Network Management Plan

Part A:

Electricity Supply for Regional Queensland

2012/13 to 2016/17

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1. INTRODUCTION AND CERTIFICATION

Ergon Energy's Network Management Plan 2012/13 to 2016/17 (NMP) details the corporation's intentions for the next five years in relation to network reliability, capacity, security and supply quality. It provides our stakeholders with an insight into the key challenges Ergon Energy faces and our responses to them. It also increases the transparency of our network's management and operation.

Ergon Energy is acutely aware of how important a high standard of electricity supply is to the continued economic growth, prosperity and lifestyle of regional Queensland. We are committed to the maintenance and continued development of a supply network that fulfils this requirement, while delivering value for money.

This NMP is an expression of that commitment and other specific performance commitments, made as a Government-owned Corporation (GOC) to our shareholding Ministers. This includes operating within the five-year revenue allowance set by the Australian Energy Regulator (AER).

It also aims to ensure we meet the requirements of the Queensland Electricity Industry Code (the Code or EIC).

The NMP clearly identifies the need for innovation and the deployment of new technologies in providing solutions to customer energy requirements. Demand-side initiatives, coupled with innovative supply-side solutions, are being developed as part of our broader infrastructure plans. In particular, new innovation and technology is a key focus in improving the supply from our rural Single Wire Earth Return (SWER) systems.

The corporation is also acutely aware of the need to respond effectively to the challenges associated with climate change and is committed to demonstrating leadership through its mitigation, adaptation and leveraging activities.

Ergon Energy believes that implementation of the NMP is key to achieving its vision '*to be a high-performance, customer-driven energy business'.*

In accordance with the requirements of the Code, we hereby certify that:

- this NMP meets Ergon Energy's obligations under its Distribution Authority
- this NMP accurately represents the relevant policies of Ergon Energy
- Ergon Energy has complied with those policies and/or provides details of where it has not complied herein, and
- Ergon Energy is committed to implementing this NMP.

This plan builds on the progress made over the past 12 months against the 2011/12 NMP and has been developed within the framework of Ergon Energy's current corporate priorities.

2011/12 was the second year of the current five-year Distribution Determination for Ergon Energy under the auspices of the Australian Energy Regulator (AER)[1]. Over this period, Ergon Energy was committed to operating within the parameters set by the Final Distribution Determination and the outcomes of the Queensland Government instigated Electricity Network Capital Program (ENCAP) Review, while ensuring regional Queensland has an electricity network that will meet the challenges of the future.

Although weather events during 2011/12 were not of the same magnitude as those experienced in 2010/11, significant tracts of Central Queensland were impacted by bushfires and several towns across the state's south experienced major flooding during the summer period, which affected our network and the supply of electricity to customers.

[1] AER Queensland Distribution Determination, 2010-11 to 2014-15, Final Decision, May 2010

In addition a significant weather event occurred in Townsville in March, which saw tornado type winds of up to 170 kilometres per hour cause significant network damage and loss of power supply to over 7,800 properties in several Townsville residential suburbs.

These natural disasters enabled Ergon Energy to again demonstrate the professionalism of our emergency response and customer communication capability, and in many ways the increasing resilience of the network.

Ergon Energy's reliability performance for the 2011/12 year resulted in meeting five of the six Minimum Service Standards (MSS) limits administered by the Queensland Competition Authority (QCA) with the SAIDI MSS for the Long Rural feeder category being the one not met. Adverse weather conditions and storm activities especially during the summer period had a significant impact on the overall SAIDI performance of this feeder category. This was particularly evident with the Long Rural feeder category having the worst SAIDI for the month of January 2012.

Ergon Energy places a high priority on achieving the MSS and continues to use its best endeavours to meet its annual MSS obligations.

During 2011/12, Ergon Energy continued to focus on its operational practices to improve the response times to unplanned outages and the management of planned outages in striving to meet the MSS limits. In addition, Ergon Energy is progressing with the implementation of many improvement strategies for reliability improvement through its major capital works projects.

These efforts are part of a whole-of-business plan developed for operating under the AER's Service Target Performance Incentive Scheme (STPIS) and the QCA's MSS limits as set for the 2010-15 regulatory control period.

Many of Ergon Energy's other achievements for 2011/12 are discussed in this document. They include the delivery of a $740 million system asset capital program, including:

- provision of Supervisory Control and Data Acquisition (SCADA) capability at 16 zone substations associated with the SCADA acceleration program
- the establishment of new 11kV feeders to the townships of Springsure in Central Queensland and Seaforth in the Mackay area
- increase of 35MVA of installed transformer capacity involving the Kelsey Creek and Mundubbera zone substations
- completion of the redevelopment of the Lannercost zone substation, Ingham and the re-development of the Dalby Central zone substation and Roma Bulk Supply Point both nearing completion which will provide an additional 23.5MVA of installed transformer capacity, and
- replacement of generating sets at Pormpuraaw, Gununa, Camooweal, Bedourie, Birdsville, Dauan Island and Stephens Island.

At the end of June 2012, 18 of the 43 priority projects in the 2011/12 works program were completed with a further eight expected to be completed by end of December 2012. Of the remaining 17 projects, 10 have been further delayed as a result of resource constraints, six as a result of project scope issues and one as a result of property issues.

There have been two primary reasons regarding the resource constraints in the last 12 months that have impacted on the delivery of the capital program. The first has been the Central Queensland mining boom drawing on internal and external field resources. To alleviate this Ergon Energy has sourced additional contract construction resources outside of Queensland, leading to longer than expected project delivery times. This is being managed through closer working partnerships with major existing suppliers to ensure continuity in contract labour requirements. There has also been a significant constraint within test and commissioning work groups. Nationally this is a high demand competency group that has proven difficult to source.

To manage this Ergon Energy is sourcing short term supplementary specialists, as well as targeting expansion in existing contractor test capability. Longer term sustainable internal capacity is being increased through para professional training and development programs.

The impact of the global financial crisis was still evident during 2011/12 with the actual expenditure of customer-initiated capital works only 4% higher than the previous year's actual expenditure.

The key features of the NMP for 2012/13 to 2016/17 include:

- a continued focus on network performance improvement resulting in reduced customer supply interruptions
- a substantial ongoing investment to increase available network capacity to meet customer demand, and
- the delivery of ongoing strategies and initiatives consistent with the AER's Final Distribution Determination for Ergon Energy for 2010-15 and the outcomes of the Queensland Government instigated ENCAP Review to identify capital expenditure savings for the 2010-2015 regulatory control period.

Ergon Energy is very aware that cost pressures are a very real concern for our customers and a further review is currently being undertaken to ascertain if further reduction in the forecast capital expenditure for this regulatory control period may be possible. This review is expected to be completed by end of September 2012.

These initiatives and the increased level of investment planned are in response to the need to renew an ageing network and develop infrastructure appropriate to the needs of a growing and technologically sophisticated community. This is key to supporting the continued economic growth and prosperity of regional Queensland.

Ian McLeod
CHIEF EXECUTIVE

Neil Lowry
EXECUTIVE GENERAL MANAGER
ASSET MANAGEMENT

2. BACKGROUND

2.1 Background and purpose

Ergon Energy's NMP aims to provide our many stakeholders with a broad insight into our network planning and operations. It is a public document published annually following review by the QCA. The document details how Ergon Energy will manage and develop its network with the objective of delivering an adequate, economic, reliable and safe connection and supply of electricity to customers consistent with the AER's Final Distribution Determination for Ergon Energy for 2010-15 and the Queensland Government's ENCAP Review.

