embedded generation solutions and other non-traditional approaches.

Security

Our approach to network security is dictated by our Safety Net obligations specified in our Distribution Authority. Overall the Ergon Energy network is performing well against these obligations as result of efficient network planning, management and our operational capability. There were no network events in the 2018/19 period where the customer Safety Net targets were breached.

With regard to managing peak demand, relatively warmer ambient temperatures compared to last year across most of regional Queensland over the summer months, resulted in the summer system peak of 2,623MW at 6:00 pm (20/02/2019) and less than the previously recorded highest system peak (2,637MW in February 2017 at 7.30 pm).

Ergon Energy experienced a total of 13 significant weather events impacting its networks and requiring an escalation of its fault response actions. Severe bushfires were experienced across the State and a total of five tropical cyclones impacted the Queensland coast. Three of these tropical cyclones resulted in a costal crossing in the Far North with subsequent damage to the Ergon Energy infrastructure. In addition, multiple severe storm events impacted the network requiring escalated responses in the Northern and Southern regions.

In February 2019, the largest mobilisation of staff occurred in response to the North Queensland Monsoon and Flooding which included the severe flooding in Townsville and Western Regions. This Monsoon trough resulted in interruption of supply to over 17,000 customers. Supply was restored 24 hours ahead of target to affected customers.

In 2018-19, Ergon Energy's reliability of supply was favourable to five of the six measures for the Distribution Authority's Minimum Service Standard (MSS) limits, while Long Rural SAIDI was unfavourable to the MSS Limit. Ergon Long Rural network's unplanned performance was significantly impacted during wet season, by severe thunder storms and lightning strikes, affecting the network in the Wide Bay, South West, North West and Capricornia regions. The Long Rural supply network also experienced a significant increase in the frequency of planned supply interruptions, due to an increase in Priority 2 (P2) lines and coordinated maintenance lines and substation works across Ergon. Our overall reliability performance has improved since the inception of MSS in 2005 with both the duration and frequency of overall outages reducing by 26% and 36% respectively. These examples are a reflection of the targeted investment made during the last two regulatory control periods towards achieving regulated MSS standards.

In 2018-19, Ergon Energy's reliability of supply outperformed the unplanned performance targets under the Australian Energy Regulator's STPIS scheme for all six measures. 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 15% and 19% respectively.

Feedback through the development of our regulatory submission has reinforced that customers generally don't want us to improve network performance but expect it to be maintained. Paramount for long term network security and reliability is ensuring that we maintain a sustainable program of work to deal with network replacement and that we continue to evolve our approach as markets and technology evolves.

Cyber security is also 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.

Sustainability

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, as well as the next generation of home and commercial energy management systems. We see this as fundamental to our role in the future and this has been supported by feedback from our customers as part of recent engagements. More importantly, we see ourselves increasing our collaboration with our customers and market proponents, to help leverage the benefits of this new technology in our network and help deliver overall improved outcomes for customers.

Queensland has one of the highest penetrations of solar PV systems on detached houses in the world. Connected solar PV capacity continues to grow in Queensland. During the 2018/19 financial year, Ergon Energy's distributed solar PV systems were connecting at an average rate of over 1,400 connections per month. At the end of June 2019, there were 160,166 solar PV systems connected to the distribution network, with a total generation capacity of 1,240 MVA. Amongst residential customers, the take-up rate is nearly 23%. In addition, more than 350 MW of large-scale renewable generation were connected to the Ergon Energy network.

The rapid uptake of solar PV has changed distribution of electricity impacting the Low Voltage (LV) network and creating a number of system design and operation challenges. Strategic planning initiatives, such as implementation of the 230 V LV Standard, help to manage network voltages for residential customers and enable controlled uptake of solar PV.

Fringe of Grid Customers

The Ergon Energy network is typified by long distances and low customer densities. Ergon Energy's 64,000km Single Wire Earth Return (SWER) network is approximately 40% of Ergon Energy's distribution network and one of the largest in the world. We are actively engaged with the Queensland Government in looking at the cost of supply into our Western networks, including SWER to look at how technology advances may be able to deliver better customer and economic outcomes in these networks.

2020-25 Regulatory Submission

Ergon Energy submitted Regulatory Proposals to the AER in January 2019 and, based on the AER Draft Determination Revised Regulatory Proposals in December 2019. Our Regulatory Proposals explained our plans and the funding we need to deliver them. We want to ensure our capital investment, operating and pricing plans for 2020 to 2025 reflect our customers' preferences and place us in the best position to deliver for regional Queensland, our industry, our communities and our customers into the future.

Improving our Connection Process

During 2018-19, we continued to align the connection process or Energex and Ergon Energy Network to deliver consistent customer experiences and increased efficiencies. This has included a major system investment and process reviews focused on improvements to the customer experience, which will enable customer and industry partners access to information to improve the network connections process. We are also working with stakeholders to evolve regulations around connection requirements to enable innovation for new electricity supply solutions that deliver balanced outcomes.

Changes from 2018 DAPR

- Chapter 3 Community and Customer Engagement has been updated to include detailed information on our current community and customer engagement activities. This also includes recognising our customer commitments and responding to the continuous feedback from our customers as described in Sections 3.3 and 3.4.
- Ergon Energy has adopted a detailed and mathematically rigorous approach to forecasting peak demand, electricity delivered (energy), and customer numbers. The methods applied and forecasting results are described in Chapter 5 Network Forecasting. Ergon Energy continues to improve demand and energy forecasting modelling outcomes which are validated by regular audits performed by external forecasting specialists.
- A new regional approach has been developed to provide the 'top-down' forecast in regard to Section 5.4 System Maximum Demand Forecast. Each of Ergon Energy's regions are modelled separately and the sum of each of these regional peak demands at network peak coincidence provides an econometric ten-year total system maximum demand forecast based on identified factors which affect the load for each regional level. An overview of the revised system demand forecast methodology can be found in Figure 17.
- 68 distribution feeders will exceed the capacity planning levels (but not necessarily asset capability thresholds to trigger capital investments) within the next two years; this compares to 75 last year. This reduction is largely due to:
    - network improvements, load transfers and demand management
    - improved data accuracy, additional line surveys, analysis and network modelling capabilities
    - different load profiles and feeder growth rates
- Under contingency conditions, there is one substation with load at risk for each year in the forward planning period (2019-20 to 2023-24).
- Under contingency conditions, there are six sub-transmission feeders with load at risk in the forward planning period (2019-20 to 2023-24).
- There are currently nine RIT-D projects in progress addressing network limitations having credible options with augmentation or asset replacement components greater than $6 million[1]. All RIT-D consultation activities are reported in Section 7.7.
- A customer friendly version of the DAPR has also been compiled to assist customers, communities and stakeholders in understanding DAPR and exploring future opportunities.
- Solar PV heat maps have been added to include the uptake of solar PV across the Ergon Energy network.

[1] On 20th November 2018 the AER published a final determination of the 2018 cost threshold review. The AER's final determination for the distribution thresholds is that: The $5 million capital cost threshold referred to in NER clause 5.15.3(d)(1) be increased to $6 million. This is the cost threshold over which a RIT–D applies; The revised cost thresholds will take effect on 1st January 2019.

Chapter 1

Introduction

1. Introduction

1.1 Foreword

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

The DAPR supports our commitment to open and transparent customer, community and shareholder engagement. It presents the outcomes from our distribution network service provisions carried out in 2018-19 for the forward planning period 2019-20 to 2023-24 and is also a requirement under the National Electricity Rules (NER).

The DAPR provides information for interested parties on our:

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

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

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

Ergon Energy's planning maps and forecast load and capacity information are now presented via an Environmental Systems Research Institute (ESRI) Graphical Information System (GIS) portal. This provides an interactive experience, with subtransmission and distribution constraints as well as tables presented in a geospatial context. The ESRI GIS Portal is accessible via the following web link:

https://www.ergon.com.au/daprmap2019

1.2 Reporting Requirements

This DAPR has been prepared to comply with NER Rule 5.13 and Schedule 5.8. Clause 5.13.3 is a rule change that came into effect 1st July 2017 requiring DNSPs to submit a Distribution System Limitation template (DAPR template).

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

The forward planning horizon covers from 2019-20 to 2023-24. The aim of this document is to inform network participants and stakeholder groups about development of the Ergon Energy network, including potential opportunities for non-network solutions – particularly for large investments where the AER's Regulatory Investment Test for Distribution (RIT-D) applies.

These requirements are cross-referenced in Appendix B of this report.

1.3 Network Overview

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

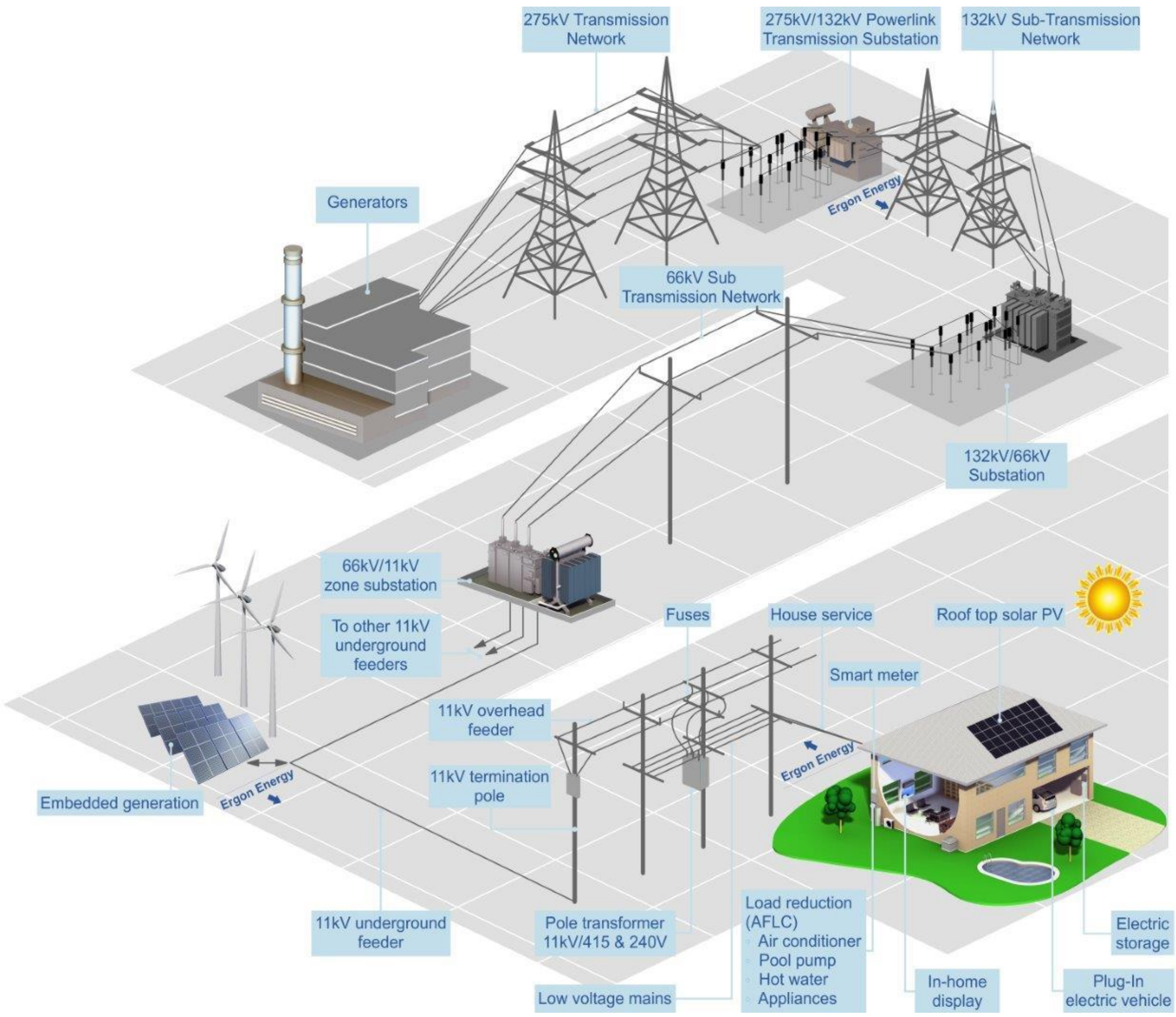
The electricity grid, including transmission and distribution networks, connects and facilitates the distribution of electrical energy between generators and users. The bulk of electricity is generated on demand at locations remote to the point of supply. The state's largest generators typically connect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

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

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

With the increase in embedded generation (EG) systems being connected to the network, including small and large scale solar PV and other renewable energy sources, electricity is now being generated and exported into the grid from customers' premises. Depending on the size and number of these systems, parts of the conventional supply chain are now at times operating in reverse, creating both challenges and opportunities for the network.

Figure 1: Typical Electricity Supply Chain[2]



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

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

Asset boundaries between Ergon Energy and other parties also vary.

1.4 Peak Demand

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

In a positive demand growth environment, increasing peak demand is a major driver of network costs. Ergon Energy must maintain sufficient capacity to supply every home and business on the day of the year when electricity demand is at its maximum, no matter where those customers are connected in the network. In addition, growth in peak demand may occur where new property developments are being established; whilst 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 emerging in local areas experiencing increasing peak demand or new development.

The Ergon Energy system maximum native demand for 2018-19 was recorded at 2,623MW on Wednesday 20th February 2019 at 6.00pm. This peak demand is lower than the previous highest recorded demand by 14MW (2,637MW in 2016-17).

1.5 Changes from 2018 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 2018 DAPR. These changes aim to make relevant information accessible and understood by all stakeholders, non-network providers and interested parties.

- Chapter 3 Community and Customer Engagement has been updated to include detailed information on our current community and customer engagement activities. This also includes recognising our customer commitments and responding to the continuous feedback from our customers as described in Sections 3.3 and and 3.4.
- Ergon Energy has adopted a detailed and mathematically rigorous approach to forecasting peak demand, electricity delivered (energy), and customer numbers. The methods applied and forecasting results are described in Chapter 5 Network Forecasting. Ergon Energy continues to improve demand and energy forecasting modelling outcomes which are validated by regular audits performed by external forecasting specialists.
- A new regional approach has been developed to provide the 'top-down' forecast in regards to Section 5.4 System Maximum Demand Forecast. Each of Ergon Energy's regions are modelled separately and the sum of each of these regional peak demands at network peak coincidence provides an econometric ten-year total system maximum demand forecast based on identified factors which affect the load for each regional level. An overview of the revised system demand forecast methodology can be found in Figure 17.
- 68 distribution feeders will exceed the capacity planning levels (but not necessarily asset capability thresholds to trigger capital investments) within the next two years; this compares to 75 last year. This reduction is largely due to:
    - network improvements, load transfers and demand management
    - improved data accuracy, additional line surveys, analysis and network modelling capabilities
    - different load profiles and feeder growth rates
- Under contingency conditions, there is one substation with load at risk for each year in the forward planning period (2019-20 to 2023-24).
- Under contingency conditions, there are six sub-transmission feeders with load at risk in the forward planning period (2019-20 to 2023-24).
- There are currently nine RIT-D projects in progress addressing network limitations having credible options with augmentation or asset replacement components greater than $6 million[3]. All RIT-D consultation activities are reported in Section 7.7.
- A customer friendly version of the DAPR has also been compiled to assist customers, communities and stakeholders in understanding DAPR and exploring future opportunities.

[3] On 20th November 2018 the AER published a final determination of the 2018 cost threshold review. The AER's final determination for the distribution thresholds is that: The $5 million capital cost threshold referred to in NER clause 5.15.3(d)(1) be increased to $6 million. This is the cost threshold over which a RIT–D applies; The revised cost thresholds will take effect on 1st January 2019.

- Solar PV heat maps have been added to include the uptake of solar PV across the Ergon Energy network.

1.6 DAPR Enquiries

We welcome feedback or enquiries on any of the information presented in this DAPR, via email to engagement@ergon.com.au. Alternatively, visit Ergon Energy Network Management's Distribution Annual Planning Report webpage for further information and the opportunity to provide your own commentary or questions. Full weblink reference noted below:

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

Chapter 2

Ergon Energy Overview

2. Ergon Energy Overview

2.1 Corporate Overview

Ergon Energy Network (Ergon Energy Corporation Limited) is a subsidiary of Energy Queensland Limited, the Queensland Government Owned Corporation formed through a merger in June 2016.

The Energy Queensland Group includes electricity distribution, retail and energy services businesses operating both state-wide, and in the national market.

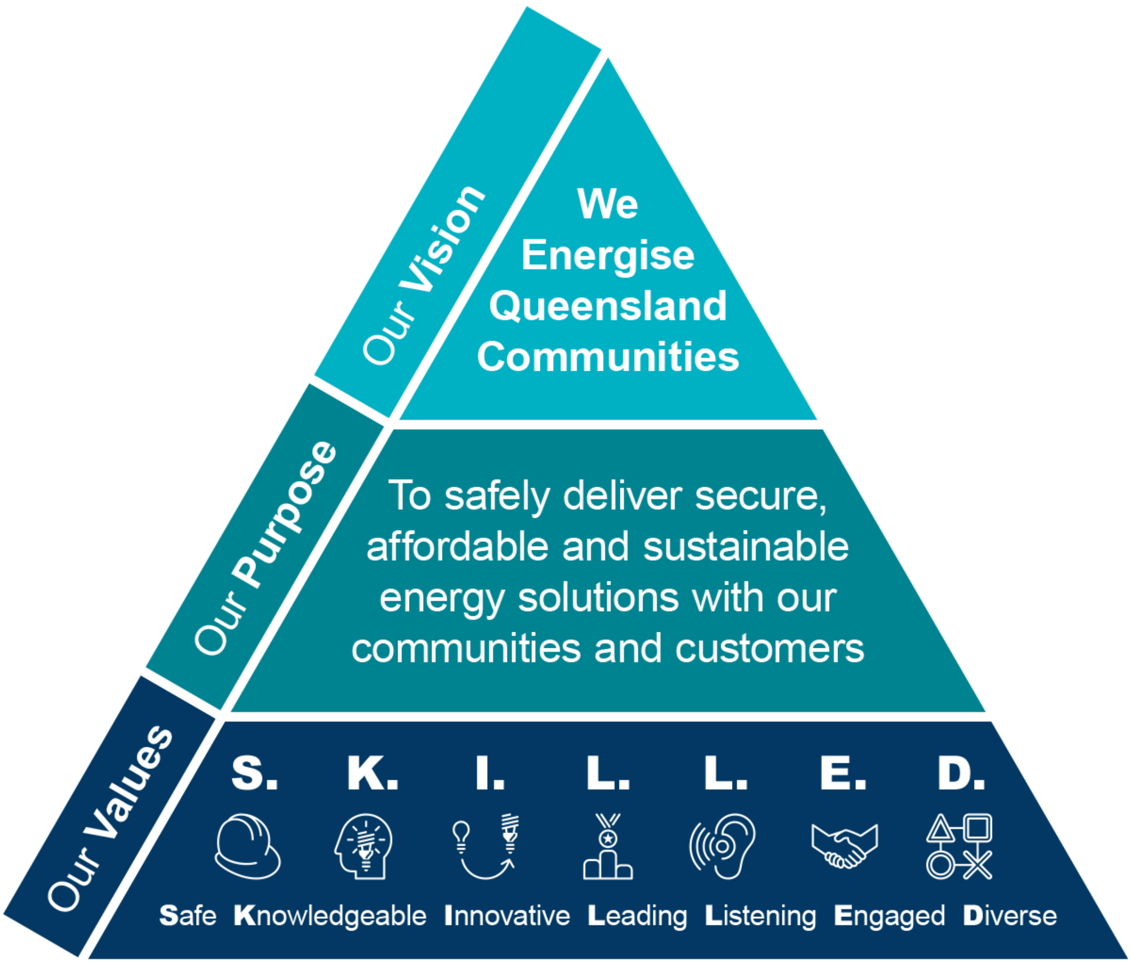
We deliver electricity across Queensland through our 'poles and wires' businesses, both Ergon Energy Network and Energex and, as Distribution Network Service Providers (DNSP).

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.

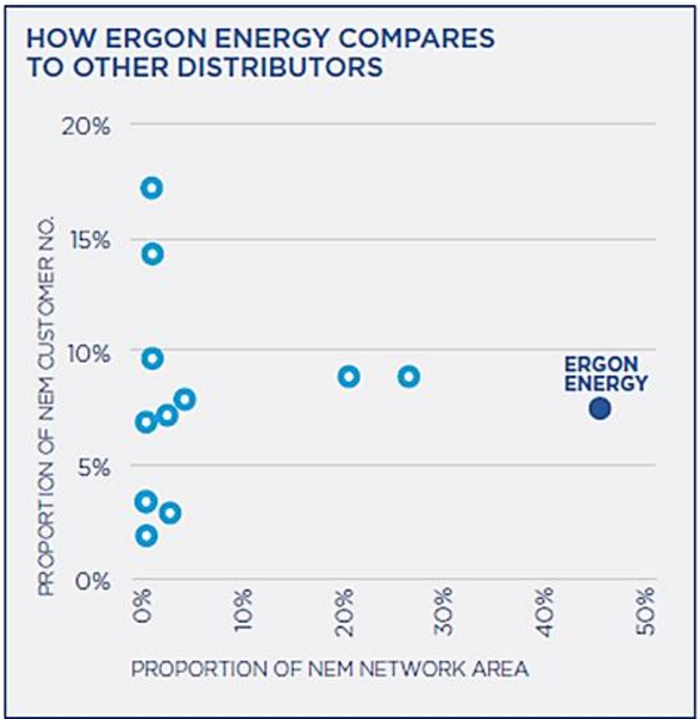
Figure 2: Energy Queensland Vision, Purpose and Values



2.2 Ergon Energy's Electricity Distribution Network

Around 70% of our electricity network runs through rural Queensland, a vast service area with large distances between communities. Our service area is by far the largest in the National Electricity Market (NEM), with the second lowest customer density per network kilometre – see Figure 3.

Figure 3: Customer Density Comparison



Our service area is by far the largest distribution area in the National Electricity Market (NEM). However, proportionally our customer base is small.

Source: Huegin Ergon Energy Expenditure Benchmarking.

We have a proportionately high investment in subtransmission assets, compared to our urban counterparts, and one of the largest Single Wire Earth Return (SWER) networks in the world. Compared to a meshed or interconnected urban network, the radial design of our rural network and the limited capacity of the SWER lines, limits what we can do when responding to peaks in demand or outages.

Our 64,000 kilometres of SWER lines (the longest approximately 1,000 kilometres in length) supply around 26,000 customers predominantly located in western areas of regional Queensland.

This section of the network operates at three voltage levels: 11kV, 12.7kV and 19.1kV in configurations as conventional, duplex, triplex and non-isolated SWERs. These systems are supplied by isolated transformers in the size range between 50kVA and 200kVA. The technology was an ideal solution in the early years of the electrification of our vast state.

Ergon Energy also has 33 stand-alone diesel-fired power stations with total installed capacity of 46MW and small amount of solar and wind energy sources. Our isolated systems operate on 33kV, 22kV, 11kV, 6.6kVA, SWER and low voltage (LV) with peaks ranging between 68kW and 4.2MW. These isolated systems supply 39 communities (approximately 7,000 customers) isolated from the main grid and are located in western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait islands and Palm Island.

Ergon Energy's network supplies the full range of end users. The bulk of the customers connected to the network use less than 100MWh of electricity a year – about 84% of these are residential customers and the remaining 16% are small to medium businesses. Our network also supplies the majority of the state's largest energy users.

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

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

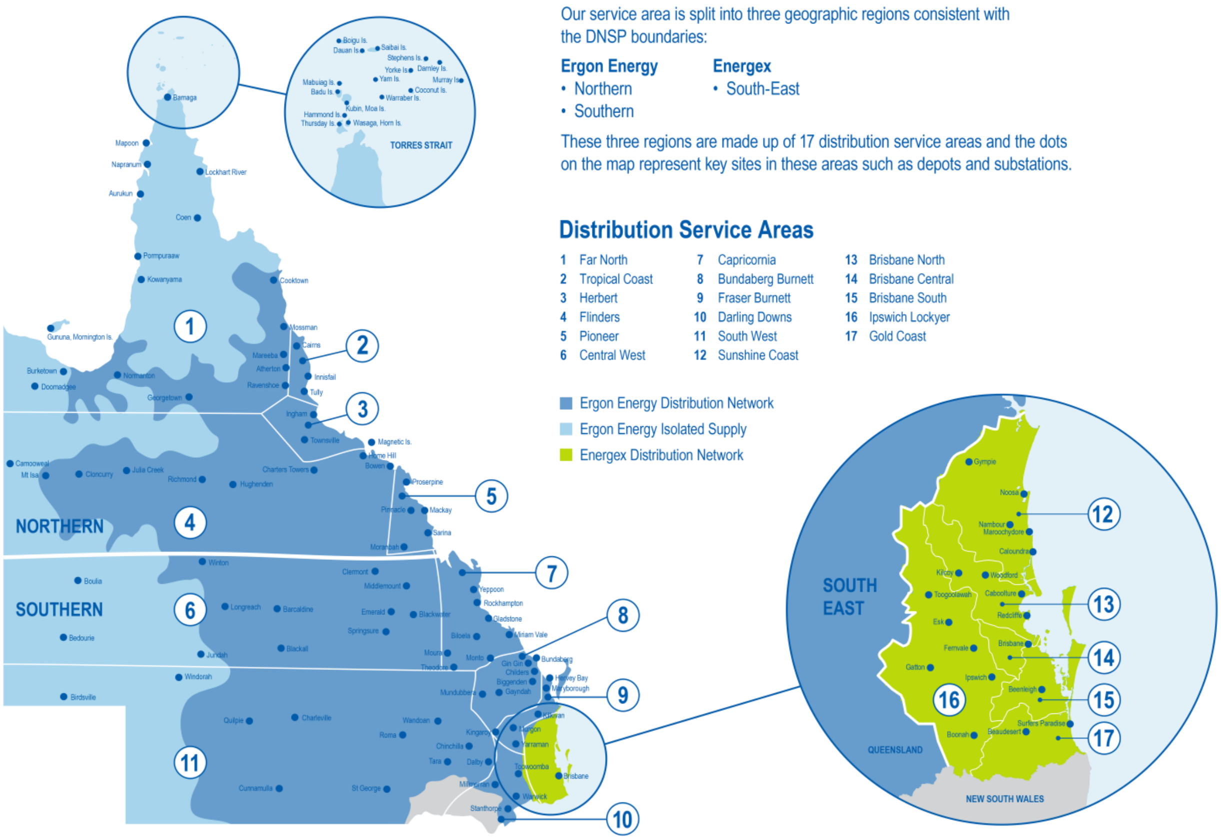
Network Statistics	
Network Area Serviced	1.7 million sq. km
Power Stations (isolated)	33
Switching Stations	20
Bulk Supply Substations	29
Zone Substations (ZS)	258
Distribution Transformers	103,307
Power Poles	1,021,278
Overhead Powerlines - Subtransmission	14,863km
- High Voltage Distribution	111,848km
- Low Voltage Distribution	16,590km
Underground Power Cable	8,979km
Number of Feeders - Subtransmission feeders	330
- Distribution feeders[4]	1,249
- Other Feeders	97
Network Customers	
Customers on Urban Network	231,478
Customers on Short Rural Network	445,707
Customers on Long Rural Network	83,891
Total Customers[5]	**761,076**
Isolated Network Customers	8,328

[4] Includes island feeders

[5] Regulated network customers, as at 30th June 2018, EB RIN T3.4

Figure 4 shows our distribution service area, including isolated community generation sites and stand-alone power supply systems.

Figure 4: Ergon Energy Distribution Service Area



2.3 Network Operating Environment

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

2.3.1 Physical Environment

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

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

The environmental aspects impacting the network include:

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

2.3.2 Economic Activity

The 2019-20 State Budget forecast Queensland's economy to grow by 2.75% in 2018-19 and strengthen to 3% in 2019-20.

The ongoing success of gas exports will continue to benefit the state and coupled with rising export earnings will continue to provide strength to the State Product from 2019 onwards. Overseas exports of coal, LNG and minerals accounted for around 83% of the nominal value of Queensland's overseas merchandise exports in 2018-19. Tourism is expected to remain solid at just over 7% from the next three years as the Australian dollar remains soft compared to previous years. Continued dampening on wage growth will, however, see an ongoing weaker pace of consumer spending and therefore only modest household consumption growth.

Customers continue to behave cautiously in response to the current economic conditions and business outlook. The electricity sector is seeing residential customers and businesses respond to electricity prices, adopting more energy-efficient behaviours. Economic considerations are also impacting the increased uptake of solar PV in the residential sector and more recently the commercial sector. These are likely to be key considerations in the future uptake of electric vehicles and batteries.

The traditional positive relationship between economic growth and electricity demand from the network is changing.

2.3.3 Social and Demographic Change

As the Australian population ages our customer base across regional Queensland continues to change. We are not only seeing an increasing proportion of people aged 65 years and over retiring, we are also seeing a further generation of primary income earners that have different electricity usage patterns than previous generations. Components of Queensland's population annual increase to December 2017 comprise; 39.0% from the state itself, 39.1% from overseas and 21.9% from interstate migration. The total annual population state grew by 1.7%, an increase of 0.4% from the previous year. Cairns and Toowoomba had the highest regional growth areas over 1%, in the year to 30th June 2017.[6]

We track social and demographic change around the way the community is using electricity in the annual Queensland Household Energy Survey (Section 2.3.5). There is significant change on the domestic front. In the commercial space, the use of electrical and digital equipment is also only expected to increase and impact our customers' residential energy use and expectations. The increase in e-commerce, the ability to work remotely, and accessibility to the internet generally, will potentially see an even greater focus from customers on power supply reliability and quality at home.

Social expectations are also growing around the pace of change in the Queensland electricity market from non-renewable to renewable energy.

These changes in society's expectations and needs are likely to occur in much shorter timeframes than what we have typically had to respond to in our network investment planning and with regards to asset lifespans.

2.3.4 Technological Change

As customer technology develops it is influencing the way our customers use our network and source electricity. We have already seen Queensland integrate the highest penetration of residential solar in Australia, and there is significant discussion around the development and deployment of complementary battery technology as the next potential wave. These technologies change customers' interaction with the grid, in terms of their energy and demand profiles. The dominant role of renewables exacerbates this issue with generation intermittency being another variable that this technology introduces.

Customers will continue to evolve their energy solutions and seek new forms of technology within their home and work, and we will continue to evolve our grid to meet these changing demands. Regardless of the type of technology, our strategy is to create a network that can operate as a platform and interconnector for this technology and our customers.

[6] Australian Government Statistician Office-personal communications.

We expect continued growth in solar PV both in residential and other customer classes. Over the last year we have seen a significant increase in applications to connect large-scale solar, particularly in our rural areas. Batteries and electric vehicles are likely to be the next technologies to emerge as the costs of these fall and customers gain their benefits.

The AER in Ergon Energy's Distribution Determination 2015-2020 supported the targeted deployment of light emitting diode (LED) public lights in a number of areas and meter capability continues to develop and provide additional network and customer functionality.

2.3.5 Shareholder and Government Expectations

Energy Queensland is continuing to build on the significant progress made since its formation now over three years ago.

Recognising the expectations of our Shareholders Ministers, as a Queensland Government Owned Corporation, we are progressing our resource plans, and transforming the operating model of the Energy Queensland Group to better align our capabilities with Queensland's energy future and deliver merger savings.

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

This supports the Queensland Government's policy commitment to increase the contribution of renewable energy to Queensland's energy mix – with a target 3,000MW of solar energy in Queensland by 2020.

Similarly, with the support of the Queensland Government, we are continuing to facilitate the adoption of emerging storage technology, both Battery Energy Storage Systems (BESS) and Electric Vehicles (EVs).

The Queensland Government's expectations are in line with Energy Queensland's four core, strategic objectives.

Figure 5: Energy Queensland's Strategic Objectives

2.3.6 Community Safety

Community Powerline Safety Strategy 2018

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 2018.

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.

We continue to target industries at risk, who frequently work in close proximity to powerlines, to raise awareness of the powerline safety dangers.

Information brochures were developed to build on our core 'Look Up and Live' and 'Dial Before You Dig' messaging. They are being used as part of our education programs targeting the agriculture, building and construction, road transport and aviation sectors, delivered through industry events. Here we again worked closely with these industry's peak bodies and 'Dial Before You Dig'. We also collaborated during the year with the Electrical Safety Office and Work Health and Safety Queensland to develop key safety messaging and progress important safety-related legislative reforms.

Statistics are used to focus our efforts in at risk areas. The majority of these remain to be out of control motor vehicles and road transport accidents. However, there were also a significant number of agricultural industry incidents, largely in regional Queensland, as well as vegetation management, construction and earth moving related incidents.

When it comes to powerline safety, planning and knowledge of the risks are paramount and our team are committed to close personal interaction with our customers and communities. Conducting face-to-face presentations and participating in industry events allows us to interact closely with and gain deeper insights into the mindset of the community and industry groups. This personal, grassroots approach also provides the opportunity for one-on-one feedback on campaigns, approaches and materials.

Most importantly, our personal approach builds trust and credibility. This is vital to helping targeted community representatives to be receptive to our messages. The measurable outcomes per industry sector will continue to provide a valuable report card on its effectiveness.

2.3.7 EQL Health, Safety and Environment Integrated Management System

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

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

The EQL HSE IMS consists of 12 Standards which are aligned to accreditation requirements.

Standard 8 Control of Work consists of 12 Hazard Control Principles (HCPs) to enable business units to implement risk controls. HCPs include requirements which are accepted practice across Energy Queensland, which may exceed legal requirements. These Principles are currently being developed in accordance with interested parties through initiative alignment in the 19/20 HSE Business Plan. The HCPs will be developed and implemented within Energy Queensland Limited by June 2020.

Existing management systems for Energex and Ergon Energy must be maintained as per the determination by the Australian Energy Regulator (AER). These management systems are subject to third party HSE IMS Surveillance audits and the Electrical Safety (ESO) Electrical Entity audit conducted once per year.

2.3.8 Environmental Commitments

Ergon Energy aspires to be an industry leader in environment and cultural heritage as reflected in Energy Queensland's Health, Safety and Environment Policy. To support this, environment and cultural heritage performance measures are being developed to support improvement. Ergon Energy is committed to working together with customers, the community and other stakeholders including traditional owners to deliver sustainable energy solutions where all interests are managed.

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

As part of a merged entity, Ergon Energy seeks to integrate, innovate and simplify our ISO14001 certified management system processes to rationalise our operations, improve environmental and cultural heritage performance while recognising environmental benefit opportunities in the process.

2.3.9 Legislative Compliance

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

Ergon Energy holds a Distribution Authority, issued by the Queensland Regulator (the Department of Natural Resources, Mines and Energy (DNRME)), to supply electricity using its distribution system throughout regional Queensland. Ergon Energy also operates in accordance with the following all relevant legislative and regulatory obligations:

- *Electricity Act 1994* (Qld), the *Electricity Regulation 2006* (Qld) (the Queensland Electricity Regulation) and the Electricity Distribution Network Code (EDNC, previously the Electricity Industry Code) 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)
- *Aboriginal Cultural Heritage Act 2003* (Qld) and *Torres Strait Islander Cultural Heritage Act 2003* (Qld)
- *Environmental Protection Act 1994* (Qld)
- *Planning Act 2016* (Qld) and subsidiary and related planning and environment legislation, such as the *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)
- *Government Owned Corporations Act 1993* (Qld), *Government Owned Corporations Regulation 2014* (Qld) and *Government Owned Corporation (Energy Consolidation) Regulation 2016 (Qld)*.

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.

2.3.10 Economic Regulatory Environment

In accordance with the requirements of the NEL and NER, Ergon Energy is subject to economic regulation by the AER. The AER regulates the revenues of Ergon Energy by setting the annual revenue we are allowed to recover from our customers during each year of the regulatory control period[7].

The AER applied the following forms of control in this regulatory control period:

- Revenue cap - for services classified as Standard Control Services8 (SCS)
- Caps on the prices of individual services - for services classified as Alternative Control Services9 (ACS).

For this regulatory control period, the AER reclassified a number of SCS as ACS, most notably, default metering services, related to types 5 and 6 meters. It should be noted that, as a result of Power of Choice taking effect on 1st December 2017, the installation and delivery of most metering services have become the responsibility of third party service providers[10]. However, Ergon Energy still recovers the costs of providing Default Metering Services through daily capital and non-capital charges based on the number and type of meters we provide the customer. These charges are billed to Retailers.

Alongside this Distribution Determination, Ergon Energy is subject to a number of nationally consistent guidelines, models and schemes including the Efficiency Benefit Sharing Scheme (EBSS), the Capital Expenditure Sharing Scheme (CESS), the Service Target Performance Incentive Scheme (STPIS) and the Demand Management Incentive Scheme (DMIS).

More information regarding Ergon Energy's allowed revenues and network prices can be found on the AER's website (www.aer.gov.au).

---

[7] 2015-20. Note that customers supplied by Ergon Energy's isolated generation assets are excluded from the jurisdiction of the AER. The isolated generation zone is regulated by DNRME.

[8] Core distribution services associated with the access and supply of electricity to customers.

[9] These services are customer specific and/or customer requested services.

[10] The Power of Choice changes only apply to supply networks that are connected to the national grid, and subject to Chapter 7 of the NER. Ergon Energy will remain responsible for metering in our Mount Isa-Cloncurry and Isolated supply networks.

Chapter 3

Community and Customer Engagement

3. Community and Customer Engagement

3.1 Overview

To ensure we're meeting the unique and diverse needs of our communities and customers we invest in talking and listening to our customers and other stakeholders about their expectations, concerns and ideas.

With our industry undergoing a period of rapid transformation, we see an open dialogue as critical to enabling diversity of thought, innovation and, ultimately, more now than ever, better, more sustainable, customer-driven solutions.

Across our Group we operate a coordinated, multi-channel community and customer engagement and performance measurement program. These conversations and the focus they provide are fundamental to creating real long-term value for our customers and our business, and for Queensland.

Most recently this activity has been used to refine our overall strategic direction, with a stakeholder issues assessment used to prioritise the economic, social and environmental and governance topics that matter most, to build on the work already undertaken to engage on the network businesses' investment plans for our Regulatory Proposals for 2020-25, and our network tariff reform program.

We also became one of the first to commit to a national Energy Charter to progress the solutions required to deliver energy in line with customer and community expectations. The Charter, launched in January 2019, aims to build accountability across the supply chain and improve customer outcomes.

These efforts have influenced the asset management strategies and investment plans in this report and helped to align our future thinking with the long-term interests of our customers.

Figure 6: Community and Customer Insights Inform Our Plans

This chapter provides an overview of these engagement activities and describes how they enable us to put customers at the heart of everything we do. These insights have better informed our plans by building on our understanding of potential future demand and energy usage scenarios, our understanding of future service expectations, and of the opportunities for our network tariff and market reform.

More information is available in our Annual Report and the 2020 and Beyond Community and Customer Engagement Report published online in January 2020, with our Regulatory Proposals.

3.2 Our Engagement Program

3.2.1 Online Engagement

To widen our reach we have established a digital engagement platform, www.talkingenergy.com.au.

The site has proven to be an effective tool to interact with targeted stakeholders, as well as a channel to reach a wider audience. Both of which are key to engaging on the issues in front of us and with our vast service area.

The key activity here for our Regulatory Proposals was our Future Energy Survey, which was open to the public and canvased over 2,000 participants. This discussion was about refreshing our service commitments and planning for the future.

3.2.2 Customer Council Framework

Through Energy Queensland's Customer Council, as our flagship listening forum, we gain a customer-centric perspective to emerging energy-related issues and around potential solutions.

We also have a wider group of customer and community representatives who have been dedicated solely to the Regulatory Proposal Submissions and the Tariff Structure Statement. This group met frequently in the development of our plans to both build their capacity to understand our industry and its regulatory framework and to explore collaboratively the decision we had under consideration.

We also have a business-as-usual Major Customer Forum, Developer Forum, Public Lighting Forum and Agricultural Forum, and are continuing to focus on engaging with our industry partners. This work includes state-wide forums to listen and share knowledge with local electrical contractors and developers, something especially important as we move through this next period of change.

3.2.3 Community Leader Forums

To better connect with our communities and ensure we are effective at the local level, we have 17 established operational areas across the state. Each area has a locally based manager who invests their time building relationships with our local community stakeholders and understanding the areas unique concerns.

To support this, we conducted five Community Leader Forums in 2018, with a holistic view for 2020 and beyond, to support our network investment plans. This saw a wider group of managers and decision-makers interacting with our local stakeholders.

3.2.4 Our customer Research Program

Our Voice of the Customer program has near 'real time' service performance monitoring at its core. The research program is based on earlier work exploring the strengths and pain points of our service delivery for each customer segment, from our major customers to our residential customers. It supports a Customer Index measure based on the customer satisfaction for each touch point.

This feedback mechanism is supported by tracking research that shows us what the wider community, who may or may not have had a recent interaction with us, is thinking in regard to value for money and reliability performance.

We are also continuing to use other targeted research to build a deeper understanding of what our customers will be expecting from us in the future.

To explore topics associated with our future network investments plans and tariff reform journey we conducted specific qualitative research (deliberative forums and focus groups) and quantitative research. The findings of this research were important to the development of our Regulatory Proposals, and future works programs outlined in this report.

Since this research we have undertaken another Queensland Household Energy Survey. Funded by Energex and Ergon Energy in conjunction with Powerlink Queensland, this independent 2018 survey captured feedback from almost 5,000 Queensland households towards understanding a variety of topics including a focus on energy use through air conditioning and other electrical appliances, energy efficiency behaviours, and emerging customer technologies. This survey also examined overall attitudes to electricity prices allowing us to plan and deliver our network services and products more efficiently as well as benchmark network forecasting against consumer trends.

3.3 What we have heard

Through all our engagement activities we continue to hear these messages:

- Safety should never be compromised – and it is an area where we could be smarter
- Electricity affordability remains the core overriding concern for many – both from a cost of living and a business competitiveness perspective
- At the same time, it is clear our communities value how we go about keeping the lights on, especially in responding to restore services after severe weather events
- Our customers are also telling us that they want greater choice and control around their energy solutions, with a strong interest in sustainability and renewable energy across the community.

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.

Our customers expressed an expectation that we continue to adopt technology and process improvements to look for smarter ways to deliver improved safety outcomes. Community education on electrical safety awareness was also seen as important, especially around natural disasters.

69%*

support investment in the technology to automatically monitor for fallen powerlines

* Kantar and PwC research.
Q: When a powerline is brought down through a localised event we may not know this outage exists until a customer contacts us to report the outage. Investments could be made in the network which would ensure we're automatically notified of the outages (improving safety and response times). Would you support this investment in the network if it cost customers an average of $1 per quarter?

3.3.2 More Affordable Electricity

Pricing

Electricity affordability remains the core concern for many of our customers, both from a cost of living and a business competitiveness perspective. Rising electricity costs over the past few years have had a detrimental effect on the value our customers place on the service we deliver. For some, distribution network charges have lifted expectations around the supply and service experience we should be able to deliver. The desire for greater control, in order to manage or moderate their bill, is behind much of the disruption across the industry.

41%*

are highly concerned about their ability to pay the electricity bill.

21% are not significantly concerned.

* Future Energy Survey.
Q: How concerned are you personally about your ability to pay your electricity bill?
High concern = 8, 9 and 10 out of 10.
Not significantly concerned = 1, 2, and 3.
'Don't know' excluded.

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

Network Tariffs

Our customers are looking for network tariffs that offer simplicity, savings, value and choice, and that reward them for their role in energy transformation. Many recognise that network tariff reform is needed to respond to the changes in the market and deliver sustainable charges for the future.

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

51%*

are willing to reduce their electricity usage in peak times for a saving of 5% on their quarterly electricity bill.
This increases to 78% with a 20% saving.

* Kantar and PwC research.
Q: Would you reduce your electricity usage in peak times (4pm-9pm in summer) for a saving on your quarterly electricity bill?

Fairness

Customers expect us to ensure equity of access to electricity, and the ‘collective good’. It is clear that we have a corporate responsibility in providing an essential service to do all we can to address electricity affordability, and to deliver to all Queenslanders whether ‘coast or bush’.

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

From a network tariff perspective, being ‘fair and equitable’ is both about minimising cross subsidies and managing the social and economic impact of any move to more cost reflective pricing.

There is also a need for a trusted advisor to provide independent impartial advice, and to help make informed choices in energy use and behaviours.

3.3.3 A Secure Supply – Keeping the lights on

Emergency Response

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

Reliability

Our communities value having a reliable and consistent electricity supply and particularly appreciate our ability to quickly and safely restore services after weather events. Most of our customers are satisfied with the current reliability standards delivered through our networks and do not value higher reliability. However, some customers, especially those in the more rural and remote areas of our networks, consider they are poorly serviced.

> **83%***
>
> **are satisfied with the overall reliability or quality of their power supply.**
>
> Consistant with our tracking research.
>
> * Future Energy Survey.
> Q: Would you (residential) prefer to be billed with a fixed plan (or largely fixed and only pay more for use above plan), like a phone or internet plan, or keep your bill as it is now with it going up and down based on how much electricity you use

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

Customer Experience

Expectations around customer experience are shifting, and generally increasing, especially around notifications around issues such as power outages. Several customers cited that information about outages and restoration times was just as important as preventing the initial outage. We need to provide this information in ways that work for all our communities.

We heard support for 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 concern around potential business and service disruption.

3.3.4 A Sustainable Future

Network as an Enabler

The way our customers source and use energy, and monitor their energy needs, are rapidly changing. As new technologies are embraced to manage energy use and costs, and to support action on climate change the industry is transforming.

Our customers recognise that new technology is important to a modern network and support initiatives that enable their choices and reduce costs. Our customers expect us to be able to facilitate and accommodate integration of renewables, battery storage and electric vehicles into the network, without creating risks to network security, supply quality or performance.

> **87%***
>
> **said it was important that we modernise our electricity networks to continue to enable customers to take up new technologies.**
>
> * Future Energy Survey.
> Q: How important is it that we modernise our electricity networks to continue to enable customers to take up new technologies? 'Don't know' excluded.

Our most recent insights in this area are from the Queensland Household Energy Survey. This report provides insights into the steady growth in the solar energy and battery storage markets. Almost a third of households currently have a long-term goal to install battery storage in the next ten years (30%).

Safety, reliability and convenience along with high feed in tariffs are the main factors that will keep households connected to the grid. Households that are most likely to take up new or disruptive technologies tend to be younger, highly educated and on a high income, with a family in newly built homes. Electric vehicles continue to be purchased at a steady rate, with the optimal price and range $50,000 with up to 500km on a single charge. Greater charging infrastructure will have a very large impact on the uptake of electric vehicles.

There are over 550,000 solar energy systems connected to our networks across the state. During 2018-19, we managed an unprecedented level of applications for the connection of large-scale energy systems, and an increasing uptake of the connection of small-scale roof top systems. At the same time, volume of batteries integrated with the grid in Queensland received a significant boost from the Queensland Government's 'Interest-free loans for solar and storage', and the take up of electric vehicles is also set for further growth with new battery EV models being released to 3,000 vehicles by the end of 2019 with expectation of this trajectory to continue.

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

They also expect us to support them to save energy and to work with them to shift demand in order to avoid building expensive new networks. Most of our councils want to transition to light emitting diodes (LED) public lighting. Our customers are concerned with our ability to 'predict the future' given the level of change and potential impacts on the grid combined with our long-life asset profile.

Collaboration

Our communities, and our many different stakeholders, expect us to engage with them in a transparent, meaningful manner and on a regular basis. They want us to listen and act on their feedback as well as show how their feedback has informed our decisions.

There is a strong desire from customers to work with us to ensure that the community benefits from today and tomorrow's emerging technologies, and to realise the network value in the energy transformation. Education is seen as important. Customers need to be informed to take advantage of emerging technologies and participate in the market. Vulnerable customers must not be left behind – providing access to information is important to removing barriers to participation.