The NMP is built up from other Ergon Energy annual planning documents, such as Subtransmission Network Augmentation Plans and Distribution Network Augmentation Plans, all of which look five years into the future.

The NMP is written to meet the requirements of section 2.3 of the Code and is in two parts, Part A and Part B, as outlined below.

Part A – Electricity Supply for Regional Queensland

This document provides:

- the corporate context of the NMP
- details of operating environment, including load growth
- an overview of planning processes and load forecasting
- the policies and strategies underpinning our asset management
- assessments of compliance with policies
- an understanding of the challenges around demand-side management
- a summary of the progress made in relation to the previous NMP
- an overview of network reliability performance and the improvement program, and
- our risk-management approach, including disaster management, summer preparedness, contingency planning and asset security levels.

To assist in understanding the terminology in this NMP, Appendix 12.1 provides a diagram of the role of distribution in the supply of electricity to customers, as well as definitions for terms used for key elements of the network.

Part B – Network Capability and Planning Report

This document provides detailed information including:

- network capacity and load forecasts by region
- identification of network limitations
- analysis, options and potential projects
- augmentation works scheduled to undergo the Regulatory Test public consultation process, and
- opportunities for non-network solutions.

Part B also facilitates public consultation and stakeholder feedback on specific network constraints, supply issues and proposed solutions. This transparency helps promote awareness of potential investment opportunities that may result in avoided or delayed network expansion while still satisfying customers' electrical requirements.

2.2 Corporate profile

Ergon Energy has a total asset base of $11.0 billion, which includes $9.2 billion of electricity related plant and equipment and property. It also has more than 4,700 employees to serve around 690,000 customers across a vast service area.

The principal operating companies in the Ergon Energy group are Ergon Energy Corporation Limited (EECL), as the electricity distribution business, and its subsidiary, Ergon Energy Queensland Pty Ltd (EEQ), a 'non-competing' electricity retailer.

EECL is incorporated under the *Corporations Act 2001* (Cth) and is a wholly-owned by the Queensland Government for the purposes of the *Government Owned Corporations Act 1993 (Qld).*

EECL's service area under its Distribution Authority effectively covers 97% of Queensland. Its responsibilities under the *Electricity Act 1994 (Qld)* (Electricity Act) are to:

- allow, as far as technically and economically practicable, a person to connect supply to its supply network or take electricity from its supply network on fair and reasonable terms, and
- operate, maintain (including to repair and replace as necessary) and protect its supply network to ensure the adequate, economic, reliable and safe connection and supply of electricity to its customers.

Additionally, EECL provides high-voltage and project management services on an unregulated contractual basis.

Our electricity distribution network has approximately 150,000 kilometres of powerlines and one million power poles. Around 70% of the network's powerlines are considered rural – approximately 65,000 kilometres of line utilises the limited capacity electricity distribution technology known as SWER (Single Wire Earth Return) – with a very low customer density and largely radial profile.

Ergon Energy also owns and operates 33 isolated power stations (and their associated local distribution networks), which supply communities isolated from the national electricity grid in Western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait islands and Palm and Mornington islands.

Through EEQ, we also own and operate a gas-fired power station in Barcaldine and the associated Cheepie to Barcaldine Gas Pipeline that supplies power into the national electricity grid.

EEQ provides electricity retail services to customers in Ergon Energy's distribution area. As a 'non-competing' electricity retailer, we are unique in that we are only permitted to offer our customers the government-regulated Notified Prices (also referred to as the Uniform Tariff) that apply to all non-market domestic, rural and business customers throughout Queensland through the Standard Retail Contract or Standard Large Non Market Customer Retail Contract. This is a legislative requirement.

Reference to EEQ in this document is minimal and, unless expressly stated to the contrary, 'Ergon Energy' refers to EECL.

2.3 Historical perspective

Ergon Energy was formed in 1999 from the six former regional Queensland Government-owned electricity distributors and their subsidiary retailer.

In many ways, this parallels the development of electricity networks around the world where greater economies of scale were sought through expansion and mergers.

The expansion of electricity networks in Australia in the second half of the 20th Century is considered one of the great modern feats of engineering – 60 years ago, there were virtually no regional electricity networks in Queensland.

An inevitable feature of the expansion has been that larger industrial loads and higher density areas (usually urban coastal) have tended to be served by more reliable systems, while network expansion into lower density rural areas has been undertaken with the objective of minimising the cost per connection. These cost constraints resulted in limited capacity SWER technology being used to span long distances to service our remote rural customers.

The ensuing decades, in particular the past 10 to 15 years, have seen a shift in end-usage patterns to include larger loads (air conditioning and increased refrigeration) and highly sophisticated and complex electronic equipment. There has also been a fundamental shift in both customer expectations and awareness of the quality of supply, in part because of the sensitivity of the new equipment. However, today's distribution system is still largely based on technologies and end-usage patterns of earlier decades.

The issues are not only in the rural systems. Customers on all parts of the electricity network are expecting greater levels of supply reliability and quality to meet their lifestyle and economic aspirations. This represents a significant challenge, along with other impacts such as greater penetration of renewable energy solutions, increased focus on emissions reduction, increasing energy costs and the corresponding need for energy conservation measures, including electrical demand reduction and efficient use of energy. This is in addition to adapting our network asset and practices to mitigate any adverse effects of significant change in weather patterns on network performance.

This NMP details how we are responding to these issues, as well as those associated with the operating environment discussed in Section 4.

2.4 Corporate strategy

At the centre of Ergon Energy's strategic plan is an aspiration to limit increases to network charges (the main component of the end price) to less than CPI over the longer term (post 2020). Our aim is to help mitigate further pressure on the price our customers pay for electricity.

In line with this, Ergon Energy will operate within the Final Distribution Determination set by the AER, and achieve the revised regulated financial targets established through the ENCAP Review in a sustainable manner. 2012/13 is the third year of the current five-year regulatory control period for Ergon Energy.

To support our overarching aspiration, at the corporate level, Ergon Energy's five-year strategy is framed around three strategic themes:

- **Customer-driven**: Understanding customer needs and offering the right balance of products, service, cost and quality will enable us to provide value to customers while improving our costs to service, offsetting our peak load and growing our unregulated revenue.
- **Asset management excellence**: Being excellent asset managers will enable us to realise greater value from existing assets and deliver new assets more prudently and efficiently while maintaining network health and reliability.
- **High-performance organisation**: High-performance hinges on people, information and technology. This theme is about Ergon Energy employees having the skills, information, technology and leadership support they need to be productive, cost-conscious and innovative.

Outworking the programs in the NMP will support the realisation of many of the individual aspirational goals associated with the strategic themes. To ensure we achieve these goals, over the longer term, the key strategic priorities for Ergon Energy over the coming year are:

- to be a high-performing and commercially-focused organisation delivering economic values with a sound corporate governance framework
- reduce unplanned outages

- improve our performance in works delivery by delivering the works plan on time and within cost, and
- improve safety performance by promoting and supporting a work environment that delivers improved safety leadership at all levels within Ergon Energy.

These priorities are again very much supported by the policies, practices and programs detailed in this NMP.

They are also supported by our Joint Workings program with our South-East Queensland counterpart, Energex, which is now at the end of phase three. This work is building from our joint Ergon Energy and Energex Network Vision Outlook to 2030. It is seeing a joint Maintenance Asset Management Framework drive greater condition-based asset risk management, as one example, and more broadly driving alignment across a range of other asset related policies, protocols standards and manuals; many of which are referenced in this plan.

2.6 Legislative environment

Ergon Energy's principal activity is the operation of an electricity distribution system. It holds a Distribution Authority administered by the Director-General of the Department of Energy and Water Supply (DEWS) (formerly the Department of Employment, Economic Development and Innovation) to supply electricity using its distribution system throughout regional Queensland.

Ergon Energy is subject to a range of legislative and regulatory obligations to ensure its network is efficiently planned, constructed, operated and maintained and that the prices charged for its services are appropriate. These obligations include:

- Economic oversight under the National Electricity Rules (Rules) by the AER[2] for its national electricity grid-connected network and isolated Mount Isa-Cloncurry network. Economic regulation relates to the method for:
    - regulating distribution services (classified as Standard Control Services, Alternative Control Services, or Negotiated Distribution Services)
    - recording assets, and forecasting future capital and operating expenditure based on economic and financial principles
    - controlling distribution entities' prices or revenues, and
    - price setting and price movements, including the principles for price development.
- Obligations for customer connection to the network and electricity supply under the Electricity Act, administered by the Department of Energy and Water Supply. The Department of Energy and Water Supply also has responsibility under the Electricity Act for the regulation of Ergon Energy's 33 isolated networks (excluding the Mount Isa-Cloncurry network).
- Technical and Minimum Services Standards, service completion timeframes and Guaranteed Service Levels (GSLs) under the Code (established under the Electricity Act), administered by the QCA.
- System security and network planning requirements under the Rules, including:
    - cooperation with the Australian Energy Market Operator (AEMO)[3] in its management of power system security and the physical dispatch of electricity to meet demand within the National Electricity Market
    - ensuring its network is operated with sufficient capacity and augmented as necessary

[2] *Responsibility for economic regulation transferred from the QCA* to the *AER on 1 July 2010.*

[3] *Renamed from 1 July 2009 - previously, National Electricity Market Management Company (NEMMCO)*

  - o ensuring its network complies with technical and reliability standards, and
  - o providing relevant information to Powerlink Queensland as the Transmission Network Service Provider in the preparation of its Annual Planning Report.
- Developing recommendations to address emerging network limitations through joint planning with Powerlink Queensland and consultation with Registered Participants and interested parties.
- Electrical safety, including licensing of electrical workers and contractors under the *Electrical Safety Act 2002 (Qld),* administered by the Electrical Safety Office.
- Fulfilling all obligations under the *National Greenhouse and Energy Reporting Act (2007)* to report scope one and two greenhouse gas (GHG) emissions to the Commonwealth Government.
- Ecological sustainability in the development of Ergon Energy's electricity supply network under the *Integrated Planning Act 1997 (Qld).*

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

2.7 Financial environment

Ergon Energy's revenue requirements for Standard Control Services are established under the Final Distribution Determination made by the AER on 6 May 2010 for the regulatory control period 2010-2015.

Ergon Energy recovers its revenue cap through charges for the use of the shared distribution system (otherwise known as Distribution Use of System charges – 'DUOS'). These charges are payable by customers and are collected via the customer's retailer.

The AER's decision resulted in total capital and operating expenditure allowances of $5.4 billion and $1.9 billion respectively for the regulatory control period. Ergon Energy's five-year budgets are developed consistent with these total allowances.

On 29 May 2011 the Australian Competition Tribunal (ACT) handed down its orders after Ergon Energy challenged the AER's Final Distribution Determination regarding the property building program. The ACT orders have resulted in an increase of $100 million to Ergon Energy's capital expenditure allowance; the allowance now being $5.5 billion for the regulatory control period.

In January 2012 the Queensland Government instigated the ENCAP Review to identify capital expenditure savings for the 2010–2015 regulatory control period. The Queensland Government endorsed the findings and recommendations of the ENCAP Review, including the recommendation that it accept the capital expenditure savings identified by Ergon Energy. The net savings/deferral of expenditure identified for the 2010-2015 period in the ENCAP Review by Ergon Energy totalled $709 million.

In addition to this, the AER's Final Distribution Determination set out arrangements for provision of Alternative Control Services. Alternative Control Services comprise Street Lighting Services, Fee Based Services and Quoted Services.

Quoted and Fee Based Services are those provided in response to a specific request from a customer and include such services as temporary connections; new large customer connections; emergency recoverable works and de-energisations and re-energisations.

For Street Lighting Services, the AER assessed Ergon Energy's total annual revenue requirements in order to set the maximum prices that can be charged for these services in each year of the current regulatory control period.

Fee Based Services are subject to a price cap determined by applying an AER-approved formula and are approved by the AER each financial year.

Prices for Quoted Services are determined by applying the AER approved formula to the customer's specific job requirements to determine an individual price for each service. That is, the price is not known in advance of the customer requesting the service.

Ergon Energy's regulated revenue cap, and arrangements for Street Lighting and other Quoted and Fee Based Services, for the current regulatory control period provides the economic foundation for the implementation of the first three years of this NMP, until the commencement of the next regulatory control period on 1 July 2015.

All the financial data provided in this, and Part B of the NMP, is based on the data available at the time of writing. Final expenditure programs are subject to regulatory oversight and, where applicable, Board approval and agreement by Ergon Energy's shareholding Ministers.

Further, specific projects/works contemplated in this document, unless expressly stated as being 'committed' represent Ergon Energy's present intention.

All projects/works remain subject to appropriate internal and external approvals and specific detailed review, prior to commitment, of all relevant factors, including actual load growth, plant condition, relative priority of the investment and resource availability. In addition, major customer works currently not confirmed that subsequently become initiated can impact on the annual capital works program.

3. NETWORK OVERVIEW

Ergon Energy manages a network of over $9.2 billion of regulated and non-regulated electricity infrastructure assets and associated property – with approximately 150,000 kilometres of powerlines and one million power poles – across one million square kilometres of regional Queensland.

Ergon Energy's service area covers 97% of the state – this is equivalent to most of the eastern seaboard of the United States. It is one of the largest and most diverse infrastructure networks in the western world; a critical point of difference between Ergon Energy and other electricity distributors.

The vast geographical spread of Ergon Energy's service area impacts the operations and performance of the distribution system in a number of ways.

The area east of the Great Dividing Range, contains approximately 90% of Ergon Energy's customers. Actual customer numbers for this area are around 600,000; this is currently growing by around 1.7% per year. However, for the 100,000 kilometres of line west of the Great Dividing Range the network has an extremely low customer density. Due to the greater lengths of line and resources required per customer the cost to supply the low-density regions is substantially higher than urban areas, from both a relative capital and operational perspective.

To accommodate this, our service area is divided into different pricing zones. The calculations for DUOS pricing accommodate the difference in the supply profile for our East Zone (i.e. the area east of the Great Dividing Range that has a higher customer density), West Zone (i.e. west of the Great Dividing Range) and Mount Isa Zone (which is isolated from the national electricity grid).

There is also an extensive list of regionally specific geographic and related environmental features that impact on the network including:

- high probability of and high exposure to cyclones
- high storm and lightning activity
- significant summer-winter and day-night temperature variations
- high rainfall areas (e.g. increases pole-top rot in Far North Queensland)
- other weather impacts (e.g. the Channel Country is flooded by rains hundreds of kilometres away, the north of the state experiences an extended wet season)
- significant termite populations affecting power pole integrity, and
- unstable soil types (e.g. Darling Downs).