69%*

would, if they had a battery energy storage system, allow us to access it to better manage loads on the network. However, most would require a reward or credit on their bill

* Kantar and PwC research.
Q: Renewable energy, such as solar, can cause challenges for the electricity network if there is an oversupply of energy being generated. This oversupply of energy can impact the quality of supply for customers within the local network, and impact the overall cost of electricity for everyone. One solution to overcome this challenge is for us to have some level of control over customer's new solar panels or battery storage systems. This would enable more solar panels and battery storage to connect to the network; with less impacts on electricity supply or price. If you had a battery storage system, electric vehicle or solar panels in your household/business in the future, would you consider allowing us to access this (together with batteries/solar from other households/businesses) to better manage loads on the network?

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

This collaboration is being outworked by Ergon Energy and Energex's Demand Side Engagement Strategy, which seeks to inform and include customer and non-network service provider participation to address any limitations in their distribution networks. Here we have a variety of facilities in 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, and for continued equitable support of embedded generator connections. Network connections need to be timely, simpler and cost-reflective – there remains support for our efforts to align our service offering across Queensland. Customers also expect that we adapt to their changing preferences on connecting to our network.

3.4 Our Customer Commitments

As part of our planning and decision-making process for our Regulatory Proposals, we have formally responded to the above feedback and the other customer insights we gained through our engagement with a set of commitments to our communities and customers for 2020 and beyond. These commitments are continuing to prioritise our investment plans, including the strategies and specific investments reflected in this report.

The following page outlines Ergon Energy's commitment to their customers.

OUR **CUSTOMER COMMITMENTS**

SAFETY FIRST

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

AFFORDABLE

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

PRICING

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

NETWORK TARIFFS

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

FAIRNESS

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

SECURE

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

EMERGENCY RESPONSE

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

RELIABILITY

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

SERVICE PROMISE

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

SUSTAINABLE

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

NETWORK AS AN ENABLER

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

COLLABORATION

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

CONNECTIONS

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

Chapter 4

Asset Management

4. Asset Management Overview

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

This section provides an overview of Ergon Energy's:

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

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).

4.2 Asset Management Policy

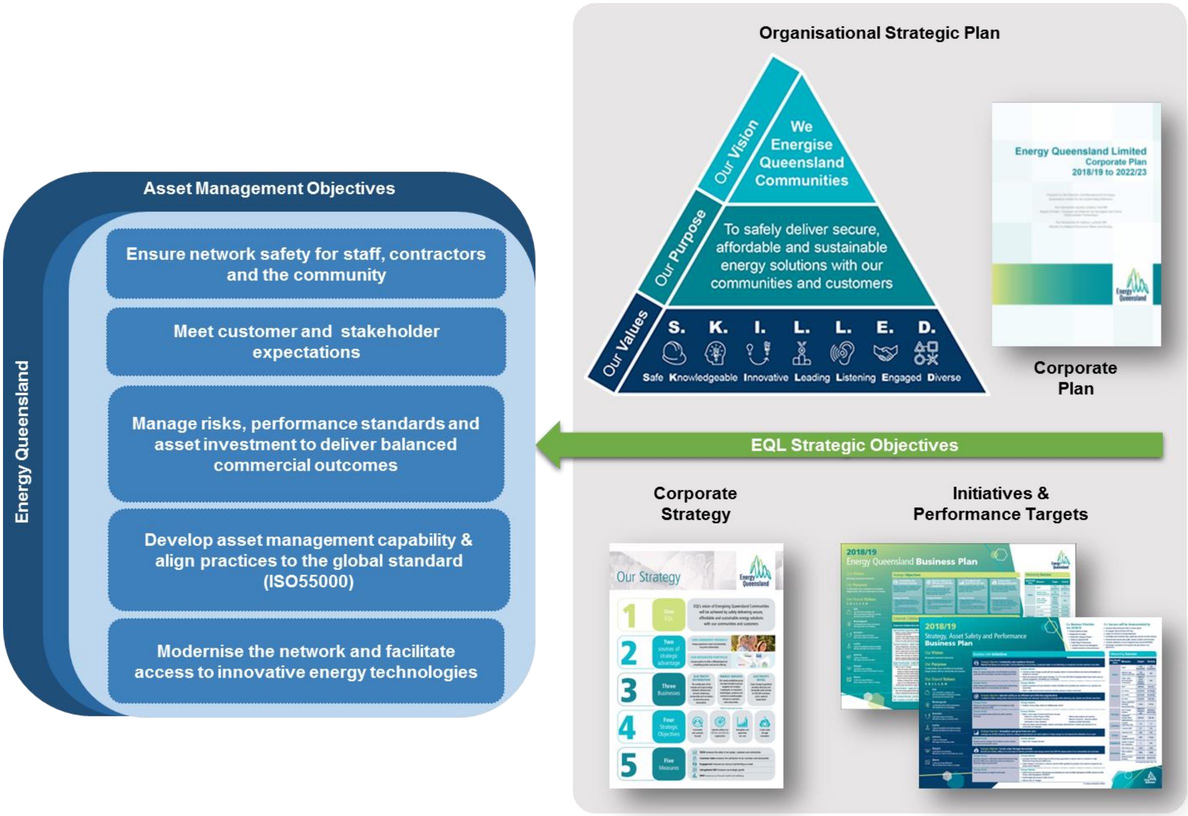
The Asset Management Policy provides the direction and broad framework for the content and implementation of Ergon Energy's asset management objectives, strategies and plans. The policy directs us to undertake requirements associated with safety, people and meeting customer needs. It describes the commitment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

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 7. 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 7: The SAMP translates Corporate Objectives to Asset Management Objectives



4.4 Investment Process

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 8.

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 8: Program of Work Governance

The four tiers include:

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

4.5 Further Information

Further information on our network management is available on the Ergon Energy website on the following link:

https://www.ergon.com.au/network/our-network

Chapter 5

Network Forecasting

5. Network Forecasting

Forecasting is a critical element of our network planning and has become a difficult and complex task. However, it is essential to the planning and development of the electricity supply network because it is the growth in peak demand and the expansion of the network into new areas, at the local and regional level, that is the key driver of investment decisions leading to augmentation of the network.

Ergon Energy has adopted a detailed and mathematically rigorous approach to forecasting network extensions, electricity delivered (energy), peak demand, and customer numbers. The methods used are described in the following sections. Audits are regularly undertaken by external forecasting specialists on Ergon Energy's forecasting models. These models continue to improve in their demand and energy forecasting methodologies.

Ten-year energy forecasts are prepared at the total system level, at customer category levels and for certain individual network tariffs. These forecasts are used to determine annual network losses and to establish network tariff prices. The energy forecasts 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.

In relation to demand, forecasts are not only undertaken at the total system level but are also calculated for all substations and feeders covering a period of at least 10 years. As growth in peak demand is not uniform across the state, these localised forecasts are used to identify emerging network limitations and risks that need to be addressed by either supply side or customer-based solutions. The forecasts then guide the timing and scope of capital expenditure (to expand or enhance the network), or the timing required for demand reduction strategies to be established, or for risk management plans to be put in place.

5.1 Forecasting Assumptions

There are a number of factors which influence forecasts of peak demand, energy, and customer numbers. Assumptions used in the development of the demand and energy models are discussed in the following sections.

5.1.1 Customer Behaviour

Customer behaviour is a major driver of peak demand and energy forecasts. There are several indicators of customer behaviour, including customer take-up of solar PV and/or battery storage, take-up of energy efficient appliances, the impact of higher electricity prices on customer response and the choices customers make about their use of electricity.

Customer behaviour is challenging to model as it can vary substantially between customer groups and from year to year. The acceptance and impact of solar PV has become clear in recent years but there is currently too little take-up of other enabling or disruptive technologies such as battery storage and electric vehicles to allow more definitive modelling of impacts on peak demand and energy. Both these examples are expected to be significant, but the timelines are little more than speculative.

5.1.2 Solar PV Systems

System types

There are two broad types of solar PV system – the small rooftop type installed by home-owners and small-to-medium commercial business owners, and the large utility-scale solar farm that acts in the similar way as a traditional electricity power generation.

Small-scale systems are referred to as Micro Embedded Generation Units (MEGUs) and have capacities no greater than 30kVA. These are designed to generate energy for use primarily within the home with any excess energy exported to the local electricity grid for use by other customers. Commercial-scale installations are larger versions of this, and in some cases consume all generated energy onsite with no export to the grid. Utility-scale solar farms are designed to act as generating stations and are located as near as possible to high-voltage transmission lines and/or zone substations for best connections. There is another form of solar generation called solar thermal which is starting to be approved and constructed. It will perform a major role in the future due to its suitability for integrated energy storage, allowing the entire installation to operate as a baseload generator.

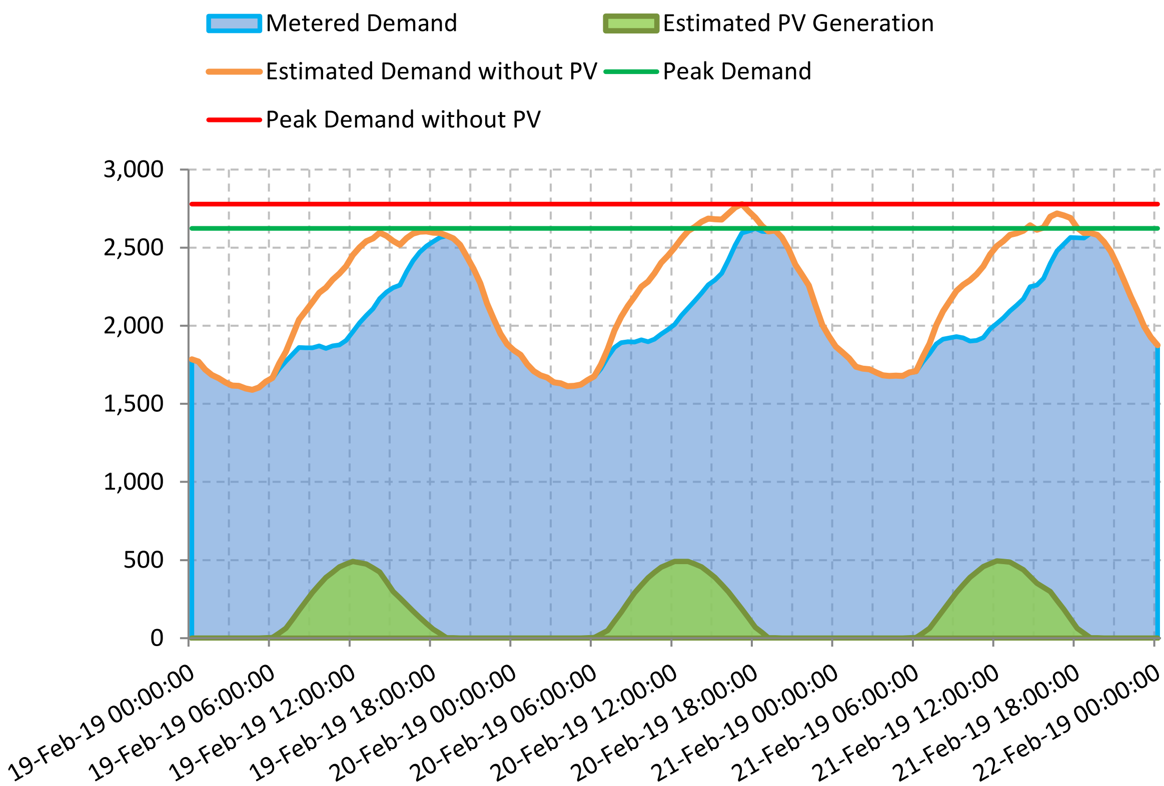
Status

Connected solar PV capacity continues to grow. Solar MEGUs are now increasing at an average of 1,400 per month. At 30th June 2019, there were 160,166 solar PV systems connected with total inverter capacity of 1240MVA. In terms of all residential customers, the take-up rate is 23%.

The cumulative solar PV generating capacity has resulted in daily load profiles with a ‘hollowed out’ pattern shown in Figure 9. This has reduced afternoon peak demand in a number of areas, some significantly. It can be seen that without solar PV generation, the time of peak would have been earlier and the level higher than the peak that remained in early evening at a lower level. The graph shows that, as solar generation wanes to zero from late afternoon into evening, the remaining demand becomes the *de facto* peak demand for the day, due to the real afternoon peak demand in actual energy having been reduced. This effect is often poorly explained as ‘solar PV having no effect on evening peaks’ when in fact, the evening peaks are what remain after higher afternoon peaks have been reduced by solar PV generation.

The 2018-19 summer system peak occurred at 6:00pm on 20th February 2019. The difference between the peak estimated *without* any reduction by solar PV generation, and the actual metered peak remaining *after* reduction by solar PV was 156MW. As can be seen in Figure 9, solar PV generation resulted in a lower peak demand than would have occurred without its effect.

Figure 9: System Demand- Solar PV Impact, 19-21 February 2019



Forecasting

Solar PV's impact on system peak demand is modelled separately by estimating and removing its historical impact, forecasting its future impact, and re-incorporating it into the overall system forecast.

However, while embedded rooftop solar PV affects peak demand at a system level, we cannot take advantage of this to reduce augmentation expenditure. This is largely due to the variable nature of solar PV demand reduction on a daily or year-to-year basis. Additionally, for solar PV generation to defer augmentation expenditure on a substation, the zone substation must consistently have peaks during daylight hours, and a growing load rated at peak demand that reaches the substation rated capacity. Although no zone substations have experienced this effect to date, they are continually reviewed to address this possible effect.

Benefits of energy storage

The growing number of solar PV installations located on commercial and industrial buildings will provide a greater benefit as the summer daytime peak demand coincides with peak solar generation. This is likely to keep rising due to the Queensland Government's aspirational target of having the equivalent of one million rooftops or 3,000MW of solar generation installed by 2020.

5.1.3 Electric Vehicles

The take-up of Electric Vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) has the potential to increase energy and demand forecasts in the future. Currently, the take-up rate of EVs and PHEVs has not been high due to a combination of factors including the high initial cost and low availability of models and therefore the impact factored into the System Demand forecast has been relatively small. It is expected that the major part of the take-up will be in South East Queensland. The estimated impact of plug-in EVs has been included in the latest forecast for residential zone substations.

5.1.4 Energy (battery) Storage

Customer interest in energy storage systems (batteries of various kinds) is increasing with the number of known systems in the Ergon Energy network being approximately 1,890 (May 2019). Over the next five to ten years this is likely to change due to several factors: price reductions, new technology (safer, higher energy densities, larger capacities), and package-deals with solar PV expected by major retailers and solar PV installers. Ergon Energy has adopted a slow but steady reduction in peak demand due to the use of energy storage. In the base case scenario forecasts for residential zone substations, forecasting assessments consider the peak day profile customer, commercial and industrial usage patterns. These assumptions however, will be refined over time as more customers adopt storage systems and information on their reliance on the network becomes available.

The effect of energy storage on customer energy consumption is ‘behind the meter’, meaning that it cannot be directly measured for forecasting. The recently developed DER Register will provide a regulated repository of installed energy storage systems.

5.1.5 Temperature Sensitive Load

Temperature sensitive loads from electrical appliances including air conditioning and refrigeration drive peak demand on the network. On particularly hot days, these loads can add significantly to levels of energy consumption and more importantly peak demand.

Population drivers have replaced air conditioning in forecasting reviews for representing broader electrical appliance use as the effects of air conditioner load uptake has become saturated.

The modelling process in forecasting also requires weather time series information to correlate daily movements in system maximum demand to weather variations. Daily minimum and maximum temperature records are employed in the methodology as part of regression modelling and relates weather drivers to the system maximum demand. Long-run weather series are also utilised to derive the 10% Probability of Exceedance (10PoE) and 50 PoE demand figures.

Weather time series are obtained from the Bureau of Meteorology (BOM) and require a 50-year history. As not all BOM weather stations have an available 50yr of reliable historical data this has restricted our understanding and forecasting of energy demand. Weather data series utilised for the system regional maximum demand model is based on a selection of weather data[11] from six weather station locations:

- Cairns
- Townsville
- Mackay
- Rockhampton
- Maryborough
- Amberley.

Amberley weather station is sourced due to its suitability to represent the South-Western region of Ergon Energy's distribution area. Other available weather stations either did not have the necessary consistent history or presented a substantial number of missing values.

In order to calibrate the models using daily maximum demand data, values for missing observations were imputed by either substituting data from a nearby weather station or by utilising linear regression of temperature against time. The choice of reliable weather data meant this imputation process involved only a small number of adjustments.

Other purposes for weather data

Weather data used for temperature correction of individual zone substation forecasts was sourced in a similar manner from the BOM (Bureau of Meteorology), but the weather station selected for any given zone substation was the one with reliable weather data closest to that substation.

5.1.6 Economic Growth

A further major driver of forecasts is the level of economic growth across the state as measured by the Gross State Product (GSP). It can be seen from Figure 10 that the Queensland's economy declined after the high of 5.5% in the 2011-12 financial year, with growth rates dropping to a low of 1.0% in 2014-15 before a resurgence to 3.4% in 2017-18. While this was still below the long-term average of 4.1%, it was boosted by the improvements in both the private (e.g. mining) and government investment as well as rises in global commodity prices, however household spending has remained subdued.

Looking forward, external sources have forecast that the Queensland economy might slow to a growth range between 2.1% to 2.3% over the next two years, largely driven by completion of the mega-construction projects in liquid natural gas (LNG), slowing job growth, weak wage gains and soft house prices. In the longer term, there is considerable divergence in forecasts around the strength of the state economy. However, the underlying economic conditions remain solid with business activity boosted by the lower value of the Australian dollar and low interest rates. Figure 10

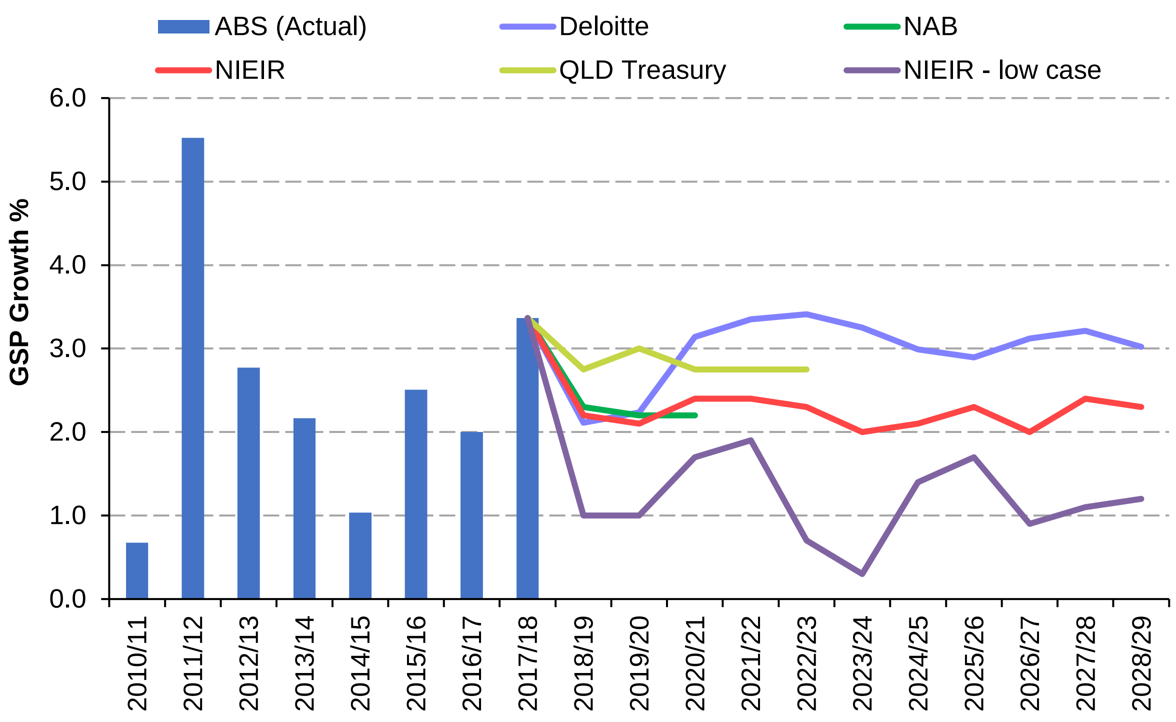
[11] This reduced set of possible weather stations is a result from selecting all weather stations with available seasonal peak demand information together with data integrity.

shows the range of forecasts of Queensland Gross State Product (GSP) developed by a range of forecasting organisations including the National Institute of Economic and Industry Research (NIEIR), Deloitte Access Economics (DAE), Queensland Treasury, and National Australia Bank. The above organisations are considered independent and authoritative sources.

NIEIR and DAE (the only ten-year Queensland forecasts available to Ergon Energy) have forecasts that sit apart by roughly 1%, DAE being the more optimistic. However, Ergon Energy has used NIEIR's figures currently (in the range of 2.0% to 2.4% per annum), and in the future, forecasts from DAE will be used at a more local level for economic growth in the peak demand forecast model.

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

Figure 10: Queensland GSP Growth Forecasts



Note: Economic data was sourced from ABS, Deloitte, NIEIR, Queensland Treasury and St George Bank.

5.1.7 Population Growth

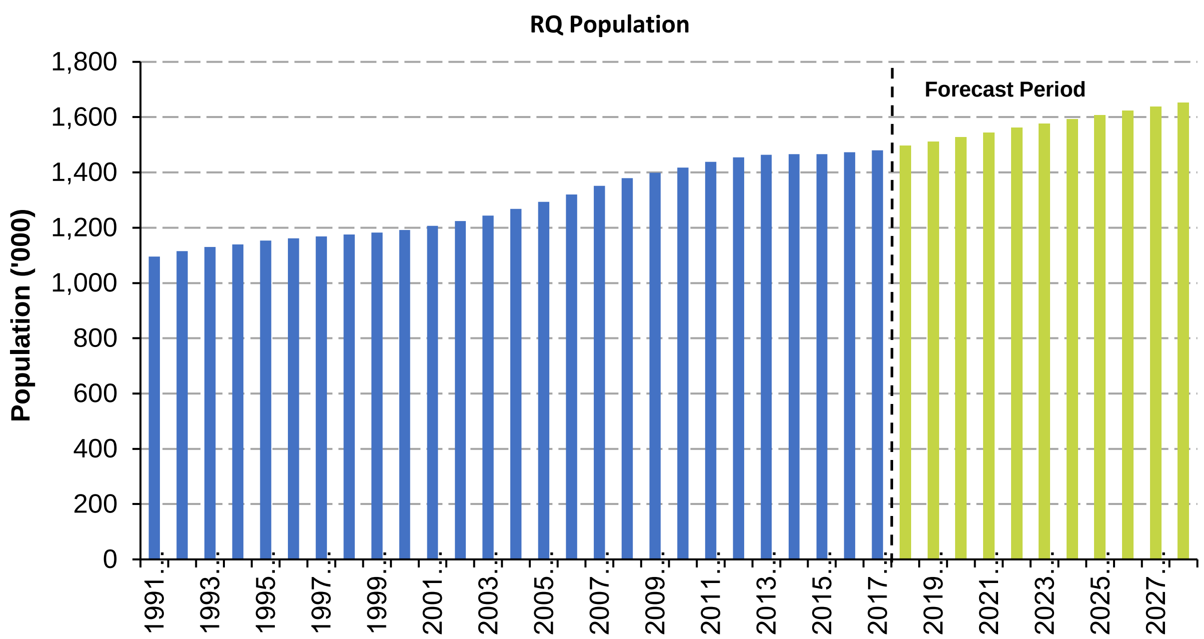
Another driver of forecasts, closely tied to economic growth, is population growth, which is aligned with electrical appliances growth. Queensland population growth has been subdued for the past three years as a direct result of the economic slowdown and reduced employment opportunities. For example;

Queensland's population increased by 1.4% in 2015-16, 1.6% in 2016-17 and 1.7% in 2017-18. In 2018, Net Overseas Migration (NOM) increased by 28,670 from that of the previous year and Net Interstate Migration (NIM) similarly increased by 24,700.

In terms of future population movements, the main economic institutions, such as NIEIR, the Queensland Government Statistician's Office (QGSO) and DAE, all project that population growth is expected to increase over the next few years, boosted by an expected rebound in the state economy (which in turn will attract more inter-state migration and overseas migration) as well as a relatively competitive Australian currency (which in turn, will attract more overseas students and tourist arrivals). Accordingly, Queensland population growth is expected to increase to 1.5% in the 2019-20 and more or less, stabilise at over the following eight financial years.

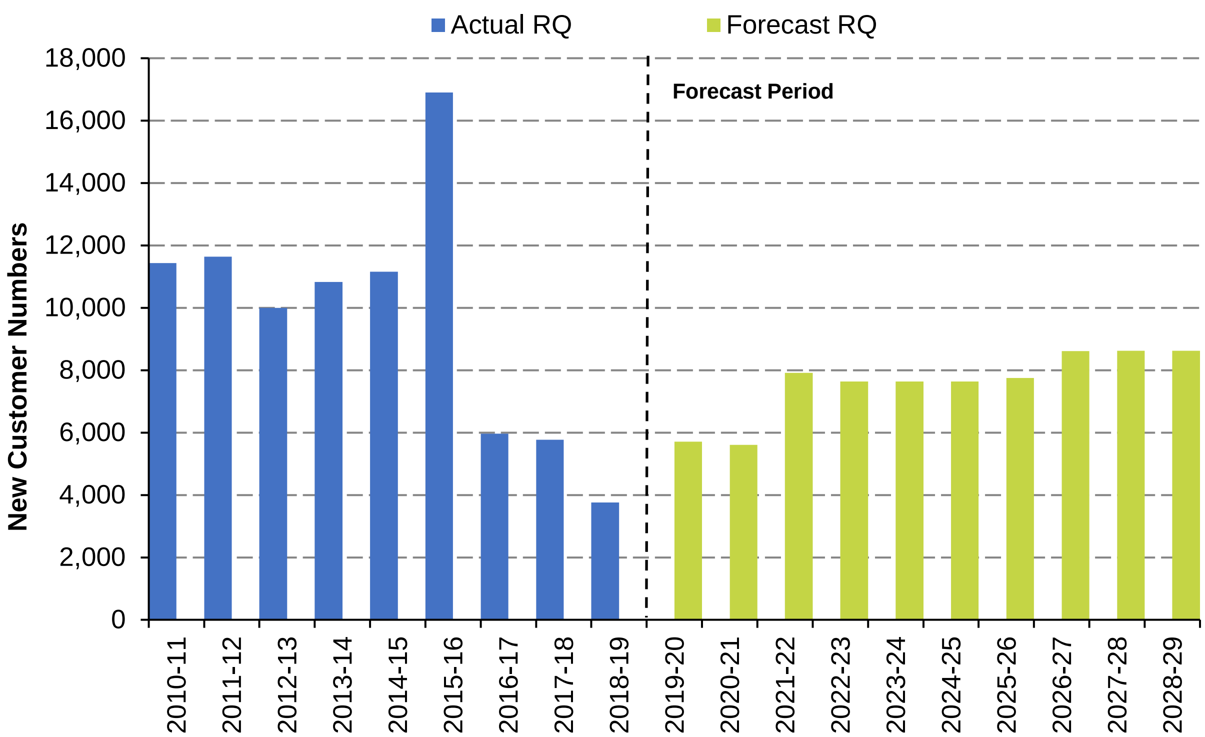
The majority of the Queensland population growth will occur in South East Queensland (with 68.8% of state population as at the end of June 2016). However, in Rockhampton and Townsville a negative migration was recorded for both cities. A summary of projected population is shown in Figure 11 below.

Figure 11: Regional Queensland Population Projections



In summary, population growth in Queensland will start to regain momentum over the next few years and consequently, customer numbers are expected to increase at a steady rate over the next ten years. Figure 12 illustrates the forecasted total new customer numbers to June 2026.

Figure 12: New Metered Customer Number Growth



5.2 Electricity Delivered Forecasts

Ten-year electricity delivered forecasts are prepared once each year using the latest electricity delivered figures, economic, demographic and weather data. The forecasts are based on customer categories and disaggregated into two major groups: residential and non-residential. Non-residential includes Standard Asset Customer – Large (SAC Large), Individually Calculated Customers (ICC), Connection Asset Customers (CAC), streetlighting and unmetered. The forecasts are used to review and develop network prices for both Ergon Energy and Powerlink networks.

5.2.1 Electricity Delivered versus Electricity Consumed

Electricity energy delivered represents the amount of electricity transported through the network and measured by meters at the premise. Electricity consumed is the amount of electricity used by customers within their premises can include electricity supplied by other resources, such as solar PV generation.

Solar PV has, and will continue to have, a significant impact on electricity delivered because consumers can use this alternative energy resource to partly (or wholly) offset the amount of electricity delivered by the network. However, it often has little impact on households' total electricity consumption, since consumption is largely determined by different drivers such as household income, electricity prices and seasonal temperatures – rather than by different supply sources.

The number of solar PV connections increased strongly over the 2009-10 to 2012-13 period, driven by escalation of electricity prices, solar feed-in-tariffs, environment issues and price reductions in solar panels. However, the growth rate has steadied with the removal of the subsidies offered by the Australian Government and the policy change of the feed-in-tariff at the state level and the market then matured. Looking ahead, new solar PV connections, as shown in Figure 13, are expected to continue to increase steadily. It is also worth noting that the capacity (kW) per new installation keeps rising mainly due to cheaper solar panel unit prices. In addition, new non-domestic installation numbers, along with their capacity sizes, will continue to increase as firms offset their electricity. The Queensland Government has a keen focus on renewables with a number of initiatives underway with an aspirational target of 3,000MW of solar PV installed by 2020, and Solar 150, which has a focus on encouraging new large-scale renewable energy projects in Queensland.

Figure 13: Number of MEGU-Class Solar PV Connections

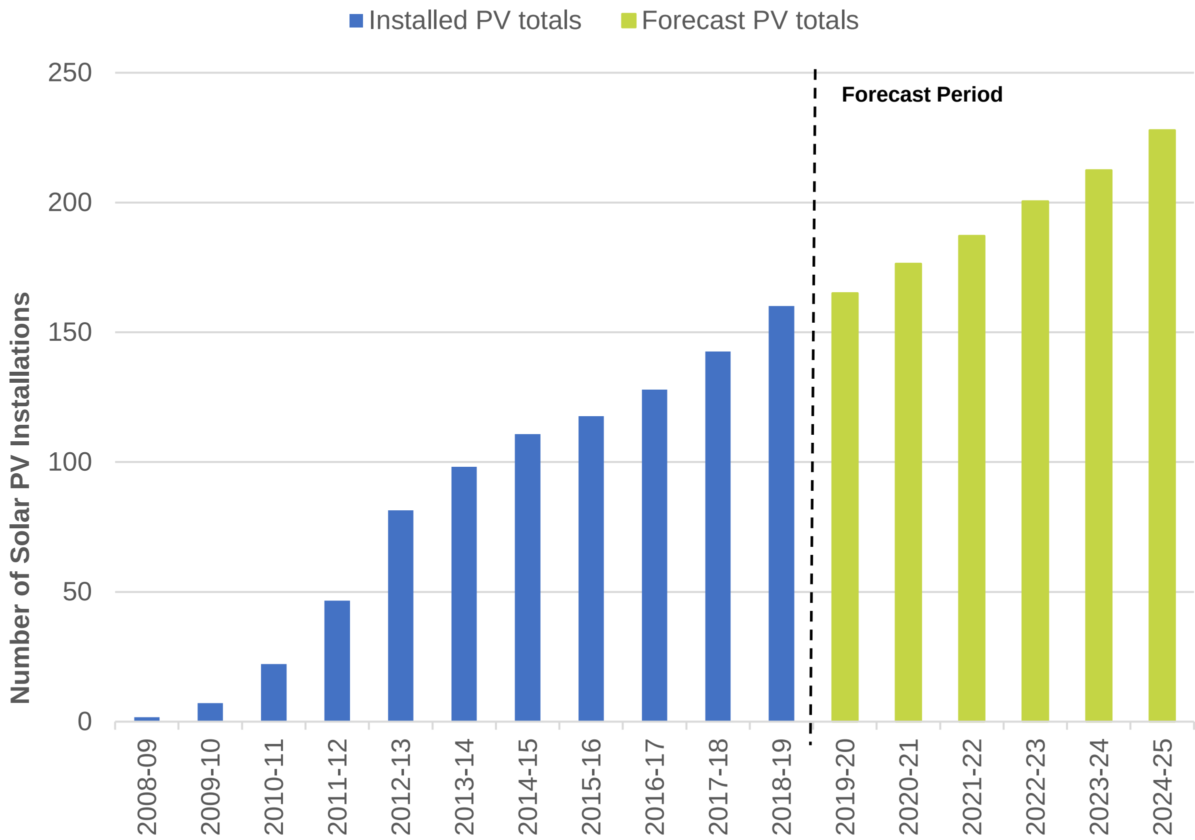
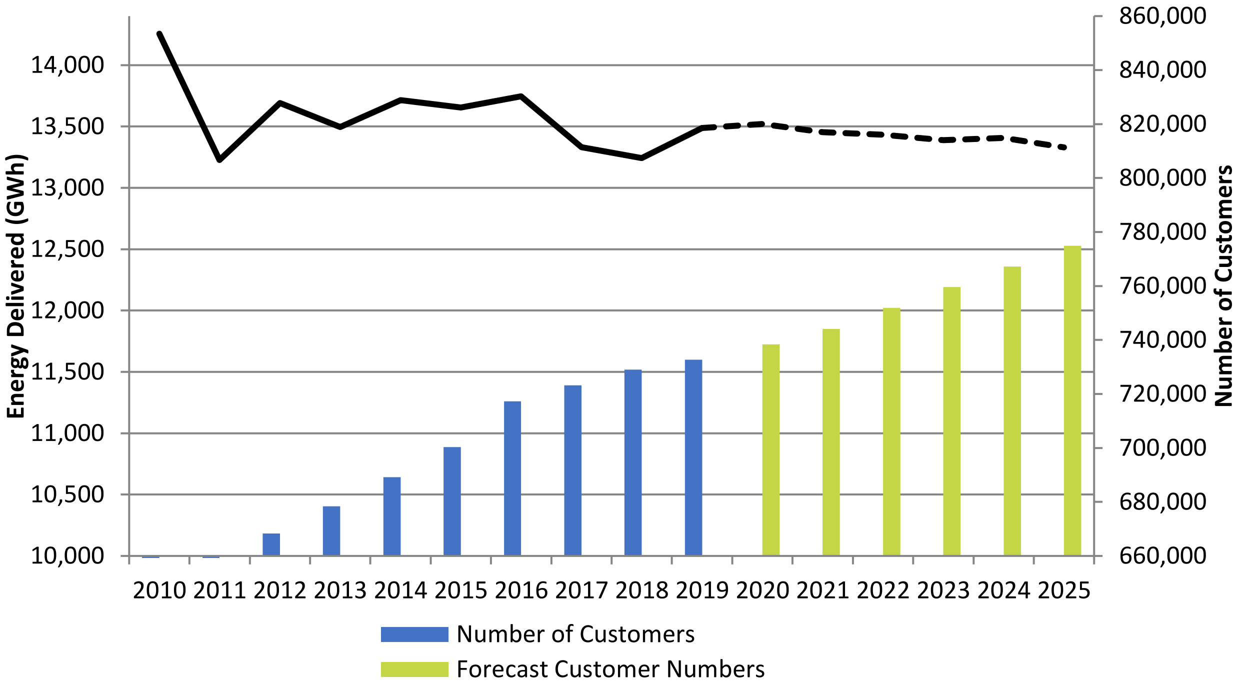


Figure 14 shows the number of customers (excluding de-energised customers and single customers with multiple tariffs) and energy delivered. While electricity delivered is expected to be flat over the next four years, electricity consumption (i.e. electricity delivered plus electricity generated and used internally) while stabilising from some volatility and will begin to increase, propelled by the expanding population base and the 'plateau effect' in energy efficiency improvements in key electrical appliances. Electricity delivered for the 2016-17 year was 13,332GWh, which was 0.3% below 2015-16.

Figure 14: Number of Customers and Energy Delivered



5.2.2 Electricity Delivered Forecast Methodology

The adopted approach for forecasting electricity delivered is a combination of statistically based time series analysis and multi-factor regression analysis. Regression models and consultant reviews are used to substantiate the forecasts, which are separately formulated for each of the following categories:

Regional Queensland service area categories
• Residential
• Commercial
• Industrial
• Rural
• Network tariff classes

For each of the categories listed above, forecasts are produced for the total customer numbers and the amount of electricity usage per connection or customer. The forecasts of customer numbers and average usage per customer are then multiplied together to obtain total electricity consumption for each segment. Total system electricity delivered is the summation of each of the components. This is a market category or bottom-up approach and provides a reasonable basis for constructing forecasts for total system electricity use.

Each category is affected by different underlying drivers for growth. For example, population and income growth are generally of greater significance in driving electricity use in the residential category, whereas GSP growth is more important in the commercial category. Given these sensitivities, Ergon Energy treats the different categories independently, rather than taking a more generalised approach that results in some loss of useful information. This methodology results in a more robust forecast.

Ergon Energy uses electricity delivered forecasts based on network tariff classes to assist with electricity pricing decisions. This approach follows a similar methodology where average consumption is modelled and multiplied by the number of customers with that tariff. It uses multiple regression techniques. The advantage of this approach is that weather, pricing and solar PV information drivers can be modelled separately giving greater insight into electricity delivered.

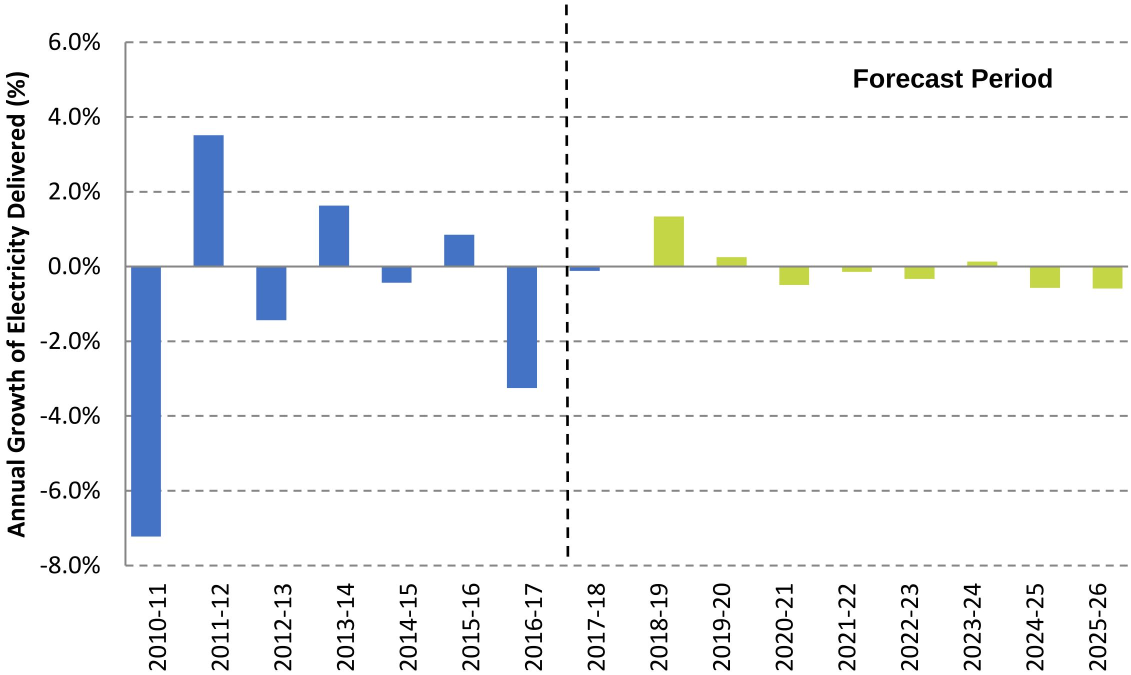
In addition, Ergon Energy has also developed an econometric electricity purchases model that is used at a total system level. This forecast is used to review and compare the bottom-up electricity delivered forecast after accounting for network losses.

5.2.3 Electricity Delivered History and Forecast

In general, growth in electricity consumption lags demographic changes and economic activity by about 9-12 months. A large decrease in electricity delivered occurred in 2010-11. During the six years from 2011-12 to 2016-17 and grew by 0.2% as shown in Figure 15.

Looking ahead, electricity delivered is expected to be similarly flat over the next ten years to 2025-26, with no annual average growth. This is likely the result of solar PV installations and the continued reduction of some industrial businesses. Even though the population shows an increase, the electricity delivered per customer is slightly declining in the forecast years, resulting in energy delivered across all customers remaining flat. However, the most likely change might come from a rebound in regional population growth. In the medium-to-long-term, however downward pressures will weigh on electricity delivered as new technologies, especially battery storage (which normally links to solar PV installation) will provide an alternative source for customers to partly bypass distributed electricity. Over the longer term, electricity delivered growth will also be tempered by reductions in consumption for low income households due to higher electricity prices but should be partly countered by the potential increase in EV sales, albeit at a slower rate than the South East of the state.

Figure 15: Growth of Total Electricity Delivered



The increase in embedded generation of electricity by solar PV has had a two-fold effect on electricity consumption. Although solar PV does not decrease consumption directly, it may have an impact on electricity usage as customers become more conscious of their consumption patterns, especially for those solar PV customers who lost the benefit of the 44 cents feed-in tariff. Conversely, it does directly affect electricity delivered from the network. Customers can reduce their purchases of electricity by using output generated directly in-house. As detailed in Section 5.1.2, solar PV output obviously occurs during daylight hours, automatically reducing electricity consumption during the middle period of the day but waning in late afternoon. This reduces the load factor, and results in a new, generally lower peak demand for domestic customers that occurs in the early evening, which is the remnant level of demand after reduction of the afternoon peak.

In addition, economic growth is a major driver of electricity consumption. As noted earlier, there are a range of views regarding forecasts of Queensland GSP growth. In summary, while Queensland GSP increased by 2.0% in 2016-17, and 3.4% in 2017-18, it is expected to drop to 2.2% in the year 2018-19 respectively, based on NIEIR's latest forecasts. GSP figures are a key input into the forecasting process.

All of these factors have been modelled in determining a view on future delivery of electricity. Based on these changing inputs, it is anticipated that electricity delivered will increase marginally with an expected average annual growth rate of 0.2% over the next ten-year period.

The contribution of solar PV is included in both residential and non-residential electricity delivered forecasts. Electricity generated by solar PV but used internally, is estimated, and when combined with electricity delivered from the network – is the total electricity consumption. Excess solar PV generation exported to the network is included in total electricity purchases. The solar PV forecast shows an ongoing solid rate of growth.

Forecasts for non-residential consumption growth are related to expected changes in GSP and the trend in changing average consumption.

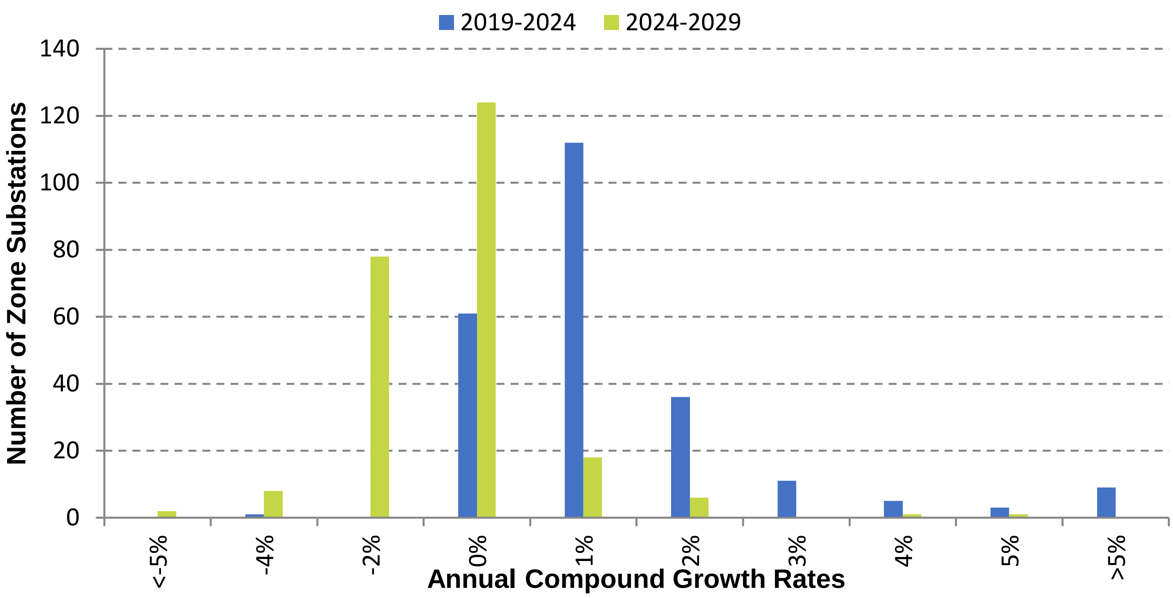
5.3 Substation and Feeder Maximum Demand Forecasts

To ensure security and reliability of supply, capital investment in the distribution network is necessary when growth in demand for electricity creates emerging limitations at substations and on feeders. 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 subtransmission and distribution networks. For consistency, the system level peak demand forecast is reconciled with the bottom-up substation peak demand forecast after allowances for network losses and diversity of peak loads. Importantly, no distribution network investment is directly driven by the total system peak demand.

Hence individual substation and feeder maximum demand forecasts are prepared to analyse and address limitations for prudent investment decisions. Customer reaction to recent electricity price increases, and the fall in prices for solar PV, has contributed to a reduced customer load at temperature-corrected conditions, well below long-term average trends. The take-up of solar PV continues as customers consciously attempt to minimise their electricity costs and energy consumption, however over the long term this will expect to be inelastic. Customer behaviour drivers are currently being incorporated into models used for system and substation demand forecasting.

Balanced against this general customer trend, the forecasts produced post-summer 2018-19 have provided a range of demand growth rates. The forecasts are used to identify network limitations and then investigate the most cost-effective solution which may include increased capacity, load transfers or demand management alternatives. The distribution of growth rates for zone substations are shown in Figure 16.

Figure 16: Zone Substation Growth Distribution 2018-28



While growth in demand continues to increase very slowly at a system level, there can be significant growth at a localised substation level.

In the 2019-24 period, 52% of substations have an average compound growth rate of between 0-2%, 8% have between 1% to 2% growth and 3% have more than 2% growth.

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 through efficiency and power factor improvements. 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 E and Appendix F 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: ABS data, Queensland Government data, Australian Energy Market Operator (AEMO) data, an independently produced Queensland air conditioning forecast, solar PV connection data, historical peak demand data, and through regional, local demographic and economic behaviour as provided by consultancy models.

Output from solar PV is generally coincident with Commercial and Industrial (C&I) peak demand. Although there are limited numbers installed at this time, increasing penetration of solar PV 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. It is misleading to refer to this as 'shifting the peak to the evening when solar PV has no effect' – the peak that occurs in the evening is directly due to solar generation having 'clipped' the afternoon peak. The result is generally a lower peak demand.

5.3.1 Substation Forecasting Methodology

Ergon Energy employs a bottom-up approach reconciled to a top-down evaluation, to develop the ten-year zone substation peak demand forecasts using validated historical peak demands and expected load growth based on demographic and appliance information. It also uses a feedback process with regional planning engineers (Delphi process) to review, discuss and agree upon growth rates and temperature-corrected starting points for the new forecast. This ensures the best forecast outcome using the local knowledge of planners in the absence of well-defined economic and demographic drivers, which are not available at the level of individual zone substations.

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

Zone substation forecasts are based on a probabilistic approach using a multiple regression estimation methodology. This approach has the advantage of incorporating uncertainty relating to weather events into the forecasting methodology.

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 regression for summer and winter going back as far as the limit of available data. Growth rates, load transfers and new major customer loads are then used to simulate the future load at each zone substation ten years in advance.

Larger block loads are included separately after validation for size and timing by asset managers. The zone substation peak demand forecasts are then aggregated up to the ten-year bulk supply point and transmission connection point demand forecasts, which take into account diversity of individual zone substation peak demands (coincidence factors) and network losses. This aggregated forecast is then reconciled with the independent system demand forecast and adjusted as required.