These geographic and environmental variations influence the design criteria for infrastructure, as well as the ability to respond to incidents on the distribution system.

The low-load density and geographical spread also impacts on network topography, with much of the subtransmission and distribution network being characterised by long radial lines.

The maximum demand on the network for 2011/12 was 2,417MW. While a rise of 2.9% from the previous summer, the past summer's peak was the second lowest summer maximum demand recorded for the previous six summers, largely as a result of the severe weather events experienced over the entire Ergon Energy area during the summer period although the effects were not as severe as in 2010/11.

While 2011/12's maximum demand on the Ergon Energy network was less than expected, the same factors are not expected to be as prevalent in 2012/13 and peak demand is expected to increase. By 2016/17 maximum demand is projected to increase to 3,301MW.

Ergon Energy is continuing to analyse major influences of peak demand, including regional Queensland's economic drivers, climatic conditions and any changes to energy usage behaviour as a result of electricity prices/energy conservation awareness both to understand the potential impacts on future network augmentation and to help develop strategies to manage and reduce peak demand into the future.

The highest maximum demand experienced to date for the whole of Ergon Energy's grid-connected network was 2,584MW during the summer of 2006/07.

When reviewing the maximum demand statistics in this report it is important to understand that the vastness of geographic area covered by the network can distort the overall demand statistic; unless the individual regions' maximum demand peaks coincide with each other they will not drive up the system-wide peak.

Ergon Energy also manages 33 isolated power stations in the remote areas of western, northern Queensland and the Torres Strait Islands with associated stand-alone distribution networks providing supply to these communities not connected to the national electricity grid.

To respond to cost drivers and climate change related obligations Ergon Energy is progressively installing reliable and sustainable renewable energy generation (to replace existing diesel plant), using bio diesel fuel where appropriate, and the implementing energy conservation programs for its customers in these isolated communities.

Since 2007, EEQ has also owned and operated the Barcaldine gas-fired power station and associated Cheepie to Barcaldine Gas Pipeline which is used to supply the national electricity grid and for network service support.

In addition, Ergon Energy is also a leader in the provision of stand-alone power supply solutions for remote properties and government services.

The following table indicates a breakdown of Ergon Energy's asset base as at 30 June 2012:

TABLE 1: Ergon Energy's Asset Base

OUR STATISTICS	2011
Network Area Serviced	1.7million km^2
Power Stations	34
Bulk Supply Points	24
Zone Substations	365
Major Power Transformers (33kV to 132kV)	738
Distribution Transformers	92,300
Power Poles	1 million
Overhead Powerlines	
- Subtransmission	15,400km
- High Voltage Distribution	112,200km
- Low Voltage: Distribution[1]	20-25,000km
Underground Power Cables	7,150km
Other Components	
- SWER Isolating Transformers	724
- Distribution Regulators	1,550
- Instrument Transformers	4,472
- Reclosers	1,918
- Air Break Switches	8,849
- Public Lighting	158,802

[1]*Estimate of length only.*

The following map shows the Ergon Energy distribution service area, including isolated community generation sites. The area covered by Ergon Energy's main network is shaded aqua.

4. OPERATING ENVIRONMENT AND GROWTH RATES

Ergon Energy operates in an environment where population and economic growth drive customer connections and demand. It also operates within the constraints of an ageing network, and faces the unique challenges associated with supplying remote and isolated customers and communities.

4.1 Customer connections

4.1.1 Customer numbers

Total customer numbers are anticipated to continue to grow on average of about 1.7%, in line with the five-year average growth rate of 1.8%. Total customer numbers by 2016/17 are expected to be approx 767,000, compared with June 2012 total customer numbers of approx 706,000.

Eastern Zone (which accounts for 90% of customer numbers), is projected to grow at a slightly higher rate, in line with historical trends, with total customers by 2016/17 of approx 694,000, compared with June 2012 total East customer numbers of approx 637,000.

Western Zone (8% of customer numbers), is projected to grow at lesser rate than total rate, with total customers by 2016/17 of approx 62,000, compared with June 2012 total West customer numbers of approx 58,000.

Mount Isa Zone (2% of customer numbers), is projected to grow at a much slower rate with total customers by 2016/17 of approx 10,990, compared with the end of 2011/12 of approximately 10,740.

The annual projections for customer numbers for all customer groups are based on extrapolations of historical data, with resultant forecasts compared to publicly available projections of population growth. Factors such as building approvals, population growth trends, demographics, etc, suggest that the level of new customer connections to the network will continue. Activity in the resources sector continues to be strong and is stimulating regional economies. Ergon Energy considers its forecast of customer numbers to be consistent with the economic outlook for Queensland.

The breakdown of the distribution customer numbers per feeder categories is as follows.

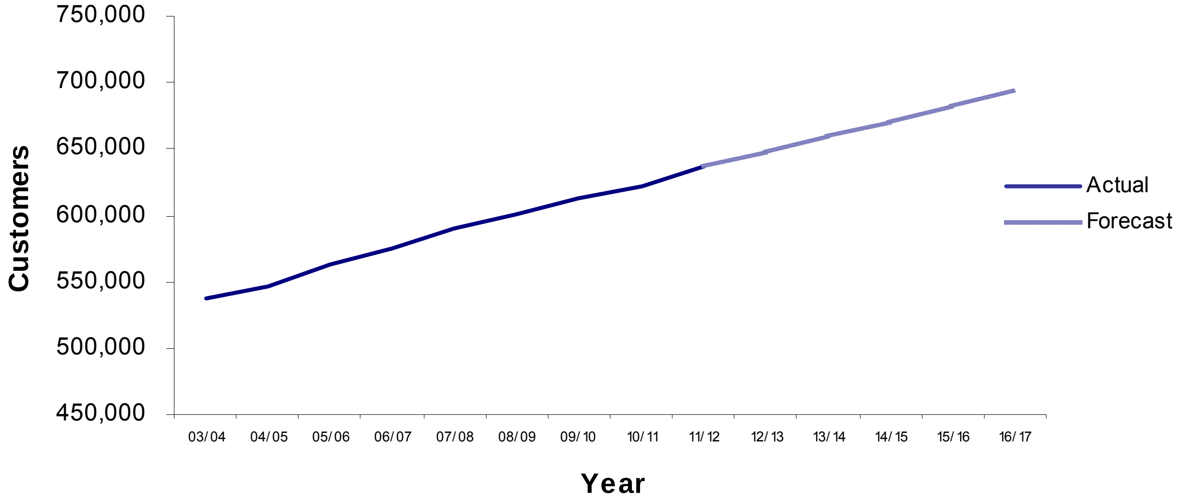
TABLE 2: Customer numbers by feeder category as at end of June 2012

QCA feeder categories	Customer numbers
Urban	229,107
Short Rural	371,374
Long Rural	69,652
TOTAL	**670,133**

Note: The total only includes the QCA categories. It excludes the customers supplied by on our isolated networks, the 410 customers that are undefined, and transmission customers not mapped to QCA categories.

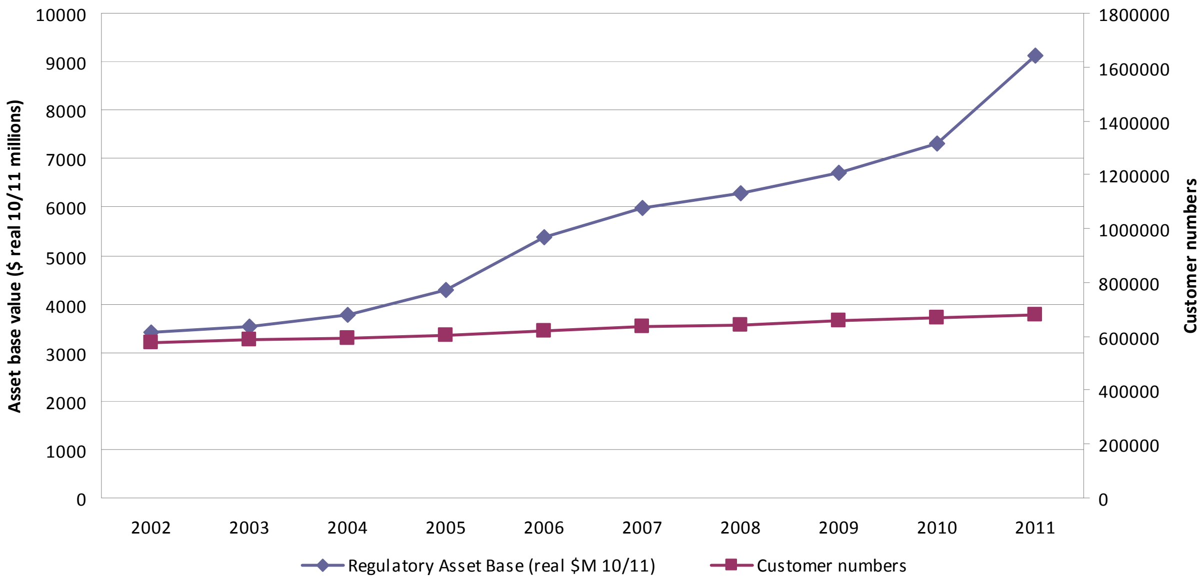
The following graph and table shows recent and projected growth in customer numbers for the Eastern Zone of Ergon Energy's supply area. As this Zone accounts for approx 90% of customers, total customer numbers grow in line with these figures.

GRAPH 1: Growth in east zone customer numbers



Graph 2 compares the growth in customer numbers to the growth in the asset base. The amount of regulatory asset per customer has more than doubled from around $6,000 to $13,500 over the past ten years. This highlights the importance of managing demand as the driving factor in asset investment, which is discussed later in this section.

GRAPH 2: Customer numbers compared to asset base value



4.1.2 Major industrial, generator and mining customers

To ensure that Ergon Energy is well positioned to service our major customers' needs, over the last 12 months we have had specific focus on our capability for connecting major industrial and mining loads to the network in a timely cost effective manner.

The Queensland Resources Council reported that "under a full-growth scenario, the resources sector is set to spend up to $142 billion on 66 projects out to 2020"[4]. While these high levels of investment in the mining sector are expected, the actual quantum and timing of these connections are difficult to predict, being subject to changes in the world financial situation, specifically world commodity prices and other economic and public policy factors.

Major customer connections can be particularly challenging in a decentralised and largely radial network, where the marginal cost of additional capacity varies widely with location. Many of the connections are located on resource fields remote from the coastal network and, therefore, require the extension of major network line assets.

At the end of June 2012, Ergon Energy had:

- An aggregated demand of 1,985MW in major customer connection projects on the development horizon from 136 separate projects. Of these, 785MW is considered likely and 1,200MW not yet advanced enough to determine likelihood. This is a significant increase from 2011 with almost a doubling of demand and 56 more projects These customer projects include those from the resources sector (new coal mines, upgrades to existing coal mines and coal terminals, new hard rock mining loads, LNG plants and coal seam methane installations) as well as other commercial and industrial development projects.
- 52 potential generator projects (embedded in the distribution network), accounting for a possible 909MW in capacity being available for export into the grid. Of these, 197MW is considered likely and 712MW unlikely. Presently with the introduction of a carbon tax it is anticipated that there will be more renewable energy generator projects appearing on the horizon. The development of large renewable generation projects in remote locations will require additional subtransmission and distribution system augmentations to carry power from the sources to load centres.

A breakdown of major customer connection enquiries and applications is provided in Table 3.

TABLE 3: Breakdown of major customer enquiries and applications

Industry Segment	Number	Percentage of total
Coal	72	38%
Gas	6	3%
Port (Coal related)	12	6%
Water	3	2%
Infrastructure (Coal related)	11	6%
Generation/Renewables	52	28%
Other Minerals: Nickel, Al, Au, Cu, Ag, Zn	11	6%
Commercial	21	11%
Total	**188**	**100%**

[4] Queensland Resource Council

The majority of enquiries are from the coal or coal related industry segments although the percentage has reduced in the last 12 months.

Most of the port and water infrastructure enquiries relate to the coal industry. Port construction activity as a result of increasing coal production is being seen in Gladstone, Mackay and Abbott Point.

There is significant coal mining activity taking place in the Surat Basin, Bowen Basin and the Galilee Basin. Powerlink will provide the transmission network for the major developments in these areas and Ergon Energy will provide reinforcement to the distribution network to meet the forecast increase in load in the surrounding townships, the smaller mines, some construction supplies and to water pumping infrastructure.

Since July 2010 Ergon Energy has been operating under the new regulatory arrangement where Major Customers fund the construction of dedicated assets used to connect them to the network. In these situations the customers have the option to build, own and operate the assets, or build and gift the assets, or pay Ergon Energy to build and own the assets.

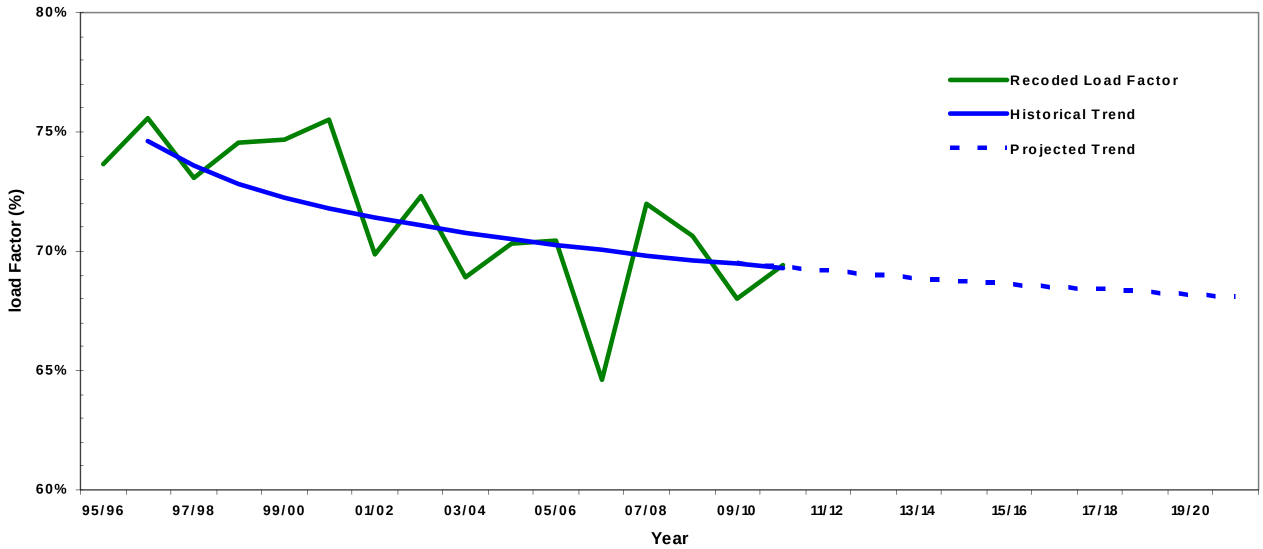
4.2 System utilisation and demand

Electricity supply networks normally are designed and built with spare capacity sufficient to accommodate several years of load growth without the need to upgrade. However, a sustained period of high growth without appropriate capital investment can deplete this spare capacity quickly, adversely affecting the quality and security of supply to existing customers.