The process 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 period
- Minimum and maximum temperatures at five BOM weather stations are regressed against substation daily maximum demand to assess the impact of each set of weather data on substation demand. The best-fit relationship is used to determine the temperature adjustment
- Substations classified as industrial tend not to be as sensitive to temperature but are subject to other often undetermined factors including seasonal effects, response to economic market movements and accordingly the 50 PoE and 10 PoE adjustments are based on sets of business rules chosen to reflect these summed effects.
- Previous substation peak demand forecasts are reviewed against temperature-adjusted results and causes of forecast error are identified
- Starting values for apparent power (MVA), real power (MW) and reactive power (MVAr) are calculated for four periods
- Demographic and population analysis are undertaken, customer load profiles are prepared, and checks made against customer connections and changes in population across the different regions
- Expected impact and growth in solar PV, battery storage, and plug-in EVs have been included at the substation level.
- Year-on-year peak demand growth rates are determined from the customer load profiles, growth trends derived from population forecasts and local knowledge from asset managers using a panel review (Delphi) process
- Size and timing of new block loads are reviewed and validated with the asset managers before inclusion in the forecast
- Size and timing of load transfers are also reviewed with asset managers before inclusion in the forecast
- Timing and scope of proposed transmission connection projects are reviewed before inclusion in the forecast
- The growth rates, block loads, transfers and transmission projects are applied to the starting values to determine the forecast demand for each of the ten years starting from a coincident demand basis
- Zone substation forecast peak demands are aggregated up to transmission connection point demands through bulk supply substations using appropriate coincidence factors and losses
- Reconciliation of the total aggregated demand with the independently produced system demand forecast ensures consistency for the ten-year forecast period
- Substation peak demand forecasts are reviewed each season and compared with previous forecasts. The relative error between recorded demand and the forecast is investigated for the most recent season. The substation forecast modelling tool can differentiate between approved and proposed projects in the process. However, to comply with the NER, the forecasts provided in the DAPR include approved projects only.

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

- Network topology (source: corporate equipment register)
- Load history (source: corporate SCADA/metering database)
- Known future developments - new major customers or additional customer load (source: Major Customer Group database)
- Customer demographics, demand profile
- Temperature-corrected start values (calculated by SIFT forecasting system)
- Forecast growth rates for organic growth (calculated by SIFT forecasting system)
- System maximum demand forecasts.

5.3.2 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 and is uploaded with peak forecast loads at each bulk supply and connection point zone substation from SIFT.

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

5.3.3 Subtransmission Feeder Forecasting Methodology

Forecasts for subtransmission 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 subtransmission feeders in the network under a normal network configuration.

Modelling and simulation are used to produce forecasts for the subtransmission 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 subtransmission network and 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.

5.3.4 Distribution Feeder Forecasting Methodology

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

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

Filtering is performed to remove short-term effects or abnormal situations. An example could be that the feeder may have been operated abnormally for some time in order to supply other load during extended contingency conditions or during prolonged maintenance works. The additional load and demand would then have to be normalised out of the forecast in order to arrive at a baseline forecast.

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

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

5.4 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 subtransmission and distribution networks. For consistency and robustness, the system level peak demand forecast ('top-down') is reconciled with the substation peak demand forecast ('bottom-up') after allowances for network losses and diversity of peak loads.

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

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

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

In recent years, there has been considerable volatility in Queensland economic conditions, weather patterns and customer behaviour which have all affected total system peak demand. The influence of Queensland's economic growth has had a moderating impact on 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 for some regions as recent years including the 2019 North Queensland flood caused by the convergence of a monsoon and a slow moving tropical low resulting in a number of deaths. Queensland has also experienced extended hot conditions over the past several summer periods. Summer conditions in the last two years have produced new record high maximum demand figures.

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

5.4.1 System Demand Forecast Methodology

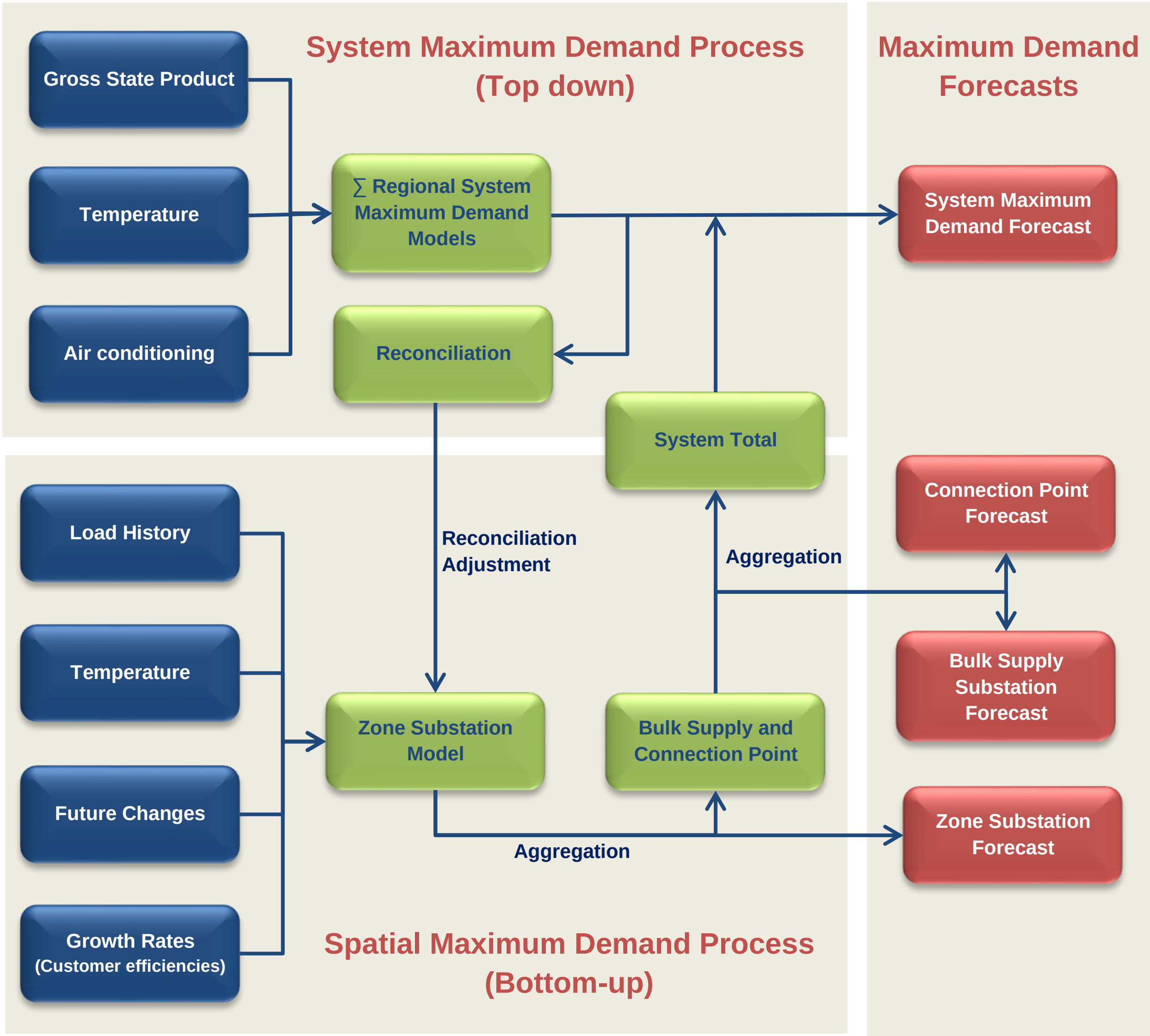
The methodology used to develop the system demand forecast is comprised of:

- 50% PoE level - this best estimate level is obtained from a maximum demand distribution such that 50% of the values are each side of this value
- 10% PoE level - this highest level is obtained from a maximum demand distribution such that 10% of the values exceed this
- The actual maximum coincident demand at the network level for historical years is extracted from the Ergon Energy system demand data set from system daily maximum demand loads. Temperature correction for 90%, 50% and 10% PoE system maximum demand is made using the past 20 years of daily temperature from selected weather stations throughout the state
- Weather normalised data is derived using the past 20 years of temperatures
- System forecasts are obtained from modelling a temperature-corrected multivariate regression model using economic, demand management, population solar PV, EV and Battery uptakes.

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.

An overview of this process is illustrated below in Figure 17.

Figure 17: System Demand Forecast Methodology



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

5.4.2 System Maximum Demand Forecast Results

In 2018-19 there was low level overall demand growth, as shown in Figure 18. The system-wide 2018-19 peak was 2,623MW at 6.00pm on 20th February 2019, an amount of 22MW more than last year's peak and, as a result of the very hot summer, significantly higher than the temperature corrected 50 POE peak for this year but still less than the 10 PoE peak. Temperature extremes across Queensland were again restricted to local areas including Rockhampton and Emerald.

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

GSP figures are continuing to return values larger than estimated as a result of higher than expected commodity prices.

Figure 18: Trend in System-wide Peak Demand

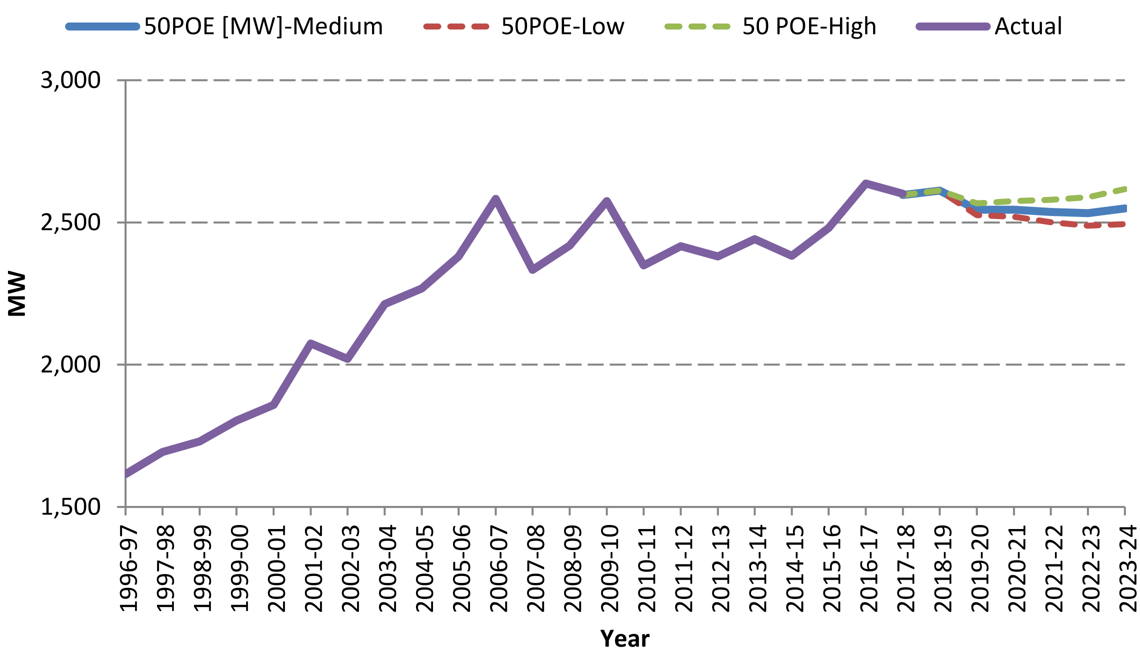


Table 2 summarises the actual and temperature-corrected (50% PoE) demands based on a range of weather station temperatures and associated maximum demand growths over the past five years. Each year the actual maximum demand recorded is corrected to a normalised or 50% PoE value by adjusting the demand up or down depending on the actual temperature recorded versus standard temperature and economic conditions. The corrected demand for each of the last four summers was derived through progressively improved ACIL Allen models. Therefore, comparisons between the 50% PoE loads for these and previous years should be made with care. Summer maximum demand was on average 2,540MW over the last five years and an average growth of 1.2% pa.

Table 2: Actual Maximum Demand Growth

Demand	2014-15	2015-16	2016-17	2017-18	2018-19
Summer Actual (MW) [1]	2,355	2,481	2,637	2,597	2,612
Growth (%)	-5.1%	5.3%	6.3%	-1.5%	0.6%

1 Native Demand.

Furthermore, Table 3 lists the maximum demand forecasts over the next five years for the 50PoE and 10PoE cases of peak demand with an average of 2,542MW and a growth of 0.04% pa.

Table 3: Maximum Demand Forecast (MW)

Forecast [1, 2]	2019-20	2020-21	2021-22	2022-23	2023-24
Summer (50% PoE)	2,545	2,546	2,536	2,533	2,549
Growth (%)	0.02%	0.01%	-0.33%	-0.15%	0.65%
Summer (10% PoE)	2,635	2,638	2,634	2,638	2,654
Growth (%)	-0.09%	0.10%	-0.17%	0.16%	0.61%

1 The five year demand forecast was developed using six weather station data as recommended by ACIL Allen.
2 The demand forecasts include the impact of the forecast economic growth as assessed in August 2018.

The forecast of general solar PV generation at the time of summer peak demand for regional Queensland is shown below in Table 4. 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. Analysis indicates that the continued growth of solar PV will reduce loads during daylight hours, causing system peak demands to occur at or around 7.30pm. This is consistent with previous 2016-17 and 2017-18 summer seasons, which had peak demands occurring at 7.30pm (the 2018-19 peak occurred at 6:00pm).

Table 4: Solar PV Reduction to Summer System Peak Demand

	2020	2021	2022	2023	2024	2025	2026	2027	2028
Solar PV Capacity impact on System Peak Demand (MW)	-3	-3	-4	-4	0	0	0	0	0

EV load has been included in the system forecast baseline for this current year and will also be included in forecast scenarios. While it is anticipated that the take-up of this technology will be slow, it has the potential to increase significantly if costs decline or government incentives are introduced as occurred with solar PV. EV charging is expected to generally occur from the early evening onwards and will extend into the middle of the night (off-peak). It is expected that the impact of EV charging on the system peak (afternoon period) will be negligible and is therefore excluded for the system peak demand. The EV impact on system demand forecast is shown in Table 5.

Table 5: Electric Vehicle Contribution to Summer System Peak Demand

	2020	2021	2022	2023	2024	2025	2026	2027	2028
EV Load impact on System Peak Demand (MW)	<1	<1	<1	1	2	3	5	7	11

Note – This assessment assumes that home vehicle charging is on controlled tariffs.

EV charging period is assumed to occur from 6pm to the early hours of the morning and will therefore not contribute to the afternoon peak demand but could well cause a rise in evening loads if not carried out on other tariffs.

Ergon Energy has also developed a model for the adoption of battery storage with the impact on peak demand being driven by large solar PV customers with little or no feed-in-tariffs (FiT). There are an increasing number of solar PV customers with systems that provide more electricity than they can use internally during the day but are not receiving the 44 cents per kWh FiT. These customers are likely to be very interested in battery storage and are seen to be the early adopters. Table 6 lists the projected potential reduction from battery storage systems on system peak demand.

Table 6: Battery Storage Systems Impact on Summer System Peak Demand

	2020	2021	2022	2023	2024	2025	2026	2027	2028
Battery Storage Systems Load impact on System Peak Demand (MW)	-7	-8	-11	-19	-8	-14	-25	-37	-46

Model assumes that battery storage will primarily be charged by solar PV and discharged over the late afternoon and early evening period between 4pm and 8pm with an initially small but growing impact on the system peak demand.

Chapter 6

Network Planning Framework

6. Network Planning Framework

6.1 Background

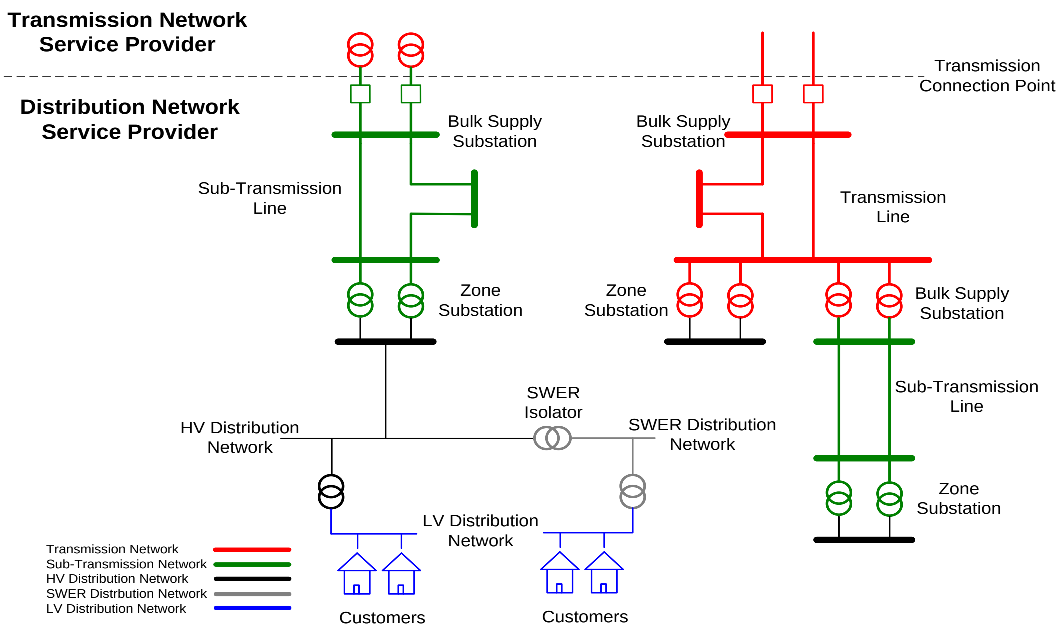
Network planning strives to strike a balance between the customers' need for a safe, secure, reliable and high quality electricity supply with the customers' desire for a minimal service cost. A key part of the network planning process is to optimise the economic benefits of network augmentation and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

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

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

This section outlines the network planning criteria, process, and framework that underpins our network planning approach. Figure 19 illustrates a traditional simplified DNSP network which typically consists of subtransmission, high voltage (HV) distribution, and low voltage (LV) networks, supplying customers at all voltage levels. It should be noted, as highlighted in other areas of this document, this traditional network topology is changing as we see greater numbers of embedded generators (and storage technology) at all voltage levels. This increased complexity and diversity at all levels within the network is both creating opportunity and challenge in the planning of the network.

Figure 19: Traditional Simplified DNSP Network



6.2 Planning Methodology

6.2.1 Strategic Planning

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

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

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

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

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

6.2.2 Detailed Planning Studies

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

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

- non-network alternatives
- fault levels
- voltage levels
- security of supply requirements
- quality of supply considerations
- asset renewal
- customer connections activity
- local, state and federal government decisions and directions.

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

6.3 Key Drivers of Augmentation

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

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

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

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

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

6.4 Network Planning Criteria

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

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

- deterministic approaches (e.g. N-1, N-2, etc. redundancy)
- probabilistic (risk-based) approaches.

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

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

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

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

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

6.4.1 Value of Customer Reliability

In September 2014, AEMO published the results of an investigation into the value that NEM customers place upon reliability. AEMO also published an application guide in December of that year.

According to the AEMO Review[12], the VCR:

> *"… represents, in dollar terms, the estimated aggregated value that customers place on the reliable supply of electricity. The actual value will vary by the type of customer and the characteristics of the outages being considered. The VCR at different points on the grid would then vary based on the mix of customer types at that point. As customers cannot directly specify the value they place on reliability, the VCR plays an important role in determining the efficient level of investment in, and efficient operation and use of, electricity services required by customers in the National Electricity Market (NEM)."*

Components in the calculation of VCR include:

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

The first three factors are combined to calculate the 'annualised probability-weighted Unserved Energy (USE)' in MWh. The last factor, customer mix, is combined with the AEMO 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 (total 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 20 years).

Changes in VCR associated with a 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.

[12] Value of Customer Reliability Review – Final Report, AEMO, September 2014, pg. 6.

Research conducted by Ergon Energy clearly indicates that there are distinct differences in reliability tolerance across various end-use customer segments. Consequently, Ergon Energy uses a sector-specific (including for example, residential, agricultural, commercial and industrial) approach to setting VCRs where appropriate.

6.4.2 Safety Net

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

The Safety Net requirements address this issue by providing a backstop set of 'security criteria' that set an upper limit to the customer consequence (in terms of unsupplied load) for a credible contingency event on our network. Ergon Energy is required to meet the restoration targets defined in Schedule 4 of Ergon Energy's Distribution Authority (shown in Table 7 below) *"…to the extent reasonably practicable".*

This acknowledges that regardless of level of preparation, there will always be combinations of circumstances where it is impossible to meet the restoration targets at the time of an event, though these should be rare. For example, if it is unsafe to work on a line due to ongoing storm activity. In addition, during the planning phase, where the risk of failing to meet the target timelines is identified as being very low probability, investment to further mitigate the risk would generally not be recommended, as per industry best practice.

Table 7: Service Safety Net Targets

Area	Targets for restoration of supply following an N-1 Event
Regional Centre[13]	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8000 customers) after 1 hour • Less than 15MVA (6000 customers) after 6 hours • Less than 5MVA (2000 customers) after 12 hours • Fully restored within 24 hours.
Rural Areas	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8000 customers) after 1 hour • Less 15MVA (6000 customers) after 8 hours • Less 5MVA (2000 customers) after 18 hours • Fully restored within 48 hours.

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

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

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

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

6.4.3 Distribution Networks Planning Criteria

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

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

CBD and Critical Loads

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

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

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

Urban Feeders

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

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

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

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

Rural Feeders

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

6.4.4 Consideration of Distribution Losses

Under the RIT-D that came into effect from 1 January 2014, it is a requirement to take into account market benefits (including network losses) in an investment decision. Ergon, as a RIT-D proponent, includes all classes of market benefits (including network losses) in its analysis that it considers to be material when applying a RIT-D. However, as per NER, the quantification of market benefits is optional for reliability driven projects.

For projects that are not subject to RIT-D process (where credible options of more than $6 million are not available), there is no regulatory requirement for the network losses (and other market benefits) to be considered in the appraisal of investment options. However, Ergon estimates the saving in network losses in detailed planning and project approval phases of the projects. The estimated loss saving is not used quantitatively in the investment comparison when comparing options, but considered qualitatively in the comparison of advantages and disadvantages of alternative options.

Ergon also takes into account network losses when specifying plant to meet the Minimum Energy Performance Standards (MEPS).

6.5 Voltage Limits

Voltage Levels

Our distribution network consists of numerous different HV levels due to legacy network topologies, various specific customer or sub network requirements, or due to industry best practice for a network configuration. Table 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	System Maximum Voltage
132kV	145kV
110kV	123kV
66kV	72kV
33kV	36kV
22kV	24kV
11kV	12kV

Maximum Customer Voltage

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

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

Table 9 below details the standard voltages and the maximum allowable variances for each voltage range from the relevant Queensland Electricity Regulation and the NER.

Table 9: 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.

Transmission and Subtransmission Voltage Limits

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

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

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

Distribution Voltage Limits

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

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

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

Table 10 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 10: Steady State Maximum Voltage Drop

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

Low Voltage (LV) Limits

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

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

6.6 Fault Level Analysis

6.6.1 Fault Level Analysis Methodology

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

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

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

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

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

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

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

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

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

6.6.2 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	25 (3s)
Sub-transmission	66	25	25 (3s)
Sub-transmission	33	13.1	25 (3s)
Distribution	22	13.1	25 (3s)
Distribution	11	13.1	25 (3s)

While Table 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, then fault level mitigation projects are initiated.

6.6.3 Fault Level Growth Factors

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

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

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

Ergon Energy obtains upstream fault level information from TNSP’s annually. Changes throughout the year are communicated through joint planning activities as described in Section 6.10.1.

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

6.7 Ratings Methodology

The evolution of large-scale renewable generation is challenging the philosophy of how network constraints are derived. This distributed generation results in two-way power flows, changing network profiles and in many cases increases the frequency in which constraints on primary assets are approached. Solar farms, for example, can push network assets to their thermal capacity daily, not seasonally. Utilisation levels have increased significantly on particular elements of the distribution and subtransmission network where large-scale renewable generation connects to the shared network. Step changes in utilisation are expected to become more prevalent in pockets of the network as more large-scale renewables are commissioned.

Ergon Energy is responding with updating ratings philosophies to meet these future challenges. Changes include restricting conductor temperature rise limits under normal and contingency operation, standardising on power cable load factors for particular types of generation and limiting power transformer capacity to base ratings.

Plant ratings are determined using Ergon Energy’s Plant Rating Guidelines and encompass primary current carrying items of all primary plant including overhead lines, underground cables, power transformers and substation HV equipment.

6.7.1 Feeder Capacity and Ratings

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

- Overhead lines – current carrying capacities are aligned to BOM Climate zones design ratings that are based on Joint Workings studies. The default overhead rating parameters used are listed in Section 6.7.2. Where the feeder backbone conductor decreases in size, the smaller conductor has been used in cases where there is minimal load upstream of the smaller conductor.
- Align the rating with the feeder load profile. While summer day is predominantly the rating restriction, low wind speeds in the morning and evening can cause network limitations.
- Loads caused by abnormal network configurations have been discounted when determining the peak demands.
- Where the existing conductor operating temperature is not known, a thermal rating of 50°C has been used. This is the typical overhead conductor thermal design temperature rating used in Ergon Energy regions.

6.7.2 Overhead Line Ratings

The overhead line rating is the maximum allowable current flow through the line without exceeding the maximum design temperature.

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

Default parameter values used by Ergon Energy to calculate the overhead line ratings are shown in Tables 12 to 18 below.

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

Weather study

In 2010, we undertook a climate study in partnership with the BOM and Aurecon to develop new overhead line rating weather parameters for the state. This study produced four major climate zones and several smaller special climate zones as shown in the Plant Rating Guidelines.

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

Table 12: Time of Day Definition

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

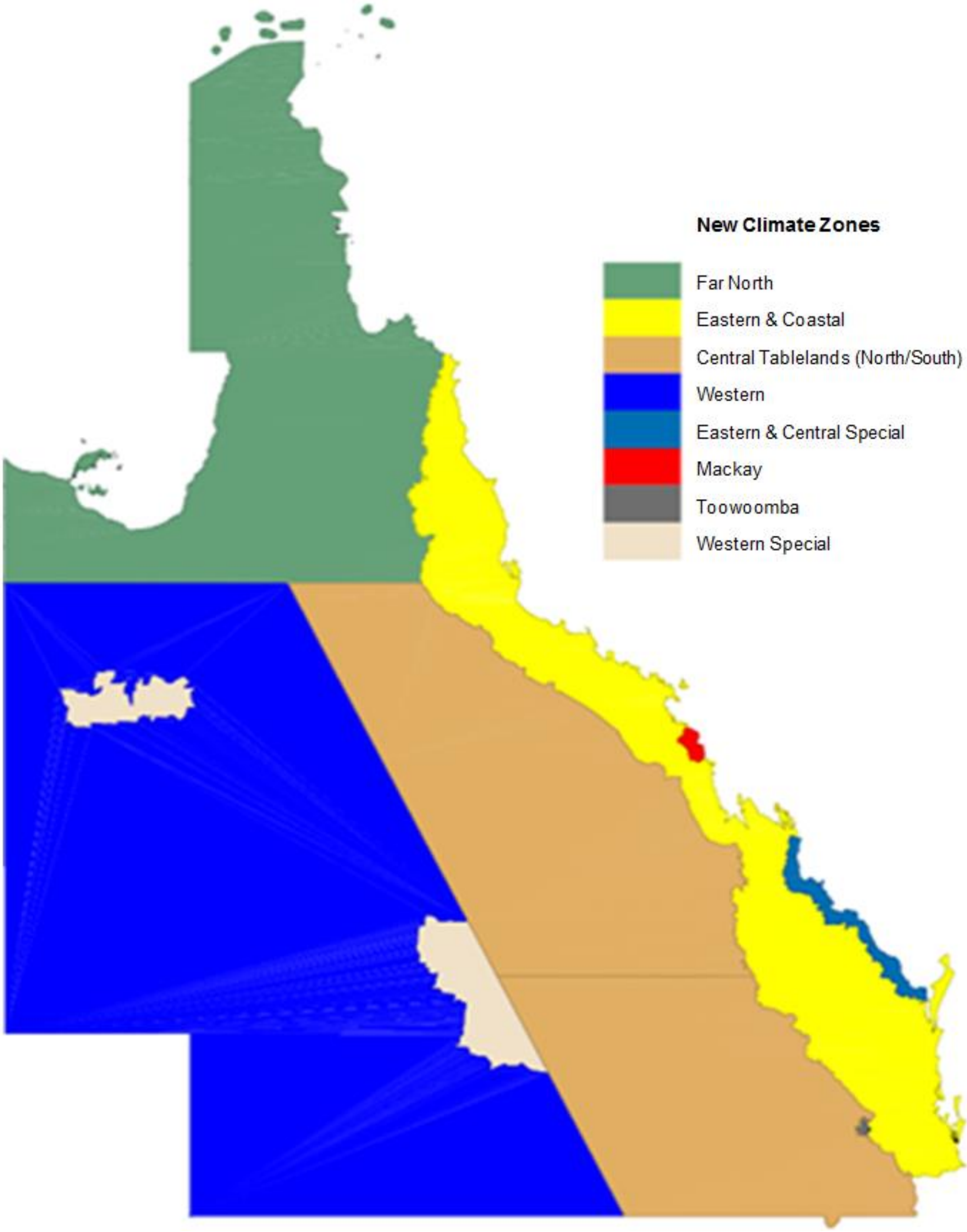
Climate zones

The climate study produced the overhead line rating weather parameters for the state shown in Table 13. These nine climate zones are shown in Figure 20.

Table 13: 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 20: Visualisation of Ergon Energy Climate Zones



Wind Angle

This is the angle of airflow across the conductor and is the next most important factor in determining the line ratings. Table 14 shows the wind angle and turbulence parameters. In practice these will vary over the full range from axial to traverse as the line changes direction and the wind direction changes.

Table 14: Wind Angle and Turbulence Parameters

Wind Angle and Turbulence Parameters	
Wind Yaw Angle	45° to the line
Wind Turbulence	0.1%

Ground reflectivity factor

The reflectivity of the ground beneath an overhead line, shown in Table 15, is based on the most appropriate ground cover.

Table 15: Ground Reflection Factor Values

Ground Cover	Ground Reflectivity Factor
Grass, Crops	0.2
Water	0.05
Forest	0.1
Urban Areas	0.15
Sand	0.3
Ice	0.5
Snow	0.75

Conductor emissivity and absorptivity

Radiation emitted and absorbed from a conductor, is based on assessment of surface condition as shown in Table 16.

Table 16: Conductor Emissivity and Absorptivity

Conductor Surface	Conductor Emissivity	Solar Absorptivity
Rural Weathered	0.5	0.5
Industrial	0.85	0.85
New Bright	0.3	0.6
Black	1	1

The ground air differential

Ground air temperature differential is based on season and time of day as shown in Table 17.

Table 17: Ground Air Temperature Differential Default Values

Time of Day	SD	SE	SN/M	WD	WE	WN/M
Ground Air (with respect to Ambient) (°C)	+5	+4	-5	+5	+2	-5

Solar radiation

The solar radiation is based on season and time of day as shown in Table 18.

Table 18: Solar Radiation Parameters

Time of Day	SD	SE	SN/M	WD	WE	WN/M
Direct Radiation	910	200	0	728	0	0
Diffuse Radiation	210	20	0	156	0	0

6.7.3 Real Time Capacity Monitoring Ratings

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

The type of monitoring used is dependent on whether it is an overhead line or underground cable constraint. The type of sensors used can be overhead line temperature sensors mounted on the limiting section of line or Resistive Temperature Devices (RTDs) attached to the outer jacket of the underground cable. For some specially constructed cables there is the capability for Distributive Temperature Sensor (DTS) measurement which can provide multiple temperature measurements along the length of the cable using an optical fibre embedded in the cable.

Overhead line temperature sensors measure the actual conductor temperature, which is used as an input to calculate available line capacity. Weather parameters such as ambient air temperature, wind speed and solar radiation are also input to provide 15 minute line ratings.

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

6.7.4 Transformer Ratings

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

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

The rating methodology takes into account the present condition of a transformer when applying a thermal rating. Ratings are not fixed for the duration of the transformer life, but rather ratings are published periodically. A fundamental process is the evaluation of transformer condition by means of oil sampling and analysis for dissolved gases, moisture content, oxygen content, oil acidity and degree of polymerisation.

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

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

6.8 Planning of Customer Connections

Connex is defined as works to service new or upgraded customer connections that are requested by Ergon Energy's customers. As a condition of our Distribution Authority, we 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.[14] 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.[15]

Ergon Energy has a Connection Policy[16] that that sets out the nature of connection services offered by Ergon Energy and the charges that may apply for those connection services. This Policy came into effect in July 2015.

Subject to certain exceptions prescribed in the policy, including where the shared network augmentation threshold is not exceeded, a capital contribution[17] is generally required when the incremental costs of providing a connection exceed the incremental revenue expected to be received from the new or altered connection over a period of 30 years for residential customers. For commercial and industrial premises, the period will vary depending on the nature of the premises and will be defined in the connection offer. For Major Customer Connections, where dedicated network assets are required to enable the load or generation to connect to the Network, those assets are funded fully by the connecting customer. For large scale EG, fully funded works also include works to remove a network constraint from the existing shared network.

[14] *Electricity Act 1994* (Qld) s 42(c).

[15] Ibid, s 43.

[16] https://www.ergon.com.au/__data/assets/pdf_file/0009/270378/Connection-Policy.pdf

[17] https://www.ergon.com.au/__data/assets/pdf_file/0009/270378/Connection-Policy.pdf

Connex undertaken are generally of the following types:

- designing and constructing shared network assets that are directly relevant to customer connections
- designing and constructing connection assets
- commissioning and energising connection assets
- installing assets as part of a real estate development
- installing assets to remove a network constraint for an EG
- providing and installing metering assets
- providing and constructing public lighting.

Not all Connex are undertaken by Ergon Energy. Depending on the type of work, services can be undertaken by one of three parties:

- Ergon Energy
- someone acting on Ergon Energy's behalf (i.e. a contractor), or
- real estate developers, major customers, or other service providers, where the assets are subsequently gifted to Ergon Energy.

Depending on the nature of the work being undertaken, Connex can be funded by:

- Ergon Energy, where it, or someone acting on its behalf, undertakes the works
- a customer paying a capital contribution, an ACS fee, or both to Ergon Energy, where Ergon Energy or someone acting on its behalf, undertakes the works
- a real estate developer paying an ACS fee to Ergon Energy, or
- a real estate developer, major customer, or another service provider, where after the assets are built, they are 'gifted' to Ergon Energy.

For contestable works, the real estate developer, major customer, or another service provider may construct and continue to own and operate the works at their cost. There may still be some costs for the works Ergon Energy needs to undertake. The way in which Connex is progressed affects both how the cost of the works is recovered and from whom they are recovered.

6.9 Major Customer Connections and Embedded Generators

Ergon Energy is committed to ensuring that, where technically viable, major customers are able to connect to the network. We have a clear Major Customer Connection (MCC) process available on our website[18] that aligns with the connection processes in Chapters 5 and 5A of the National Electricity Rules (NER). The process generally applies to proposed connections where the intended Authorised Demand (AD) or load, on our network exceeds 1,500kVA (1.5MVA) or where power usage is typically above 4GWh per annum at a single site.

[18] https://www.ergon.com.au/network/connections/major-business-connections

Ergon Energy has clear processes for the connection of Embedded Generation (EG) units, which apply to EG systems 30kVA and above. The processes may vary depending on the size of the generating unit and whether the system is exporting into our network. These processes are also listed on our website.[19]

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

Further information on the Major Customer connection process is available on the Ergon Energy website at:

https://www.ergon.com.au/network/connections/major-business-connections

6.10 Joint Planning

6.10.1 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. In the context of joint planning, geographical boundaries between transmission and distribution networks are not relevant.

The National Electricity Objective (NEO) is to promote efficient investment in, and operation and use of, electricity services for the long term interests of customers. Joint planning ensures that the most efficient market outcomes for customers are implemented. This typically involves a combination of TNSP and DNSP augmentations.

Rule 5.14 of the NER requires Ergon Energy to undertake joint planning with any TNSP and DNSP with which Ergon Energy is interconnected. In Queensland, Powerlink owns the state's 275kV and 330kV network, as the TNSP, as well as some of the 110kV and 132kV network. Energex operates the distribution network in south-east Queensland. Ergon operates the distribution network in the rest of the state.

Powerlink and Ergon Energy undertake formal annual joint planning meetings. These meetings are used to review known or emerging network constraints at the connection points or on either network where the other party is affected or has the potential to be affected in the forward planning period.

[19] https://www.ergon.com.au/network/connections/major-business-connections/large-scale-solar

As part of these discussions, both parties openly discuss the solutions that are technically and economically viable, the network security risks of the potential options and the customer impact of the consequences. Once the two companies have settled upon a potentially effective non-network or network approach, the normal Regulatory Investment Test for Transmission (RIT-T) and RIT-D conditions and processes apply. Subsequently, the market is informed and opportunities provided for input. Formal meeting minutes are recorded and accepted by both organisations. Between formal joint planning meetings, Powerlink and Ergon Energy participate in specific project based discussions where they are relevant to both organisations. Specific joint planning investments are detailed in Section 6.11.1.

In addition, Ergon Energy also meets with Energex to discuss the interface between the two business' distribution (11kV) and subtransmission (33kV and 110kV) networks. As there are very few interface points between Energex and our networks, these meetings are more irregular and are spaced at approximately 18 months apart with discussions held between formal meetings as required.

Ergon Energy also has formal discussions with Essential Energy (a DNSP operating in New South Wales), particularly in regard to the negotiation of the applicable connection agreement at Waggamba substation located in Goondiwindi. Further discussions, due to the nature of the interconnection, are irregular and hinge around projects that may affect either organisation.

Ergon Energy also has interfaces with service providers in the mining sector, and power stations in the North Queensland Western Region. Joint planning with these parties is held on an as needs basis.

6.10.2 Role of Ergon Energy in Joint Planning

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

Through this process Ergon is tasked with:

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

6.10.3 Emerging Joint Planning Limitations

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
- overhead line ratings under normal climatic conditions (dynamic rating where appropriate)
- 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.

Where forecasted power flows could exceed network capacity, Ergon is required to notify market participants of these forecast emerging network limitations through the DAPR. If augmentation is necessary, joint planning investigations are carried out with DNSPs or TNSPs in accordance with Clause 5.14 of the NER, to identify the most cost effective solution regardless of asset boundaries, including potential non-network solutions.

6.11 Joint Planning Results

6.11.1 Joint Planning with TNSP

Table 19 presents the outcomes of Ergon Energy's joint planning investments undertaken with Powerlink as described in Section 6.11.2 and 6.11.3 in 2018-19.

Table 19: 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	$1.8M	May-21	Powerlink
Northern	**T38 Mackay** - CT replacements for revenue and check metering compliance.	$2.3M	Mar-20	Powerlink
Northern	**T157 Ingham South** - Ergon Energy work related to Powerlink's Transformer 1 and Transformer 2 replacement.	$1.0M	Jan-20	Powerlink
Northern	**T51 Cairns** - Ergon Energy work to address constrained cable capacity.	$2.0M	Apr-22	Ergon Energy
Northern	**T92 Dan Gleeson** - Ergon Energy work related to Powerlink's Secondary Systems Upgrade.	$0.8M	Dec-20	Powerlink
Southern	**T035 Dysart** - Install two 66/22kV 20MVA transformers to supply the Dysart area distribution network once Powerlink remove the existing 2 x 70MVA 132/66/22kV.	$13.1M	Jun-20	Powerlink
Southern	**T032 Blackwater** - Ergon Energy to reinstate 22kV energy supply to Blackwater area distribution network once Powerlink replace 2 of 3 Transformers, 132/66/11kV with single 160MVA. Includes Ergon asset refurbishment works.	$1.8M	Mar-24	Powerlink
Southern	**Egans Hill** - Secondary Systems Replacement	$0.7M	Jul-20	Powerlink
Southern	**H015 Lilyvale** - Powerlink to replace Transformers 3 & 4, 132/66/11kV with 160MVA units	$3.5M	Sep-21	Powerlink

* Ergon Energy component (including overheads)

^ Project scope reduced from previous year's DAPR submission

6.11.2 Joint Planning with other DNSP

There were no investments resulting from joint planning in 2018-19 with Essential Energy, Energex, mining sector service providers or generators in the North Queensland Western Region.

6.11.3 Further Information on Joint Planning

Further information on Joint Planning outcomes requiring a RIT-T led by Powerlink is available on the Powerlink website at:

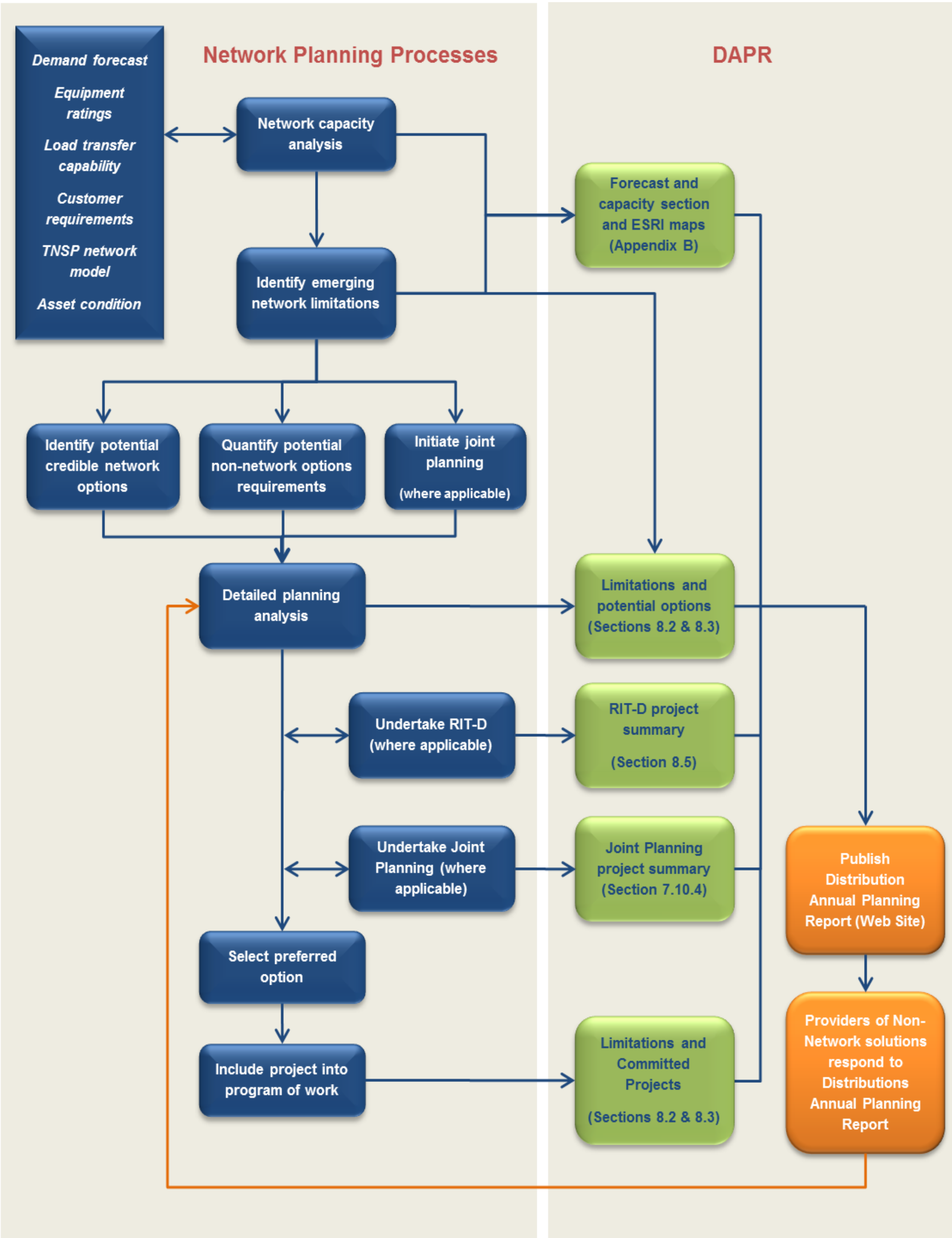
https://www.powerlink.com.au/planning-and-consultation

Alternatively, we welcome feedback or enquiries on any of the information presented in this DAPR, via email to engagement@ergon.com.au

6.12 DAPR Reporting Methodology

The methodology shown in Figure 21 is used in the preparation of the DAPR to report on subtransmission network and primary distribution feeder limitations and solutions, joint planning projects, and RIT-D projects.

Figure 21: DAPR Methodology



6.12.1 Joint Approach to Demand Forecasting

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

6.12.2 Substation Analysis Methodology Assumptions

Bulk and zone substation analysis is a build-up of multiple pieces of data. Much of the analysis is specified in Section 6.2.2 and also takes into account Ergon Energy's Plant Rating Guidelines. Ergon Energy has a program of assessing plant rating capabilities within substations, with a focus on critical substation assets.

Further analysis is also conducted, as discussed in Section 6.4.2, around the Safety Net compliance of a substation. This analysis involves evaluation to determine whether efficient investments under the Safety Net provisions will provide mitigation for credible contingencies that could otherwise result in outages longer than the Safety Net targets.

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

6.12.3 Subtransmission Feeder Analysis Methodology Assumptions

The subtransmission feeder methodology approach takes the substation maximum demand forecasts and the daily load profiles of each individual substation to produce a forecast half hour load profile for the maximum demand day at that substation. This is produced for each substation in the network and a series of load flows are then performed for each half hour period of the day using these loadings. The forecast feeder load for each period is the maximum current experienced by the feeder in any half hour interval during that period. These forecast load flows are then compared against the feeder ratings resulting from ratings methodology detailed in Section 6.7. The outcome of this methodology, as per the planning process discussed in Section 6.2, could be the creation of a project, data verification or load transfers. In these cases, these outcomes would be transferred to future forecasts and load flows.

6.12.4 Distribution Feeder Analysis Methodology Assumptions

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

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

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

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

Chapter 7

Network Limitations and Recommended Solutions

7. Network Limitations and Recommended Solutions

7.1 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 are available on the Ergon Energy website via the following link:

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

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.

7.2 Forecast Load and Capacity Tables

Forecast load and capacity information is also made available in spreadsheet format via the hyperlinks in Appendix E and Appendix F.

All files can also be downloaded directly from the Ergon Energy website at this location: https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report

7.3 Substation Limitations

7.3.1 Summary of Limitations

Substation limitations are identified using the models and processes as described in Sections 5.3.1 and 6.4.

Table 20 shows the projection of substation statistics out to 2023-24. It also provides the forecast number of substations with load at risk (LAR) under substation contingency conditions (LARc).

Table 20: Summary of Substation Limitations

Region	Substation Condition	LARc > 0MVA (Forecast Limitations)				
		2019-20	2020-21	2021-22	2022-23	2023-24
Southern	LARc > MVA	1	1	1	1	1
	Total Substations	258	258	258	258	258

Assessment based on 50 PoE forecast and Network Planning Criteria.
The zone substation total count excludes dedicated customer substations.
All information as at 30th June of each year.
Note:
Proposed strategies to manage the limitations are contained in Substation DAPR System Limitation Templates
Three substations are forecasted to experience LARc in different years over the forward period

7.3.2 Proposed Solutions

Details on proposed solutions addressing known Substation system limitations are documented in the Substation DAPR System Limitation Template (DAPR Template) which can be accessed from the following link:

Substations-Limitations-and-Proposed-Solutions-2019.xlsx

7.3.3 Committed Solutions

Details on committed solutions addressing known Substation system limitations are documented in the Substation Limitations and Committed Solutions template which can be accessed from the following link:

Substation-Limitations-and-Committed-Solutions-2019.xlsx

7.4 Subtransmission Feeder Limitations

7.4.1 Summary of Limitations

Subtransmission Feeder limitations are identified using the simulation models and processes as described in Section 5.3.1 and Section 6.4. The analysis provides load at risk information under normal and contingency conditions and evaluates whether the transmission feeder meets its allocated security of supply standard. 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.