Given the relatively long lead times for major electricity infrastructure projects, accurately predicting future loads is a challenge of critical importance.

It is important to note that maximum (or peak) demand rather than energy consumption is the key issue for network capacity, particularly where, as in Ergon Energy's case, the annual load factors are decreasing over time, as shown by the trend line in the following graph. The load factor is the ratio of the average demand to the peak demand.

GRAPH 3: Ergon Energy network load factor



Inludes East and West Zones and Mt Isa

Peak demand is, however, a volatile parameter and increasingly difficult to predict accurately. We are currently reviewing how demand is being impacted by the current economic climate, price rises and the growing awareness and take up of energy efficiency measures.

Apart from economic growth and the associated level of new customer connections, as outlined in Section 4.1 above, the take-up rate of air conditioning and the impact of climate change are considered the significant drivers of peak demand.

There is also an increasing requirement to understand the future impacts of distributed generation penetration, or take up, and the actual output on peak load and network performance.

Climate effects:

Ergon Energy continues to strengthen its response to climate change by expanding its understanding of the risks and opportunities for both the corporation and its customers. Our focus is on leveraging opportunities for mutual benefit, while embedding GHG mitigation and business adaptation measures increasingly into business-as-usual activities to best ensure that the organisation meets environmental, regulatory and market shifts.

Extensive stakeholder engagement is vital to understanding the risks and opportunities presented by climate change and the associated economic, social and technological responses to it.

Ergon Energy is continuing to develop strategies and capabilities to respond to climate change as a network operator. These include achieving a better understanding of what we need to do to ensure resilience of the network to changing weather patterns and managing the risk and opportunity of operating within an emissions trading environment and moving towards a low-carbon future.

Ergon Energy's climate change responses include proactive steps towards improving energy conservation across the community, this is allowing us to explore new energy delivery solutions and expand our demand management initiatives, thereby enhancing the sustainability of the corporation. Essentially these responses are largely aimed at mitigating climate change rather than being considered initiatives addressing the direct effects of climate change.

Climate change is expected to bring increasingly volatile weather patterns and higher temperatures. This is likely to directly impact on network reliability, particularly in those parts of Ergon Energy's supply area considered especially sensitive to the effects of changing and less predictable weather patterns.

Higher ambient temperatures, and the associated impact on peak demand, will also have a significant impact on individual asset performance and life. This has significant implications for Ergon Energy's load forecasts, given the increasing proportion of air conditioning and other temperature-sensitive load (outlined below) and the uncertainty of the effects on irrigation and associated electrical pumping loads in the highly significant and vulnerable agricultural sector.

Historically, it was Ergon Energy's practice to prepare demand forecasts for a 50% Probability of Exceedance (PoE) temperature condition (i.e. the temperature that can be expected to be exceeded once every two years). Temperature probabilities are based on historical records with no allowance made for forecast increases in average (and maximum) temperatures.

The use of 10% PoE forecasts (i.e. the risk of an event occurring once in 10 years) is one way of managing the risk associated with increasingly unpredictable temperatures. Following the Electricity Distribution and Service Delivery (EDSD) Review in 2004, Ergon Energy commissioned independent consultants to review its forecasting practices and security criteria, including the applicability of 10% PoE forecasts. This review endorsed 10% PoE forecasts where the network is at higher risk and this is reflected in Ergon Energy's current practices as described in Section 5.3.

To ensure our response is appropriate we are monitoring weather impacts on network performance and any associated impacts on asset life cycles; we are evolving our network design standards and increasing the integration of non-traditional asset and energy management practices into capital and operating programs.

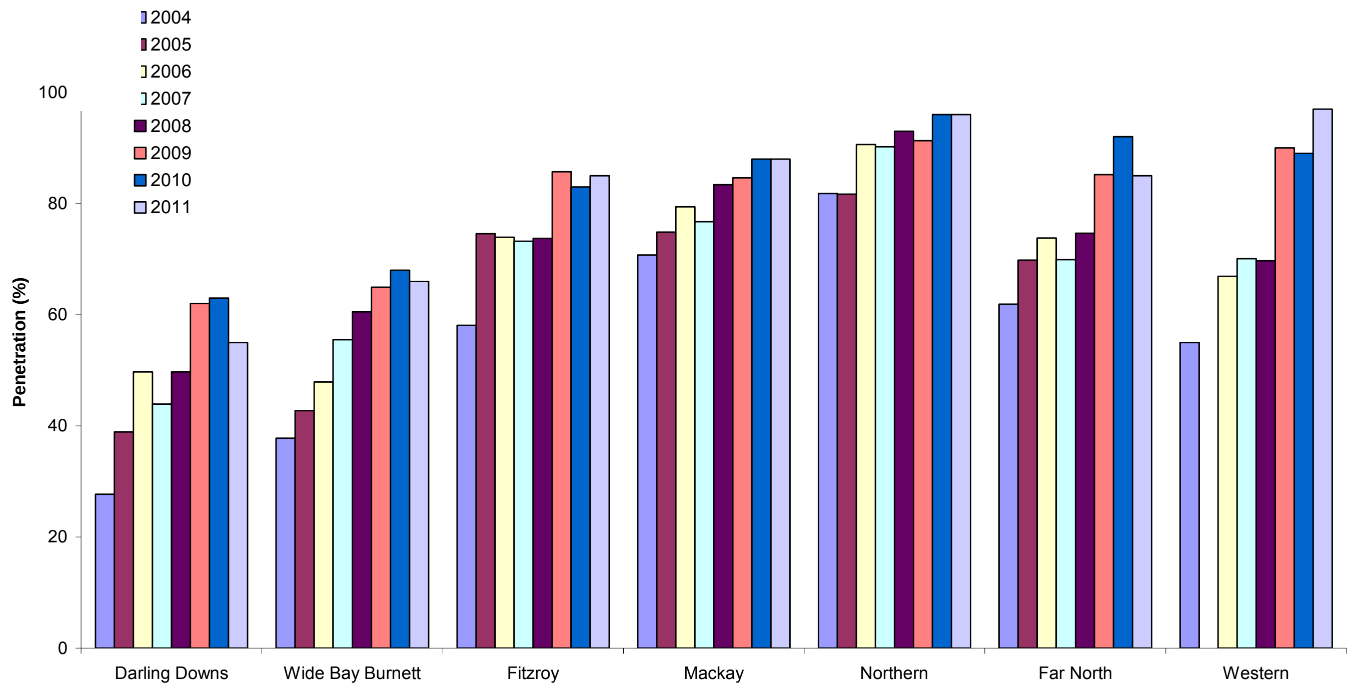
Importantly, effective response will involve enthusiastic and targeted engagement with our customers and communities to continue to deliver a safe, reliable and quality electricity supply.

Air conditioning:

Ergon Energy's network serves tropical and sub-tropical areas across the central to northern areas of the state with long established summer peaking loads, as well as the temperate south-western region, comprising Toowoomba and the Darling Downs, where the trend shows the load transitioning towards summer peaking.