Table 21: Summary of Subtransmission Feeder Limitations

Region	No of Feeders Utilisation
Northern	2
Southern	4

Limitations identified for 132kV and 110kV subtransmission feeders are also reported in the limitation tables contained in Appendix D. These tables outline the approved or proposed strategy to manage the emerging limitations, along with other related information.

7.4.2 Proposed Solutions

Details on proposed solutions are documented in the Subtransmission Feeders DAPR System Limitation Template (DAPR Template) which can be accessed from the following links:

Sub-transmission-Feeders-Limitations-and-Proposed-Solutions-2019.xlsx

Further information and reports on Projects subject to the RIT-D process can be accessed from the Ergon Energy RIT- D Consultations Web Page.

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

7.5 Distribution Feeder Limitations

Of the 1,135 distribution feeders in our network, there are 68 forecast to be constrained in the next two years based on utilisation against the distribution planning/security criteria. These capacity constraints have been assessed against the security criteria loading of 75% for Urban feeders and 90% for other feeder categories. For further details on the methodology used, refer to Section 5.3.4. Note that identification of an asset as 'constrained' does not necessarily imply that the integrity or capability threshold of the asset has been compromised.

Table 22: Distribution Feeder Summary Report

Region	Total feeder numbers**	Total forecast capacity constraints* (after 2 years)
Northern	754	34
Southern	622	34
All Regions	**1,376**	**68**

*Capacity constraint against the security criteria loading (75% for Urban Feeders and 90% for all feeder categories.

**Note dedicated customer connection assets are excluded from the analysis.

Results from analysis of Ergon Energy's Distribution Feeder loads, capacity and utilisation forecasts in the next two years are available from the following:

Distribution-Feeder-Limitations-and-Committed-Solutions-2019.xlsx

7.5.1 Proposed Solutions

Distribution feeder capacity problems can be solved in a number of ways, depending on the local characteristics of the distribution feeder. In each instance, actual solutions are subject to a detailed study and business case. Possible solutions to feeder constraints include (in approximate order of preference based on network cost):

- Network reconfiguration:
  - transferring existing load to adjacent feeders if capacity is available
  - re-rating or dynamic rating of the underground exit cable or overhead feeder.
- Demand management initiatives that reduce customer loading:
  - energy efficient appliances
  - power factor correction
  - shift loads (e.g. pool pumps, hot water storage etc.) to a controlled load tariff
  - shift loads to a time-of-use tariff
  - air conditioning 'Peak Smart'
  - customer micro EG units
  - call off load
  - commercial and industrial demand management

  - customer embedded generation to 'peak lop'
  - network embedded generation to 'peak lop'
  - energy storage.
- Network augmentation:
  - replacing the underground exit cable or overhead feeder
  - creating new substations and/or feeders and transferring existing load.

7.6 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 Chapter 4. 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 Table 23 summarises ongoing planned Programs involving Distribution Line assets for the forward planning period i.e. until 2023/24.

Asset Replacement Projects-2019.xlsx

Table 23: Ergon Asset Retirements (Program Based)

Asset	Location	Rationale for Retirement	Retirement Date	Change to Retirement Date
Overhead HV reconductoring	Northern & Southern Regions	Asset condition and Risk	2019-23	NA
Overhead LV reconductoring	Northern & Southern Regions	Asset condition and Risk	2019-23	NA
Overhead Service Line replacement	Northern & Southern Regions	Asset condition and Risk	2019-23	NA
Pole Replacements	Northern & Southern Regions	Asset condition and Risk	2019-23	NA
Pole mounted plant replacement	Northern & Southern Regions	Asset condition and Risk	2019-23	NA

7.7 Regulatory Investment Test Projects

7.7.1 Regulatory Investment Test Projects - In Progress

This section describes the RIT-Ds that were commenced in 2018-19 and includes several replacement driven projects that now require RIT-D assessment, as specified in the National Electricity Amendment published by the AER on 18th July 2017. Estimated costs are provided in real 2018-19 dollars and are inclusive of overheads.

Table 24: Regulatory Test Investments - In Progress

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
WR1310762 Addressing reliability requirements in the Garbutt network area	$26.5M	Commissioning Est. Dec 2022	*Nil impact beyond regulated revenue.*

Project need:

A structural engineering report in 2016 identified a number of at risk aged structures. Consequently, a substation condition assessment report (SCAR) was completed in early 2018 which identified the assets which are nearing (or at) end of life. The predominant assets which were identified for replacement was the 66kV outdoor switchgear including; circuit breakers, voltage and current transformers, insulators stacks, isolators, the strung bus, the solid bus and all their supporting structures.

The identified need for investment is to remediate the safety and reliability risks currently associated with the aged assets at Garbutt Substation in order to maintain a safe, reliable supply of electricity to customers in the Townsville region.

Credible Options:

1) Replacement of the aged 66kV assets at Garbutt Substation with 66kV Gas Insulated Switchgear (GIS) (NPV = -$11.75M)
2) Replacement of the aged 66kV assets at Garbutt Substation with 66kV Air Insulated Switchgear (AIS) (NPV = -$13.35M)

Conclusion: The final recommendation is currently being developed.

Status: Draft Project Assessment Report published.

Ergon Energy has published a Draft Project Assessment Report to external parties to notify the market of Ergon Energy's intentions. This consultation is yet to close.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
WR1273666 Ensuring Reliability of Electricity Supply and Managing Asset Risks in the Douglas Shire Area	$20.6M	Commissioning Est. early 2023	*Nil impact beyond regulated revenue.*

Project need:

• The Mossman 66/22kV substation was constructed in 1964 and supplies some 3250 customers from the local 22kV distribution network in the Douglas Shire Council area from Mossman and north to the Daintree.

• The Mossman substation is supplied by two aged 66kV timber pole lines from Powerlink's Turkinje 132/66kV substation via Mossman 1 (MOSS 1) and Mossman 2 (MOSS 2) feeders constructed in 1975 and 1958 respectively.

• A substation condition assessment has highlighted the aged assets, reliability, safety and environmental risks at the Mossman substation. The Mossman 66kV feeders which also supply the Mount Molloy substation in the Northern Atherton Tableland area experience reliability issues and high maintenance costs reflecting late 1950s' design standards, assets reaching end of service life (e.g. 35km of 1958 vintage 7/0.104 HDBCC 66kV conductor) and exposure to adverse operating conditions (i.e. termites, bushfires, lightning activity, wet tropic rainforests and cyclones).

Credible Options:

1) Transition Mossman Substation from 66/22kV to 132/22kV and extend the Yalkula 132kV bus (NPV = -$13.57M)
2) Staged Replacement of the 66kV Line and Aged Mossman Substation Plant as Required (NPV = -$15.01M)
3) Full Retirement/Recovery of Mossman 66/22kV Substation, Upgrade Craiglie Substation to Supply Mossman 22kV Distribution Area (NPV = -$13.79M)

Conclusion: The final recommendation is currently being developed.

Status: Notice of non-network options report has been published.

Ergon Energy has published a non-network options report to external parties to identify the requirements that Option 1 addresses. This initial phase of the consultation closes on 29th November 2019.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
WR1273009 Planella Substation Reinforcement	$4.5M	Commissioning Est. mid-late 2023	*Nil impact beyond regulated revenue.*

Project need:

Planella substation does not have N-1 security and is reliant on the 33kV radial feeder between North Mackay and Planella. Planella does not comply with the Safety Net requirements based on credible contingencies benchmarked against 50% PoE load in the present configuration.

Under most circumstances, the wood poles of the 33kV North Mackay – Planella transmission line are accessible; however in the event of periods of heavy rainfall and/or king tides, sections of the line passing through low lying area become virtually inaccessible. For the loss of the incoming 33kV feeder, resulting from a pole failure or wires on ground in an inaccessible location, the customer outage duration would be greater than 12 hours hence supply restoration is not Safety Net compliant for this scenario.

Credible Options:

1) Rebuild 1.5km section of existing 33kV feeder in flood zone with concrete poles, obtain easements and develop additional 11kV feeder ties (NPV = -$5.57M)
2) Establish second 33kV feeder from Glenella to Planella constructed as a mixed overhead and underground feeder (NPV = -$10.76)
3) Establish two new 66kV feeders from Glenella to Planella constructed as a mixed overhead and underground DCCT feeder and convert Planella from 33/11kV to 66/11kV (NPV = -$17.1M)

Conclusion: The final recommendation is currently being developed.

Status: Notice of non-network options report has been published.

Ergon Energy has published a non-network options report to external parties to identify the requirements that Option 1 addresses. This initial phase of the consultation closed on 19th September 2019.

Project Need, Credible Options and Conclusion	Preferred option Cost	Preferred option Est. Delivery	Impact on Network Users (Preferred Option)
WR1274424 Cannonvale and Jubilee Pocket 66kV Reinforcement	$21.9M	Commissioning Est. Late 2023	*Nil impact beyond regulated revenue.*

Project need:

Low reliability due to reliance on manual switching at Cannonvale (Cannonvale does not have a fully switched 66kV bus).

Aged and poor condition asset replacement (the transformer CTs, 66kV CBs and UG feeder cable are due for replacement).

Cable loading constraints (load exceeds rating of 66kV cable entry during contingency conditions).

Credible Options:

1) Establish fully switched 66kV switchyard at Cannonvale Substation using 7 CB Gas Insulated Switchgear and replace 66kV feeder exit cables (NPV = -$13.45M)
2) Construct dedicated 66kV feeder from Proserpine to Proserpine Mill substation, replacement of Cannonvale transformer CBs & CTs, and duplication of 66kV cables (NPV = -$14.18M)
3) Construct 66kV switchyard at future Riordanvale substation site, replacement of Cannonvale transformer CBs & CTs, and duplication of 66kV cables (NPV = -$16.25M)

Conclusion: The final recommendation is currently being developed.

Status: Notice of non-network options report has been published.

Ergon Energy has published a non-network options report to external parties to identify the requirements that Option 1 addresses. This initial phase of the consultation closed on 19th September 2019.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
WR1266688 - M028 Childers - Gayndah - Aged Line Rebuild	$66.5M	Dec 2023	*Nil impact beyond regulated revenue.*

Project need:

The existing 66kV M028 feeder forms part of the 66kV subtransmission network supplying the 66/11kV zone substations Degilbo (DEGI), Gayndah (GAYN), Mundubbera Town (MUTO) and Eidsvold (EIDS) as well as the Mount Rawdon gold mine (MORW). Feeder M028 is 92km long, 64 years old and has reached its end of life based on the condition of the 7/.104 HDBC conductor and wooden poles.

The identified need of the project can be broken down into three main objectives as detailed below.

The first objective of the proposed investment is to maintain a safe and sustainable energy supply to customers by reducing the significant safety and environmental risks associated with the aged M028 feeder to as low as reasonably practicable (ALARP).

The second objective is to ensure that there is sufficient capacity in the network to meet existing customer demand and enable customers to connect new loads in the future.

The third objective is to provide a secure and reliable energy supply to customers by ensuring that the network meets Ergon Energy's statutory network security and reliability performance standards.

Credible Options:

1) Replacing the entire aged M028 feeder with a new 66kV single circuit concrete pole feeder, strung with Neon conductor and optical ground wire (OPGW), originating from the 132/66kV Isis Bulk Supply Point and connecting Degilbo and Gayndah zone substations by December 2023.

Conclusion: The preferred option will be determined during the RIT-D process.

Status:

Ergon Energy has published a non-network options report to external parties to identify potential non-network options that address the identified needs of the project. The consultation period is currently open for submissions and is due to close on 16 Jan 2020.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
WR1214829- Reliable Provision of Electricity to the Kilkivan Supply Area	$26M	Jun 2022	*Nil impact beyond regulated revenue.*

Project need:

The primary objective is to identify alternative cost-effective, reliable solutions for providing electricity to the consumers in the Kilkivan supply areas. The key drivers requiring Ergon Energy to make further investments in the Kilkivan supply areas are the reliability of assets that are at the end of their life, environmental risk and compliance with safety and current standards. In identifying the most cost effective solution, Ergon Energy must continue to meet its legal and regulatory requirements including the customer service standards.

Credible Options:

1) Full substation rebuild of Kilkivan Substation (KILK) on the area adjacent to the existing substation site by May 2023.

Conclusion: The final recommendation is currently being developed.

Status:

Notice of non-network options report has been published.

Ergon Energy has published a non-network options report to external parties to identify the requirements that Option 1 addresses. This initial phase of the consultation closed on 18th October 2019.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
WR1266675 - Pittsworth Regional Reinforcement	$6M	Dec 2021	*Nil impact beyond regulated revenue.*

Project need:

The first objective is to ensure there is sufficient capacity to enable customers to connect new loads and to avoid customer load shedding during peak demand. Load forecasts show demand is expected to exceed the transformer capacity into the future.

The second objective is to increase the reliability of customer supply by managing the lifecycle of primary plant at Broxburn Zone Substation. A significant number of primary plant are at their end of life. If this aged equipment is not replaced before the nominated end of life there will be an increased likelihood of plant failure.

Credible Options:

1) Install a 10MVA skid transformer at BROX by December 2021.

Conclusion: The preferred option will be determined during the RIT-D process.

Status:

Ergon Energy has published a non-network options report to external parties to identify potential non-network options that address the identified needs of the project. The consultation period is currently open for submissions and is due to close on 10 Jan 2020.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
WR1339663 - Reliability and Capacity Reinforcement for the North Toowoomba Network	$10.2M	July 2024	Nil impact beyond regulated revenue.

Project need:

The Northern suburbs of Toowoomba are identified as a key growth area for over the next 15 years resulting in increased loading on local Zone Substations.

A combination of reliability, safety and load growth considerations across the three substations in the North Toowoomba area that will require network investment in the 2020-25 timeframe.

Meringandan substation (built in the 1960s) has a number of assets approaching end of life, which are at a high risk of failure, and should be replaced in 2021 to ensure a reliable and safe supply.

Highfields substation is of similar vintage, with a number of aged assets to be replaced by 2024.

In addition, load growth in the supply area has resulted in Cawdor skid substation to be loaded above the substation security of supply criteria and current load forecasts predict that it will not meet the substation security criteria by the year 2021.

Credible Options:

1) 2021 – Build a single 33/11kV 20MVA transformer at Kleinton with associated switchgear
   Decommission items of high-risk plant at Meringandan Substation
   Transfer 1.6MVA load from Cawdor substation to Kleinton substation
   2024 – Transfer Highfields load (1.9MVA) to Kleinton substation
   Decommission Highfields substation (NPV = -11.75M)
2) 2021 - Build KLTN substation with 2 x 33/1 kV 20MVA transformers, decommission MERN substation.
   (NPV = -$19.33M)
3) 2021 - Install a 2nd 33/11kV 10MVA SKID at CAWD
   2024 – Transfer Highfields load (1.9MVA) to Kleinton substation and decommission Highfields substation
   2034 – Install a 33/11kV 10MVA SKID at MERN (NPV = -$16.33M)
4) 2021 - Install a 33/11kV 10MVA SKID at MERN
   2034 - Build 2 x 33/11kV 20MVA KLTN and decommission MERN (NPV = -$16.14M)

Conclusion: The preferred option will be determined during the RIT-D process.

Status:

Notice on screening for non-network options report has been published.

Ergon Energy has determined that no non-network option is, or forms a significant part of, any potential credible option for this RIT-D. A draft project assessment report is due to be published in 2019.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
WR1305132 Cape River East Future Substation	TBA	Commissioning Est. Apr 2024	*Nil impact beyond regulated revenue.*

Project need:

Ergon Energy has identified a need for investment to remediate the safety and reliability risks currently associated with the aged assets at Cape River Substation in order to maintain a safe, reliable supply of electricity to customers in the Cape River region.

A Condition Based Risk Management (CBRM) analysis of the effect of current condition and ageing of Cape River Substation has revealed that a number of assets have reached retirement age and are in poor condition including but not limited to a 66/11kV 1MVA transformer and 66kV circuit breakers.

Credible Options:

Credible options are currently being assessed as of December 2019 and shall be published once completed.

Conclusion: The preferred option will be determined during the RIT-D process.

Status:

Notice on screening for non-network options report has been published as of mid-December 2019.

As of December 2019 Ergon Energy will be processing non-network options or determining whether this forms a significant part of, any potential credible option for this RIT-D. A draft project assessment report is due to be published early 2020.

Further information on current augmentation and replacement RIT-D consultations is available on the Ergon Energy website at:

https://www.ergon.com.au/network/network-management/network-infrastructure/regulatory-test-consultations

7.7.2 Regulatory Investment Test Projects - Completed

This section describes the RIT-Ds that were completed in 2018-19. Estimated costs are provided in real 2018-19 dollars and are inclusive of overheads.

Table 25: Regulatory Test Investments - Completed

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
WR445103 Charleville SVC Replacement	$1.8M	Dec 2023	*Nil impact beyond regulated revenue.*

Project need:

Ergon Energy is responsible (under its Distribution Authority) for electricity supply to the Charleville, Quilpie and Cunnamulla area in south west Queensland.

Charleville is located in the Maranoa area of the South West Region of Ergon Energy's Network. The Charleville area is supplied via a single 276km 66kV sub-transmission Feeder from T83 Roma Bulk Supply Point (ROMA) and customers in Quilpie and Cunnamulla are supplied via separate 200km long 66kV feeders from Charleville. Distribution supply from Charleville and Cunnamulla is at 11kV for urban, and 22kV and 19.1kV single wire earth return (SWER) for more rural customers. Supply from Quilpie zone substation is exclusively 11kV with extensive 19.1kV SWER networks. Charleville substation contains 1 x 66/11kV transformer, 1 x 66/22kV transformer, and also a 22/11kV transformer to link the 22kV and 11kV busbars and hence provide backup for each of the 66kV transformers. The Charleville zone substation contains a static var compensator (SVC) which is connected to its 11kV bus. The SVC is set up to control the 66kV bus voltage and has a range of 7Mvar inductive to 10Mvar capacitive.

The Charleville SVC is approaching the end of its design life and it is recommended for replacement on the basis of its age and reliability in 2019. The SVC performs the function of maintaining stable voltages at both high and low load times. At low load times, without the SVC in service, significant voltage rise would occur on the Charleville area network. Similarly, without the SVC's capacitive support, voltage would become low during high load periods. The SVC also provides some Negative Phase Sequence (NPS) correction to address voltage balance issues associated with SWER networks. If the Charleville SVC fails, inductors and capacitors are manually switched. This switching however creates transients on the network, is difficult to manage, and also relies on some plant which is also approaching end of life. At peak load times, without the SVC in service, some loads may also need to be shed in order to maintain a suitable voltage.

Credible Options:

1) 10Mvar STATCOM (a 5Mvar STATCOM connected to each of the 11kV and 22kV buses at Charleville Substation) – Internal Option (NPV = -$11.64M)
2) Network Support Arrangement for the provision of reactive power via an external provider - External Submission Provider (NPV = -10.58M)

Conclusion: The final recommendation was Option (2)

Status: Final Project Assessment Report (FPAR) published.

Ergon Energy published the FPAR on 22nd of May 2019.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
WR1073652 Addressing reliability requirements in West Toowoomba Substation	$11.8M	Jun 2023	*Nil impact beyond regulated revenue.*

Project need:

Ergon Energy is responsible (under its Distribution Authority) for electricity supply to West Toowoomba in south west Queensland.

West Toowoomba Zone Substation (WETO) provides electricity supply to approximately 8923 predominantly residential customers in the Newtown and Wilsonton areas. There are approximately 640 industrial customers consisting of a hospital, shopping centres, schools and other retail / offices complexes.

West Toowoomba Substation was originally built around 1945. The last major upgrade of the substation occurred in the early 1970s. The substation is a 33/11kV substation and is a crucial part of the Toowoomba electricity supply network. There are four incoming 33kV feeders, two from South Toowoomba T043 bulk supply substation and two from Torrington T116 bulk supply substation. WETO is normally supplied from Torrington T116 substation.

Past load on West Toowoomba substation has been an average of 24MVA, however, after the commissioning of the new Toowoomba Central (TWCE) substation in 2016, the load at West Toowoomba has not exceeded 21MVA.

A number of assets in the substation are nearing end of life and are planned to be replaced. The assets due for earliest replacement are the oil circuit breakers on seven 11kV feeders, three 11kV transformer circuit breakers, airbreak switches and a number of relays.

Credible Options:

1) Replace several spans of cable for seven distribution feeders, install a new 11kV switchboard, replace 33kV VT, house and local transformer and update secondary protection systems for bus and distribution feeders. (NPV = -$3.6M)
2) (NPV = -$5.7M)
3) (NPV = -$5.3M)

Conclusion: The final recommendation was Option (1)

Status: Final Project Assessment Report (FPAR) published.

Ergon Energy published the FPAR on 23rd of October 2018.

Project Need, Credible Options and Conclusion	Preferred option		Impact on Network Users (Preferred Option)
	Cost	Est. Delivery	
WR168413 South West Toowoomba Reinforcement	$3.5M	Apr 2022	*Nil impact beyond regulated revenue.*

Project need:

Ergon Energy Corporation Limited (Ergon Energy) is responsible (under its Distribution Authority) for electricity supply to the Toowoomba Region in Southern Queensland.

The South Western edge of Toowoomba is experiencing strong population and load growth in the communities of Westbrook, Drayton, Wyreema, Cambooya and Vale View. The existing Westbrook and Eiser St feeders predominantly supply these areas.

The Eiser St Feeder which extends from South Toowoomba 110/33/11kV Zone Substation, is heavily loaded and has voltage issues emerging towards the extremities of the feeder. Eiser St Feeder supplies approximately 2730 customers and during high load periods is approaching its rating. There is also a lack of transfer capacity which impacts the ability to operationally manage loads during contingency scenarios. Eiser St Feeder's reliability performance has historically been challenging given the long radial nature of this feeder comprised of approximately 80km of line length. On average over the last three years there has been approximately 300 000 customer minutes lost each year.

Westbrook Feeder extends from Torrington 110/33/11kV Zone Substation and predominately supplies approximately 1630 customers in the immediate Westbrook area. Westbrook Feeder is also heavily loaded and strong growth in the area is predicted with 2 applications totalling 700kVA being connected before the end of 2018, and an additional 1500 lot development planned which is expected to drive further block load type connections. Given Toowoomba is geologically constrained due to the Eastern boundary of Toowoomba range, the Toowoomba Regional Council sees the Western area of Toowoomba including Westbrook as key areas for development to meet future population growth.

In order to address these constraints Ergon Energy has proposed to develop a new feeder from Kearney Springs 110/11kV Zone Substation. As part of this feeder development, significant aged assets approaching their end of life will be replaced. This includes approximately 5 km of line where the majority of poles have an age profile of approximately 60 years. By incorporating this replacement into a single project Ergon Energy gains not only construction efficiencies, but also the required extra capacity to meet the load growth occurring in this area.

Credible Options:

1) Develop a new feeder from Kearney Springs Zone Substation.

Conclusion: The final recommendation was Option (2)

Status: Final Project Assessment Report (FPAR) published.

Ergon Energy published the FPAR on 22nd of May 2019.

Note: Whilst the estimated project value does not exceed the Regulatory Investment Test for Distribution (RIT-D) financial threshold of $5 Million, Ergon Energy is focussed on ensuring investments are both prudent and efficient, irrespective of this threshold.

Further information on completed augmentation and replacement RIT-D consultations is available on the Ergon Energy website at:

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

7.7.3 Foreseeable RIT-D Projects

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

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

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

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

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

Table 26: Foreseeable RIT-D Projects to address long term constraints (>$6M)

Region	Driver	Proposed Solution	Expected Investment Test Commencement (Month-Year)	Expected Completion (Month-Year)
Southern	Load Growth	Burnett Heads Reliable Provision of Electricity to the Burnett Heads Supply Area	Jun-20	Dec-23
Southern	Load Growth	Nikenbah Reliable Provision of Electricity to the Nikenbah Supply Area	Feb-20	Apr-24
Southern	Asset Condition	Pialba Reliable Provision of Electricity to the Pialba Supply Area	May-20	Aug-24
Southern	Asset Condition	East Bundaberg Reliable Provision of Electricity to the Nikenbah Supply Area	Feb-20	Dec-23
Northern	Load Growth	Duchess Road Reliable Provision of Electricity to the Cloncurry supply area	May-20	Jun-23
Northern	Asset Condition	Turkinje Reliable Provision of Electricity to the Turkinje supply area	May-20	Dec-24
Northern	Asset Condition	Mt Garnet Reliable Provision of Electricity to the Mt Garnet supply area	Feb-22	Sep-25

7.7.4 Urgent and Unforeseen Projects

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

Chapter 8

Demand Management Activities

8. Demand Management Activities

Our demand management program forms part of an integrated approach that also includes our forecasting, planning, intelligent grid and tariff strategies, to help lower electricity charges for our end use customers. When it is efficient to do so, the implementation of non-network solutions will replace or complement the need for network investment. This involves working with end use customers and our industry partners to reduce demand to maintain system reliability in the short term and over the longer term, defer capital projects. The implementation of a non-network alternative is commonly referred to as demand management (DM).

DM solutions can be in front or behind the meter and include:

- direct load control
- distributed generation, including standby generation and cogeneration
- demand response
- energy efficiency
- fuel substitution (e.g. solar PV)
- interruptible loads
- load shifting
- power factor correction
- pricing/tariffs.

The planning process, as outlined below and the following sections, includes the identification of network limitations and the assessment of non-network solution (refer to Figure 22 and Figure 23). When a network limitation 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 limitation), market engagement and investigation of possible DM solutions is initiated.

'In market' engagement activity depends upon forecast expenditure, size and timing of the limitation. Where total capital expenditure of the most expensive credible option is greater than $6 million, a RIT-D is undertaken (refer to Figure 23).

Where the forecast capital expenditure for the most credible option is less than $6 million, opportunities for credible non-network solutions are developed by gauging interest and ability of service providers and customers to participate. This can be done publishing network limitations (Target Areas) online using incentive maps or inviting proponents to respond to a Request for Proposal (RFP). Details of Target Area locations are found on the [Ergon Energy Incentives Search website](https://www.ergon.com.au/network/manage-your-energy/incentives/search-incentives), link below:

https://www.ergon.com.au/network/manage-your-energy/incentives/search-incentives

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

Figure 22: Non-Network Assessment Process for expenditure >$6M (RIT-D)

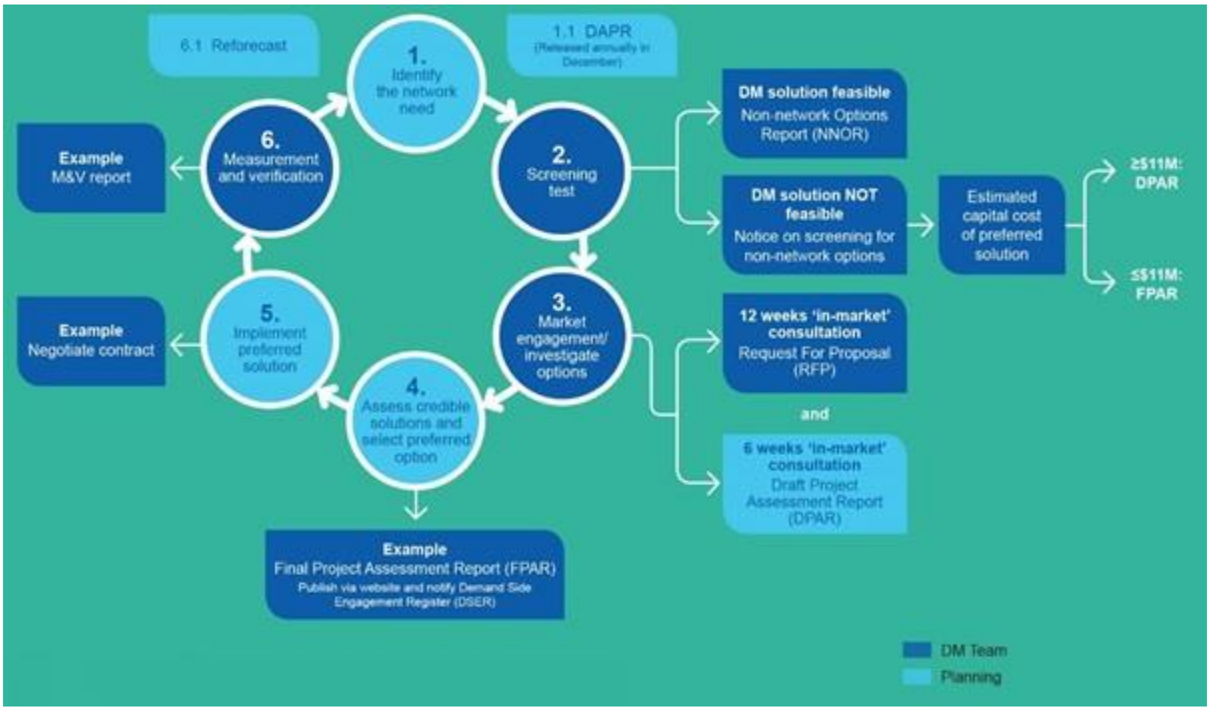
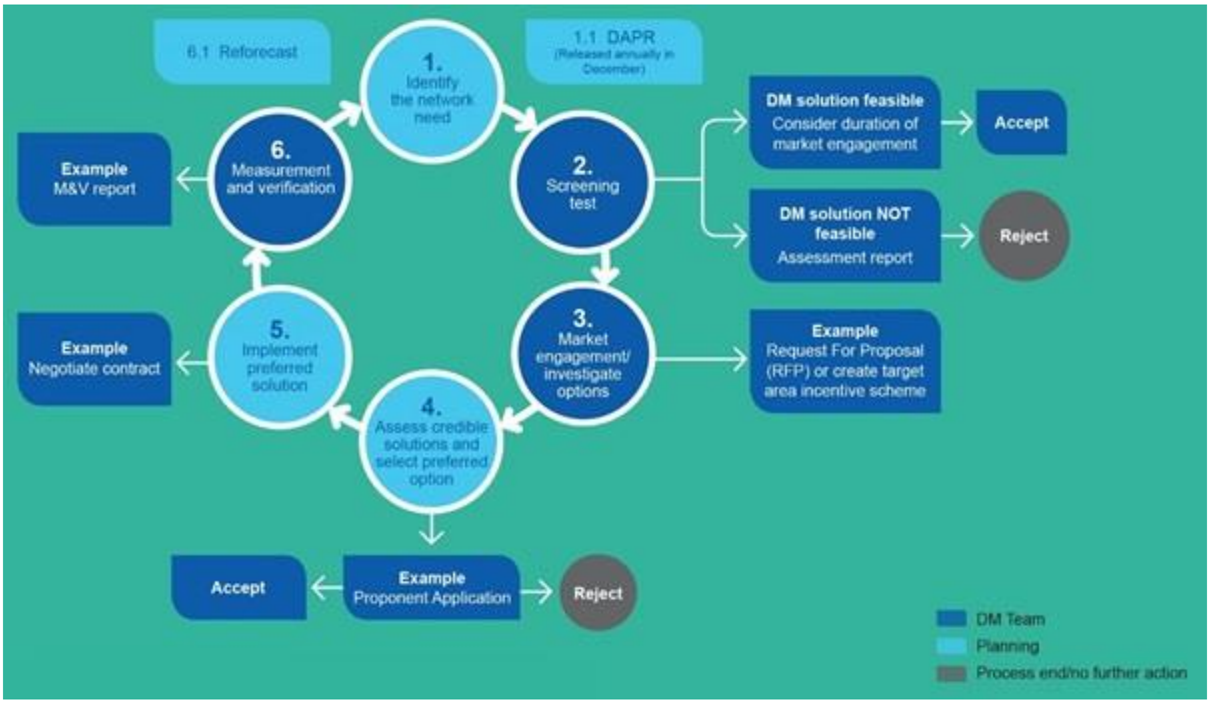


Figure 23: Non-Network Assessment Process for expenditure <$6M



Broad based DM is also incentivised across the region. It delivers demand reductions across the whole network, rather than just in a local area with a network limitation. These demand reductions achieved from appliances connected to control load and PeakSmart air conditioners, can be called upon during emergency or extreme peak demand summer events. This same capability can also be called upon to provide demand response to the AEMO. For example, it has been used in response to lack or reserve events.

8.1 Non-Network Options Considered in 2018-19

In 2018-19, 'in market' engagement for DM solutions occurred in eleven 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, eight embedded generation contracts were maintained to provide non-network solutions during the 2018-19 year.

8.2 Actions Promoting Non-Network Solutions in 2018-19

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

- embed demand side engagement and non-network screening of network limitations into the distribution planning process
- identify and transparently provide details of Ergon Energy and Energex network limitations 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 Ergon Energy and Energex's 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 at the link below:

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

In addition to the Targeted, Broad based and embedded generation DM initiatives described above, Ergon Energy has also promoted non-network options through:

- inputting and being involved in a range of market and industry consultations, forums and development of standards, and will continue to support the long-term development of demand management capabilities
- providing information to customers on non-network opportunities that may be available as well as providing richer sources of information on our network, including our Target Area maps
- undertaking a large customer related DM initiative. This includes supporting customers by providing information to assist with tariff selection and implementation of best practice electricity strategies
- embarking on initiatives to transform the Western Network. This initiative involves identification of high cost to serve network areas in Western Queensland and seeking non-traditional solutions, transition strategies and business models to enable customers' access to a safe, secure, affordable, reliable and efficient electricity supply
- partnering with the agricultural industry groups and irrigation customers to encourage small irrigation customers to utilise an existing small customer load control tariff (Tariff 33). An extension of such tariff offering for Standard Asset Customer - Large (i.e. SAC Large, 100MWh – 4GWh) customers is proposed, as part of the on-going tariff reform process. We are planning a trial with small number of customers to inform development of proposed load control tariff
- innovating to create a network that supports future energy choices. Through utilising the Demand Management Innovation Allowance (DMIA) to undertake innovative trials and projects to test and validate DM products and processes.

8.3 Demand Management Activities in 2019-20

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
- Activate customer response enablers
- 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.

Demand Management Plan 2019-20

Further information on our DM program and the promotion non-network options are detailed on our website at the link below:

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

8.4 Key Issues Arising from Embedded Generation Applications

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

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

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

Table 27: Embedded Generation Connections

NER Requirement	No. received since 1st July 2018	Average Time to complete (Business days)
EG connection enquiries received under clause 5.3A.5	59	–
EG applications to connect received under clause 5.3A.9	2	–
Average time to complete EG applications to connect	0	n/a (projects in progress)

Chapter 9

Asset Life-Cycle Management

9. Asset Life-Cycle Management

9.1 Approach

Ergon Energy has historically had a replacement program which was primarily reactive in nature and driven from defects identified through inspection. The combination of an aging network, as well as observed deterioration in asset performance and increase in network risk has necessitated a change in asset management strategy to ensure that safety and legislative obligations as well as customer requirements are met. This change to a balance of proactive replacement provides a more sustainable approach to managing asset lifecycle. It is necessary to make this shift in strategy to ensure that the observed asset performance trends and risks are managed in a sustainable manner and in a time frame that enables efficient and achievable delivery of work.

Under the Queensland Electrical Safety Act and associated regulations, Ergon Energy has an obligation to ensure that its works and assets are and operate electrically safe. This includes a duty to ensure that it does all that is reasonably practicable. In addition to this, the Regulations impose specific Clearance to Structure / Clearance to Ground (CTS/CTG) measurement requirements which require strict compliance.

The CTS/CTG program is one important part of delivering an overall safe outcome for the community. This issue was highlighted by the 24 July 2019 submission from the Queensland Electrical Safety Office (ESO) which states that “rectification of CTG and CTS non-compliances with safety regulations is an important safety issue which has not been adequately addressed.” EQL has advised the ESO that works to address these issues will be carried out in the next three years, and as such EQL is required to carry out this program in order to be compliant with the Queensland Electrical Safety Act.

The historical approach to pole remediation in Ergon has been through periodic inspection and replacement or nailing of defective poles. An early 2019 review of the pole strength calculation algorithm in Ergon resulted in a change to this algorithm to align it with the methodology used in Energex, and in accordance with Australian Standards. This change led to significant increase in defect pole rates considered in our submissions for the 2020-25 regulatory control period.

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 so far as is reasonably practical, and if not practical to eliminate, to mitigate so far as is reasonably practical.

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 service and network performance to meet the required standards, and maintaining an efficient and sustainable cost structure.

Policies are used to provide corporate direction and guidance, and plans are prepared to provide a safe, reliable distribution network that delivers a quality of supply to customers consistent with legislative compliance requirements and optimum asset life. These policies and plans cover equipment installed in substations, the various components of overhead powerlines, underground cables and other distribution equipment. The policies and plans define inspection and maintenance requirements, and refurbishment and renewal strategies for each type of network asset. Asset life optimisation takes into consideration maintenance and replacement costs, equipment degradation and failure modes as well as safety, customer, environmental, operational and economic consequences.

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

9.2 Preventative Works

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

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

- analysis of power transformer oil to monitor for trace gases produced by internal faults
- inspection of customer service lines
- assessing the extent of decay in wood power poles to determine residual strength
- inspection of timber cross-arms to detect visible signs of degradation
- 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. Ergon Energy has a three year rolling average in-service pole failure rate of 81 failures per annum of the 978,754 pole population, achieving 99.9935% pole reliability, which is better than the Queensland code of practice guideline limit of 99.9900%.

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 annual 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.

9.2.2 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 causal factor in network outages during storms and high winds.

Ergon Energy annually updates its 3D geo-spatial representations of network assets to assist not only with ongoing vegetation management but other aspects of asset inspection. This technology includes predictive capability for vegetation growth rates.

Ergon Energy maintains a comprehensive vegetation management program to minimise the community and field staff safety risk and provide the required network reliability. To manage this risk we employ the following strategies:

- A cyclic program, to cut vegetation on all overhead line routes. Cycle times are varied, based upon Lidar analysis and network analytics enabling optimisation of field crew dispersion, ensuring the powerline clearance zone is kept clear at all times.
- Reactive spot activities to address localised instances where vegetation is found to be within clearance requirements or has been reported for action by customers.

For some considerable time now, Ergon Energy has worked cooperatively with local councils to reduce future risk of vegetation contacting powerlines. Initiatives include the development of tree planting agreements, specifying requirements for the selection of tree species for use near powerlines and programs to remove existing unsuitable trees and replace with powerline friendly trees. These relationships are now quite mature.

9.3 Asset Condition Management

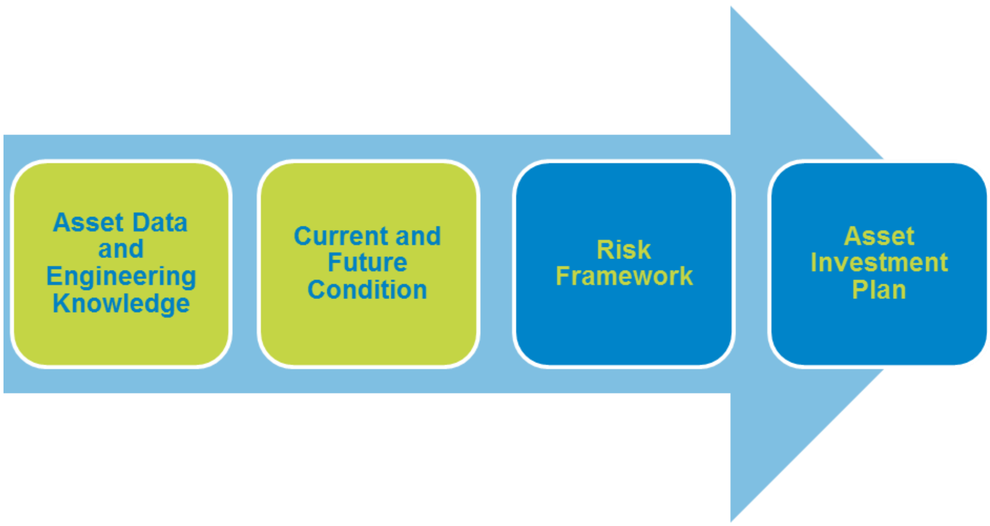
The processes for inspection and routine maintenance of Ergon Energy's assets are well established and constantly reviewed. Ergon Energy uses its asset management system to record and analyse asset condition data collected as a part of these programs. Formal risk assessments are conducted for all asset 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 has recently implemented Intelligent Process Solutions' (IPS) condition monitoring and management software, to collect and analyse asset condition data. The IPS system employs test result analytics, supporting targeted and prioritised maintenance strategies. The primary application of IPS in Ergon Energy is currently in managing the power transformer fleet and plans are progressing to expand across other asset types.

Ergon Energy employs EA Technology's Condition Based Risk Management (CBRM) modelling methodology for high value assets where the effort required to develop, maintain, support and collect the associated information 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. 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 24 below provides a summary of the process for delivering network asset investment planning condition based risk management.

Figure 24: Process to Create Asset Investment Plan



9.4 Asset Replacement

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 site 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 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 limitation 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.

9.4.1 Substation Primary Plant

Power Transformer Replacement and Refurbishment

Transformers are condition monitored and require regular tap-changer maintenance. Failure consequences involve safety impacts for employees and nearby assets in the vicinity at the time of failure, reliability impacts related to technical ability to meet demand, environmental impacts from the quantities of oil involved, and high costs of replacement. Explosive bushing failures and transformer fire are recognised as significant safety risks. Due to the potential failure consequences, Ergon Energy has adopted a CBRM approach to define the highest priority end-of-life replacement time of these assets, optimised for overall least cost and risk.

Circuit Breaker and Switchboard Replacement and Refurbishment

Circuit breakers and switchboards are condition monitored and require regular maintenance. Failure consequences involve safety impacts for employees and nearby assets in the vicinity at the time of failure and reliability impacts related to technical ability to meet demand. Explosive failure of the circuit breaker, electrical arcing consequences causing collateral damage to nearby equipment, and inability to break load and fault currents are recognised as significant safety risks. Due to the potential failure consequences, Ergon Energy has adopted a CBRM approach to define the highest priority end-of-life replacement time of circuit breakers, optimised for overall least cost and risk.

Instrument Transformer Replacement and Refurbishment

Current Transformers (CTs) and Voltage Transformers (VTs) are condition monitored and require little maintenance. Failure consequences are related to safety impacts for employees and nearby assets in the vicinity at the time of failure and reliability impacts related to technical ability to meet demand. Explosive failure of the transformer, electrical arcing consequences causing collateral damage to nearby equipment, and inability to perform network protection functions are recognised as significant safety risks. Due to the failure consequences, Ergon Energy has adopted a CBRM approach to identify the highest priority end-of-life replacement of current and voltage transformers for replacement, optimised for overall least cost and risk.

Substation Outdoor Isolator and Earth Switch Replacement and Refurbishment

Outdoor isolators are condition monitored and require periodic mechanical maintenance. Failure consequences are generally related to delays in performing other maintenance on other substation assets. Because this is relatively simple equipment which requires minimal regular maintenance, Ergon Energy has adopted a near run-to-failure approach for outdoor isolators and earth switches.

Capacitor Banks Replacement and Refurbishment

Capacitor banks are condition monitored and require little maintenance. Failure consequences are generally related to ability to supply load under transformer contingency situations and in some locations, increased risk of power system instability. As these assets are often able to be repaired by the replacement of lower cost internal components, Ergon Energy has adopted a near run-to-failure approach for Capacitor Banks. Prior to replacement, a review is made to confirm the ongoing need for these assets.

Static VAR Compensators (SVC)

SVCs are condition monitored. Modern units require little maintenance; however older units require extensive maintenance. Failure consequences are generally related to dynamic network voltage performance, ability to meet legislated voltage compliance obligations, ability to supply load under high system load conditions and in some locations, increased risk of power system instability and voltage collapse. These assets are uniquely designed to suit local power system conditions. Replacement is justified individually, based upon operational and financial performance outcomes.

9.4.2 Substation Secondary Systems

More detail can be found for secondary system replacement programs in Chapter 15.

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

Remote Terminal Unit Replacement Program

Remote Terminal Units (RTUs) are condition monitored and require little maintenance. RTUs allow remote monitoring and control of substations. Failure consequences include safety impacts including: inability to de-energise the network upon reported emergency situations, reliability impacts including an inability to operate the power system, and an inability to react to asset alerts and alarms in a timely manner which also extends customer outages.

Aged RTU technology deployed in our network has become obsolete. Due to the extensive wiring in place when installed, replacement is time and resource intensive, and a high-cost exercise. Due to the failure consequences, Ergon Energy has adopted a proactive replacement program targeting ageing and obsolete RTUs and a planned replacement program for this asset class is underway.

Audio Frequency Load Control (AFLC) Replacement Program

AFLC equipment is condition monitored and the electromechanical types require some maintenance. AFLC systems achieve customer demand management by facilitating peak load lopping of hot water systems, pool pumps and other large fixed installation loads. Failure consequences generally have reliability impacts, including increased localised load peaks, overloading of distribution assets (shortening life) and overload tripping of assets, with the potential for customer outages. In addition, load increases due to loss of demand management ability arising from failed AFLC assets could be recognised as additional network load. This has the consequential effect of increasing load forecasts, which promotes earlier augmentation expenditure. Condition monitoring has identified near end-of-life of some assets and a planned replacement program for this asset class is underway.

Substation DC Supply ystems

Substation DC supply systems are condition monitored and require little maintenance. Failure consequences include: loss of protection capabilities, loss of circuit breaker functional capabilities, loss of substation monitoring and control capabilities, and loss of communications system capabilities. The impact of this loss of facility includes adverse safety, reliability and business function performance. Due to the failure consequences, Ergon Energy has adopted a proactive replacement program targeting battery systems.

9.4.3 Subtransmission and Distribution Line Equipment

Line Defect Remediation Program

Ergon Energy has an obligation to meet the requirements of the *Electrical Safety Act (2002)* (Qld) to inspect, test and maintain all assets. This program remediates risk prioritised lines defects found by ground based inspection at every asset location. This achieves incremental renewal of all lines based assets at near end of life, maximising the utility of the assets. Ergon Energy is not expecting any legislative change, and, except for specifically-targeted safety risks, defect repair rates are generally expected to be in line with asset age trends.

Conductor Clearance to Ground Defect Remediation

Ergon Energy has an obligation to meet the minimum clearance standards specified under the Electrical Safety Act (2002) (Qld) and associated regulations. The Fugro RoamesTM LiDAR technology has allowed the recent individual identification of conductor span clearance issues for all conductor types except service lines. This has revealed 30,000 (11,000 remaining) separate locations where legislative minimum clearances are not being met. A risk prioritised program over three years is underway to ensure compliance. The current works program is expected to be completed before 2022. Ergon Energy is planning to resurvey the network using LiDAR technology through next regulatory period to maintain clearance compliance.

Conductor Clearance to Structure Defect Remediation

Ergon Energy has an obligation to meet the minimum clearance standards specified under the Electrical Safety Act (2002) (Qld) and associated regulations. The Fugro RoamesTM LiDAR technology has allowed the recent individual identification of conductor span clearance to structure issues for all conductor types except service lines. This has revealed 3,400 separate locations where legislative minimum clearances to structures need to be resolved. A risk prioritised program over two years is underway to ensure compliance. The works program is expected to complete before 2022. Ergon Energy is planning to resurvey the network using LiDAR technology through next regulatory period to maintain clearance compliance.

Distribution Feeder Reconductoring Program

Aged and annealed small diameter copper conductors are at risk of breaking and falling to the ground. This very old conductor is at or beyond economic end-of-life and failure has led to Dangerous Electrical Events (DEEs). There was a fatality in 2009 due to a member of the public making contact with energised LV copper conductor on the ground, and several similar close-call events since then. There was also a subsequent ‘Request for Improvement’ from the Queensland Electrical Safety Office. These assets are considered a significant safety risk, and renewal works are ongoing. This program will replace in excess of 500 kms every year for next 6 years and beyond of 7/.064 and smaller copper conductors targeting high risk locations as the priority. The program will also replace the degraded poles, services and pole top structures as part of bundling work for efficient delivery. The works program is expected to extend beyond 2025, and it is anticipated that other aging conductor replacement issues will also become prominent during this time, extending these sorts of works programs indefinitely.