Graph 4 below show the break down by region of air conditioning penetration.

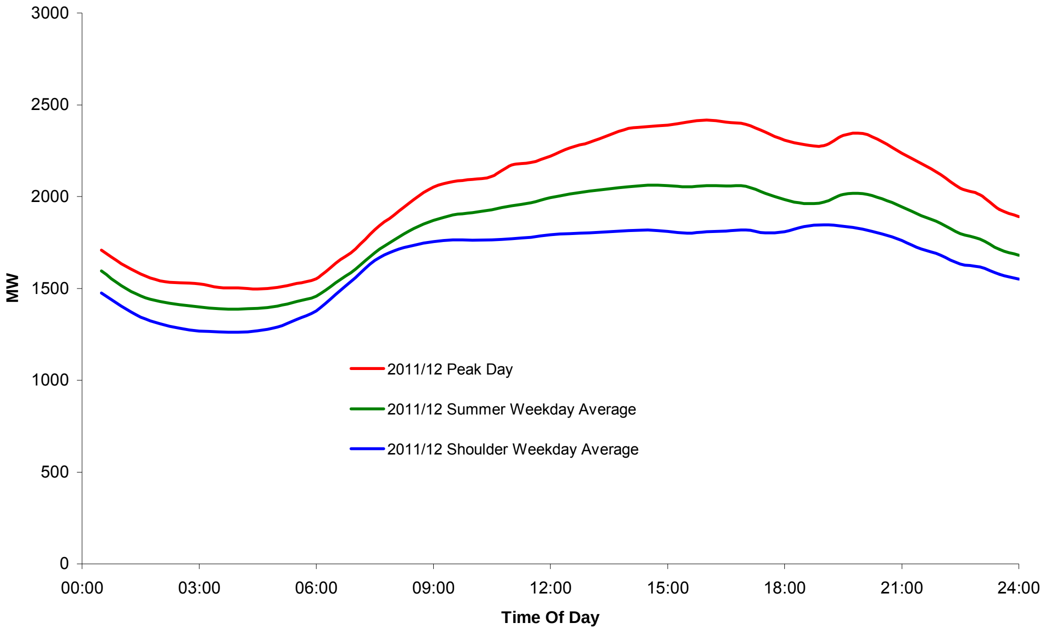
GRAPH 4: Household air conditioning penetration 2004 to 2011



Note: Data sourced from Queensland Household surveys. There have been some changes to the boundaries of the statistical divisions, and there are some sampling variations between the surveys, so direct comparisons should be treated with caution. Nevertheless it is apparent that most areas have experienced an increased penetration of air conditioners, although there was some drop-off in 2011.

It is now well established that domestic and commercial loads have a strong temperature-dependant component. Graph 5 below compares several daily profiles. The lower (blue) trend shows the average normal weekday profile for the 'shoulder' period (i.e. not winter or summer) for 2011/12 (March to February). It shows the fundamental load profile of a predominantly flat day time commercial-industrial driven load trend, continuing into a household-driven evening peak. The middle (green) trend is the average weekday profile for the earlier summer months. It shows the increased demand caused by temperature-sensitive loads (mainly air conditioning). Finally, the higher (red) trend shows the profile of the year's peak day, showing further increases in temperature-sensitive loading, especially around the middle of the day.

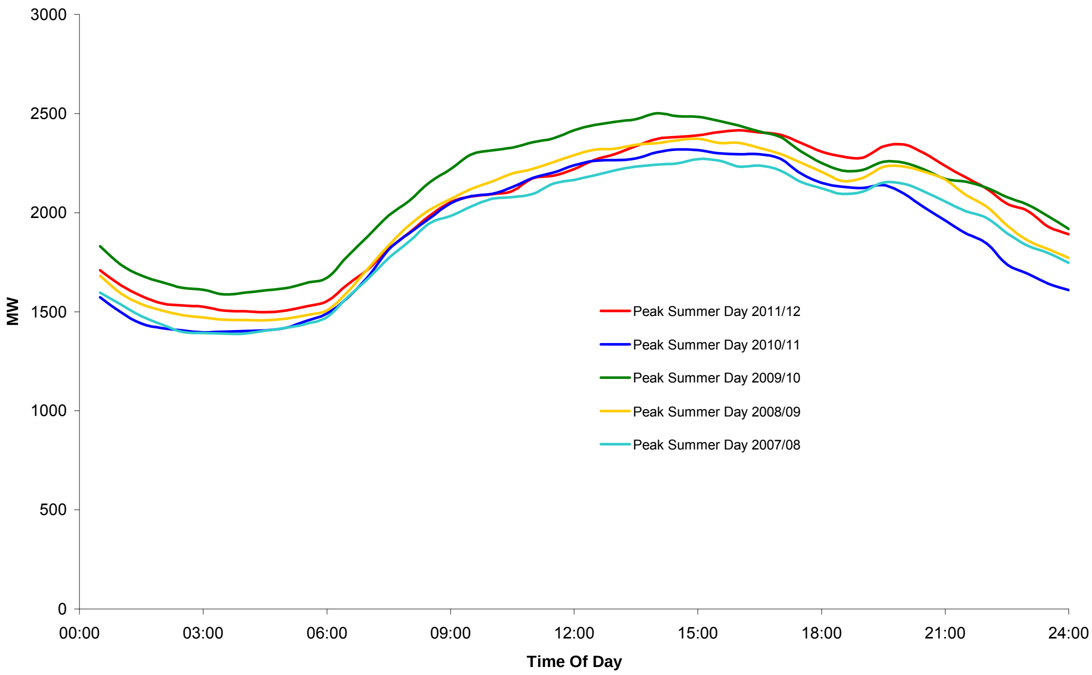
GRAPH 5: Ergon Energy total load profiles



Total network coincident demand profiles for each peak day over the past six years are shown in Graph 6. Unlike the corresponding graphs presented in the reports of a few years ago, these graphs do not show any convincing growth patterns.

While this may be due to changing weather patterns for the La Nina conditions of the last few years contrasted with El Nino conditions of the previous period, we are continuing to analyse other major influences of peak demand in order to ensure an appropriate response.

GRAPH 6: Peak day load profiles 2007/08 to 2011/12 for seasonal year



Challenges to electrical infrastructure:

The rating of electrical infrastructure is usually dependant on the ambient temperature. This is due to the fact that a hot transformer, for example, cannot dissipate as much heat on a hot day as it can on a cold day. Furthermore, equipment that services a peak load spread over a relatively long period will heat up more than it would for a short sharp peak, so cannot service as high a peak load value. The means Ergon Energy's present profiles are challenging for electrical infrastructure in that:

- the peak loads are occurring in the hottest parts of the day
- the peak loads are not short-term but remain high for most of the day and continue into the evening, and
- the peak load increases with temperature increases while the effective rating of plant decreases when the ambient temperature increases.

As a result, plant augmentation and reinforcement needs to occur earlier to stop the risk of equipment failure escalating.