Cast Iron Pot Head Replacement Program

Cast iron pot heads are a very old type of cable termination filled with oil. They are frequently rusted with moisture ingress. They cannot be condition monitored for oil degradation and it would be uneconomic to do so if it were possible. Eventually the water/oil degradation results in flashover, with sometimes explosive failure. The potheads are typically in urban and business centre locations frequented by the community so the outcome could be catastrophic. This replacement program is progressing to replace this type of asset with polymeric alternatives which have benign failure modes.

Expulsion Drop Out Fuse Replacement in High Fire Risk Areas

Operation of Expulsion Drop Out (EDOs) fuses can produce sparks and molten metal that fall to the ground. In dry tinder locations, this has been demonstrated to initiate bushfires. This presents public safety, asset, and significant legal and corporate risks. Past settlements relating to the Victorian bushfires, with the DNSP and the Victorian Government, associated with this phenomenon have been substantial. Even though Ergon Energy’s service area has lower risk bushfire areas compared to the conditions in Victoria, we intend to mitigate these risks by replacing EDOs with spark-less fuses. Replacement of these assets represents a key risk mitigation strategy. The program is around 50% complete and scheduled to be complete by 2020.

Laminated Veneer Crossarms

There is a material safety risk due to a loss of strength of laminated veneer cross-arms resulting from Alkaline Copper Quaternary preservative leeching and subsequent fungus development. To mitigate public safety risks this program removes laminated cross-arms in special and high-risk locations (high rainfall/humidity and high pedestrian traffic locations) from service. Monitoring programs have been established to determine degradation patterns.

Replacement of Non-ceramic Fuses

Ergon Energy owns a population of obsolete non-ceramic service fuses which are installed on customer's premises. A failure mode has been identified, which could result in the fuse overheating and potentially creating a fire risk. This program involves relocation and/or replacement of this type of fuse installation. The targeted program has commenced.

Customer Service Lines

Customer service line replacement occurs through a combination of failing inspection, capital works (including augmentation projects), and proactive replacement where age, type, condition, and network risk are considered. The proactive replacement of customer service lines is currently focused on open wire and concentric neutral services, as well as a population of problematic XLPE services experiencing insulation degradation, as they have been assessed as presenting the highest safety risk.

Failure of the neutral circuit components of customer service lines is the leading cause of asset related public shocks. While service line replacement mitigates this problem, it is typically a reactive solution, Ergon Energy intends to establish an LV Visibility and Control project that will use technology-based techniques to identify high impedance and open circuit neutral situations. Pre-emptive repair is intended to occur before anyone experiences any shocks. A trial is intended for a small number of residences to confirm viability of the approach. If effective, the trial will be expanded.

9.5 Derating

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

Refer to Section 7.5, 7.6 and 7.7 for information on the assets that Ergon Energy is planning to replace as major projects and proactive replacement programs in the next five years.

We welcome feedback or enquiries on any of the information presented in this DAPR, via email to engagement@ergon.com.au.

Chapter 10

Network Reliability

10. Network Reliability

10.1 Reliability Measures and Standards

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

10.1.1 Reliability Measures and Standards

Ergon Energy uses the industry recognised reliability indices to report and assess the reliability performance of its supply network. The key measures used are:

- System Average Interruption Duration Index (SAIDI). This reliability performance index indicates the total minutes, on average, that the system is unavailable to provide electricity during the reporting period
- System Average Interruption Frequency Index (SAIFI). This reliability performance index indicates the average number of occasions the system is interrupted during the reporting period.

10.1.2 Minimum Service Standards (MSS)

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

The reliability limits are prescribed in Ergon Energy's Distribution Authority, No. D01/99, 30th June 2014. Ergon Energy is required to use all reasonable endeavours to ensure that it does not exceed the SAIDI and SAIFI limits set out in the Distribution Authority for the relevant financial year. Circumstances beyond the distribution entity's control are generally excluded from the calculation of SAIDI and SAIFI metrics. In particular, the MSS calculation excludes any interruption:

- with a duration of one minute or less (momentary)
- resulting from load shedding due to a shortfall in generation
- resulting from a direction by AEMO, a system operator or any other body exercising a similar function under the *Electricity Act 1994* (Qld), NER or NEL
- resulting from automatic shedding of load under the control of under-frequency relays following the occurrence of a power system under-frequency condition described in the power system security and reliability standards
- resulting from failure of the shared transmission grid (Powerlink)
- resulting from a direction by a police officer or another authorised person exercising powers in relation to public safety
- that commences on a major event day
- caused by a customer's electrical installation or failure of that electrical installation.

Under Ergon Energy's Distribution Authority, exceedance of the same MSS limit in three consecutive financial years is considered a 'systemic failure' and constitutes a breach. The MSS limits for the regulatory control period in Schedule 3 of the Distribution Authority remain flat to 2020. They are presented in Section 10.1.3, along with our performance against these limits.

During 2018/19 Energy Queensland recommended (the DNRME) to retain the current SAIDI and SAIFI MSS limits across the three feeder categories for 2020-25 regulatory term for both Energex and Ergon Energy. This proposal was reviewed by the Queensland Competition Authority (QCA) with the following key points mentioned in the authority's final report (Reliability standards for Energex and Ergon Energy for the 2020-25 period, June 2019).

- The MSS limits should be held at their current levels for both Ergon Energy and Energex for 2020-25 period. Maintaining minimum reliability levels as currently specified will encourage Ergon Energy to deliver the same level of reliability experienced by the customers, with no material change in costs borne by its customers.
- The definitions and exclusions of measure and/or events between the MSS and the Service Target Performance Incentive Scheme (STPIS) should be aligned where opportunities exist. This will not lead to the deterioration in the reliability performance experienced by the customers however will change the ways in which reliability performance is characterised and reported.
- The provisions relating to the Worst Performing Feeders be aligned between Ergon Energy and Energex. The goal in aligning these provisions is to realise opportunities for more efficient and integrated network planning and reporting across the two business.

In October 2019, the DNRME issued the revised DAs for Ergon Energy and Energex with the above recommendations materialised in the respective areas.

10.1.3 Reliability Performance in 2018-19

The normalised results in Table 28 highlight favourable performance against the MSS for five of six Ergon Energy's network performance measures in 2018-19.

Table 28: Performance Compared to MSS

Normalised Reliability Performance		2017-18 Actual	2018-19 Actual	2015-20[20] MSS
SAIDI (mins)	Urban	124.82	147.72	149
	Short Rural	318.23	409.69	424
	Long Rural	891.29	1017.99	964
SAIFI	Urban	1.490	1.297	1.98
	Short Rural	2.708	3.141	3.95
	Long Rural	5.551	5.863	7.40

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

In 2018-19, Ergon Energy reliability of supply was favourable to the Distribution Authority's MSS limits for five performance measures, while Long Rural SAIDI was unfavourable to the MSS Limit. Ergon Energy's long rural network's unplanned performance was significantly impacted during October 2018 and March 2019, by severe weather conditions, mostly affecting the network in the Wide Bay, South West, North West and Capricornia regions. Long rural network's reliability performance was also influenced by a significant increase in the frequency and duration of planned supply interruptions primarily required to accommodate high priority defect repairs and maintenance works on lines and substations across regional Queensland.

Figure 25 and Figure 26 depict the five-year rolling average reliability performance for both SAIDI and SAIFI at whole of regulated network level, which demonstrate continual improvement. The overall network performance outcomes for 2018-19 have been impacted by the unfavourable reliability outcomes for rural networks. Nevertheless, the performance trends indicate the optimal performance capability of the network without further reliability specific investment on its infrastructure.

Ergon Energy's overall reliability performance continues to show improvement since the inception of MSS in 2005 with both the duration and frequency of overall outages reducing by 26% and 36% respectively. This is a reflection of the targeted investment made during the last two regulatory control periods towards achieving the regulated MSS standards.

Figure 25: Network SAIDI Performance Five-year Average Trend

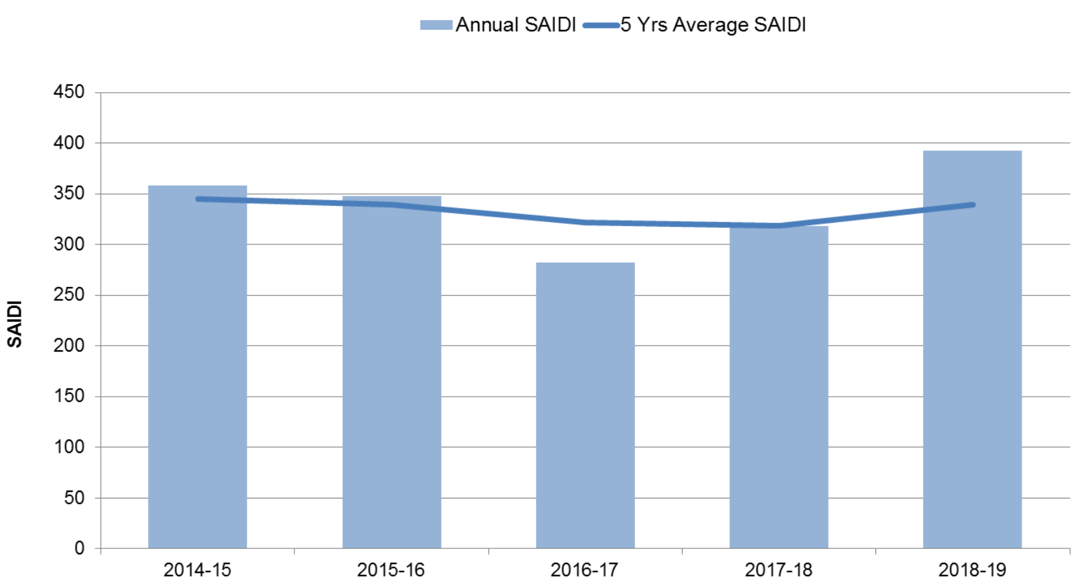
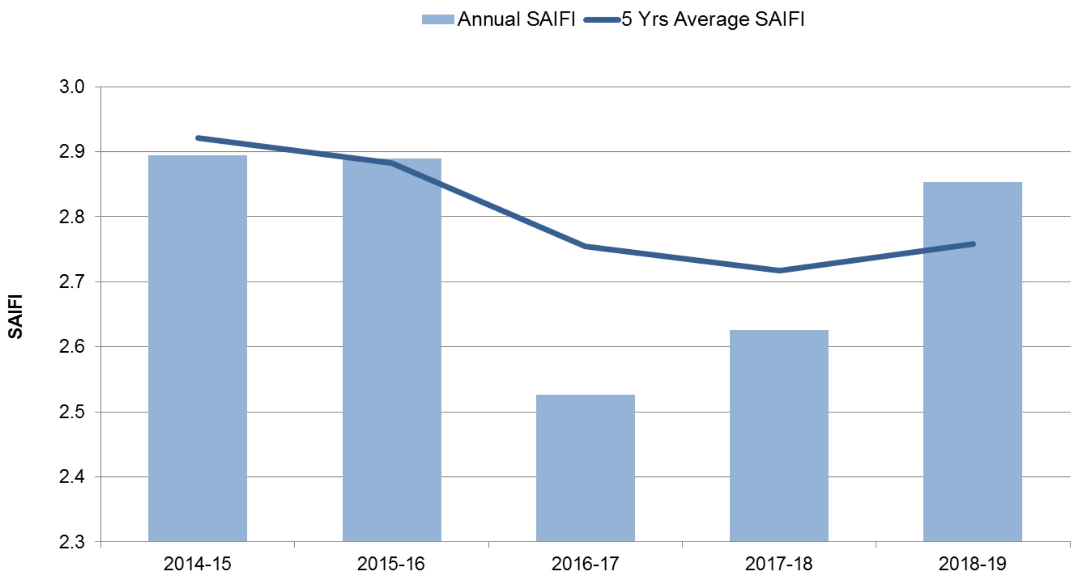


Figure 26: Network SAIFI Performance Five-year Average Trend



10.1.4 Reliability Compliance Processes

To ensure that it delivers the annual reliability performance favourable to the MSS limits, Ergon Energy sets its internal overall SAIDI/SAIFI targets lower than the MSS limits for each of the feeder category for a regulatory year. There is, however, no capex allocated specifically to achieve these internal targets. These targets are intended to define the performance incentive for the operational teams across the business to outperform the MSS limit. The internal targets are used as the reference for tracking performance during a year and to put necessary operational measures where required and feasible.

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

10.1.5 Reliability Corrective Actions

As previously shown in Table 29, Ergon Energy has met five of the six MSS limits for its SAIDI/SAIFI performance measures in 2018-19. We have continued to put significant focus on our operational practices to improve the response time to unplanned outages and the management of planned outages that have direct impact on overall SAIDI, especially for our long rural network for which meeting the MSS SAIDI limit remains a challenge with Long Rural SAIDI exceeding the MSS limit for 2018-19. Following are the reasonable endeavours currently being implemented by Ergon Energy to ensure compliance with MSS in 2019-20:

1. Proactive deployment of mobile generators on selected high contributing Long Rural feeders
2. Bundling of planned works (as reasonably practical)
3. Expedited return to service of failed assets with high reliability impact, such as automatic circuit reclosers and remote-controlled switches
4. Expedited completion of existing Long Rural feeder projects with potential reliability impact where feasible
5. Prioritised inspections of high contributing radial sub-transmission feeders and long rural feeder to identify any vegetation, bird nest, asset failure and access issues
6. Frequent reporting and closer monitoring of impact of planned works on overall SAIDI (including mapping)
7. Establishment of a working group to monitor and manage performance

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. Ergon Energy continues to put a greater emphasis on returning of the key out-of-service plant to service and reducing network risk while weather forecasting services are being used to predict storm activity and prepare additional resources to respond to faults.

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

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

Ergon Energy's Regulatory Proposal on reliability for 2020-25 has only included the investment on Worst Performing Feeder improvement program as required by the DA. This supports our customers' unwillingness to pay for improved network reliability.

10.2 Service Target Performance Incentive Scheme

Since 2010-11, Ergon Energy has submitted data and information on an annual basis, relative to its performance under the AER's Electricity Distribution Network Service Providers, Service Target Performance Incentive Scheme[21] (STPIS). The information collected enables the AER to perform a review of service performance information (as required under clause 7.2 of STPIS).

The AER's 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 include 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 VCR value used in the STPIS for the regulatory control period 2010-15 was $47,850/MWh (2008). For the regulatory control period 2015-20, the AER applied a VCR value of $40,206/MWh for each feeder category. This was based on the VCR values published by AEMO in September 2014, escalated to the March 2015 quarter CPI.

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 2018-19 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 https://www.aer.gov.au/networks-pipelines/network-performance

[21] November 2009

10.2.1 STPIS Results and Forecast

The normalised results in Table 29 highlight a favourable year end performance against STPIS for all of network categories in 2018-19. 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 29: Performance Compared to STPIS

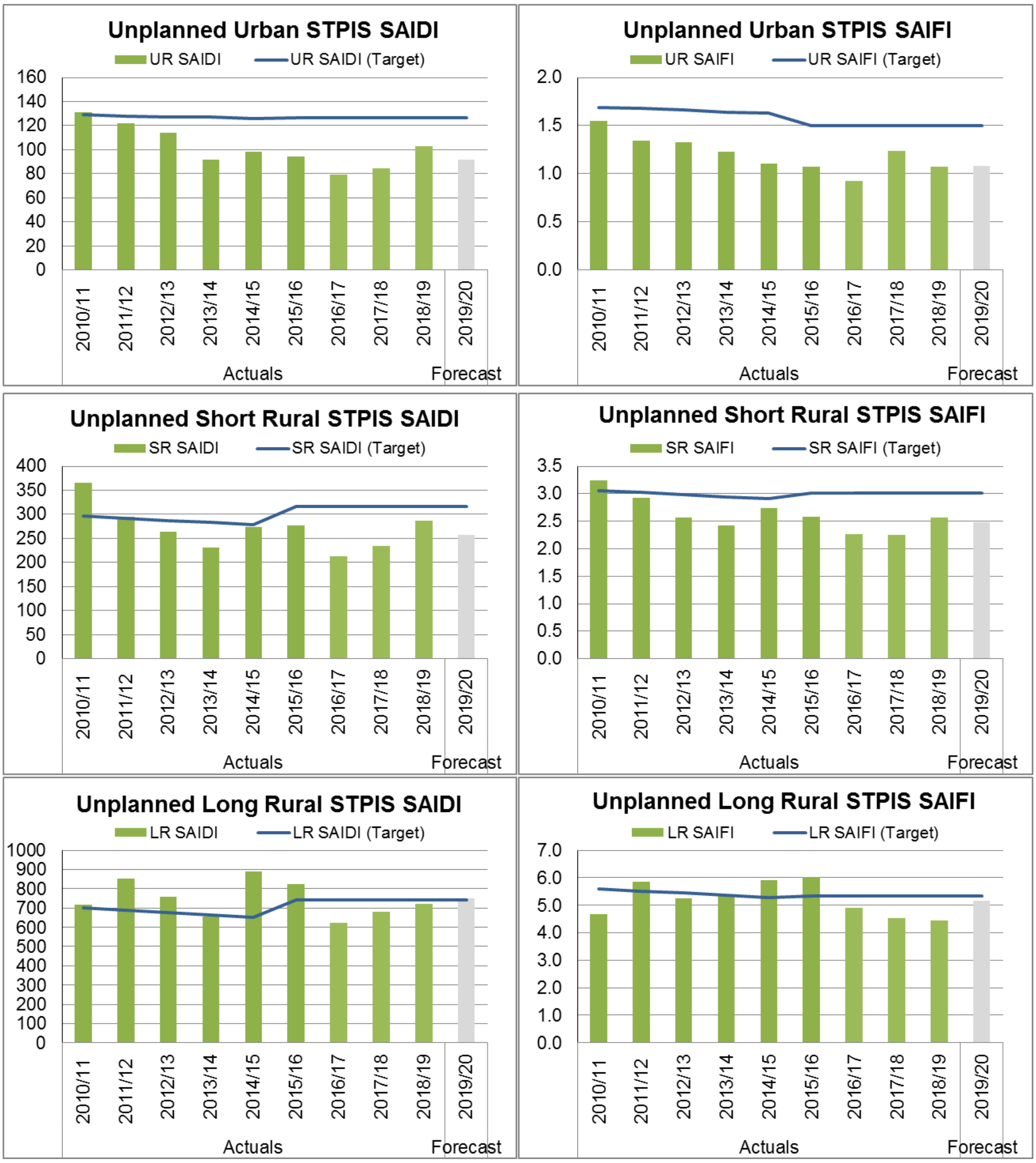
Normalised Reliability Performance		2017-18 Actual	2018-19 Actual	2015-20[22] STPIS
Unplanned SAIDI (mins)	Urban	84.55	103.08	126.73
	Short Rural	234.56	287.65	317.06
	Long Rural	681.58	722.98	742.47
Unplanned SAIFI	Urban	1.233	1.075	1.503
	Short Rural	2.253	2.568	3.019
	Long Rural	4.539	4.455	5.348

In 2018-19, Ergon Energy's reliability of supply outperformed the unplanned performance targets under the Australian Energy STPIS for all six measures. 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 15% and 19% respectively.

Figure 27 depicts the STPIS targets and results for the 2011-19 period. The STPIS SAIDI and SAIFI forecast for the three feeder categories are based on their historical five year average performance. Both the actuals and the future forecast are the normalised values (i.e. exclusions are applied as per Clause 3.3 of the STPIS).

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

Figure 27: STPIS Targets and Results for 2011-19 Period



10.3 High Impact Weather Events

10.3.1 Emergency Response

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

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

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

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

Disaster and Emergency Exercises

To better enable our network to cope with emergency events, a number of preparation exercises will be conducted in preparation for the upcoming storm season. Participation in these exercises involves key staff across Ergon Energy to confirm and enhance their knowledge of the approach to an emergency response. Ergon Energy also participates in external disaster exercises and working closely with the State Disaster Coordination Centre as well as local disaster management groups to further enhance our response capability, test process and ensure readiness.

Damage Assessment

The damage assessment process has been significantly enhanced through greater utilisation of technology including Field Force Automation and mapping services. The combined process produces more accurate and timely field data for the planning, restoration and recovery, which supports improved response times and savings to Ergon Energy and the local economy.

Forecasting/Modelling/Tracking

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

Post Event Reviews and Actions

Our response capability is constantly tested by a range of severe weather events across the state, and each event is unique in terms of scale and impact. The most significant event occurred between January and February 2019 when a monsoon trough caused major flooding in North Queensland from the Daintree River through to Herbert, Flinders and Burdekin Rivers and Bluewater Creek in Townsville interrupting supply to over 17,000 customers. Comprehensive post implementation reviews are conducted to identify further opportunities to enhance our processes, plans, technology, people development and overall response capability. These types of reviews are critical as part of continually meeting stakeholder expectations and reducing the negative impact of large scale disasters on the Queensland community.

10.3.2 Summer Preparedness

Summer Preparations for the 2019-20 storm season

The specific activities being undertaken to prepare the network for the 2019-20 summer season, and generally improve reliability, include:

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

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

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

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

Resources

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

- a field workforce of approximately 2,800 employees and contractors (including design, construction, maintenance, inspection and vegetation workers). This capability is deployed as necessary for any event that occurs through summer.
- leave rosters that are managed to ensure adequate availability of field resources for the summer period.
- additional resource support from Ergon Energy Network and interstate DNSPs.

Customer and community engagement

Ergon Energy keeps its customers informed and engaged through:

- the Customer Contact Centre
- community awareness and education campaigns
- direct media and community engagement forums
- website, social media and other online communications.

10.3.3 Bushfire Management

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

10.4 Guaranteed Service Levels

Section 2.3 of the EDNC 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 30. 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 30: GSL Limits Applied by Feeder Type

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

10.4.1 GSL Payment

The EDNC requires that a DNSP use its best endeavours to automatically remit a GSL payment to an eligible customer. Customers receive the payment for most GSLs within one month of confirmation, however, in the case of Interruption Frequency GSL the payments will be paid to the currently known customer once the requisite number of interruptions has occurred. Table 31 shows the number of claims processed to date and paid in 2018-19.

Table 31: Number of Claims Processed to Date and Paid in 2018-19

GSL	Number Paid	Amount Paid
Wrongful Disconnection	53	$7,526
Connection of Supply	4	$513
Customer Reconnection	32	$5,857
Hot Water Supply	0	$0
Appointments	149	$8,664
Planned Interruptions	1,154	$40,353
Duration of Interruption	9,601	$1,094,512
Frequency of Interruption	7	$798
TOTAL	**11,000**	**$1,158,223**

10.5 Worst Performing Feeders

In accordance with Section 11 of the Distribution Authority, Ergon Energy continues to monitor the worst performing feeders on its distribution network and report on their performance. Under the authority, Ergon Energy is also required to implement a program to improve the performance outcomes for the customers served by the worst performing feeders.

Ergon Energy's worst performing feeders are classified based on three years of performance data and average performance indices. The distribution feeders are ranked (status assigned) according to their actual average SAIDI performance over that time. Feeder rankings are defined below:

- green feeders have a three years' average SAIDI ≤ MSS
- yellow feeders have a three years' average SAIDI > MSS < 150% MSS
- amber feeders have a three years' average SAIDI > 150% MSS < 200% MSS
- red feeders have a three years' average SAIDI > 200% MSS.

The Distribution Authority requires that we determine the top 50 worst performing feeders across all feeder categories, excluding feeders with less than 20 customers. Ergon Energy assesses the red feeders by looking for the highest (top 50) SAIDI ratios. The worst performing feeders in each of the Urban, Short Rural and Long Rural feeder categories are then analysed to identify performance improvement opportunities (the exclusion of feeders with less than 20 customers from the worst performing list allows sharing of the benefits of improvement investment across more customers). These opportunities are then evaluated and where appropriate, projects raised and carried through to the works program to deliver reliability improvement.

The list of our worst performing feeders, based on three years' average annual SAIDI performance up to June 2019, has been provided in Appendix E. Ergon Energy's worst performing feeder assessment for 2018-19 is summarised below:

- 14% of our distribution feeders supplying more than 20 customers have been identified as red feeders at June 2019 (145 in total – 10 Urban, 109 Short Rural and 26 Long Rural). In addition, there are 54 red feeders, individually supplying less than 20 customers. However, these 54 feeders only supply a total of 0.03% of Ergon Energy customers
- There has been a decrease of 1% in the total number of red feeders supplying more than 20 customers compared to the last financial year. These red feeders supply less than 5.17% of Ergon Energy's total distribution customers
- The top 50 worst performing feeders, which equate to 4.16% of the total distribution feeders, are targeted for reliability improvement investments
- 39 of the worst performing feeders have carried over from the list identified either in 2017-18 or previous years in the 2015-20 regulatory control period.

Review of Worst Performing Feeders Reported for 2017-18

- 52% of the 50 worst performing feeders identified in 2017-18 saw an improvement in their annual SAIDI as of June 2019. Four of those feeders now have significantly improved annual SAIDI, and are now favourable to the June 2019 MSS limits
- During 2018-19, Ergon Energy completed detailed engineering reviews of 14 of the 50 worst performing feeders that were identified based on their three years' average SAIDI performance up to 2017-18. This included 1 Urban, 12 Short Rural and 1 Long Rural feeders scattered mainly in the Northern Queensland and Wide Bay supply regions. Six of these feeders did not present any opportunities for capital investment to improve reliability with some of them showing significant performance improvement as of June 2019
- The Northern Queensland region of Ergon Energy's network dominates the worst performing feeder list for the Short Rural feeder category. This is because the region has the highest number of Short Rural feeders compared to the other supply regions of Ergon Energy and the category dominates its total distribution feeder base at 57%
- The worst performing feeders reviews included detailed analysis of different type of outages (planned and unplanned) and outage triggers and contributing causes. The contributions from different segments of the electricity supply chain (subtransmission, distribution, SWER etc.) were also analysed to understand the drivers of the poor performance and to identify the reliability improvement opportunities for the reviewed feeders
- The contribution from the subtransmission network outages to the worst performing feeders, especially for the Urban and Short Rural feeders, is proportionally high (more than 50% in most of the cases). Adverse weather conditions have also been the key contributor to the worst performing feeder performance
- A small number of the worst performing feeders were found to have high average SAIDI due to one-off, low-probability events, often triggered by storm conditions. Most of the time, these feeders did not show need/prospect for capital investment and as such are being monitored for any potential deterioration in their future performance.

The outliers in the Southern region are mostly due to the radial nature of the network resulting in higher exposure to the adverse environmental elements.[23] This supply region also has a higher exposure to thunderstorm activity compared to other regions. The length of exposure of Long Rural and Short Rural feeders, coupled with the geographically dispersed locations of attending depot/staff and their subtransmission systems contribute significantly to the adverse performance of these feeders. The larger customer densities are on urban feeders, which mean a single outage event in this category contributes significantly to the SAIDI value for the feeder. Limited accessibility during the wet season has also been found to be one of the key contributing factors to the longer outage duration of the worst performing feeders. Network asset solutions that could be applied at subtransmission network level are usually very high cost options and such investment cannot be considered prudent to improve reliability for a small cluster of customers or a feeder/feeder section with very low customer density.

Ergon Energy only sought limited capex for the Worst Performing Feeder Improvement program from the AER for the 2015-20 regulatory control period. We are ensuring that the investment in the Worst Performing Feeders Improvement program is prudently spread across different feeders/regions.

The reliability improvement solutions identified from the worst performing feeder reviews conducted in this regulatory control period have mainly included low to moderate capital investment options. The low cost, quick win solutions mainly included protection setting changes, installation of Line Fault Indicators with communication and Fuse Savers. The moderate investment options included installation of new Automatic Circuit Reclosers, Sectionalisers, Remote Controlled Gas Switches and also relocation and/or replacement of switching devices. The identified solutions are currently being implemented. Ergon Energy will continue reviews of its worst performing feeders during 2019-20.

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

1. Improved network operation by:
    - investigating to determine predominant outage cause
    - implementing reliability or operational improvements identified through the investigation of any unforeseen major incidents
    - improving fault-finding procedures with improved staff-resource availability, training and line access
    - improving availability of information to field staff to assist fault-finding, which could include communications, data management and availability of accurate maps and equipment
    - planning for known contingency risks until permanent solutions are available
    - improving and optimising management of planned works.

[23] Approximately 60% of the customers in the South West supply region are supplied by radial networks.

2. Prioritisation of preventive-corrective maintenance by:
    - scheduling asset inspection and defect management to poorly performing assets early in the cycle
    - scheduling red feeders first on the vegetation management cycle
    - undertaking wildlife mitigation (e.g. birds, snakes, possums, frogs) in the vicinity of red feeders
3. Augmentation and refurbishment through capex by:
    - refurbishing or replacing ageing assets (for both powerlines and substations).

10.6 Safety Net Target Performance

Ergon Energy's Distribution Authority describes the performance reporting obligations against service Safety Net targets.

Supply interruption events over 2018-19 have been reviewed in detail to identify any instances where the actual restoration performance may not have achieved the service Safety Net targets set out in Schedule 4 of the Distribution Authority (as described in Section 6.4.2).

In 2018-19, there were no events exceeding the service Safety Net targets.

Chapter 11

Power Quality

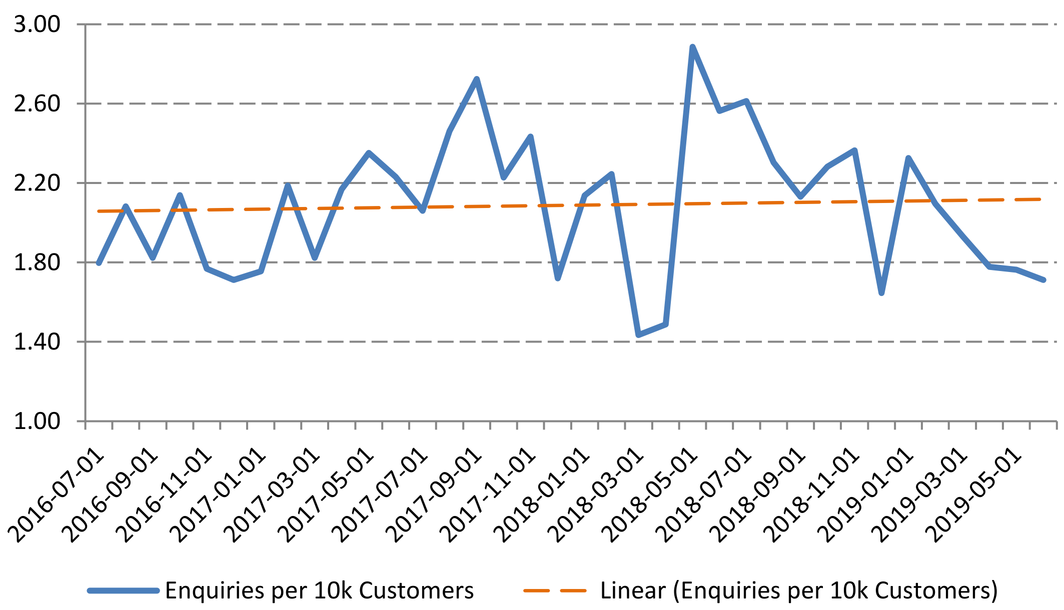
11. Power Quality

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

11.1 Customer Experience

The QoS experienced by customers is measured by the number of QoS enquires lodged by customers. QoS enquiries occur when a customer contacts Ergon Energy with a concern that their supply may not be meeting the standards. Figure 28 shows that the number of enquiries on a normalised basis per 10,000 customers per month. On average, there has been a slight increase over the last 3 years with 2018-19 showing a slight decrease.

Figure 28: Quality of Supply Enquiries per 10,000 customers



QoS enquires are selected from categories on initial contact as follows: low voltage, voltage dips, voltage swell, voltage spike, solar PV, TV or radio interference, motor start problems, and noise from appliances. Figure 29 shows a breakdown of the enquiries received by the reported symptoms over the last 12 months, with the largest identifiable category, at 47%, related to solar PV issues. Many of these are associated with customer installations where solar PV inverters could not export without raising voltages above statutory limits (although inverters are designed to disconnect when voltage rises excessively, regular occurrences of this reduce the level of electricity exported and can often cause voltage fluctuations and customer complaints). The comparison to the previous five years is shown in Figure 30.

Figure 29: Quality of Supply Enquiries by Category 2018-19

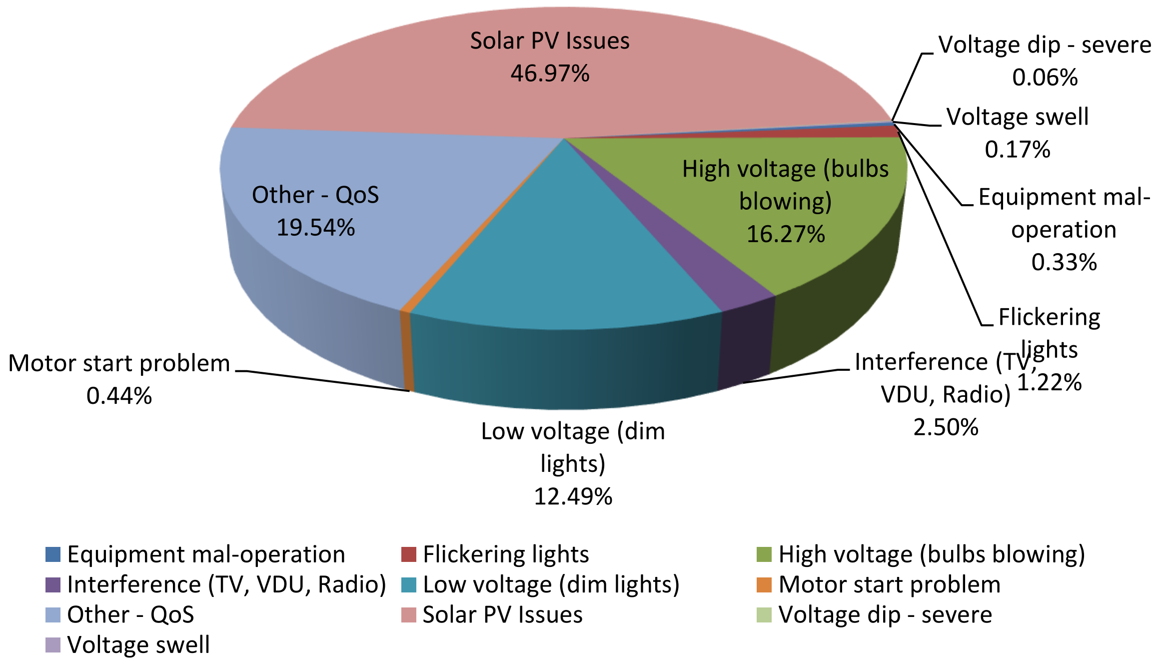
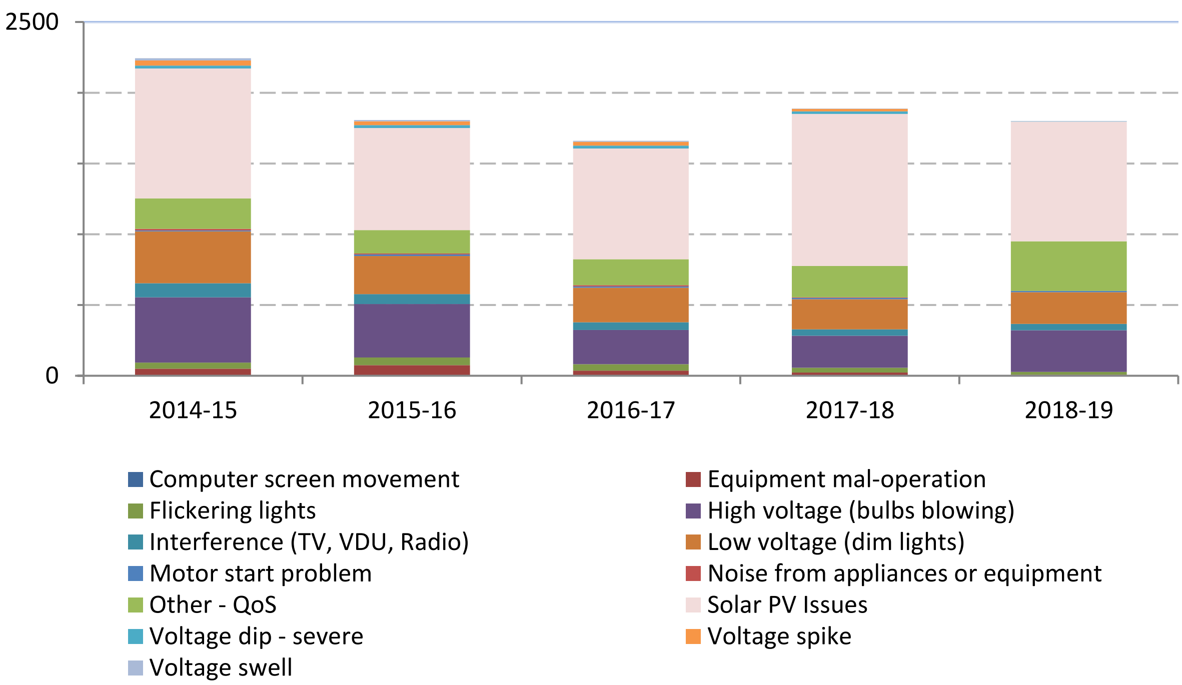


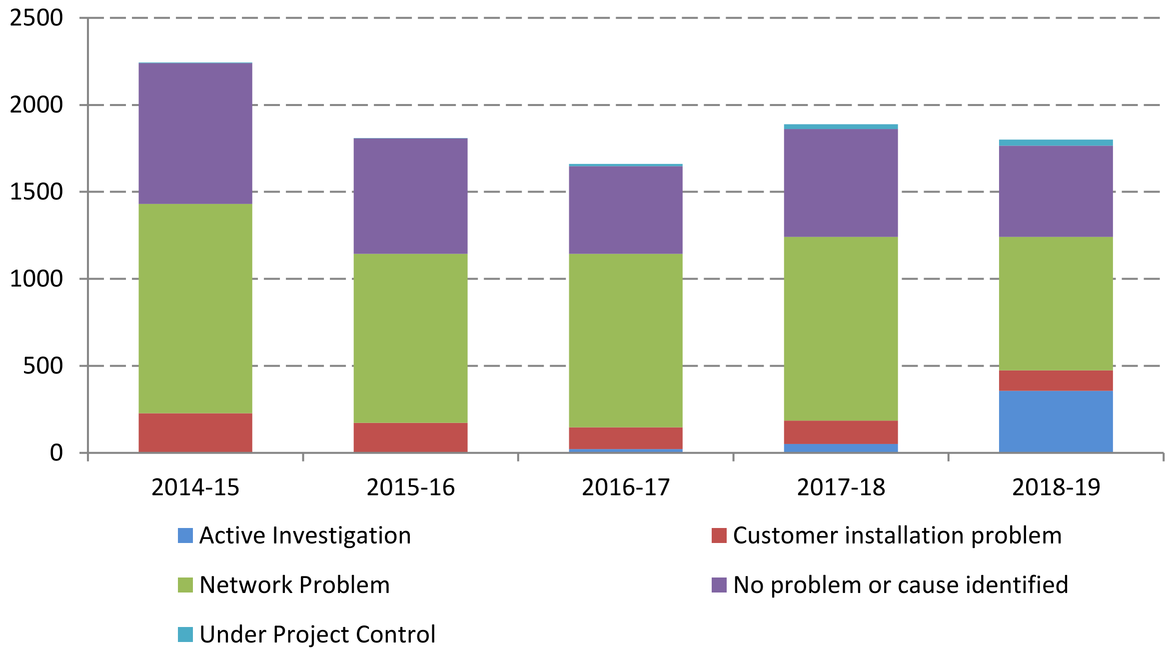
Figure 30: Quality of Supply Enquiries by Year



The number of QoS enquiries received in 2018-19 decreased by 4.6% when compared to the previous year from 1,888 to 1,801 enquires. The connection of solar PV systems has led to numerous network voltage issues, which have required responses ranging from reviewing tap plans, reviewing regulator settings to augmenting low voltage (LV) and high voltage (HV) networks in order to accommodate the solar PV systems.

The close out types of QoS enquires is shown in Figure 31. The data shows that 39% of the enquires to date were due to a network issue there was no fault found for 26% and the fault was on the customers side of the connection for 6% of the total enquiries. There are however, 676 (27%) enquires considered open and under investigation.

Figure 31: Quality of Supply Enquires by Type at Close Out



11.2 Power Quality Supply Standards, Code Standards and Guidelines

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

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

Some of the relevant requirements under the Regulations/Rules are listed below and further defined in Table 32, Table 33, Table 34 and Table 35, 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 32: Allowable Variations from the Relevant Standard Nominal Voltages

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

Table 33: Allowable Planning Voltage Fluctuation (Flicker) Limits

Voltage Levels	Electricity Regulations	NER
Low voltage (less than 1kV)	Not Specified	7.30%
Medium voltage (11kV)	Not Specified	6.60%
Medium voltage (33kV)	Not Specified	4.40%
High voltage (110kV, 132kV)	Not Specified	3%

Table 34: Allowable Planning Voltage Fluctuation (Flicker) Limits

Voltage Levels	Electricity Regulations	NER
Low voltage (less than 1kV)	Not Specified	2.5%
Medium voltage (1kV to 33kV)	Not Specified	2%
High voltage (33kV to 132kV)	Not Specified	1%

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

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

11.3 Power Quality Performance in 2018-19

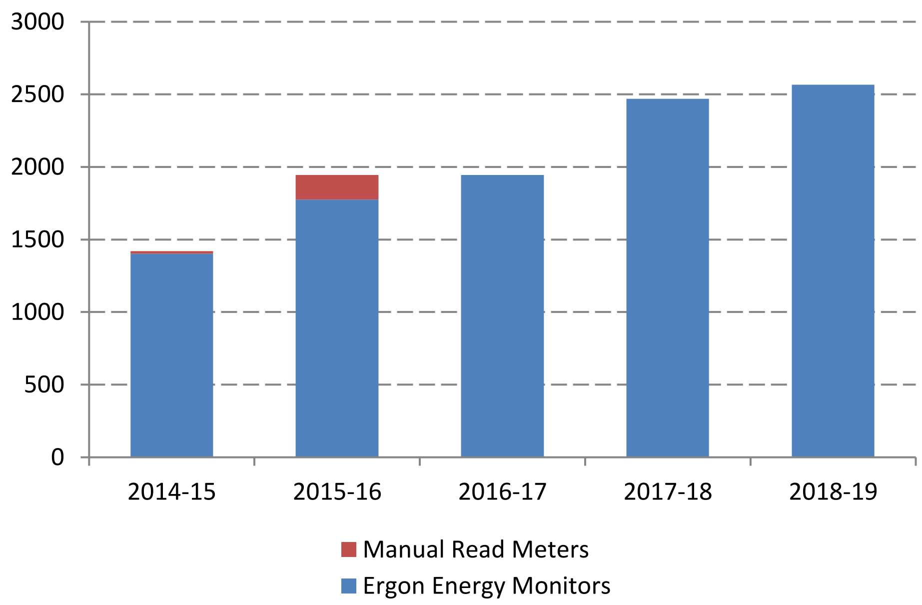
11.3.1 Power Quality Performance Monitoring

Processes for PQ monitoring have been developed from the requirements of the Queensland Electricity Regulations and the NER Rules. Ergon Energy started to install network monitors in 2009 and currently has in excess of 2,569 PQ monitors on distribution transformers throughout the network that monitor and record the network PQ performance. These monitors are remotely monitored and provide an insight into power quality performance at the junction of the Medium Voltage (MV) and LV networks. Monitors currently cover more than 930 feeders or roughly 78% of the feeders in the network.

Each of these monitors contributes to give an indication of the state of the network for PQ parameters. The monitor data is downloaded four times daily, recorded, accessed and presented based on 10 minute averages. The data is usually available the following day. PQ reports are presented in various ways to identify potential network issues that may need urgent investigation and resolutions. All PQ monitors are installed on the terminals of the distribution transformers and therefore there maybe differences at the end of the LV feeder due to high load during the evening and rise in voltage during the day depending on the amount of solar along the feeder. The breakdown of the types of monitor numbers being read is shown in Figure 32. In previous years customers meters have been used for PQ parameters however they are no longer used to monitor network PQ health status due to the variation of the availability and the changes due to Power of Choice (PoC).

Voltage data presented in this report is based on the 230V +10/-6 limits.

Figure 32: Types of Power Quality Monitors and Meters



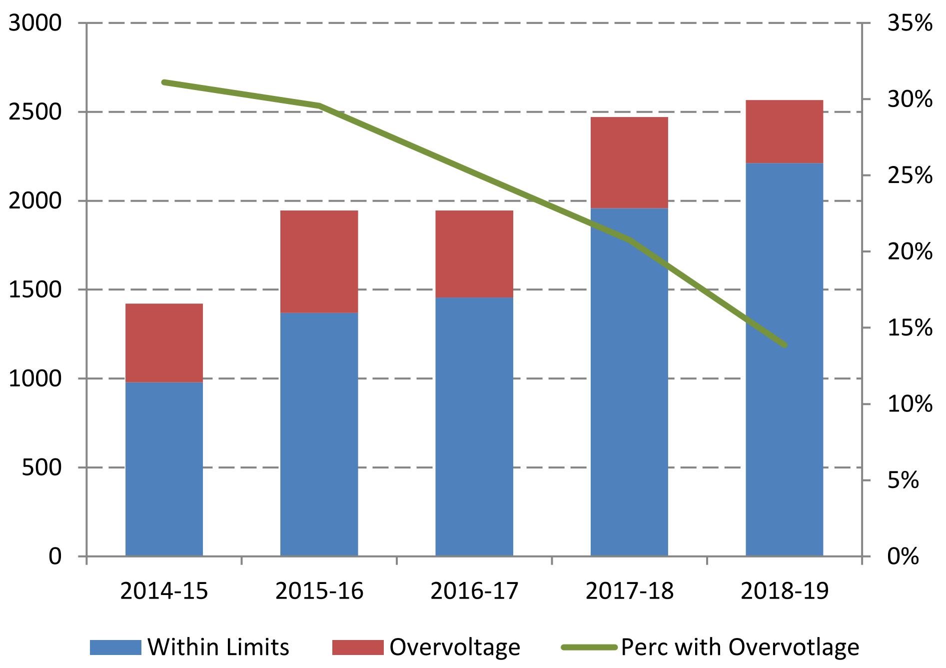
11.3.2 Steady State Voltage Regulation – Overvoltage

The number of monitored sites that reported overvoltage outside of regulatory limits of 253V was 13.87% for 2018-19. This means 13.87% of sites recorded an exceedance of the upper limit for more than 1% of the time based on 10 minute averages. This is a notable improvement from the 17-18 year when there were 17.85% of sites with overvoltage. Figure 33 shows the number of monitored sites that have recorded over-voltage conditions for the last five years and percentage of overvoltage sites for each year. This is the fifth consecutive year that improvement has occurred to reduce the number of sites with overvoltage issues.

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

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

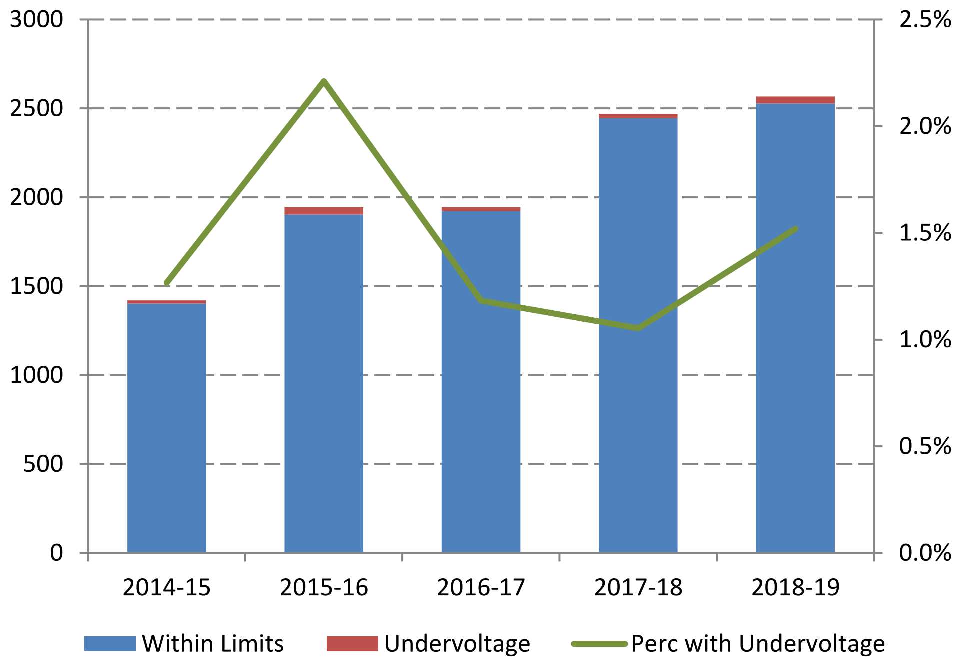
Figure 33: Overvoltage sites



11.3.3 Steady State Voltage Regulation – Undervoltage

The change to 230V sees the lower limit for low voltage move to 216.2V. The number of monitored sites recording under-voltage issues outside of the regulatory limit of 216.2V was 1.5% for 2018-19. This means 1.5% of monitored sites recorded an exceedance of the lower limit for more than 1% of the time based on 10 minute averages. Figure 34 shows the number of monitored sites that have recorded under-voltage conditions for the last five years. There has been a slight increase in the number of sites experiencing under voltage issues.

Figure 34: Undervoltage sites

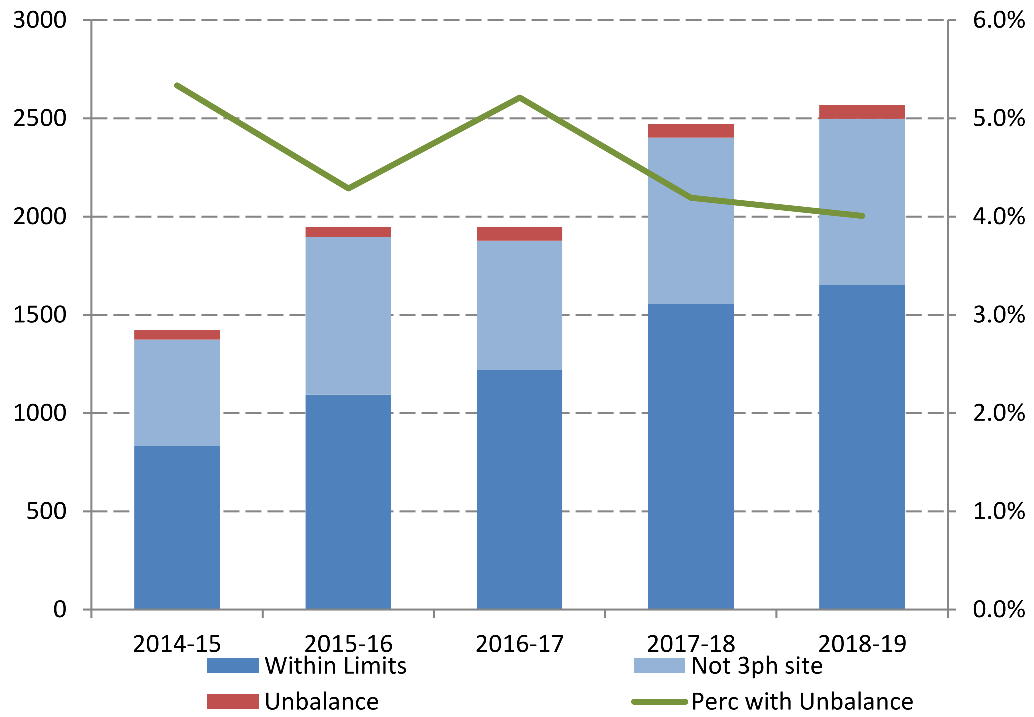


11.3.4 Voltage Unbalance

Data from the monitored 3-phase sites shows that 4.0% of these sites were outside of the required unbalance standard of 2.5% during 2018-19. Figure 35 shows the number of sites that have recorded unbalanced conditions for the past five years.

Typically, unbalance is seen on the rural feeders where there are SWER networks and a large number of single phase customers in the associated downstream feeder, which impacts on the overall balance of the three phase feeder. Due to predominantly radial nature and high number of single phase transformers, Ergon Energy's distribution network has a high number of monitors on single phase transformers. Monitored sites that are not three phase, are also shown as part of the five year trend shown in Figure 35.

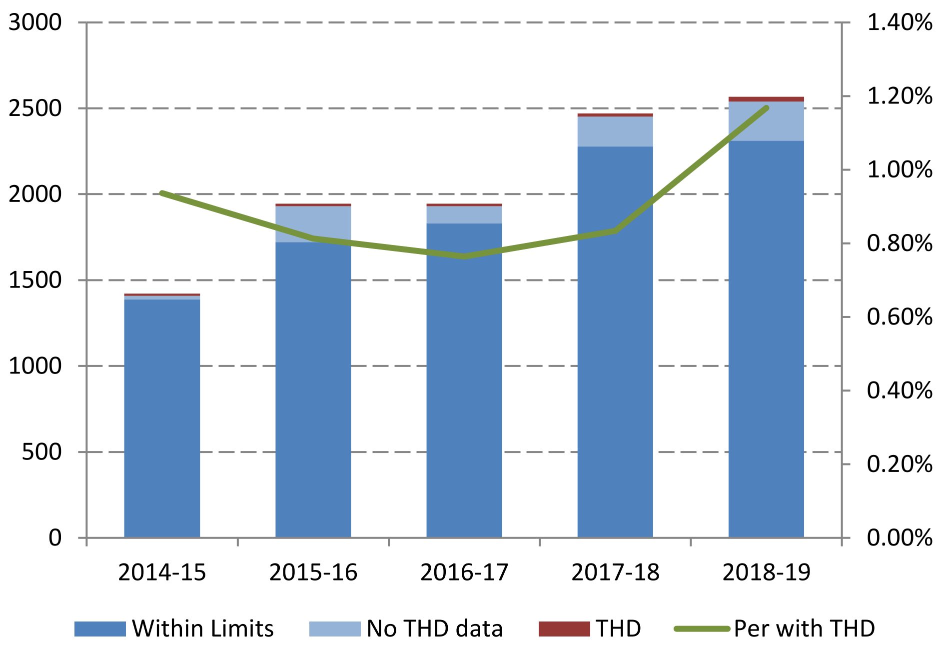
Figure 35: Voltage Unbalance Sites



11.3.5 Harmonics Distortion

Harmonics are a measure of the impurity of the voltage and are recorded as Total Harmonic Distortion (THD) representing all harmonics levels from the second to the fiftieth harmonic. Not all monitored sites are capable of measuring harmonic with 228 of the 2,567 sites (8.8%) not capable of harmonic reporting. There were 1.17% of sites recording harmonics that exceeded the regulatory limits of 8% during 2018-19. This figure will be at the upper limit as when some faults occur with voltage and unbalance it impacts on harmonics recorded values. Figure 36 shows the percentage of sites that exceed THD limits.

Figure 36: Total Harmonic Distortion (THD) sites



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

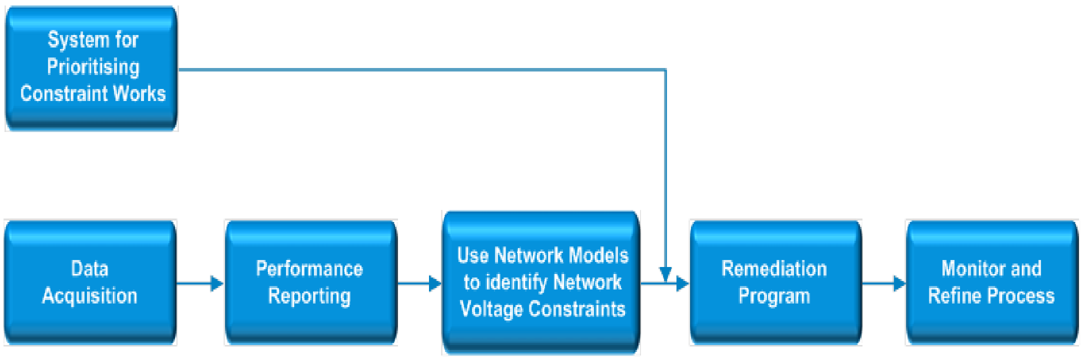
11.4 Quality of Supply Process

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

Due to the complexity of the network and the large number of sites involved, the management of quality of supply presents many challenges. To address these challenges, a proactive and systematic approach shown in Figure 37 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 37: Systematic Approach to Voltage Management



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

11.5 Strategic Objectives 2015-20

During 2018-19 Ergon Energy continued to focus its voltage management strategy on all voltage levels of the network however a high percentage were associated with the LV customers. In the 2018, Energy Queensland finalised the Customer Quality of Supply Strategy which covers the Power Quality strategy for Ergon Energy and Energex. It covers the changing network connections and configurations, increasing customer peak demands, the high penetration of solar PV and its continued growth, the battery energy storage systems and the impact of EVs.

During 2018-19 Ergon Energy continued the implementation of the current PQ strategy by installing 395 PQ monitors on distribution transformers and 12 PQ analysers within substations to disturbing load and embedded generator feeders. This will bring the total installed monitors to more than 3,295 which represent approximately 3.2% of the distribution transformers in regional Queensland. The number of analysers installed to a total of 152.

The network PQ monitors throughout the network are now accessed and downloaded every hour and the sites that are exceeding the PQ parameters are tabled for action by a daily email to PQ staff. There have been numerous examples where the PQ monitors have identified network faults before being noticed by customers or systems. In addition, a monthly phenomenon report summarises and grades the PQ issues for action. The report shows all sites that are exceeding any of the PQ standards. The report is used to determine if there is equipment failure or where a review of regulator settings or tapping plans is required, equipment maintenance, replacement or augmentation is needed.

In the 2015-20 regulatory control period Ergon Energy has targeted to install approximately 1,100 additional PQ monitors to provide maximum coverage of feeders throughout the network to ensure a comprehensive report on PQ parameters is available from most feeders. An additional 50 PQ analyser s are also targeted to be installed within substations connected to disturbing load feeders.

Due to the diversity and type of the Ergon Energy networks, unbalance is another PQ parameter that shows exceedances in various locations and numerous times throughout the year. Unbalance will be managed as per the PQ Planning Guidelines and the Standard for Transmission and Distribution Planning.

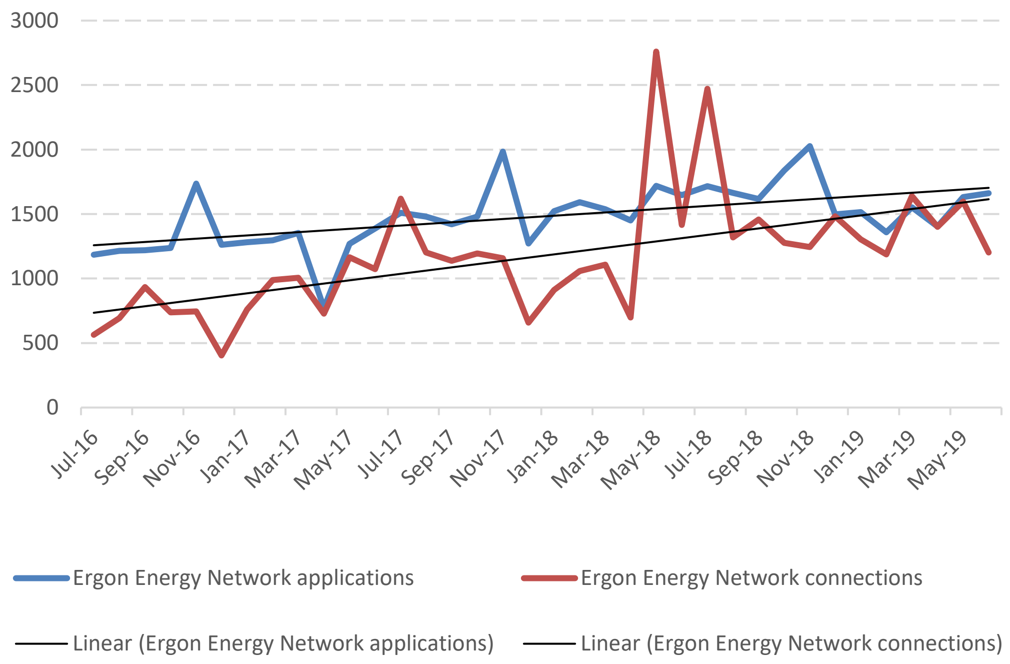
The Harmonic levels being seen on the network have remained constant. Continual vigilance will need that harmonics levels do not impact on the effective operation of the network.

11.6 Solar PV Systems

Ergon Energy’s strategy continues to have a strong focus on the voltage management for low voltage customers due to the high number of residential customers with a high percentage of solar systems. During the period 2018-19 the number of Solar PV applications and connections continued to show continued growth. Figure 38 shows that the number of solar applications and connections has continued to increase each year for the past 3 years.

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

Figure 38: Solar PV Applications and Connections



Throughout regional Queensland there has been high number of applications for large scale solar farms during 2018-19 and more than 65MW of solar farms have been connected. Refer to Chapter 12 for further details of all solar farms connections. Solar Farms larger than 1.5MW are required to have a PQ analyser at the connection point. The PQ analyser is used as part of the commissioning process and used to ensure ongoing compliance when operating.

11.7 Queensland Electricity Regulation Change

In October 2017 the Queensland Government changed the Queensland Electricity Regulation for a change in the low voltage from 415/240 +/-6% to 400/230 +10 /-6%. This is also known as 230V standard. The change requires initial compliance with the new statutory voltage limits of 216-253V as per AS60038 to be achieved by October 2018 with full compliance to AS 61000.3.100 by October 2020.

The change has seen a number of zone substations bus voltages adjusted to meet the requirements. At the same time, feeder model reviews are continuing to occur to determine the required changes to regulator settings and transformer tap positions. As of 30th June 2019, the changes that have been implemented, show that 92% of Ergon Energy's network is compliant for 230V standard. The data shows that the number of sites with overvoltage is high for the first half of the year with considerable reduction in the second half of year. The current modelling and measurements indicate that the number of future changes will require some augmentation costs and some transformer upgrades along with conductor upgrades and changes could be required.

11.8 Power Quality Ongoing Challenges and Corrective Actions

11.8.1 Medium/High Voltage Network

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

11.8.2 Low Voltage Network

The high penetration of solar PV systems on the LV networks has highlighted some of the limitations in the network. The main issues have been in balancing the solar PV systems during the day and peak loads during non-daylight periods on the LV network. This continues to require on going work to ensure the PQ parameters are maintained within limits and to ensure neutral currents are limited. The Customer Quality of Supply Strategy for 2020-25 has identified the need for further monitoring of the LV network. The strategy has been used to build the 2020-25 regulatory submission for PQ. The submission has proposed to monitor all transformers larger than 200kVA suppling a large number of residence customers with the total solar ratio greater than 50% to have a PQ monitor installed. It has also been found that where there are long LV feeders exceeding 400 meters, there is a need to monitor the end of the LV run also.

Table 35 lists the initiatives that were completed during 2018-19 along with the expected work for 2020-21.

Table 35: Summary of Power Quality 2018/19 Initiatives

Initiative Title	2018-19 units	2020-21 Proposed units
Monitoring / Reporting & Data Analytics		
Distribution Transformer monitoring Including SWER	350	250
Distribution Transformer monitoring – Padmount	45	30
Rectification Works		
Uprate & Reconfigure LV Network — Overhead (OH)	80	50
Uprate & Reconfigure LV Network — Underground (UG)	Nil	Nil

With regard to remediation measures that address the impacts of high levels of solar PV penetration, Ergon Energy has considered the practical range of network options shown in Table 36. In general, as the solar PV penetration level rises, so does the cost of remedial work.

Table 36: Network Solutions for Varying Levels of solar PV Penetration

Solar PV Penetration Level	Network Solutions
From 30% to 70%	1. Balance of PV load 2. Change transformer tap
From 40% to 100%	3. 1 and 2 above 4. Upgrade transformer 5. Additional transformer (incl. reconfigure LV area) 6. Re-conductor mains
From 100% to 200%	7. 1 to 6 above 8. New technology (On load tap transformer, LV regulator, Statcom)

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.

11.8.3 Planned actions for 2020-25 Regulatory Control Period

For the next regulatory control period, Ergon Energy will continue to have a strong focus on voltage management for low and medium voltage network issues identified through PQ data analysis. This will be further supported by installation of additional PQ monitors and analysers on the network at the terminals of distribution transformers and at the end of long LV feeders and PQ analysers at the connection point of embedded generators. Typical rectification of voltage and PQ issues will include installation of Statcoms, switched capacitor, Low Voltage Regulator (LVR) and On Load Tap Changers (OLTC).

11.9 Risk Assessment

Ergon Energy is managing the risks associated with high solar PV penetration and voltage rise on the LV network through the Customer Quality of Supply Strategy and the strategic initiative to invest in fit for purpose smart technologies. The PQ strategy will provide enhanced LV visibility by rolling out PQ data monitors across the LV network and will review the suitability of real-time 'State Estimation' algorithms as part of the intelligent grid transformation. The most recent initiative extends monitoring from the LV distribution transformer terminals to the end of LV circuits and within customer switchboards. Based on the PQ monitoring data and predictive models developed, Ergon Energy identifies and prioritises areas for PQ improvement.

Compliance risks are also being managed through the revised connection standards for solar PV inverters / batteries and the implementation of the 230V standards.

Chapter 12

Emerging Network Challenges and Opportunities

12. Emerging Network Challenges and Opportunities

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

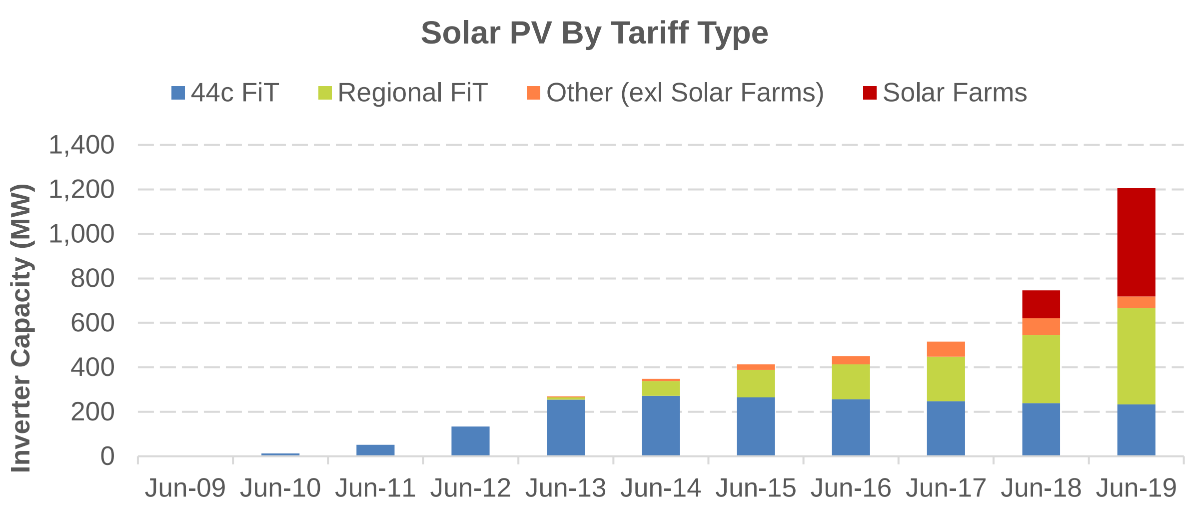
12.1 Solar PV

12.1.1 Solar PV Emerging Issues and Statistics

Queensland has the highest penetration of solar PV systems on detached houses (32%) not only in Australia[24], but compared with any country. In our network, 26% of detached houses have a solar PV system connected. The rapid uptake of solar PV has changed the way power travels through the network, from a purely one-way to bi-directional energy flow. The impact is greatest in the LV network and creates a number of system design and operation challenges. Due to the PV penetration level and the nature of its network, Ergon Energy is on the leading edge of the Australian distribution industry in responding to these issues. It is deploying a range of projects and initiatives to ensure safe operation of the network, a secure and high-quality supply, and economically viable solutions for customers both with and without solar PV.

Figure 39 shows the increase in installed capacity associated with solar PV, including both solar farms and small-scale PV. Over the past 12 months, the volume of connections increased by 12%, and the PV capacity increased by more than 66%. As a comparison, the previous 12-month period saw a 12% volume and 45% capacity increase.

Figure 39: Grid-Connected Solar PV System Installed Capacity by Tariff as at June 2019



[24] Australian PV Institute, "Mapping Australian Photovoltaic Installations". Accessed 03/08/19, Available: http://pv-map.apvi.org.au/animation

The escalating issue of reverse power flow occurs where local generation exceeds demand on a network element such as a feeder. Ergon Energy estimates that there are over 516 feeders on which generation during the middle of the day is exceeding the demand of the feeder.

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

Ergon Energy had approximately 850 QoS complaints in the past 12 months related to solar PV, predominantly resulting from high voltages. As the number of solar PV systems increases, managing the voltage within statutory limits becomes more challenging. We are undertaking a range of initiatives to minimise the impact of solar PV on the network and reduce the cost to resolve constraints, including finalising the transition to a 230V network standard, tariff review, trialling new technologies such as LV Statcom and energy storage trials. We have also worked with a diverse group of industry partners through the Solar Enablement Initiative and Expanded Network Visibility Initiative with the aim of applying advanced modelling techniques to enhance our network modelling capability and improve its hosting capacity. Implementing a 230V network standard is allowing more voltage variation, allowing many existing solar PV systems to operate more effectively and allow more customers to connect solar PV systems and export to the grid.

From a customer perspective Ergon Energy continues to streamline the application process and reduce network risks by enabling minimal- and partial-export connections. Minimal-export generating units essentially don't permit export of generated electricity to the distribution network. Applications for export-limited inverters remain in the minority as the increase in September 2017 to the capacity limit under the Queensland Government's regional Feed-in-tariff (regional FiT) from 5kW to 30kW has made exporting more attractive for some customers. Ergon Energy and Energex have jointly released an updated LV connection standard and draft HV connection standard covering solar PV systems, as discussed in Section 12.4.2.

12.1.2 Impacts of Solar PV on Load Profiles

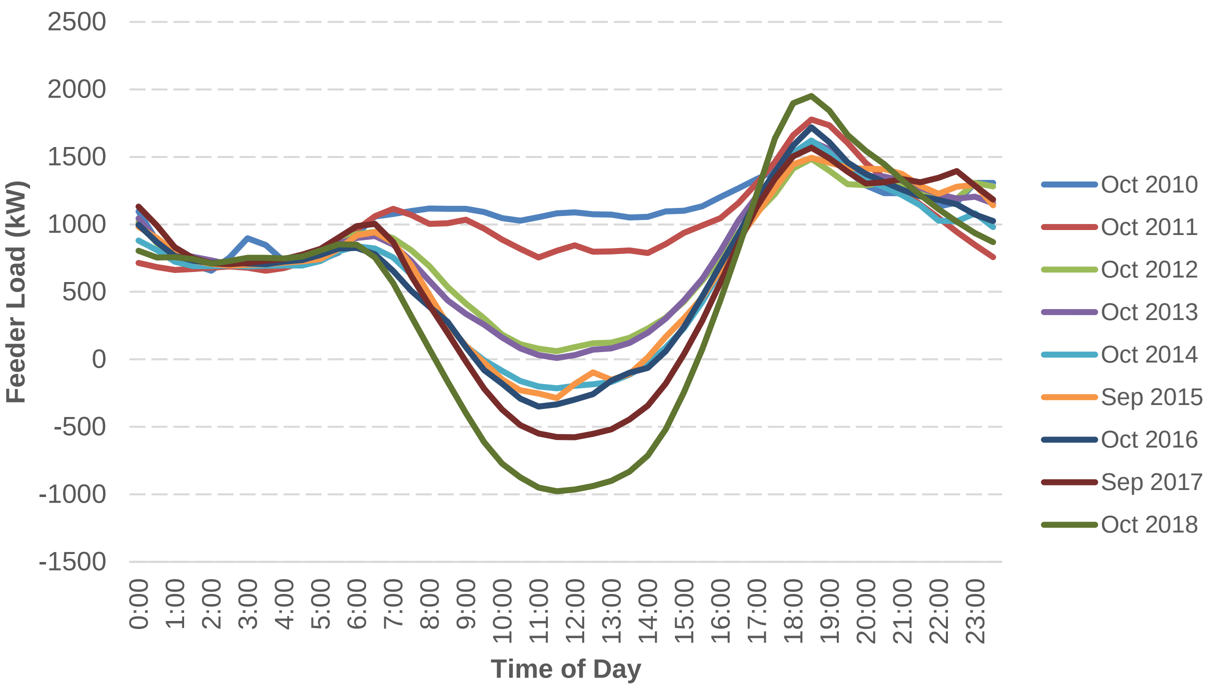
Solar PV is impacting load profiles, asset utilisation, load forecasting and load volatility.

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. While the 2018-19 demand peak was recorded at 6.00pm in the evening, the actual peak in consumption would have occurred at 5.00pm. However, on that day in February 2019, solar generation was meeting almost 19% of the total network demand at midday, and nearly 7% at 5.00pm when the peak would have occurred. While this changed the shape of the network demand during the day, the evening peak remained unaffected, as PV systems were not generating at this time.

The change in load pattern as the penetration of solar PV systems on a feeder has increased is illustrated in Figure 40. This figure shows the daily load pattern on a residential feeder in Burrum Heads (near Hervey Bay) for the lowest spring midday demand day over nine consecutive years. The daytime generation of solar has increased to the point that the feeder back-feeds significantly through to the zone substation.

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

Figure 40: Burrum Heads Feeder Profile: Annual changes observed for Spring 2010-18



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

Figure 41 highlights that on the occasions when the solar PV generation is not available, such as during an afternoon thunderstorm, the full customer load is supplied from the network, which can result in large and rapid variations in energy flows.

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

As networks are designed for supplying the maximum demand required by our customers, increasing penetrations of intermittent embedded generating units will significantly increase the complexity of planning and operating networks. Network volatility events, such as the peak seen in Figure 41, could result in excessive voltage drops, overloading of components, protection operation issues and loss of supply if not appropriately managed.

Figure 41: Dundowran Feeder: Storm event exposing hidden demand

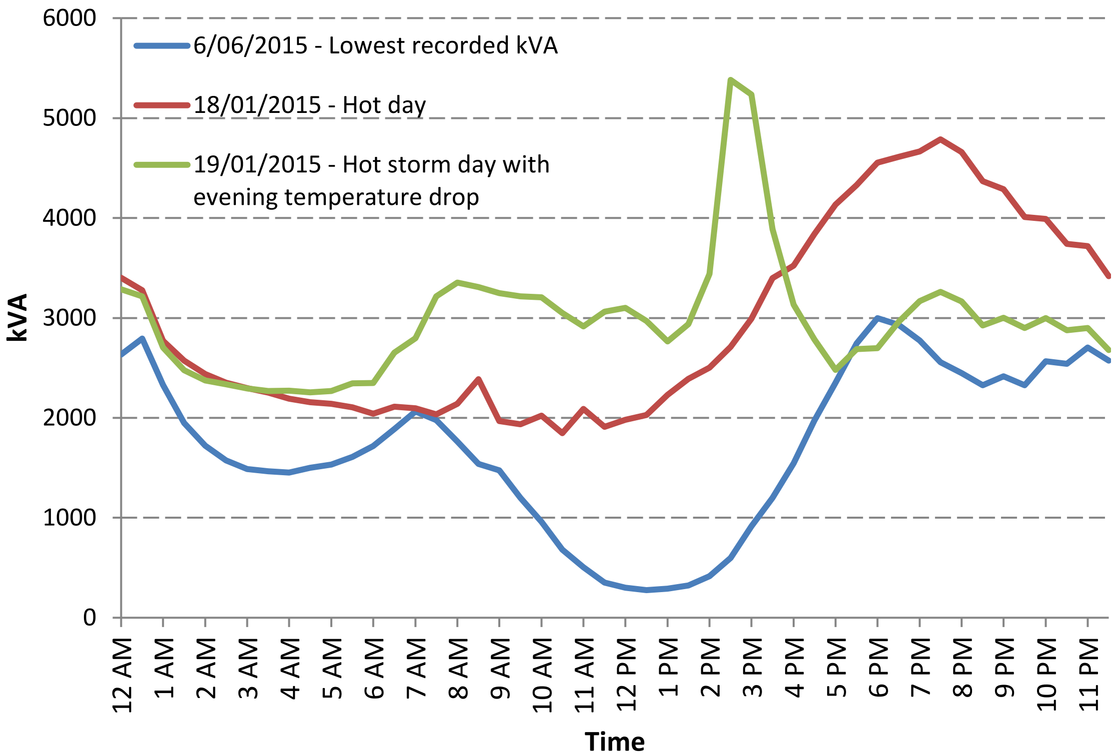


Figure 42 and Figure 43 show the uptake of solar PV across the Ergon Energy network based on zone substation supply areas. Figure 42 indicates the total number of customers in each zone substation who have solar PV installed, and Figure 43 indicates the total installed capacity in the same areas. The five zone substation areas with the highest numbers have been highlighted on each map.

Figure 42: Number of customers with Solar PV by Zone Substation

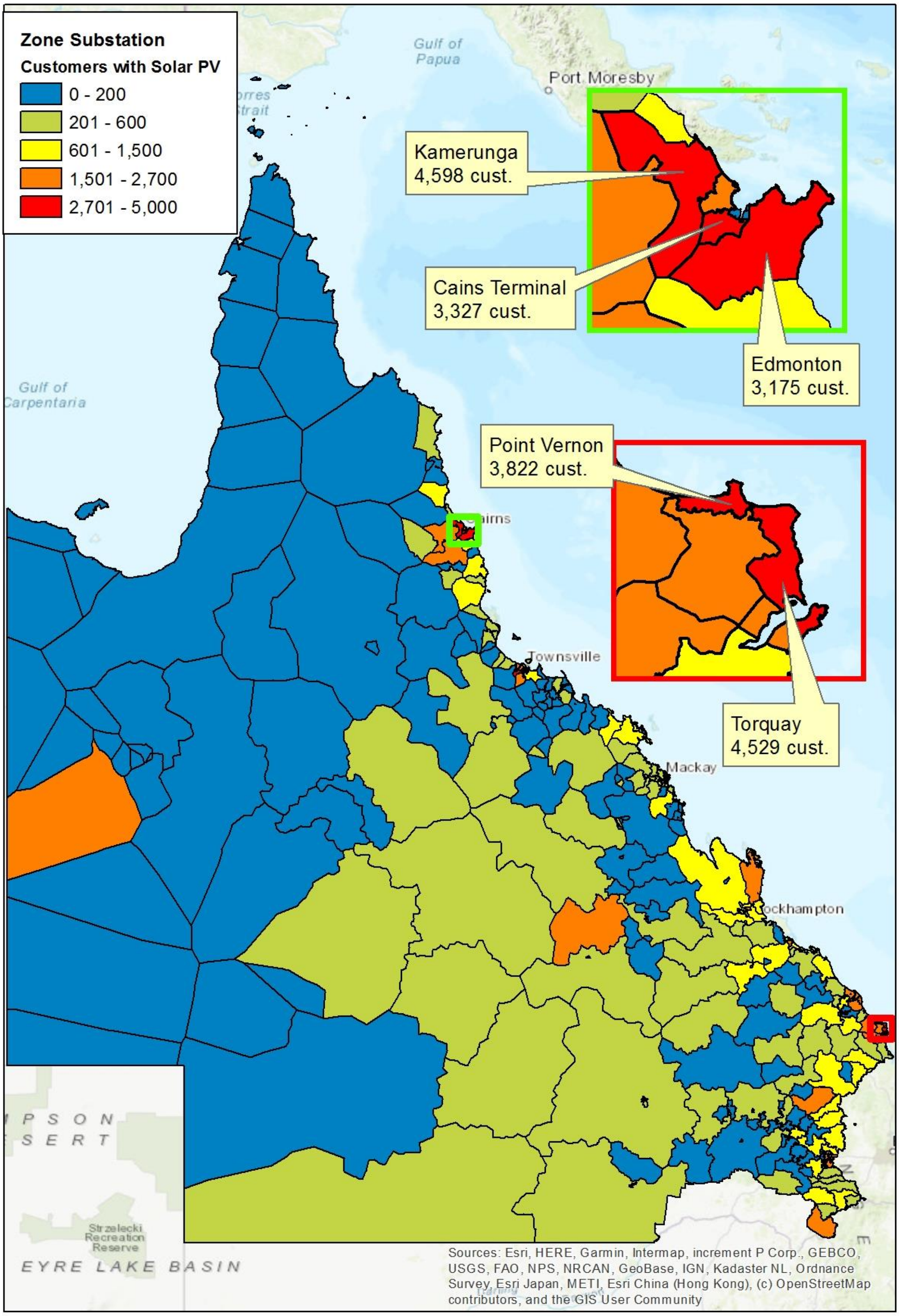
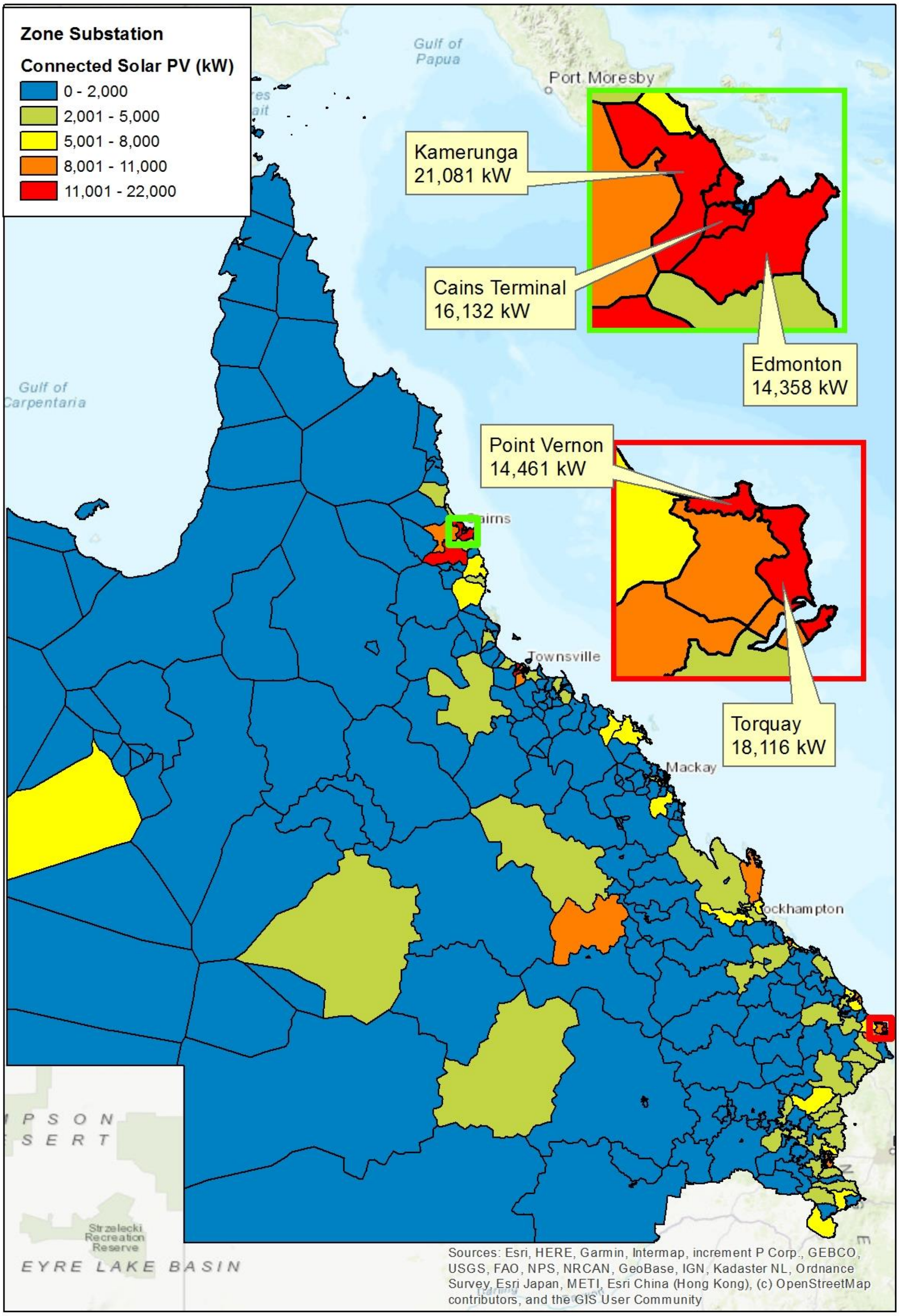


Figure 43: Installed Capacity of Solar PV by Zone Substation



12.2 Battery Energy Storage Systems

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

After Ergon Energy and Energex updated the joint standard for micro EG units up to 30kVA in 2016-17 the joint 'Standard for the Connection of EG Systems (>30kW to 1,500kW) to a Distributor's LV Network' has since been updated. Among other things, this has enabled greater opportunity for business customers to connect BESS to new or existing solar PV installations.

We are continuing to deploy our Grid Utility Support System (GUSS) comprising energy storage in SWER networks where these units provide an economically efficient alternative to network augmentation. We will also investigate how we may use customer-side BESS to achieve the same result in the future.

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

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

12.3 Electric Vehicles

Ergon Energy aims to remove as many barriers to EV ownership as possible and is developing strategies to do this. This will enable our customers' choice in transport fuels and, if EV charging is managed appropriately, also enhance network utilisation and place downward pressure on electricity prices. EVs, which are still an emerging industry in Australia, are already popular overseas and their numbers are expected to grow dramatically in Queensland as their purchase costs decrease, availability increases and more charging infrastructure is deployed. In the 12 months to 30th June 2019, the volume of plug-in EVs registered in Queensland has increased by 29% to more than 1900 vehicles. A number of promoted EV releases in Australia in 2019-20 are likely to accelerate the growth rate dramatically.

In 2017-18, Energy Queensland's unregulated business Yurika Energy worked with industry partners, including Ergon Energy, and the Queensland Government to deploy an EV charging highway from Toowoomba in the south east of Queensland to Cairns in the north. Ergon Energy plays a vital role in enabling access to our network for other entities now wishing to deploy significant public EV charging infrastructure. Ideally, EV charging would minimally increase peak demand but notably increase demand at times when the network has ample capacity such as the middle of the day and especially during the night.

12.4 Strategic Response

12.4.1 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 (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' to provide a guiding holistic pathway for transforming the network business to have the capability necessary to achieve the following:

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

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

12.4.2 Improving Standards for Increased DER Connections

In order to ensure that Ergon Energy continues to develop collaborative and mutually beneficial stakeholder relationships we have continued to engage with the solar PV and battery industries to evolve DER connection standards. Ergon Energy has the highest volume of confirmed large DER connections of any DNSP on the NEM. With the rapid connection of large DER onto the network Ergon Energy is uniquely positioned to identify opportunities for standards improvement to assist in streamlining and reducing the cost of connections while ensuring safe and secure operation of the network.

In September 2017 Ergon Energy delivered a draft joint LV connection standard for DER with Energex which delivered modern and streamlined requirements for LV connected DER between 30kW and 1.5MW. The new standard has been positively received as it delivered benefits for industry and the network by delivering:

- Cost reduction by eliminated the requirement for Neutral Voltage Displacement (NVD) protection and zero export relays
- Improved equipment performance by utilising use of volt-var reactive control in inverters
- Ease of compliance with clear requirements for protection and definitions for the various types of generating technology (inverters or rotating machines).

Ergon Energy has delivered a draft joint HV connection standard for DER with Energex which:

- Leverages modern industry standards for solar PV inverter technology, aligning with the joint LV standard and removing barriers for solar connections under 1.5MW
- Introduces Class A1, A2 and B based on system size and the strength of the network where the connection is occurring. Having the three categories enable Proponents to have improved visibility of DER connection requirements based on the location and size of their planned connection
- Replaces four standards for HV DER connections in Queensland with one. Minimising the number of standards will enable improved compliance and assist in delivering aligned and streamlined connection application processes and assessments in Queensland. Ultimately having greater standards alignment in Queensland will reduce the time it takes to review, approve and connect DER to the network.

Ergon Energy is planning to align to the National guidelines to assist in delivering improved alignment and continuity of DER connection standards in Australia.

12.5 Large Scale Renewable Projects

Ergon Energy is currently actively managing more than 110 enquiries, from preliminary to final commissioning stages, totalling more than 3GW of renewable energy investment. To date, more than 900MW of large-scale renewable generation projects are committed and/or connected to the Ergon Energy network, similar to Powerlink's published existing and committed generators totalling 1.6GW[25]. Our support for these projects has the potential to provide a major economic windfall 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.

Table 37- Generation Capacity - Existing and Committed Large Generators[26]

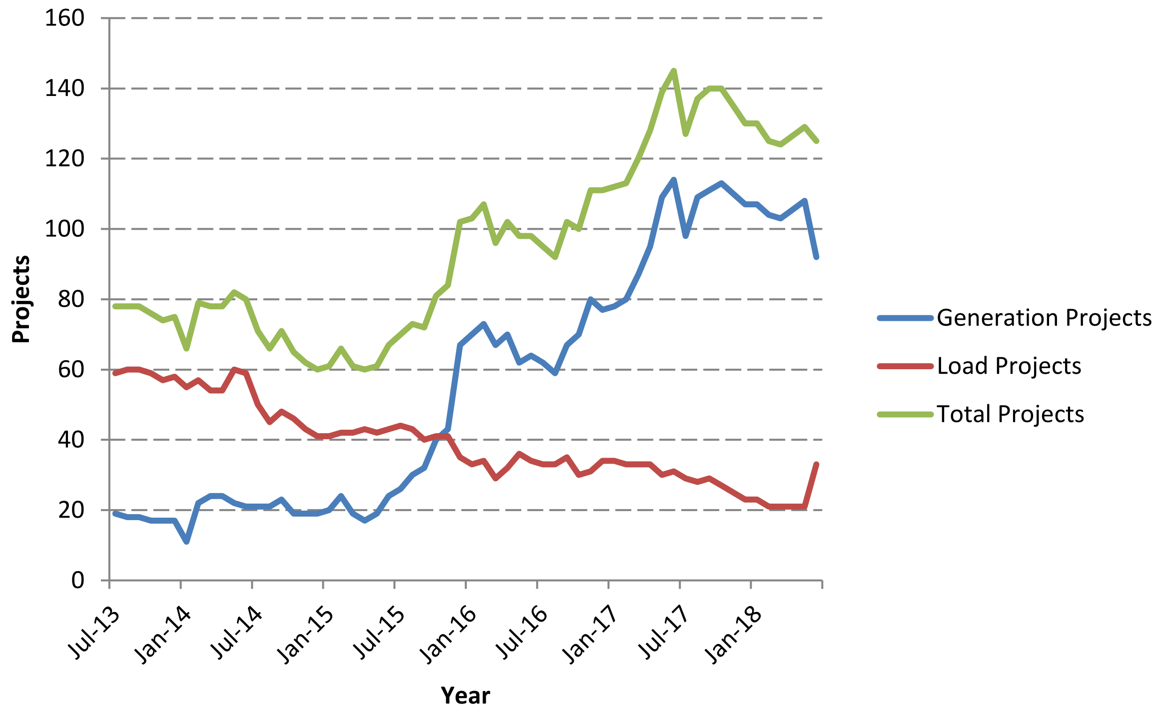
Generator	Location	Generation Capacity (MW)	Generation Technology
Baking Board Solar Farm	Chinchilla	14.7	Solar PV
Barcaldine Solar Park	Barcaldine	20	Solar PV
Clermont Solar Farm	Clermont	75	Solar PV
Collinsville Solar Farm	Collinsville	42	Solar PV
Hughenden Solar Farm	Hughenden	18	Solar PV
Kidston Solar Farm	Kidston	50	Solar PV
Longreach Solar Farm	Longreach	14	Solar PV
Normanton Solar Farm	Normanton	4.9	Solar PV
Oakey 1 Solar Farm	Oakey	25	Solar PV
Oakey 2 Solar Farm	Oakey	55	Solar PV
Aramara Solar Farm	Aramara	104	Solar PV
Childers Solar Farm	Childers	64	Solar PV

[25] 2019 Powerlink TAPR

[26] registered generators. Generators exempt from registration with AEMO, or that have been granted exemption, have not been listed. Information on Exempt systems can be found in the Register of completed Embedded Generation Projects (https://www.ergon.com.au/__data/assets/pdf_file/0017/220940/Register-of-Completed-Embedded-Generation-Projects.pdf)

Generator	Location	Generation Capacity (MW)	Generation Technology
Emerald Solar Park	Emerald	72	Solar PV
Kingaroy Solar Farm	Kingaroy	40	Solar PV
Maryrorough Solar Farm	Yarranlea	27	Solar PV
Middlemount Sun Farm	Middlemount	26	Solar PV
Susan River Solar Farm	Susan River	75	Solar PV
Warwick Solar Farm 1 and 2	Warwick	64	Solar PV
Yarranlea Solar Farm	Yarranlea	103	Solar PV
Kennedy Energy Park	Hughenden	50	Hybrid: Wind + Solar PV + Battery
Windy Hill	Ravenshoe	12	Wind
Pioneer Sugar Mill	Ayr	68	Bagasse
Racecourse Mill Power Station	Ooralea	48.5	Bagasse
Tableland Mill	Arriga	24	Bagasse
Barcaldine Power Station	Barcaldine	37	Gas Turbine
Mackay Gas Turbine	Mackay	32	Gas Turbine
Roma Gas Turbine	Roma	80	Gas Turbine
Townsville Gas Turbine	Townsville	82	Gas Turbine
German Creek Power Station	Lilyvale	45	Reciprocating Engine
Oaky Creek Power Station	Lilyvale	20	Reciprocating Engine
Oaky 2	Lilyvale	15	Reciprocating Engine

Figure 44: Major Load Connections 2013-19



12.6 Stand Alone Power Systems

Ergon 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.

Energy Queensland 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 kilometres of Single Wire Earth Return lines, one of the largest Single Wire Earth Return networks in the world supplying only 4 per cent of Ergon Energy Network’s customers. The majority of the Single Wire Earth Return network was installed in the1970’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 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 Stand Alone Power Systems 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 Stand Alone Power Systems.

In May 2019, the Australian Energy Market Commission released a final report recommending that the regulatory framework should be changed to allow distributors to supply customers by Stand Alone Power Systems where it is more cost efficient to do so, compared to a traditional network solution.

We continue to advocate and work with regulatory bodies to deliver community and customer focused energy supply solutions. We are trialling Stand Alone Power Systems as an alternative to network supply for individual customers supplied by long Single Wire Earth Return lines and exploring the long-term opportunities Stand Alone Power Systems may provide for our customers.

12.7 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.

12.8 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, an increase in the severity of tropical cyclones, storms and storm surges as well as changing oceans and sea levels. This suggests that there may be the likelihood of inundation or other damage to exposed and low lying Energy Queensland assets creating reliability problems as well as associated maintenance and asset replacement expenditures.

Ergon Energy as part of Energy Queensland partners with various organisations such as the Queensland Climate Resilient Council, Queensland Climate Adaption Strategy Partners and Queensland Reconstruction Authority to develop strategies dealing with climate change and to build more disaster resilient energy infrastructure.

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 adaptations that mitigate the risk of bushfire (e.g. LV spreaders, spark-less fuses, conductor replacement).

Ergon Energy has works programs to adapt network assets to mitigate the risks of severe environmental events (e.g. cyclones, floods, bushfires and storms). These programs include both capital and operating expenditures.

Chapter 13

Information and Communication Technology

13. Information and Communication Technology

13.1 ICT Investment 2018-19

This section summarises the material investments Ergon Energy has made in the 2018-19 financial year, relating to ICT systems.

Significant work continued during the year to initiate the remaining key programs within the Digital Enterprise Building Blocks (DEBBs) portfolio, with the following major investments approved to commence delivery:

- Asset and Works Management
- Health Safety and Environment
- Governance Risk and Compliance
- Desktop Transformation Program
- Enterprise Content Management.

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

Table 38 provides an initiative level summary of ICT investment undertaken in 2018-19. These include projects which commenced prior to this year and investments not completed by 30th June 2019. Further information on the scope of each initiative can be noted below.

Table 38: ICT Investments 2018-19

Description	2018-19 Actual Cost $M
Corporate Services	$41.63
Infrastructure, Security and Devices	$18.83
Customer, Market and Metering	$9.96
Network Asset Management	$4.19
Minor Applications Change and Compliance	$4.01
Network Operations	$3.00
Enterprise Services	$2.94
Total	**$83.13**

Note: Actuals includes 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).

Corporate Services

ERP EAM Portfolio of Projects

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

People, Culture and Safety

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

Procurement

- Replace systems and processes that support procurement with a single unified Energy Queensland solution. Including managing, sourcing, contract and supplier management, and buying processes
- Integrated processes and systems, both internally and externally, improving collaboration with stakeholders and suppliers
- An advanced source-to-settle solution with the ability to acquire goods and services from the community with simplicity, governance and affordability.

Enterprise Services

- Enable common processes and standardised analysis and reporting to provide oversight and insights into organisational performance. This includes end-to-end purchasing; maintenance work execution (non-network); time capture and reporting; financial accounting and reporting; solution accessibility through internal network and mobile devices
- Deploy foundation capability for portfolio and project management processes.

Finance and Planning

- Deploy foundation capability for financial planning, budgeting and consolidation financial reporting processes.
- Implement a unified chart of accounts, legal entity, purchasing organisation, and maintenance organisation structures for Energy Queensland.

Customer Market and Metering

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

Investment against this initiative in 2018-19 was focused on providing customers with contemporary communication channels, workflow automation and alignment (across all area of the state) to meet customer requirements and exploit opportunities to streamline process. This period also finalised enhancements and upgrades to the existing suite of market systems to meet the Power of Choice requirements. This program incorporates the current customer information system (CIS), service order management system, meter data management, and business-to-business (B2B) systems.

Network Asset Management

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

The Field Client Migration project for Ergon Energy, was established to sustain the current outdated FMC application, which is used to perform field inspections of Ergon Energy's network pole and line assets and reached end of vendor support in February 2017. Investment in this solution will ensure the stability and security of the asset inspection solution until the Unified EAM solution is delivered for EQL.

Enterprise Services

The Desktop Transformation program has 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. Investment in this program will provide Ergon Energy users with the ability to securely connect and consume digital services and information via contemporary software solutions such as Microsoft Office, SharePoint and other collaboration tools, on current operating environments and devices.

Infrastructure, Security and Devices

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

A significant activity is in progress the modernisation of the wireless corporate network fully enabling wireless access capability at Ergon Energy sites, including a number of regional depots and substations that have historically not had this capability. Phase 1 has completed and Phase 2 has commenced and will continue during 2019-20.

Network Operations

Investment in this area included the completion of a project to improve field work management capability for the Field Force Automation platform while also maintaining supportability. This was achieved by an upgrade of ABB Service Suite to version 9.5, enabling the future use of contemporary Windows 10 devices as an option for FFA.

Type 6 Meter Reading devices are used by Ergon Energy crews to collect customer data from meters in the field. A project commenced in 2018-19 to replace end-of-life equipment with contemporary devices (iPhones) ensuring the continuity of network billing.

Minor Applications Change and Compliance

This includes minor improvements and updates across the ICT systems footprint including; work force automation, asset management, market systems, network operations systems, knowledge management systems, and customer service systems which support Ergon Energy's business operations. Key investments in this area across 2018-19 included the investment to maintain the security of the network, improved scheduling of network asset related work via the Microscheduler solution, the updates to the Market Systems suite of solutions required to meet market compliance obligations, and implementation of processes and reporting requirements to meeting AER ringfencing compliance.

13.2 Forward ICT Program

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

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

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

The significant component of the ICT Program in 2019/20 will continue the replacement of Ergon Energy's Enterprise Resource Planning (ERP) and Enterprise Asset Management (EAM) systems, with the remainder of the program focused on operational renewal, replacement and compliance investments for the broader set of technologies that the business utilise.

In the coming regulatory control period, from 2020/21, the ICT Program for Ergon Energy will continue to maintain ICT systems and capability consistent with the established ICT asset lifecycle management practices. Upon replacement of key systems, EQL will take the opportunity to consolidate and rationalise legacy application with consistent best-practice business processes. Planned investment during this time has been grouped within a set of seven roadmap segments including:

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

An high level summary of potential ICT investment for the Distribution Business for the forward ICT Program is shown in Table 39 noting forecasts are based on the ICT plan submitted to the regulator for the 2020-2025 AER period and may require adjustments dependent on the determination received. Forecasts have been grouped by initiative names as included in the ICT Plan for 2020-2025

Table 39: ICT Investment Forecast 2019-20 to 2023-24

INITIATIVE NAME	2019-20 $M	2020-21 $M	2021-22 $M	2022-23 $M	2023-24 $M
Asset and Works Management	$15.99	$11.58	$8.06	$13.88	$16.82
Distribution Network Operations	$7.50	$13.37	$10.92	$2.25	-
Customer and Market Systems	$2.75	$4.89	$10.27	$9.86	$5.19
Corporate Systems	$29.78	$2.45	$0.43	$3.26	$1.97
ICT Management Systems, Productivity and Cybersecurity	$4.37	$0.94	$2.92	$2.77	$3.28
Infrastructure Program	$8.85	$7.14	$8.07	$8.38	$9.12
Minor Applications Change	$2.11	$3.57	$3.68	$3.79	$3.91
Grand Total	**$71.35**	**$43.94**	**$44.35**	**$44.19**	**$40.29**

Note: Forecasts includes 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).

All financials presented in this document are correct at the time of writing and are representative of the ICT plan submitted to the regulator for the 2020-25 AER period. Forecasts may require adjustment dependent on the regulator's determination due later in 2019/20.

Chapter 14

Distribution Metering

14. Distribution Metering

14.1 Metering Environment

The metering environment is changing rapidly, driven by a range of national market reform initiatives making metering services contestable and driven by the electricity Retailer. Ergon Energy is supporting the development and introduction of a national competitive metering framework to provide customers with a range of choices in metering and related services.

Ergon Energy seeks to provide cost-effective Type 7 metering services and continued efficient maintenance of existing Type 6 meters that remain in service.

We currently operate around 1.088 million meters. The total meter count has been slowly declining due to the policy of installing (for both new and replacement activities):

- a three phase meter in place of multiple single phase meters on two or three phase installations
- a dual element meter in place of two single phase meters for installations with a controlled load tariff.

This count will further decline due to the Power of Choice legislation that prevents Ergon Energy from installing new and replacement meters.

Around 9,282 of our meter population are unregulated meters in isolated generation communities. 5,249 of these units are card operated prepayment meters, used in remote Aboriginal and Torres Strait Island communities.

Our current fleet of meters includes 737,518 electro-mechanical (disc) meters and 349,269 electronic meters. Approximately 348,000 of the electronic meters are capable of recording interval data. In accordance with the *National Metrology Procedure Part A,* Ergon Energy no longer installs mechanical meters and now installs only electronic load profile meters. The weighted average age of our electronic meters is 7.35 years; indicating considerable remaining functional life.

As the default Metering Coordinator for Type 6 meters installed prior to 1st December 2017, Ergon Energy will manage these in accordance with the Metering Asset Management Plan (MAMP). This will ensure that the value of these meters is maximised over their full useful life while they remain in service and are deemed fit for purpose.

Currently over 393,000 customers are connected to a controlled load tariff. This involves installation of a load control relay (remote controlled switch) in their meter box, which is switched via audio frequency signals superimposed over the supply network. Where audio frequency signals are not available to control load switching, control is provided using the built-in time clocks in electronic meters.

Load control management equipment reduces peak demand and helps defer capital intensive network augmentation; it is a valuable tool for network management and contingency planning. The benefits are shared amongst all customers in the form of more efficient network operation and investment. Ergon Energy is currently reviewing developments in new network control devices with expanded capability and functionality. External load control relays are referred to as Network Devices under the new competitive metering environment.

Responsibility for the provision of metering services to electricity customers changed on 1st December 2017 with the commencement of the expanding competition in metering and related services rule change. The new regulatory arrangements provide a framework for the competitive provision of advanced meters for residential and small business customers and greater opportunities for those customers to access a range of cost-effective service offerings. With the implementation of the new framework on 1st December 2017, DNSPs are no longer responsible for installing meters but will continue to provide metering services at customers' premises until existing meters are replaced by an advanced meter. To support this change, from 1st July 2015, Ergon Energy moved its metering assets out of its Standard Control Services (SCS) Regulatory Asset Base (RAB) to a separate Metering Asset Base (MAB). This ensures that the costs of providing Type 5 and 6 metering services are separated from the core costs associated with the access and supply of electricity to customers, appearing as a separate charge on customer bills.

Ergon Energy has been preparing for the transition to the new framework by ensuring our meters remain operationally relevant. Until 1st December 2017, new meters were installed as standard Type 6 accumulation and manually read installations, as per current operations. These are capable of providing customer and network services until they are replaced by electricity Retailers with Type 4 advanced meters that meet the minimum services specification. Until they are replaced, the ongoing capability of existing metering assets will be maintained to ensure the cost-effective delivery of metering services to customers and to enable network benefits, such as real time monitoring of PQ and customer loads to better manage voltage regulation on the LV network, to be captured where appropriate.

Ergon Energy plans to maintain load control as it relates to network operation and will work closely with Metering Coordinators to retain the Ergon Energy load control assets installed in customer switchboards to maintain our considerable load control facilities. Load control equipment and network devices external to the meter are provided as SCS and recovered as part of our network tariffs.

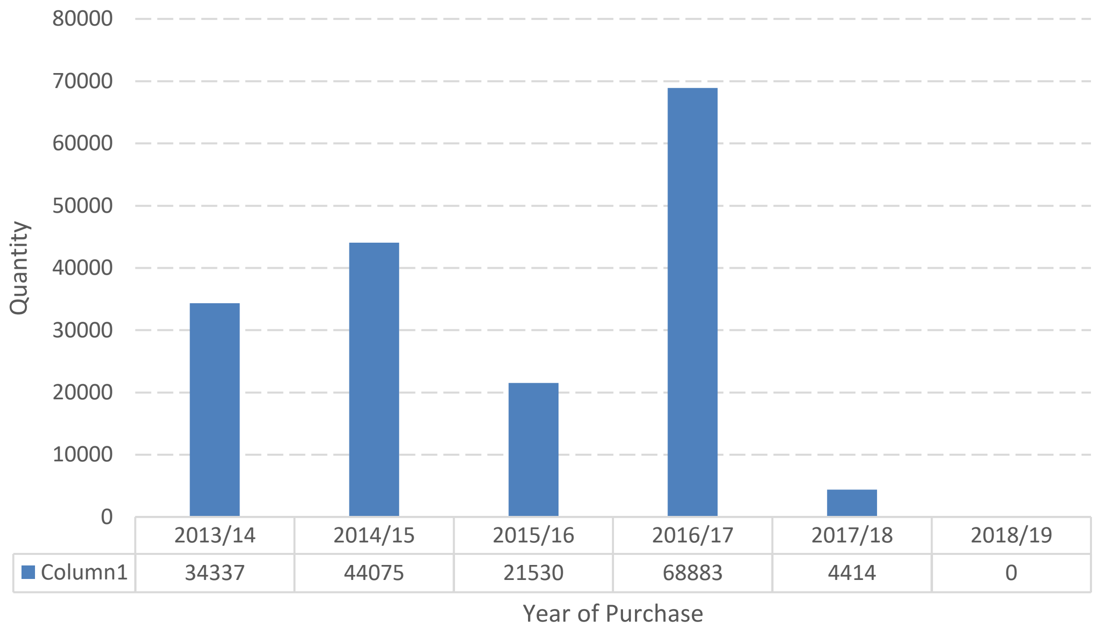
Under the Metering Asset Management Plan, Ergon Energy performs meter family testing, meter replacement programs and time-based meter testing for large customers.

Ergon Energy will continue to develop and implement consistent work practices and supporting standards, such as the Queensland Electrical Connection and Metering Manual, to separate the DNSP requirements from meter provider obligations and ensure these align with the rollout of communications enabled meters in a contestable marketplace.

As a contestable metering market is introduced, Ergon Energy will work to ensure that critical standards such as safety are updated to cover the growing range of metering service providers and market participants.

Figure 45 shows meter purchases from 2013-14 to 2018-19.

Figure 45: Meter Purchases 2013 to 2019



The above average purchase requirements in 2014-15 related the replacement of BAZ non-compliant meters in the South West Queensland region, which is continued into 2015-16. The increase in purchases in 2016-17 is largely attributed to the BAZ and WF2 non-compliant meter replacement program across all regions of Ergon Energy.

Other metering equipment installed this year includes load control relays and current transformers.

14.2 Ageing Meter Population

Figure 46 shows the age profile of both electro-mechanical and electronic Type 6 meters currently in service, and Table 44 shows the age profile of single and poly-phase electronic meters.

The economic life of electro-mechanical meters is 25 years, and for electronic meters this expectancy is 15 years. These figures illustrate that a large number of electro-mechanical meters have exceeded their economic life with some reaching twice that age. The electronic meter populations are only now reaching the end of their economic life. The AER has approved the replacement of 108,500 meters over the current regulatory control period 2015-20. This includes 105,150 electro-mechanical meters that are more than 50 years old and 3,350 electronic meters that have failing components.

Figure 46: All Meters by Age Profile

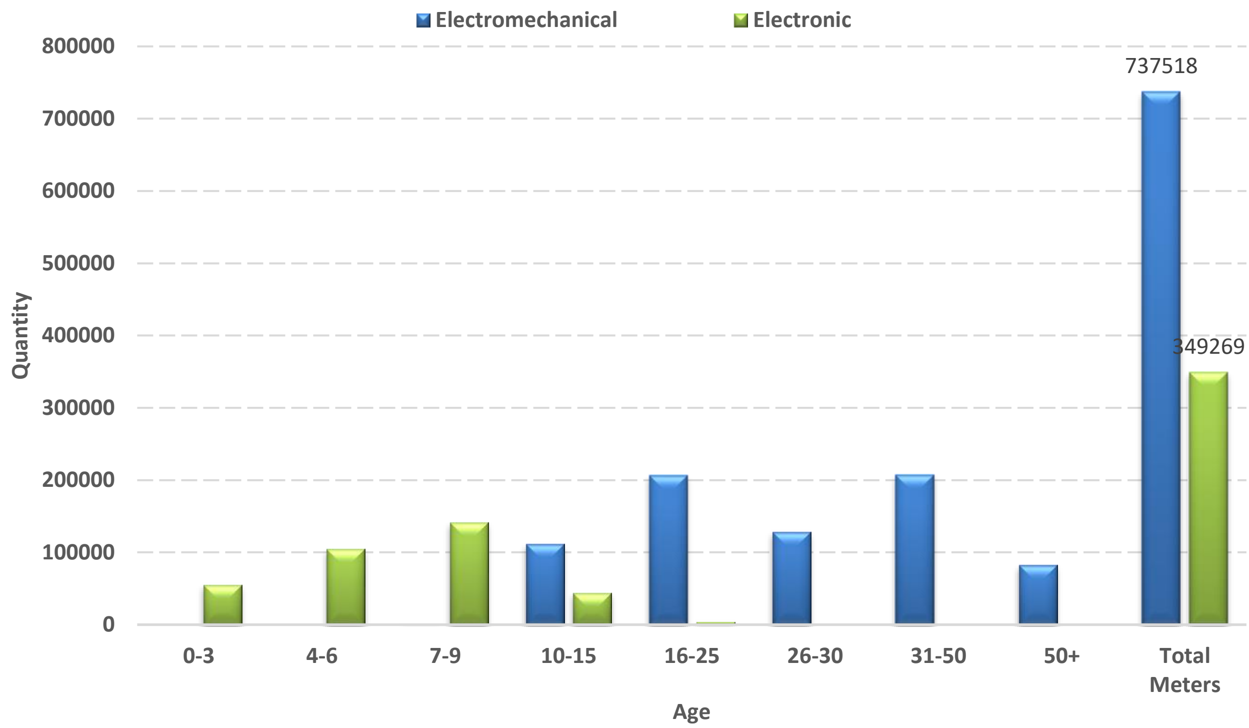
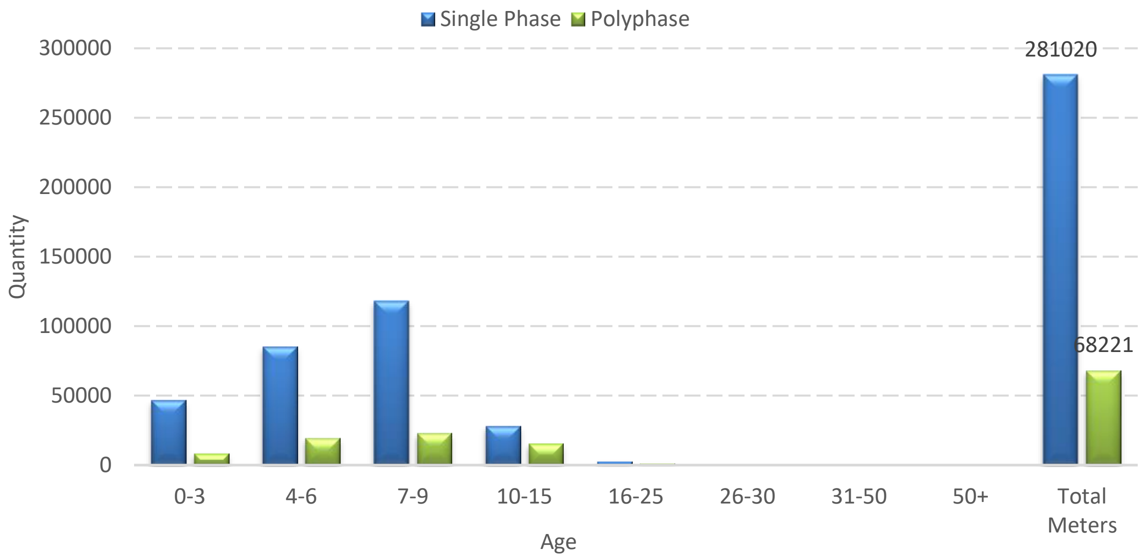


Figure 47: Electronic Meters by Age Profile



Ergon Energy will continue to utilise the aged assets and only replace these assets when they are determined to be non-compliant based on condition monitoring of population samples and failure rates as outlined in the MAMP. All meter failures and non-compliant meter replacements will be reported to the Retailer's nominated Meter Coordinator to arrange a Type 4 remote read meter replacement.

14.3 Metering Investments in 2018-19

Table 40 provides a summary of metering opex expenditure for planned routine maintenance for 2018-19.

Table 40: Metering Operational Expenditure 2018-19

Category	2018-19 $M Budget	2018-19 $M Actual[27]
Planned maintenance ACS	2.021	2.741

14.4 Planned Metering Investments for 2019-20 to 2023-24

Metering investment in Ergon Energy will be minimal due to legislation changes preventing Ergon Energy from installing new and replacement meters from the 1st December 2018. The current approved AER expenditure for 2015 to 2020 was $40.709 million (2014-15 real dollars). Table 41 shows Ergon Energy's forecast capex metering replacement from 2018-19 to 2022-23. This has been revised down from the AER approved dollar values for 2017-18 to 2019-20 due to the impact of the Power of Choice. The revised capex for reactive and planned meter replacements is estimated at $0.5 million for the period 2019 to 2023. The small allocations of capex funds beyond 2018-19 allow for planned and reactive meter replacements for Non-NEM locations.

Table 41: Metering Capex Replacement Cost Estimates 2019-20 to 2023-24

Category	2019-20 $M[28]	2020-21 $M	2021-22 $M	2022-23 $M	2023-24 $M	Total $M
Reactive replacements approved	1.34	0.05	0.05	0.05	0.05	**1.55**
Reactive replacements estimated	0.05	0.05	0.05	0.05	0.05	**0.25**
Planned replacements Approved	6.74	0.05	0.05	0.05	0.05	**6.95**
Planned replacements estimated	0.05	0.05	0.05	0.05	0.05	**0.25**
Total ($M) Approved	**8.09**	**0.10**	**0.10**	**0.10**	**0.10**	**16.57**
Total ($M) Estimated	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.50**

Note: Any discrepancy in total cost can be attributed to rounding error.

[27] Actual Expenditure to May 2019.

[28] Figures approved as per the AER Distribution Determination for 2016-17 to 2019-20. Estimated figures as per expected impact of the Power of Choice from 1 Dec 2017.

Chapter 15

Operational Technology and Communications

15. Operational Technology and Communications Systems

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.

Energex and Ergon Energy have developed a joint Network Technology Strategy and Roadmap to guide the use of technology. The roadmap identifies the key technologies to be researched and implemented in the periods 2015-20 and 2020-30. It is being used to guide technology in key areas of real time condition monitoring, communications networks, reliability, power quality, demand management, environmental sustainability, customer energy management and power system operational management.

15.1 Telecommunications

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

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

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

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

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

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

1. Field Mobile Networks – These networks provide field workforce primary mission critical voice communications to support a safe and efficient work environment
   - Over the last seven years, from Toowoomba to the North of Cairns, the legacy VHF two-way mobile network has been progressively replaced by a P25 based network. This area typically has the highest density of network and staff within Ergon distribution areas. P25 provides a secure digital two-way network and achieves the required quality, availability and reliability to support the field mobile radio networks strategy. The final P25 projects required to complete the planned replacement of the east coast VHF two-way mobile network are currently in delivery. These projects will be completed progressively completed over the next two years
   - 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. Implementation of SATPTT will be completed in the 2019-20 financial year
2. Communications Site Infrastructure Program - this program replaces site support infrastructure such as power supplies, diesel generators and air conditioning to ensure that services remain in operation. This is an ongoing business as usual aged replacement program that is based on a condition assessment of equipment's capacity to provide satisfactory service and performance to meet the requirements for the distribution network. Accelerated battery replacements are anticipated over the next three years due to the asset categories' age profile and higher than forecast battery cell failure rates
3. Communications Network Assets Program - these invest in the renewal of aged and unsupported active telecommunications equipment, based on a condition assessment of equipment's capacity to provide satisfactory service and performance to meet the requirements for the distribution network. Projects progressed over 2018-19 include Network Management Systems and legacy voice related aged replacements. Significant projects that have been approved for implementation over the next five years include Time Division Multiplexing (TDM) related projects. These projects will:
   - Extend the life of the existing TDM network
   - Confirm a Tele-protection solution for carriage over an IP/MPLS network
   - Replacement of a Legacy Telco service management system.

   Aged replacement projects will cover the following technologies:
   - Ethernet related asset classes
   - Microwave Radios assets
   - Operational Support Systems servers
   - Additional Legacy Voice related asset classes.

4. Network Capacity and Coverage - The purpose 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.

15.2 Operational Systems

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

Our OT strategies therefore include:

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

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

The current systems within the OT scope are detailed below.

15.2.1 Supervisory Control and Data Acquisition

Currently there is a dedicated substation control system across a large portion of the network, with 97% of customers connected to substations with Supervisory Control and Data Acquisition (SCADA) capability. This includes approximately 75% of the zone substations and the majority of pole top devices. These are managed centrally through the Operational Control Centre (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.

15.2.2 Totem

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

15.2.3 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.

15.2.4 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.

15.2.5 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.

15.2.6 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.

15.2.7 Intelligent Grid Enablement

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

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

- Low Voltage Management System – manages the various streams of data from the LV network and feeds this information into a constraint engine which determines the active network performance and limits, and then passes those values and subsequent constraint envelopes via an orchestration system to deliver the best outcome.
- Demand Response System - this capability allows EQL to transition the existing and successful direct load control (AFLC) system to individually addressable load for network support.
- Distributed Energy Resources Management System - this capability will allow EQL to interact with market participants, including Virtual Power Plants/Aggregators, for generation and load management, as well as directly with large scale distributed energy resources (DER) to enable efficient connections and network support now, and longer term.
- Real Time Analytics - this capability will be used to actively manage the dynamic operational ranges across EQL's 140,000 Low Voltage networks. The insights gained will be able to automatically tune network performance.

15.2.8 LV Network Safety Monitoring Program

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

15.3 Investments in 2018-19

Table 42 summarises Ergon Energy's Information Technology and Communication systems investments for 2018-19.

Table 42: Information Technology and Communication systems Investments 2018-19

Description	Direct Cost ($M, 2018-19)
Telecomms network	
Field Mobile Networks	$4.1
Communications Site Infrastructure Program	$2.2
Communications Network Assets Program	$2.2
Network Capacity and Coverage	$0.5
Operational Systems	
Intelligent Grid Enablement	$0.1
Total	**$9.1**

Note: All financials presented in this document are correct at the time of writing and represent the existing organisational accounting treatment, which may be subject to change. Energy Queensland is finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.

15.4 Planned Investments for 2019-20 to 2023-24

Table 43 summarises Ergon Energy's OT and associated Telecommunication planned investments for 2018-19 to 2022-23[29].

Table 43: Operational Technology Planned Investments 2019-20 to 2023-24

Description	Direct Cost ($M)
Telecoms network	
Field Mobile Networks	$13.9
Communications Site Infrastructure Program	$10.7
Communications Network Assets Program	$29.4
Network Capacity and Coverage	$9.9
Operational Systems	
SCADA and Automation Refurbishment / Replacement	$4.9
OT Refurbishment / Replacement	$1.8
Intelligent Grid Enablement	$10.0
Secure Data Zone	$0.3
Control Room Productivity	$0.4
OT Security enhancements	$2.6
OT Meter Management	$0.1
OT Environment enhancements	$0.7
CMS Expansion	$0.6
Totem Expansion	$2.0
LV Network Safety Monitoring Program (pilot and rollout)	$40.53
Total	**$ 127.71**

Note: All financials presented in this document are correct at the time of writing and represent the existing organisational accounting treatment, which may be subject to change. Energy Queensland is finalising the alignment of its Cost Allocation Methodology between Ergon and Energex, potentially impacting the treatment of some Capital and Operational Project costs.

[29] Expenditure is provisional only and will be dependent on AER submission outcomes for 2020-21 to 2023-24 financial years.

Appendix A

Terms and Definitions

Appendix A. Terms and Definitions

Term/Acronym	Definition
10 PoE Forecast	Peak load forecast with 10% probability of being exceeded in any year (i.e. a forecast likely to be exceeded only once every 10 years), based on normal expected growth rates and temperature corrected starting loads. 10 PoE forecast load is not to exceed NCC for system normal (network intact) in all cases excepting distribution substations network element category.
50 PoE Forecast	Peak load forecast with 50% probability of being exceeded in any year (i.e. an upper range forecast likely to be exceeded only once every two years), based on normal expected growth rates and temperature corrected starting loads.
ABS	Australian Bureau of Statistics
AC / ac	Alternating Current
ACR	Automatic Circuit Recloser: an Integrated fault break switch and control system (including protection trip and reclose) suitable for pole mounting.
ACS	Alternative Control Services: a distribution service provided by Ergon Energy that the AER has classified as an Alternative Control Service under the NER. Includes fee based services, quoted services, Public Lighting Services and Default Metering Services.
ADMD	After Diversity Maximum Demand
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFLC	Audio Frequency Load Control: a method of switching loads by modulating audio frequency signals transmitted over the powerline.
AIDM	Asset Inspection and Defect Management
AVR	Automatic Voltage Regulator
BAU	Business As Usual
BESS	Battery Energy Storage Systems
BOM	Bureau of Meteorology
BSS	Bulk Supply Substation is a substation that converts energy from transmission voltages to subtransmission voltages. Note: A Bulk Supply Substation is not a Transmission Connection Point if Ergon Energy owns the incoming 'transmission voltage' feeder. Refer to definition of 'TCP' and 'Transmission Network' below for further explanation.
B2B	Business to business
CA	Capricornia Region
CAC	Connection Asset Customers
CAIDI	Customer Average Interruption Duration Index: a network reliability performance index, indicating the interruption duration that each customer experiences on average (minutes) per interruption.
Capacitor bank (Shunt Capacitor)	An assembly at one location of capacitors and all necessary accessories, such as switching equipment, protective equipment and controls, required for a complete operating installation.
CAPEX / capex	Capital Expenditure
CBRM	Condition-Based Risk Management
CESS	Capital Expenditure Sharing Scheme
C&I	Commercial and Industrial – Customer classification

Term/Acronym	Definition
Circuit Breaker (CB)	A mechanical switch device capable of making, carrying and breaking currents under normal circuit conditions as well as making, carrying for a specified time and breaking currents under specified abnormal conditions, such as those of short circuit.
CIS	Customer Information System
CMS	Configuration Management System
CNOC	Communications Network Operations Centre
Committed Investment	For the purposes of this document a committed investment has received project approval and financial release of funds by the authorised investment governance authority. In accordance with the Ergon Energy Investment Approval Gated Methodology this correlates with project approval and full funding release for an appropriate Gate 3 business case.
CONNEX	Customer Initiated Capital Works
Constraint	A condition whereby a limit, that has been pre-set to a declared criteria, is exceeded. For the purposes of this document a constraint is deemed to be a condition that exceeds the planning and security criteria for each asset class, as determined by Ergon Energy. It should be noted that identification of an asset as 'constrained' does not necessarily imply that the integrity or capability threshold of the asset has been compromised.
Contingency Event	As defined by the NER, 'an event affecting the power system which AEMO expects would be likely to involve the failure or removal from operational service of one or more generating units or transmission elements'
CPI	Consumer Price Index
CP	Corporate Plan
CPSS	Community Powerline Safety Strategy
CT	Current Transformer: a device typically used in protection and metering systems to measure current in primary conductors.
Customer Minutes	Customer Minutes: a measure of the number of customers interrupted multiplied by the duration of a power outage or outages, incorporating any staged restoration.
Cyclic Load	Power load that occurs in such a way that periods of overloads are followed by periods of light load. A piece of equipment may be cyclically loaded and the life expectancy will not be reduced if the accelerated rate of deterioration of the insulation during the heavily loaded periods is counterbalanced by the decelerated rate of deterioration during the light loaded periods.
CymCap	Software by CYME International T&D for calculation of ampacity and temperature rise calculations for power cable installations
DA	Ergon Energy's Distribution Authority DO1/99 (DA)
DAE	Deloitte Access Economics
DAPR	Ergon Energy's Distribution Annual Planning Report
DC / dc	Direct Current
DEBB	Digital Enterprise Building Blocks
Demand Side Management (DSM)	Demand Side Management: the design and implementation of programs designed to influence customer use of electricity in ways that will produce a desired change in system load shape.
DEE	Dangerous Electrical Event
DER	Distributed Energy Resources

Term/Acronym	Definition
DF	Distribution Feeder
DFD	Distribution Feeder Database
DLC	Direct Load Control
DM	Demand Management. Alternate term is Non-Network Alternatives
DMIA	Demand Management Innovation Allowance
DMS	Distribution Management System
DMIS	Demand Management Incentive Scheme
DNAP	Distribution Network Augmentation Plans
DNCR	Distribution Network Capability Report
DNRME	Queensland Department of Natural Resources, Mines and Energy
DNSP	Distribution Network Service Provider
DR	Demand Reduction
DRIM	Demand Reduction Incentive Map, where customer demand reduction incentives, reflective of the value of capital deferral and network security risk, will be provided to the market
Dropout Fuse	A fuse in which the fuse carrier drops into a position to provide an isolating distance after the fuse has operated.
DT	Distribution Transformer
DTS	Distributive Temperature Sensor
DUOS	Distribution Use Of System
EAM	Enterprise Asset Management
EaR	Energy at Risk
EBSS	Efficiency Benefit Sharing Scheme
EDNC	Electricity Distribution Network Code (replaced the EIC on 1st July 2015)
EDO Fuse	Expulsion Drop-Out (EDO) disconnector fuse units
EECL, Ergon Energy	Ergon Energy Corporation Limited
EMF	Electro Magnetic Field
EQL	Energy Queensland Limited
EG	Embedded generating units >30kVA in size.
EQL	Energy Queensland Limited
ERP	Enterprise resource planning: business management software, typically a suite of integrated applications, that a company can use to collect, store, manage and interpret data from many business activities.
ESRI	Environmental Systems Research Institute
EV	Electric Vehicle

Term/Acronym	Definition
Fault	1. A defect in any equipment in the system. 2. In an electric power system, a fault is any abnormal electric current. For example, a short circuit is a fault in which current bypasses the normal load. An open-circuit fault occurs if a circuit is interrupted by some failure. In three-phase systems, a fault may involve one or more phases and ground, or may occur only between phases. In a 'ground fault' or 'earth fault', charge flows into the earth.
Feeder Utilisation	Percentage of feeder rating utilised under network maximum demand conditions with thermal rating of the feeder measured at the time and season of maximum demand.
FFA	Field Force Automation
FiT	Feed-in-tariff
FN	Far North region of Queensland
FPAR	Final Project Assessment Report
GIS	Geographic Information System: a system that lets users visualize, question, analyse, interpret, and understand data to reveal relationships, patterns, and trends.
GOC	Government Owned Corporation
GSL	Guaranteed Service Level
GSP	Gross State Product: sourced from the ABS website
GUSS	Grid Utility Support System: an energy storage system developed by Ergon Energy and optimised for Single Wire Earth Return (SWER) systems. The main functions of GUSS are: Peak Load and Voltage support of the SWER. It provides a solution to relieve both capacity and voltage constraints as an alternative to traditional poles, wires & transformer upgrades.
High Voltage (HV)	(1.) For distribution networks in Australia, HV normally refers to 11,000 V or higher. (2.) For the purpose of the *Electrical Safety Act 2002* (Qld), HV is defined as voltage above 1000V AC or 1500V DC. (3.) HV and LV may also be used to distinguish between the higher voltage side of a transformer and the lower voltage side of a transformer.
HSE	Health, Safety and Environment
ICC	Individually Calculated Customers
ICT	Information and Communications Technology
IoT	Internet of Things
IPS	Intelligent Process Solutions
IT	Isolation Transformer (SWER)
Joint Workings	Collaboration between Ergon Energy and Energex to jointly work on key initiatives to reduce customer cost and provide a consistent customer experience throughout the State.
KPI	Key Performance Indicators
KRA	Key Result Areas
LAR	Load at Risk
LARc	Load at Risk under Contingency Conditions
LDC	Line Drop Compensation
LED	Light-emitting Diode. Is a semiconductor device that emits visible light when an electric current passes through it
LiDAR	Light Detection And Ranging. A remote sensing technology that measures distance by illuminating a target with a laser and analysing the reflected light.

Term/Acronym	Definition
Load Factor	The ratio of the average demand to the peak demand. This gives an indication of the ‘flatness’ of load profile.
Load Forecast	Forecast loads for a minimum of 10 years based on validated starting loads, forecast growth rates, identified load transfers and block loads.
Long Rural Feeder (LR)	A feeder which is not a CBD, urban or isolated feeder with a total route length greater than 200km.
Low Voltage (LV)	1. For distribution networks in Australia, LV is nominally 240/415V AC. or 230/400V AC at 50Hz. 2. For the purpose of the electrical safety act, LV is defined as voltage above 32V AC or 120V DC (ripple free) and not exceeding 1,000V AC. or 1,500V DC. respectively. 3. HV and LV may also be used to distinguish between the higher voltage side of a transformer and the lower voltage side of a transformer.
LVR	Low Voltage Regulator
MAB	Metering Asset Base
MARS	Meter Asset Register and Services.
MAMP	Metering Asset Management Plan
Maximum Demand (MD)	The maximum electrical load over a set period of time. The figure may be for use with tariff calculations or load surveys and the units may be in; kVA, kW or amps.
MCC	Major Customer Connection
MD	Maximum or Peak Demand
MDI	Maximum Demand Indicator
MED	Major Event Day
MEGU	Micro embedded generating units which are between 0 to 30kVA in size as defined in AS4777, which includes inverter energy systems such as solar PV generators
MK	Mackay region
MSS	Minimum Service Standards
MVA	Mega Volt Amp
MVAr	Mega Volt Amps (reactive)
MVARu	Mega Volt Amps (reactive uncompensated)
MW	Megawatt – nameplate capacity
N/A	Not available as yet or Not applicable to the requirement
N-1	The conditions under which all (or a certain percentage) of the electricity load will continue to be supplied under conditions whereby a critical system element is out of service. ‘N’ is all elements in service, ‘N-1’ is with one element (normally one with the highest capacity) out of service. Also known as a credible contingency.
NAPM	Network Asset Preventative Maintenance
NCC	Normal Cyclic Capacity
NECF	National Energy Customer Framework is a set of national laws, rules and regulations governing the sale and supply of energy (electricity and reticulated natural gas) to consumers. Refer to https://www.dews.qld.gov.au for more information.
NEL	National Electricity Law
NEM	National Electricity Market

Term/Acronym	Definition
NEO	National Energy Objectives (AEMC)
NER	National Electricity Rules
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
Network Limitations	A network limitation can be defined as a situation when the HV network is unable to supply electricity to the customer in accordance with the following supply standards.
NGER	National Greenhouse and Energy Reporting Act 2007 (Cth)
NIEIR	National Institute of Economic and Industry Research
NIM	Net Interstate Migration (NIM)
NNA	Non-Network Alternatives. An alternate term is Demand Management
NODW	Network Operations Data Warehouse
NOM	Net Overseas Migration
NOMAD	A 10MVA mobile substation developed by Ergon Energy for planned work and emergency response.
Net Present Value (NPV)	A calculation that compares the amount invested today to the present value of the future cash receipts from the investment. In other words, the amount invested is compared to the future cash amounts after they are discounted by a specified rate of return.
NQ	North Queensland region
NTC	Network Tariff Code
NVD	Neutral Voltage Displacement
OC/EF	Over Current and Earth Fault
OCC	Operational Control Centres
OH	Overhead
OHEW	Overhead Earth Wires
OLTC	On Load Tap-Changer: A device for changing a transformer's tapping ratio suitable for operation while the transformer is energised or on load. Generally, it consists of a diverter switch with a transition impedance and a tap selector which can be with or without a change-over selector, the whole being operated by the driving mechanism. In some forms of tap-changers, the functions of the diverter switch and the tap selector are combined in a selector switch.
ONAN	Oil Natural Air Natural
OPEX / opex	Operating Expenditure
OT	Operational Technology (OT) is the information communications technology (ICT) systems, applications, and intelligent power network devices and their data that can directly, or indirectly, monitor, control or protect the power network.
PHEV	Plug-in Hybrid Electric Vehicle
Power factor (pf)	The ratio of 'real' power (W) to total power (VA)
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.

Term/Acronym	Definition
PoE	Probability of Exceedance
PoW	Program of Work
Powerlink	Queensland Electricity Transmission Corporation Limited
PQ	Power Quality
Primary Distribution System	Refers to the 11kV and 22kV and in some instances 33kV electricity supply network.
p.u.	Per unit. A per-unit system is the expression of system quantities as fractions of a defined base unit quantity.
PV	PV stands for photovoltaic which is a technical term for solar power generation.
QCA	Queensland Competition Authority
QGSO	Queensland Government Statistician's Office
QHES	Queensland Household Energy Survey
QoS	Quality of Supply
RAB	Regulated Asset Base
Recloser	A fault-make and break device which monitors the line current and automatically trips for a fault condition. It is fitted with auto reclosing capability.
Regional FiT	The regional FiT rate is set by the Queensland Competition Authority each year and is paid by the electricity retailer. All eligible customers connecting an eligible solar PV system to an approved network receive the regional FiT.
RFI	Request For Information
RIN	Regulatory Information Notice. The AER issues RINs under Division 4 of Part 3 of the National Electricity (Queensland) Law (NEL) to EECL for information collection purposes.
RIT-D	The RIT-D or Regulatory Investment Test for Distribution is a cost-benefit test that electricity distribution network businesses must apply when assessing the economic efficiency of different investment options
RMS	Root Mean Square
RTD	Resistive Temperature Device
RTU	Remote Termination Unit. This is a key part of the Supervisory Control and Data Acquisition (SCADA) system used in substations.
SAC Large	Standard Asset Customer - Large
SAIDI	System Average Interruption Duration Index – Network reliability performance index, indicating the total minutes, on average, that customers are without electricity during the relevant period (minutes).
SAIFI	System Average Interruption Frequency Index – Network reliability performance index, indicating the average number of occasions each customer is interrupted during the relevant period (interruptions).
SCADA	Supervisory Control and Data Acquisition
SCAR	Substation condition assessment report
SCI	Statement of Corporate Intent

Term/Acronym	Definition
SCS	Standard Control Services: are core distribution services associated with the access and supply of electricity to customers. They include network services (e.g. construction, maintenance and repair of the network) and some connection services (e.g. small customer connections). We recover our costs in providing Standard Control Services through network tariffs billed to retailers.
SEQ	South East Queensland
SIFT	Substation Investment Forecast Tool, used to produce the demand forecasts.
SKID	Refers to Ergon Energy's 33/11kV and/or 66/11kV skid mounted substations located across the network. The units were developed for longer term emergency/contingency response, and longer term maintenance works at substations without N-1 capacity or sufficient Safety Net contingency.
SMDB	Statistical Metering Database
SNAP	Subtransmission Network Augmentation Plan
SSI	Sag Severity Index - a value given to a voltage sag based on contours of the CBEMA curve. As voltage sags increase in depth and duration so does the sag severity index reflecting the increasing disturbance of sags as this occurs. SSI is based on the University of Wollongong's methodology.
Statcom or Static Synchronous Compensator	A shunt device, which uses force-commutated power electronics, to control power flow and improve transient stability on electrical power networks. In addition, static synchronous compensators are installed in select points in the power system to perform the following: Voltage support and control Voltage fluctuation and flicker mitigation Unsymmetrical load balancing Power factor correction Active harmonics cancellation Improve transient stability of the power system
STPIS	Service Target Performance Incentive Scheme, as documented under *Electricity Distribution Network Service Providers Service Target Performance Incentive Scheme (AER, Nov 2009)* with targets set through the AER's Distribution Determination process.
Substation (S/S or SS)	An assemblage of equipment at one location, including any necessary housing, for the conversion or transformation of electric energy and connection between two or more feeders.
Subtransmission	An intermediate voltage used for connections between transmission connections points / bulk supply substations and zone substations. It is also used to connect between zone substations. Typically, subtransmission voltages are 33kV and above. (Note however that 33kV is also used for distribution in some parts of the Ergon Energy network.)
Surge Arrester / Surge Diverter	A device designed to protect electrical apparatus from high transient voltage.
SVC	Static Var Compensator
SVR	Step Voltage Regulator
SW	South Western region of Queensland
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

Term/Acronym	Definition
Switchgear	The combination of electrical disconnects, fuses and/or circuit breakers used to isolate electrical equipment. The use of switchgear is both to de-energize equipment to allow work to be done and to clear faults downstream
TAN	Trade Ally Network. A registry of local, state and national businesses that can assist customers in exploring energy efficiency and demand management opportunities and cashback incentive payment claims.
Transmission Connection Point (TCP)	Transmission Connection Point: A point at which connection is made between a transmission network and the Ergon Energy network. Otherwise known as a transmission-distribution connection point.
TDM	Time Division Multiplexing
TF, TX	Transformer
THD	Total Harmonic Distortion
THDI	Total Harmonic Distortion Index – THDI is the maximum of the three (one for each phase) 95th percentile THD levels at a site. THDI is expressed as a percentage of the reference voltage.
TMU	Target Maximum Utilisation
TNI	Transmission Node Identity
TNSP	Transmission Network Service Provider
Transmission Network	Generally, the electricity supply network operating at or above a nominal voltage of 110kV. However, as Ergon Energy owns some HV assets that might otherwise be owned and operated by a TNSP, clause 9.32.1(b) of the NER provides a permanent derogation in relation to the definition of 'transmission network' in Queensland to allow Ergon Energy to own and operate these assets as a DNSP. Hence Ergon Energy does not own or operate a transmission network.
UG	Underground
UoSA	Use of System Agreement
UR	Urban
V	Volts
VA	Volt Amps - unit of the vector magnitude of electrical power
VAR	Volt Amps Reactive - unit of the reactive component of electrical power
VCR	Value of Customer Reliability – an economic measure of unsupplied energy to customers
Voltage Regulation	The level of variation in the voltage that occurs at a site
Voltage Regulator (VR)	A device that controls voltages in the power networks
Voltage Sag	A temporary reduction of the voltage at a point in the electrical system below 90% of the nominal. The description of voltage sags can be by retained voltage and duration. Voltage sags may last from half a cycle to one minute.
Voltage Unbalance	A condition in poly-phase systems in which the RMS values of line-to-line voltages (fundamental component) or the phase angles between them are not all equal.
VT	Voltage Transformer: a device typically used in protection and metering systems to measure voltage in primary conductors.
W	Watts - unit of the 'real' component of electrical power
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 subtransmission voltages to distribution voltages.

Appendix B

NER and DA Cross-Reference

Appendix B. NER and DA Cross-Reference

Table 44: NER Cross Reference

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(a) information regarding the DNSP and its network including:		
(1)	a description of its network;	**1.3** Network Overview **2.2** Ergon Energy's Electricity Distribution Network **12** Emerging Network Challenges and Opportunities **Appendix C** Network Security Standards
(2)	a description of its operating environment;	**1.3** Network Overview **2.2** Ergon Energy's Electricity Distribution Network **2.3** Network Operating Environment **3** Community and Customer Engagement **10.1** Reliability Measures and Standards **10.2** Service Target Performance Incentive Scheme **10.3** High Impact Weather Events **11.2** Power Quality Supply Standards, Code Standards and Guidelines **12** 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	**6.2** Planning Methodology **6.4** Network Planning Criteria **6.5** Voltage Limits **6.6** Fault Level Analysis **6.7** Ratings Methodology **6.12** DAPR Reporting Methodology **Appendix E** Substation Forecast and Capacity Tables **Appendix F** Feeder Forecast and Capacity Tables
(5)	analysis and explanation of any aspects of forecasts and information provided in the Distribution Annual Planning Report that have changed significantly from previous forecasts and information provided in the preceding year;	**1.5** Changes from 2018 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;	**5** Network Forecasting
(2)	load forecasts (i) at the transmission-distribution connection points; (ii) for subtransmission lines; and (iii) for zone substations,	**7.1** Emerging Network Limitation Maps **7.2** Forecast Load and Capacity Tables **Appendix E** Substation Forecast and Capacity Tables

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
	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;	**Appendix F** Feeder Forecast and Capacity Tables
(3)	forecasts of future transmission-distribution connection points (and any associated connection assets), subtransmission lines and zone substations, including for each future transmission-distribution connection point and zone substation: (i) location; (ii) future loading level; and (iii) proposed commissioning time (estimate of month and year);	**7.1** Emerging Network Limitation Maps **7.2** Forecast Load and Capacity Tables **Appendix E:1** Transmission Connection Point Load Forecast **Appendix E:3** Forecasts for Future Substations and TCPs
(4)	forecasts of the Distribution Network Service Provider's performance against any reliability targets in a service *target performance incentive scheme*; and	**10.2** Service Target Performance Incentive Scheme
(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 **6** Network Planning Framework **7** Network Limitations and Recommended Solutions **8.2** Actions Promoting Non-Network Solutions in 2018-19 **8.3** Demand Management Activities in 2019-20 **9** Asset Life-Cycle Management **10.1.5** Reliability Corrective Actions **10.3** High Impact Weather Events **10.5** Worst Performing Feeders **11** Power Quality **12** Emerging Network Challenges and Opportunities

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(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;	**7.6** Network Asset Retirements and De-Ratings

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(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;	**7.6** 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;	**7.1** Emerging Network Limitation Maps **7.4** Subtransmission Feeder Limitations **Appendix E:2** Substation Capacity and Load Forecasts **Appendix E:3** Forecasts for Future Substations and TCPs **Appendix F:1** Subtransmission Feeder Capacity and Load Forecast
(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 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(5)	where an estimated reduction in forecast load would defer a forecast system limitation for a period of at least 12 months, include: (i) an estimate of the month and year in which a system limitation is forecast to occur as required under subparagraph (1); (ii) the relevant connection points at which the estimated reduction in forecast load may occur; and (iii) the estimated reduction in forecast load in MW or improvements in power factor needed to defer the forecast system limitation;	
(d) for any primary distribution feeders for which a Distribution Network Service Provider has prepared forecasts of maximum demands under clause 5.13.1(d)(1)(iii) and which are currently experiencing an overload, or are forecast to experience an overload in the next two years the Distribution Network Service Provider must set out:		
(1)	the location of the primary distribution feeder;	**7.1** Emerging Network Limitation Maps **7.3** Substation Limitations **Appendix F:3** Distribution Feeder Limitations Forecast
(2)	the extent to which load exceeds, or is forecast to exceed, 100% (or lower utilisation factor, as appropriate) of the normal cyclic rating under normal conditions (in summer periods or winter periods);	
(3)	the types of potential solutions that may address the overload or forecast overload; and	
(4)	where an estimated reduction in forecast load would defer a forecast overload for a period of 12 months, include: (i) estimate of the month and year in which the overload is forecast to occur; (ii) a summary of the location of relevant connection points at which the estimated reduction in forecast load would defer the overload; (iii) the estimated reduction in forecast load in MW needed to defer the forecast system limitation;	
(e) a high-level summary of each RIT-D project for which the regulatory investment test for distribution has been completed in the preceding year or is in progress, including:		
(1)	if the regulatory investment test for distribution is in progress, the current stage in the process;	**7.7** 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);	

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(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;		**7.7.3** Foreseeable RIT-D Projects
(g) a summary of all committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more (as varied by a cost threshold determination) that are to address an urgent and unforeseen network issue as described in clause 5.17.3(a)(1), including:		
(1)	a brief description of the investment, including its purpose, its location, the estimated capital cost of the investment and an estimate of the date (month and year) the investment is expected to become operational;	**7.7.4** Urgent and Unforeseen Projects
(2)	a brief description of the alternative options considered by the Distribution Network Service Provider in deciding on the preferred investment, including an explanation of the ranking of these options to the committed project. Alternative options could include, but are not limited to, generation options, demand side options, and options involving other distribution or transmission networks;	
(h) the results of any joint planning undertaken with a Transmission Network Service Provider in the preceding year, including:		
(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;	**6.10** Joint Planning **6.11** Joint Planning Results

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(2)	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;	**6.10** Joint Planning **6.11** Joint Planning Results
(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;	**10** Network Reliability **11** Power Quality
(2)	a summary description of the quality of supply standards that apply, including the relevant codes, standards and guidelines;	
(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;	**10.2** Service Target Performance Incentive Scheme

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(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;	**4** Asset Management Overview **9** 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;	**6.4.4** Consideration of Distribution Losses
(2)	a summary of any issues that may impact on the system limitations identified in the Distribution Annual Planning Report that has been identified through carrying out asset management; and	**4** Asset Management Overview **7.6** Network Asset Retirements and De-Ratings **9** 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;	**4.5** Further Information
(l) information on the Distribution Network Service Provider's demand management activities, including:		
(1)	a qualitative summary of: (i) non-network options that have been considered in the past year, including generation from embedded generating units; (ii) key issues arising from applications to connect embedded generating units received in the past year; (iii) actions taken to promote non-network proposals in the preceding year, including generation from embedded generating units; (iv) the Distribution Network Service Provider's plans for demand management and generation from embedded generating units over the forward planning period;	**8** 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;	**8.4** Key Issues Arising from Embedded Generation Applications

National Electricity Rules Version 116 Chapter 5: Network Connection, Planning and Regulation Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		Report Section
(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		**13** Information and Communication Technology **14** Distribution Metering **15** Operational Technology and Communications 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	**7.1** Emerging Network Limitation Maps
(2)	any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders	

Table 45: 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.	**6.4.2** 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.	**10.6** 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;	**10.5** Worst Performing Feeders **Appendix G** Worst Performing Feeder Improvement Program
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.	

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.	**6.4** Network Planning Criteria **10** Network Reliability **Appendix G** Worst Performing Feeder Improvement Program

Appendix C

Network Security Standards

Appendix C. Network Security Standards

Under the Distribution Authority, Ergon Energy is obligated to promulgate customer value, which provides customer safety net targets approved under the provisions in the *Electricity Act 1994*. These targets applied from 1st July 2014 and form the basis for the Distribution Annual Planning Report and the AER regulatory determination covering the period 2015-20. Safety Net requirements address the network operation issues and the customer impacts arising from high-consequence-low-probability network events and are only applicable to credible contingency (N-1) events.

Customer value can be leveraged by combining Minimum Service Standard (MSS) provisions, Worst Performing Feeder programs, concurrent maintenance plans, network operating strategies, contingency plans, and safety net targets. This underpins prudent capital and operating costs and delivers value to the customer. To this end, Ergon Energy's strategic planning practices have adopted the safety net targets.

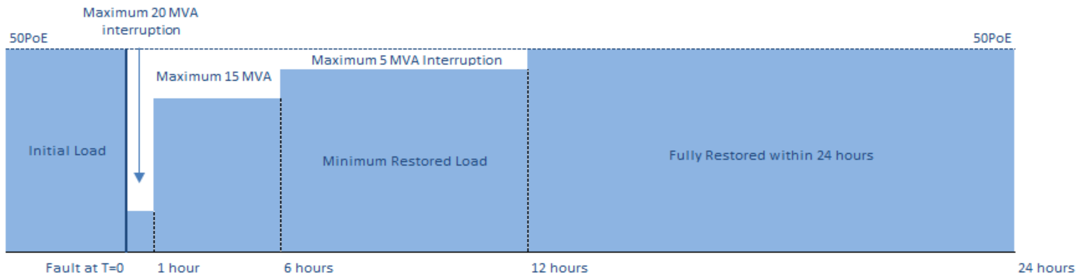
The Safety Net criteria allow Ergon Energy to make use of available network transfers and zone substation and bulk supply capabilities and are inherent in the assessment of security standard compliance. Where these assessments indicate that the network is not able to meet the required security standards, the resulting system limitation are addressed to ensure customer service expectations are achieved. A range of actions to defer or avoid investments such as non-network solutions, automated, remote and manual load transfer schemes and the deployment of a mobile substation and/or mobile generation increase utilisation of network assets are also considered to comply with Safety Net criteria. Specific security requirements of large customer connections that are stipulated under the relevant connection agreement are treated separate to the Safety Net criteria.

The safety net targets contained in the Ergon Energy's Distribution Authority and applied in the Ergon Energy's strategic network planning are shown in Table 46.

Table 46: Ergon Energy Safety Net Targets

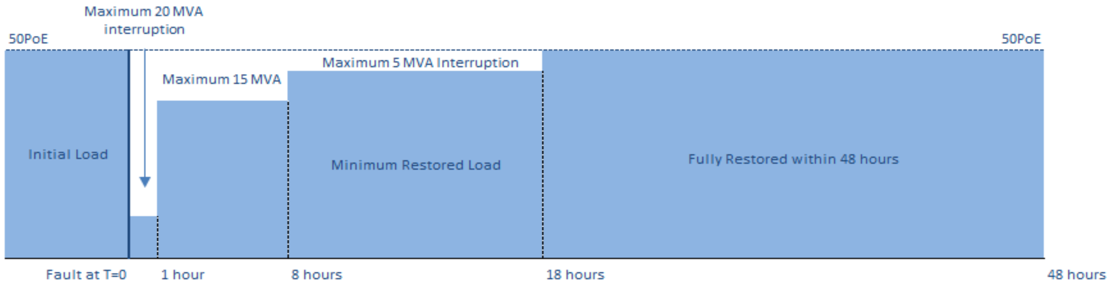
<table>
<tr><th>Area</th><th>Targets for restoration of supply following an N-1 Event</th></tr>
<tr><td>Regional Centre[30]</td><td>
Following an N-1 Event, load not supplied must be:

- Less than 20MVA (8,000 customers) after 1 hour;
- Less than 15MVA (6,000 customers) after 6 hours;
- Less than 5MVA (2,000 customers) after 12 hours; and
- Fully restored within 24 hours.



</td></tr>
<tr><td>Rural Areas</td><td>
Following an N-1 Event, load not supplied must be:

- Less than 20MVA (8,000 customers) after 1 hour;
- Less 15MVA (6,000 customers) after 8 hours;
- Less 5MVA (2,000 customers) after 18 hours; and
- Fully restored within 48 hours.



</td></tr>
</table>

In compliance with the Distribution Authority, Regional Centre applies to non-CBD urban areas predominantly supplying actual maximum demand per total feeder route length of greater than 0.3MVA per km. Rural Areas then apply to non-CBD and non-urban areas. All analysis is based on 50% Probability of Exceedance (PoE) loads.

The economic merits of exceeding safety net targets will be derived by customer reliability value assessment. A key input to calculating the economic value customers place on reliability is Value of Customer Reliability (VCR). The economic customer value based approach will be utilised to optimise the timing of individual projects and to assist in prioritising significant projects addressing Safety Net issues.

In a limited number of cases, a higher level of network security will be considered in the interest of public safety or significant economic or community impact.

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

Appendix D

Network Limitations and Mitigation Strategies

Appendix D. Network Limitations and Mitigation Strategies

This section provides details concerning asset limitations and presents committed solutions or potential options for each limitation.

In comparison to the 2018 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 2018 DAPR have been deferred beyond the forward planning period due to declining growth in demand forecasts. Furthermore, some projects have been re-assessed and subsequently cancelled. This section provides updated information for the forward planning period.

Details of asset limitations and their associated potential solutions are contained in the Distribution System Limitation Templates prepared in accordance with Australian Energy Regulator's (AER) in the following hyperlinks:

- Substation-Limitations-and-Committed-Solutions
- Substation-Limitations-and-Proposed-Solutions
- Transmission-and-Subtransmission-Feeder-Limitations-and-Proposed-Solutions
- Distribution-Feeder-Limitations-and-Committed-Solutions
- Asset-Replacement-Projects

Further details can be obtained from the Ergon Energy website accessible via the following link:

https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report

GIS based mapping including forecasts and limitations are available via an ESRI GIS Portal accessible via the following weblink:

https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report/dapr-map-2019

Appendix E

Substation Forecast and Capacity Tables

Appendix E. Substation Forecast and Capacity Tables

The following subsections contain Substation Forecast and Capacity Tables as well as Transmission Connection Point (TCP) details in the Ergon Energy network.

Further details can be obtained from the Ergon Energy website accessible via the following link:

https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report

GIS based mapping including forecasts and limitations are available via an ESRI GIS Portal accessible via the following weblink:

https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report/dapr-map-2019

E:1 Transmission Connection Point Load Forecast

The detailed load forecasts for TCPs are presented on the ESRI GIS Portal and in Microsoft Excel™ format via the following link. (Note that TCPs where Ergon Energy owns the power transformers are categorised in this document as bulk supply substations and are included in **Appendix E:2** Substation Capacity and Load Forecasts).

Forecast	Link to Microsoft Excel compatible file and ESRI GIS Portal
TCPs (where Ergon Energy does not own the power transformers)	Transmission-Connection-Point-Forecasts-2019.xlsx
	https://www.ergon.com.au/__data/assets/excel_doc/0005/1082273/Transmission-Connection-Point-Forecasts-2019.xlsx

Contents

The tables contained in this spreadsheet include the following information for 50 PoE and 10 PoE loads in Summer and Winter:

- Ergon Energy region;
- TNI: NEM-Transmission Node Identity
- TCP Name : Name of the Transmission Connection Point
- Forecast Peak Load (MW)
- Forecast Peak Load (MVARu) (VARu = Volt Amps Reactive Uncompensated, i.e. with stated compensation not active)
- Forecast Compensation (MVAR)

Note: The forecast loads are given exclusive of any connected embedded generation.

Appendix E. Substation Forecast and Capacity Tables

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

Embedded generation

Table 47 presents embedded generation connected to the load side of TCPs where Ergon Energy does not own the power transformers. All other embedded generation appears in the substation capacity and load forecasts below in Appendix E:2 Substation Capacity and Load Forecasts.

Table 47: Embedded Generation Connected to Load Side of TCP

Region	Connection Point	Nameplate Rating (MW)
Northern	South Johnstone Mill 22/11kV Substation, 22kV	17.3
Northern	Gordonvale 22kV Switching Station, 22kV	13
Northern	T048 Tully 132/22kV Substation, Tully Mill 22kV Feeder	19.8
Northern	T055 Turkinje 132/66kV Substation, Dimbulah 66kV Feeder	24
Northern	Kidston 132/6.6kV Substation, 132kV	50
Northern	Pioneer Mill 66kV Switching Station	67.8
Northern	Townsville Power Station 66kV Switchyard	82
Northern	Ingham 66/11kV Substation, Victoria Mill 66kV Feeder	24
Northern	Collinsville 33kV Substation	42.5
Northern	T38 Mackay 33kV	30
Northern	T141 Pioneer Valley to GLEL Glenella 66kV Feeder	38
Northern	T34 Moranbah 11kV	12
Northern	T34 Moranbah 66kV	100
Southern	H015 Lilyvale 66kV	63
Southern	Barcaldine Substation 132kV	37
Southern	T83 Roma 132kV	2x45
Southern	Emerald Solar Park - Lilyvale & Blackwater 66kV	72

E:2 Substation Capacity and Load Forecasts

The detailed capacity and load forecasts for bulk supply and zone substations where Ergon Energy owns the power transformers are presented on the ESRI GIS Portal and in Microsoft Excel™ format via the following link. Where limitations are identified in this table, further explanation is given in Section 7.3.

Forecast	Link to Microsoft Excel compatible file and ESRI GIS Portal
Bulk supply and zone substations:	Substation-Forecasts-2019.xlsxm
	https://www.ergon.com.au/__data/assets/excel_doc/0003/1082271/Substation-Forecasts-2019.xlsm

Contents

The tables include the following information:

- Region
- Substation name
- Capacity of commissioned Embedded Generation (with Connection Agreements)
- Forecast over the next five years for:
    - Normal Cyclic Capacity - the total capacity with network components and equipment intact
    - Emergency Cyclic Capacity – the long term firm delivery capacity under single contingency conditions
    - Maximum demand (MVA) (50% PoE and 10% PoE)
    - Hours above 95% of maximum demand
    - Expected power factor at peak load
    - Summer and Winter firm capacity
    - The load in MVA which can be transferred to other supply sources (automatically and manually)
    - Whether required security is achieved.

Exclusions

- Where transfers or generation are not required to meet Safety Net, available transfer capacity has not been assessed and therefore is not included in the reports.
- Bulk supply substations owned by Powerlink or other NSPs connected to the Ergon Energy network.
- Bulk supply substations dedicated to major customers at which the security criteria are a function of the particular customer connection agreement.
- Bulk supply substations that are shared sites where Ergon Energy does not own the bulk supply power transformers.

- Zone substations owned by Powerlink which provide a connection point at 11kV or 22kV to the Ergon Energy network.
- Zone substations dedicated to major customers at which the security criteria are a function of the particular customer connection agreement.
- Minor zone substations (Maximum demand <0.5MVA) which are regarded as 'defacto' distribution transformers.
- De-rating factors such as transformer cables and bus ratings are not considered in these forecasts. Substation capacity is based on transformer ratings only.

E:3 Forecasts for Future Substations and TCPs

Table 48 and Table 49 set out the forecast capacity for the forward planning period for approved future substations and transmission connection points.

Table 48: Forecasts for Future Substations

Region	Future Substation	Location	Proposed Commissioning Time	Future Loading Level
Northern	Cape River East – New Substation	North Queensland North-West Region	Feb 2023	Available in 2020
Southern	Gracemere 66/11kV - New Substation	Rockhampton Region	Apr 2021	Refer Appendix E:2
Southern	Kleinton 33/11kV – New Substation	Toowoomba Region	Sep 2024	Available in 2020

Table 49: Forecasts for Future Transmission Connection Points

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

Appendix F

Feeder Forecast and Capacity Tables

Appendix F. Feeder Forecast and Capacity Tables

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

Further details can be obtained from the Ergon Energy website accessible via the following link:

https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report

GIS based mapping including forecasts and limitations are available via an ESRI GIS Portal accessible via the following weblink:

https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report/dapr-map-2019

F:1 Subtransmission Feeder Capacity and Load Forecast

Subtransmission line capacity and load forecasts for both summer and winter are presented on the ESRI GIS Portal and in Microsoft Excel™ format via the following link:

Forecast	Link to Microsoft Excel compatible file and ESRI GIS Portal
Subtransmission feeder	Sub-transmission-Feeder-Forecasts-2019.xlsx
	https://www.ergon.com.au/__data/assets/excel_doc/0004/1082272/Subtransmission-Feeder-Forecast-2019.xlsx

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

The subtransmission line tables include the following information:

- Ergon Energy region
- Ergon Energy ECORP code
- Ergon Energy operational code
- Subtransmission feeder name and description
- % 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.

F:2 Forecasts for Future Subtransmission Lines

Table 50 sets out the forecast capacity for the forward planning period for approved future subtransmission lines.

Table 50: Forecasts for Future Subtransmission Lines

Region	Future Subtransmission Line	Location	Proposed Commissioning Time	Future Loading Level
Southern	Egans Hill – Gracemere - New 66kV OH Line Construction	Rockhampton Region	Apr 2021	Refer **Appendix F:1** (refer to Gracemere substation forecast)
Southern	Reinforce Burnett Heads - New 66kV OH Line Construction	Bundaberg Region	Jun 2025	Available in 2020
Southern	Nikenbah to Point Vernon – New 66kV Line Construction	Maryborough Region	Jun 2022	Available in 2019

F:3 Distribution Feeder Limitations Forecast

Primary distribution feeders which are currently overloaded or forecast to experience an overload in the next two years are presented on the ESRI GIS Portal and in Microsoft Excel™ format via the following link:

Forecast	Link to Microsoft Excel compatible file and ESRI GIS Portal
Distribution feeder limitations	Distribution-Feeder-Limitations-and-Committed-Solutions-2019.xlsx
	https://www.ergon.com.au/__data/assets/excel_doc/0012/796728/Distribution-Feeder-Limitations-and-Committed-Solutions-2019.xlsx

Contents of Table:

The distribution feeder limitation tables include the following information:

- Ergon Energy region
- Distribution feeder name, ID and location
- Load exceedance after two years (MVA)
- Forecast season that exceedance occurs (Summer / Winter)
- Forecast year that exceedance occurs
- Forecast month/s that exceedance occurs
- Load reduction needed to defer the exceedance by 12 months (MW).

Note: assumed power factor of 0.9.

Connection Points for Load Reduction:

In all cases, the connection point to apply load reduction would be downstream of the substation exit feeder cable and/or first section of line.

Possible Solutions:

Refer to Section 7.4 for a list of possible solutions.

Exclusions:

Dedicated customer connection assets are excluded from the analysis.

Appendix G

Worst Performing Feeder Improvement Program

Appendix G. Worst Performing Feeder Improvement Program

Table 51: Worst Performing Feeders

Feeder Asset ID	Review Complete	Carried Over from Previous Years	WPF Plan Item Status	Region	2018-19 Length (km)	Feeder Category	2018-19 MSS SAIDI LIMIT	Customer Number	3 Yr Avg SAIDI	3 Yr Avg SAIDI Ratio
10020674	2014-15	YES	Completed	FN	885	LR	964	67	10,975	11.39
25273274	2016-17	YES	Completed	NQ	134	SR	424	21	3,706	8.74
20005787	2015-16	YES	No Capital Work	NQ	73	SR	424	46	3,694	8.71
20008784	2017-18	YES	Implementation	NQ	264	LR	964	35	8,273	8.58
20011824	2016-17	YES	Implementation	NQ	224	LR	964	31	7,289	7.56
20003550	2014-15	YES	Completed	NQ	50	SR	424	342	3,014	7.11
20010480	2015-16	YES	Completed	NQ	96	SR	424	106	2,952	6.96
25268404	2014-15	YES	No Capital Work	NQ	3	UR	149	161	994	6.67
30053867	2017-18	YES	Implementation	MK	98	SR	424	197	2,805	6.61
40001032	2016-17	YES	Implementation	CA	141	SR	424	31	2,764	6.52
10020848				FN	77	SR	424	99	2,530	5.97
20007373				NQ	9	UR	149	51	876	5.88
20008837	2017-18	YES	No Capital Work	NQ	264	LR	964	28	5,534	5.74
25272934	2015-16	YES	Completed	NQ	90	SR	424	21	2,429	5.73
20006350	2018-19	YES	No Capital Work	NQ	130	SR	424	245	2,370	5.59
20003983	2016-17	YES	Implementation	NQ	139	SR	424	76	2,282	5.38
40001033	2017-18	YES	No Capital Work	CA	395	LR	964	92	5,064	5.25
20008745	2016-17	YES	Implementation	NQ	398	LR	964	35	4,739	4.92
50000011	2016-17	YES	Completed	WB	185	SR	424	87	2,076	4.9

Appendix G. Worst Performing Feeder Improvement Program

Feeder Asset ID	Review Complete	Carried Over from Previous Years	WPF Plan Item Status	Region	2018-19 Length (km)	Feeder Category	2018-19 MSS SAIDI LIMIT	Customer Number	3 Yr Avg SAIDI	3 Yr Avg SAIDI Ratio
20010444	2015-16	YES	Completed	NQ	59	SR	424	43	2,062	4.86
30053777	2016-17	YES	Implementation	MK	116	SR	424	282	1,928	4.55
20007736				NQ	466	LR	964	86	4,319	4.48
20007497	2018-19	YES	Under Review	NQ	34	SR	424	25	1,790	4.22
20008686	2015-16	YES	Completed	NQ	300	LR	964	49	4,045	4.2
40001206	2017-18	YES	No Capital Work	CA	30	SR	424	75	1,777	4.19
20013453	2016-17	YES	Implementation	NQ	104	SR	424	226	1,749	4.12
60026778	2018-19	YES	Under Review	SW	63	SR	424	116	1,741	4.11
20011515	2017-18	YES	No Capital Work	NQ	78	SR	424	60	1,741	4.11
20011096				NQ	162	SR	424	22	1,736	4.09
20006383	2014-15	YES	No Capital Work	NQ	505	LR	964	185	3,942	4.09
25267901	2016-17	YES	Implementation	NQ	413	LR	964	43	3,814	3.96
40200482	2014-15	YES	No Capital Work	CA	47	SR	424	30	1,647	3.88
20010573	2018-19	YES	No Capital Work	NQ	82	SR	424	24	1,616	3.81
50000230				WB	130	SR	424	263	1,610	3.8
82563123				MK	3	UR	149	527	561	3.77
20013273	2014-15	YES	No Capital Work	NQ	56	SR	424	64	1,577	3.72
40001207	2016-17	YES	Completed	CA	162	SR	424	160	1,554	3.67
30053785	2014-15	YES	Completed	MK	119	SR	424	56	1,523	3.59
10020804				FN	74	SR	424	1,816	1,512	3.57
82934570	2018-19	YES	Under Review	NQ	71	SR	424	358	1,505	3.55
50000161	2017-18	YES	No Capital Work	WB	77	SR	424	89	1,484	3.5

Appendix G. Worst Performing Feeder Improvement Program

Feeder Asset ID	Review Complete	Carried Over from Previous Years	WPF Plan Item Status	Region	2018-19 Length (km)	Feeder Category	2018-19 MSS SAIDI LIMIT	Customer Number	3 Yr Avg SAIDI	3 Yr Avg SAIDI Ratio
25273297	2016-17	YES	Completed	NQ	296	LR	964	60	3,366	3.49
20009306				NQ	99	SR	424	307	1,456	3.43
25276003	2016-17	YES	Implementation	NQ	322	LR	964	50	3,295	3.42
25268413	2016-17	YES	Implementation	NQ	937	LR	964	128	3,287	3.41
40001138				CA	45	SR	424	48	1,419	3.35
20009035				NQ	58	SR	424	86	1,390	3.28
60026792	2016-17	YES	Implementation	SW	77	SR	424	95	1,385	3.27
20007634	2015-16	YES	Implementation	NQ	1,296	LR	964	295	3,148	3.27
20001962				NQ	75	SR	424	310	1,375	3.24
25273274	2016-17	YES	Completed	NQ	134	SR	424	21	3,528	8.32
20010480	2015-16	YES	Completed	NQ	96	SR	424	104	3,448	8.13
40001032	2016-17	YES	Implementation	CA	139	SR	424	31	3,020	7.12
25268404	2014-15	YES	No Capital work	NQ	3	UR	149	159	1,004	6.74
10020674	2014-15	YES	Completed	FN	885	LR	964	69	6,383	6.62
20011824	2016-17	YES	Implementation	NQ	224	LR	964	31	6,243	6.48
20005787	2015-16	YES	No Capital work	NQ	73	SR	424	45	2,544	6
20010444	2015-16	YES	Completed	NQ	59	SR	424	44	2,348	5.54
30053777	2016-17	YES	Implementation	MK	116	SR	424	284	2,322	5.48
20008686	2015-16	YES	Completed	NQ	300	LR	964	49	5,167	5.36
25272934	2015-16	YES	Completed	NQ	90	SR	424	21	2,190	5.16
40001123	2016-17	YES	No Capital work	CA	12	UR	149	98	761	5.11
25273297	2016-17	YES	Implementation	NQ	292	LR	964	61	4,844	5.03
20008784	2017-18	YES	Implementation	NQ	329	LR	964	35	4,728	4.9
20006350				NQ	130	SR	424	246	2,049	4.83
20008745	2016-17	YES	Under Review	NQ	398	LR	964	35	4,630	4.8
25276003	2016-17	YES	Implementation	NQ	323	LR	964	50	4,607	4.78
20003387	2017-18	YES	No Capital Work	NQ	4	UR	149	180	706	4.74
20007634	2015-16	YES	Implementation	NQ	1,285	LR	964	292	4,332	4.49
60026705	2015-16	YES	No Capital work	SW	86	SR	424	74	1,844	4.35

Appendix G. Worst Performing Feeder Improvement Program

Feeder Asset ID	Review Complete	Carried Over from Previous Years	WPF Plan Item Status	Region	2018-19 Length (km)	Feeder Category	2018-19 MSS SAIDI LIMIT	Customer Number	3 Yr Avg SAIDI	3 Yr Avg SAIDI Ratio
60026792	2016-17	YES	Implementation	SW	77	SR	424	96	1,824	4.3
20013273	2014-15	YES	No Capital work	NQ	55	SR	424	65	1,808	4.26
82772961	2017-18	YES	No Capital Work	MK	4	UR	149	71	626	4.2
25267901	2016-17	YES	Implementation	NQ	419	LR	964	44	3,968	4.12
40001033	2017-18	YES	No Capital work	CA	395	LR	964	91	3,905	4.05
20007497				NQ	34	SR	424	26	1,686	3.98
20006383	2014-15	YES	No Capital work	NQ	505	LR	964	180	3,744	3.88
50000043	2017-18	YES	Implementation	WB	42	SR	424	70	1,605	3.78
20003550	2014-15	YES	Completed	NQ	50	SR	424	343	1,570	3.7
50000011	2016-17	YES	Completed	WB	185	SR	424	90	1,566	3.69
20008373				NQ	51	SR	424	250	1,557	3.67
50000161	2017-18	YES	No Capital Work	WB	77	SR	424	93	1,549	3.65
40001206	2017-18	YES	No Capital Work	CA	30	SR	424	76	1,534	3.62
60026702	2016-17	YES	Implementation	SW	184	SR	424	142	1,522	3.59
20003983	2016-17	YES	Implementation	NQ	139	SR	424	76	1,500	3.54
30053867	2017-18	YES	Implementation	MK	98	SR	424	193	1,484	3.5
60026743	2015-16	YES	No Capital work	SW	108	SR	424	81	1,461	3.45
25268407	2016-17	YES	No Capital work	NQ	19	SR	424	136	1,453	3.43
60026839	2014-15	YES	Completed	SW	105	SR	424	36	1,415	3.34
20003471				NQ	7	UR	149	224	493	3.31
25268413	2016-17	YES	Under Review	NQ	936	LR	964	130	3,185	3.3
40200482	2014-15	YES	No Capital work	CA	49	SR	424	30	1,393	3.29
84653782				NQ	28	SR	424	54	1,393	3.28
30053751	2017-18	YES	No Capital Work	MK	5	SR	424	76	1,385	3.27
60026764	2016-17	YES	Implementation	SW	82	SR	424	77	1,377	3.25
20020666				NQ	306	LR	964	32	3,113	3.23
82934570				NQ	71	SR	424	354	1,367	3.22
20010573				NQ	82	SR	424	22	1,362	3.21
60026741	2016-17	YES	Implementation	SW	119	SR	424	132	1,361	3.21
40001207	2016-17	YES	Completed	CA	162	SR	424	160	1,361	3.21

Appendix H

Network Description and Maps

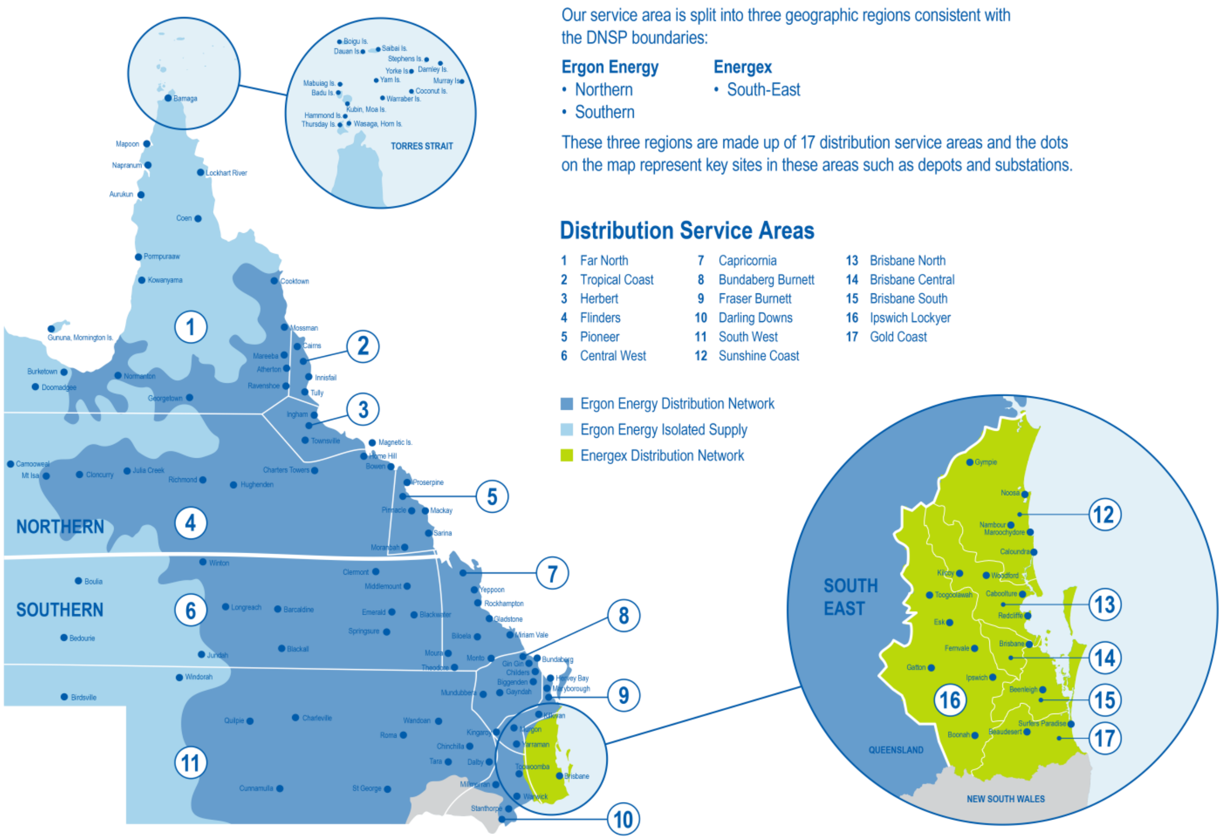
Appendix H. Network Description and Maps

H:1 Planning Regions Overview

As Energy Queensland moves into its current structure, new boundaries and terminology are being adopted for grouping field areas to support efficient service delivery. There are three geographic regions in the Distribution business unit - Northern, Southern and South East.

Ergon Energy has grouped the network broadly into two new planning areas: Northern and Southern as shown in Figure 48 below.

Figure 48: Ergon Energy Network Planning Areas



Within the Northern and Southern regions there are now eleven distinct planning regions within these areas, as shown in Table 52 below. The following sections provide a description of the planning regions and the hubs they envelop.

Table 52: Ergon Energy Network Planning Regions

	Planning Areas	
	Northern	Southern
Planning regions	Far North	Central West
	Tropical Coast	Capricornia
	Herbert	Bundaberg Burnett
	Flinders	South West
	Pioneer	Fraser Burnett
		Daring Downs

H:2 Network GIS Online Maps

Network maps covering the entire Ergon Energy area are provided in GIS format in an ESRI GIS Portal accessible via the following weblink:

https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report/dapr-map-2019

The map also shows the forecast emerging network limitations. The limitations include: subtransmission lines, zone substations and primary distribution feeders that are forecast to have constraints.

H:3 Northern Region

The Northern Region commences at St Lawrence on the east coast, extending west to the Northern Territory border and north to the northern most island in Torres Strait, Boigu Island. The region consists of five major areas – Far North, Tropical Coast, Herbert, Flinders and Pioneer.

The Far North and Tropical Coast areas, with Cairns as the major centre, are tropical environments with high annual rainfall and exposure to summer electrical storms and cyclones. A substantial part of the wet tropics is also World Heritage Listed, requiring special consideration with regard to the operation and maintenance of any electrical infrastructure.

The Herbert (with Townsville as the major centre) and parts of the Flinders areas are also tropical environments with exposure to summer electrical storms and cyclones. These two areas extend from Bowen in the south to Ingham in the north and west to the Northern Territory border.

The Pioneer region is a sub-tropical environment with exposure to summer electrical storms and cyclones and consists of two main geographic areas (Mackay and Bowen Basin) with regard to electrical infrastructure.

The Northern Region includes many small regional towns with the following listing identifying some of the larger communities in the area:

Sub Regions	Regional Communities
Far North	Cooktown, Mossman, Port Douglas, Mareeba, Atherton, Malanda, Millaa Millaa, Mt Molloy, Dimbulah, Chillagoe, Ravenshoe, Georgetown, Normanton, Croydon and Karumba
Tropical Coast	Cairns, Gordonvale, Babinda, Innisfail, Tully, Mission Beach and Cardwell
Herbert	Townsville, Ingham, Magnetic Island
Flinders	Ayr, Clare, Home Hill, Giru, Gumlu, Bowen, Collinsville, Charters Towers, Julia Creek, Hughenden, Winton, Richmond, Mount Isa, Cloncurry
Pioneer	Mackay, Carmila, Proserpine, Airlie Beach, Laguna Quays, Hayman, Hamilton, Daydream, South Molle, Long Islands, Moranbah, Glenden Nebo, Sarina, Pleystowe, Eungella, Eton and Rosella

Far North

The Far North area is centred on the major rural towns of Mareeba and Atherton and includes the smaller rural communities of Malanda, Millaa Millaa, Mt Molloy, Dimbulah and Chillagoe. In addition, the coastal communities of Mossman, Port Douglas and Cooktown are supplied from the Far North network. The area is served from the one 132/66kV connection point, T55 Turkinje substation (located near Mareeba). The Far North system consists of a 66kV subtransmission network, a dual circuit 132kV transmission line from Turkinje to the Craiglie 132/22kV zone substation near Port Douglas, and a single circuit 132kV line to the Lakeland 132/66/22kV substation that supplies the Cooktown area.

In addition, the Far North western system takes in the Georgetown, Normanton, Croydon, and Karumba communities in the Gulf of Carpentaria. The area is served from the H13 Ross connection point in Townsville where a 132kV single circuit line owned by Ergon Energy to supply this area originates.

Tropical Coast

The Tropical Coast area covers the city of Cairns and environs, as well as the townships of Tully, Innisfail, Cardwell and Mission Beach along the coastal strip. The area is served by 132/22kV connection points which are supplied from the Powerlink 132kV network. In addition the Cairns City and Cairns North 132/22kV zone substations are supplied via Ergon Energy owned 132kV dual circuit lines connected to Powerlink’s Woree 275/132kV connection point.

Herbert

The Herbert area covers the city of Townsville and environs, as well as the townships and surrounding rural areas north to and including Ingham. The area is served by five 132/66kV connection points (one in Ingham and four in Townsville), and one 132/11kV connection point, which are supplied from the Powerlink 132kV network. Ergon Energy takes supply at the 66kV side of Powerlink's 132/66kV transformers for five of these connection points, and at the 132kV terminals of the 132/11kV transformers at the Alan Sherriff 132/11kV connection point. Where Ergon Energy takes supply from Powerlink at the four connection points in Townsville a meshed 66kV network is formed that provides supply to fifteen 66/11kV zone substations.

Flinders

This area basically covers Burdekin/Bowen, Midwestern and Western areas of the North Queensland region.

South of Townsville is the coastal strip centred around the major rural towns of Ayr and Home Hill in the Burdekin, and the coastal community of Bowen. It also includes the mining township of Collinsville and its surrounding rural loads. The Burdekin area is served from the connection point at T193 Clare South, located near the Clare township, the Bowen area including the township of Merinda is served from the T181 Bowen North connection point, located near the Merinda township and two 66kV feeders emanating from the T039 Proserpine 132/66kV connection point which is located in the Ergon Energy Mackay region. Collinsville is supplied at 33kV from an Ergon Energy 33kV switching station connected to the T220 Collinsville North connection point.

The mid-western system of the Flinders area extends from Charters Towers west to Julia Creek and takes in the towns of Hughenden, Winton and Richmond. All these towns are connected at 66kV. Ergon Energy's Millchester 132/66kV substation is located on the outskirts of Charters Towers and is supplied by an Ergon Energy owned single circuit 132kV transmission line from Powerlink's Ross substation in Townsville. Limited capacity is also available via 66kV lines from Stuart substation (Townsville) and T193 Clare South substation to Charters Towers substation. The area west of Charters Towers is supplied by two 66kV feeders, one from Charters Towers substation and one from Millchester substation, to Hughenden substation. Each of these 250km long feeders goes through a 66kV voltage regulator at Cape River substation, which is about 100km from Charters Towers.

The Flinders western area comprises the Mount Isa and Cloncurry regions, and also the non-regulated network supplying the Carpentaria Minerals Province mining loads. This network is isolated from the coastal network, which interconnects eastern Australia, and operates outside of the NEM. Our network here is supplied at 132kV from the Mica Creek Power Station and Diamantina Power Station in Mount Isa. The Duchess Road substation, which services the Mount Isa load, is supplied by two 132kV feeders from Mica Creek B Yard. Ergon Energy's Mica Creek 132/220kV C Yard supplies the Carpentaria Minerals Province mining loads and the Chumvale 220/66kV substation by two 220kV feeders. Chumvale substation provides 66kV supply to two 66/11kV substations that serve the township of Cloncurry.

Pioneer

The Pioneer region is a sub-tropical environment with exposure to summer electrical storms and cyclones and consists of two main geographic areas (Mackay and Bowen Basin) with regard to electrical infrastructure.

The Mackay area centred on the provincial city of Mackay and extends from the small rural community of Carmila in the south, to the rural township of Proserpine and surrounding area in the north including the tourist destinations of Airlie Beach and Laguna Quays. The coastal strip supply area also provides supply to the Hayman, Hamilton, Daydream, South Molle and Long Islands of the Whitsunday group. The area is served by the two 132/33kV connection points of Alligator Creek and Mackay and two 132/66kV connection points of Pioneer Valley and Proserpine, all of which are supplied from Powerlink's 132kV network. Ergon Energy takes supply at the connection points at the 33kV or 66kV sides of Powerlink's transformers.

The Bowen Basin area is centred about the mining towns of Moranbah, Glenden and Nebo and includes around 16 major coal mines. The mines are either supplied from substations connected to the 66kV supply system from the Moranbah 132/66kV connection point, the 66kV supply system from the Kemmis 132/66kV connection point or from substations connected to the Powerlink 132kV network.

H:4 Southern Region

The Southern Region commences near Stanthorpe in the South East Queensland and extends west to the South Australia and Northern Territory boarder. The Northern extremity of the region includes areas of Rockhampton, Middlemount, Clearmont and Longreach. The area includes the Sub Regions of Central West, Capricornia, Bundaberg Burnett, South west, Fraser Burnett and the Darling Downs.

The Southern Region includes many small regional towns with the following listing identifying some of the larger communities in the area:

Sub Regions	Regional Communities
Central West	Longreach, Barcaldine, Blackall, Springsure, Emerald, Blackwater, Clermont, Middlemount, Dysart, Boulia, Bedourie, Birdsville, Windorah
Capricornia	Yeppoon, Rockhampton, Gladstone, Miriam Vale, Moura, Biloela, Monto, Theodore, Anges Waters, Seventeen Seventy, Taroom
Bundaberg Burnett	Bundaberg, Gin Gin, Childers, Mundubbera, Biggenden, Gayndah, Proston, Eidsvold, Mt Perry, Bargara, Moore Park, Woodgate
South West	Quilpie, Charleville, Cunnamulla, Roma, St George, Wandoan, Chinchilla, Tara , Dalby, Miles, Dirranbandi, Mitchell, Augathella, Thargomindah
Fraser Burnett	Murgon, Kingaroy, Yarraman, Kilkivan, Maryborough, Hervey Bay, Nanango, Yarraman, Blackbutt, Wondai, Howard, Burrum Heads
Darling Downs	Toowoomba, Millmerran, Warwick, Stanthorpe, Pittsworth, Oakey, Crows Nest, Cecil Plains

Central West

The Central West area takes in the major rural and mining communities of Emerald, Blackwater, Barcaldine, Clermont and Dysart, along with their surrounding areas. The area also extends west to supply the communities of Barcaldine, Longreach and Blackall and further west to the west to the Queensland/Northern Territory/South Australia state border. This area is supplied from the Powerlink connection points of T032 Blackwater, H15 Lilyvale and T035 Dysart, and also Ergon Energy's T076 Barcaldine. Ergon Energy also takes supply at lower voltages at Blackwater (66kV and 11kV) and Dysart (22kV). The Central West systems include extensive SWER networks.

Capricornia

The Capricornia area incorporates the provincial city of Rockhampton and the surrounding coastal area including Yeppoon and Emu Park, as well as Biloela and Gladstone areas. The Rockhampton area takes supply from Powerlink 132/66kV connection points at T23 Rockhampton, T127 Egans Hill and T061 Pandoin. Ergon Energy takes supply at the connection points at the 66kV sides of the Powerlink 132/66kV transformers.

The Gladstone area is supplied from T019 Gladstone South, H067 Calliope River, T199 Yarwun bulk connection points, and Ergon Energy's Boat Creek and Gladstone North 132/66kV substations. Biloela, Moura and surrounding areas are supplied from the T026 Biloela and T027 Moura 132/66kV bulk connection points. South of the Gladstone area, Ergon Energy has the T166 Granite Creek 132/66kV substation which then supplies Ergon Energy's 66/22kV Agnes Water zone substation. Ergon Energy takes supply from Powerlink at 132kV for Boat Creek and Gladstone North substations, 66kV and 11kV at Gladstone South, 66kV and 11kV at Biloela, 66kV and 22kV at Moura and 132kV at Gin Gin to supply Granite Creek. Supply from Biloela also extends into the North Burnett to supply Ergon Energy's Monto substation.

Bundaberg Burnett

The local Bundaberg area is centred about the provincial city of Bundaberg and also takes in the smaller rural communities of Givelda, Bullyard, South Kolan, Wallaville, Gooburrum, Meadowvale as well as the coastal communities of Bargara and Burnett Heads. Bundaberg is supplied from Powerlink Gin Gin and Teebar Creek 275/132kV substations. Voltage is transformed from 132kV to 66kV at Ergon Energy's T20 Bundaberg supply point. Two main 66kV rings exist; the first connects the Bundaberg and South Kolan substations, and the other connects the Bundaberg, South Bundaberg, East Bundaberg, Bundaberg Central and West Bundaberg substations. Ergon's Isis 132/66kV substation supplies Childers, as well as parts of the North Burnett including Degilbo, Munduberra, Gayndah and Eisvold.

South West

Ergon Energy's Roma 132/6/33kV substation is supplied via an Ergon Energy owned double circuit 132kV line from Powerlink's Columboola 132kV switchyard. A 132/66kV transformer at Roma substation supplies 66kV feeders to St George substation and Charleville substation (from which 66kV feeders to Cunnamulla and Quilpie emanate). The distribution supply network from these systems also extends through to Thargomindah, Dirranbandi and Augathella.

Ergon Energy's Dalby East substation which services the Dalby region is supplied via two Ergon Energy owned single circuit 110kV transmission lines from Powerlink's Tangkam 110kV switching station. Chinchilla substation is supplied by Powerlink owned double circuit 132kV line from either Powerlink's Tarong switchyard or Powerlink's 275/132kV Columboola substation. The Columboola 132/33kV substation connects the Condamine power station into the Chinchilla-Roma 132kV lines and provides 33kV supply to the surrounding region including Miles 33/11kV zone substation. A number of 33kV feeders emanate from Dalby, Chinchilla, Miles and Columboola substations to supply the 33/11kV and 33/22kV zone substations (and several customer owned 33/0.433kV substations) in the area.

Numerous 19.1kV and 12.7kV SWER systems existing in the South West Area

Fraser Burnett

Ergon Energy's Kingaroy substation is supplied via Powerlink's H18 Tarong 275/132/66kV substation. 66kV feeders emanate from Kingaroy Substation to supply rural communities of Nanango, Yarraman and Kumbia as well as Sunwater and Stanwell pumping sites. A 66kV line connects the Kingaroy substation with the Murgon zone substation that is supplied from the Kilkivan 132/66kV substation. This line is operated normally open at the Kingaroy substation.

Ergon Energy's Maryborough 132/66kV substation is supplied from Ergon Energy's Aramara Switching station which connects via two 132kV feeders into Powerlink's Tee Bar Creek 275/132kV substation. Maryborough 132/66kV substation supplies Maryborough, Hervey Bay, and rural communities of Owanyilla, Gootchie, Woolooga and Howard to the south west, and the Hervey Bay coastal area. The area is presently served by nine zone substations which are supplied from the Maryborough 132/66kV substation. Ergon Energy's Kilkivan 132/66kV substation is supplied via dual circuit 132kV feeder from Powerlink's 275/132kV Woolooga site. Kilkivan 132/66kV substation supplies Kilkivan, Goomeri, Murgon, Wondai and Proston. A 66kV ring exists connecting the Kilkivan Town and Murgon substations. From Murgon a 66kV line also connects with the Kingaroy substation but is operated normally open at Kingaroy.

Darling Downs

To supply the Toowoomba, Warwick and Stanthorpe areas, Ergon Energy takes supply at 110kV from Powerlink owned 110kV feeder bays at the Middle Ridge 330/275/110kV connection point. 110kV feeders supply Ergon Energy's South Toowoomba, Torrington, Yarranlea, Warwick, and Stanthorpe 110kV bulk supply substations, and the Kearneys Spring and Toowoomba Central 110/11kV zone substations.

The T189 Oakey 110/33kV bulk supply substation, the 110kV lines and 110kV bus are owned by Powerlink with Ergon Energy owning the 110/33kV transformers. A number of 33/11kV zone substations are then supplied from the 110kV bulk supply substations mentioned above.

In addition, Ergon Energy takes supply at 33kV from the Energex owned Postmans Ridge substation. From Postmans Ridge substation two Ergon Energy owned 33kV lines supply a number of Toowoomba Regional Council water pumping stations as well as Ergon Energy's Crows Nest zone substation. Another 33kV feeder bay at Postmans Ridge substation provides a 33kV contingency supply to the North Street zone substation in Toowoomba.

NETWORK

ergon.com.au

Ergon Energy Corporation Limited
ABN 50 087 646 062

2-18-0032