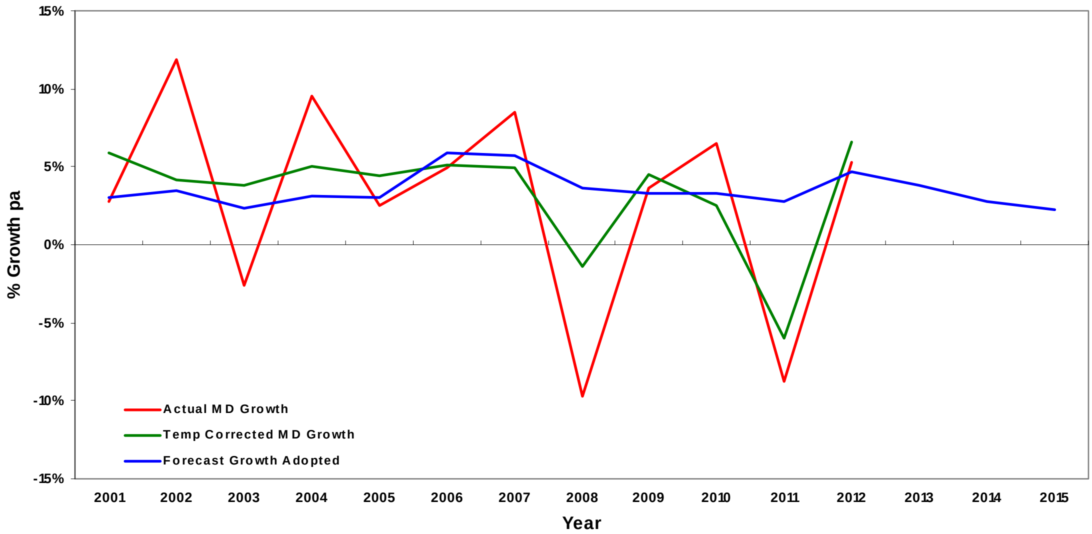
There has been considerable discussion for the potential of solar generation to reduce system peaks. Increased penetration of household photovoltaic (PV) solar generation embedded within the system will help reduce the growth of the afternoon peak but will not alleviate the evening peak until cost-effective energy storage systems become available. If installed in sufficient quantities, it could help reduce the fuel needed to service the afternoon load and help move the peak to a cooler time of day, evening, when system plant has a slightly improved rating. Based on existing trends however, PV generation will not, on its own, act to curb our growing system demand.

In the short term, Ergon Energy considers that reducing household and commercial demand by encouraging more energy-efficient buildings is a more effective strategy than increasing PV generation on its own. The potential effects of climate change, including the likelihood of higher summer temperatures, serve to both increase the uncertainty of load forecasts and reduce the tolerance for error because of the lower capacity ratings of electrical equipment operating at higher ambient temperatures with flat load profiles.

Load forecasting uncertainty:

Graph 7 below shows the volatility of maximum demand in previous years, including the effects of two summer peaks driven by average temperatures much higher than a 10% PoE, let alone the 50% PoE on which forecasts were based, and how the 2007/08 mild summer contributed to a reduced demand.

GRAPH 7: Ergon Energy network total annual maximum demand growth rate



Demand growth:

Like the summer peak for 2010/11, the 2011/12 summer was affected by notable weather events over much of the Ergon Energy area, although the effects were not as severe as in 2010/11.

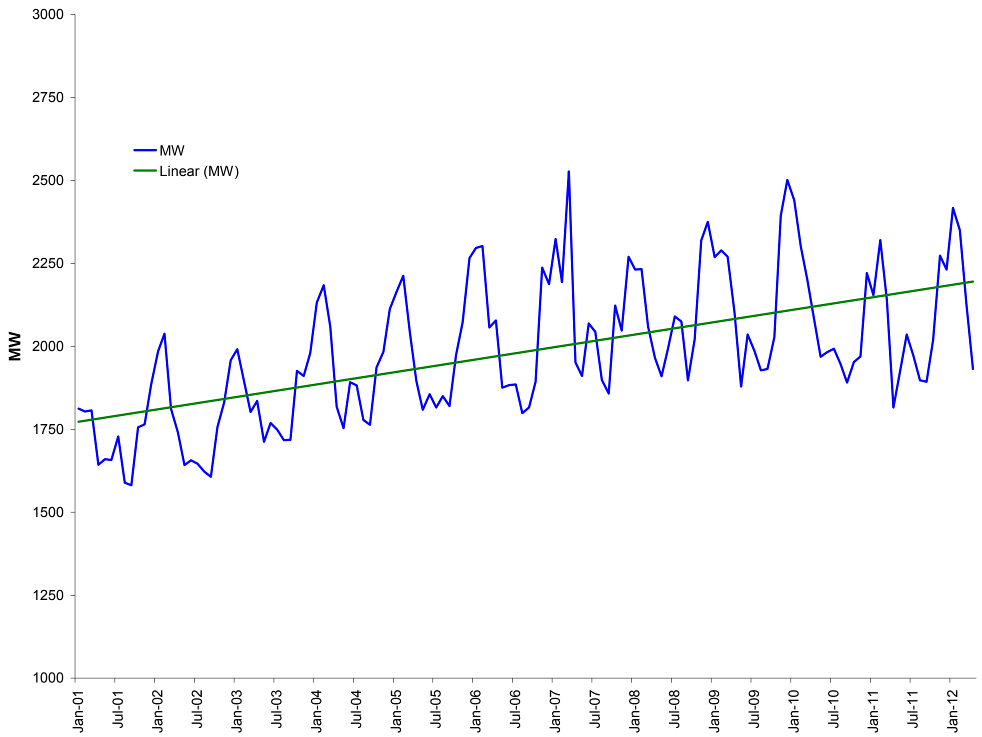
Mining operations in Central Queensland and elsewhere were again heavily impacted by widespread rain and subsequent flooding. Saturation of coal stockpiles at ports slowed exports while flooding and subsequent disruption to the rail transport network prevented further coal deliveries.

In Capricornia the recorded temperatures for the season were below what would be expected from a normal summer, with only two days where the average daily temperature exceeded the 10% PoE temperature value.

Norwich Park mine in Central Queensland has ceased operation, in part at least because of the loss of profitability following disruptions due to flooding together with labour cost escalation. While other new mines are opening up in the area, some of these are so large that they require supply direct from Powerlink; so the growth in demand in the area does not all appear as growth in Ergon Energy demand. The weather events and resulting changes in support industry workloads also led to other disruptions to transport and industry. Meanwhile the tourism industry (particularly around Cairns) recovery from last year's devastation has been severely hampered by the continuing high Australian dollar.

Graph 8 following shows the total Ergon Energy monthly demand since 2001.

GRAPH 8: Ergon Energy maximum demand



The Ergon Energy summer maximum demand for 2011/12 was 2,417MW, a rise of 2.9% from the previous summer. While this represents a return to growth, the step reductions following 2007 and 2010 have not been recovered. The 2011 winter peak was 2,035MW, a rise of 2.2% from the previous winter.

Over the past five years, the average growth rate for summer and winter respectively has been +0.8% and +1.5%. This trend is post the highest maximum demand experienced to date during the summer of 2006/07 of 2,584MW when the individual region peaks were highly coincident with each other to create the system peak.

For 2011/12, the Northern region (previously reported as Far North and North regions) recorded a summer maximum demand of 849MW, up 7.5% from the previous summer. Winter maximum demand was 584MW, down 5.7% from the previous winter. Over the past five years, the average growth rate for summer and winter respectively has been +1.0% and +0.6%.

The Central region (previously reported as Mackay and Capricornia regions) recorded a 2011/12 summer maximum demand of 1,019MW, up 7.3% from the previous summer. Winter maximum demand was 839MW, up 0.8% from the previous winter. Over the past five years, the average growth rate for summer and winter respectively has been +1.9% and +1.1%.

The Sothern region (previously reported as Wide Bay and South West regions) recorded a 2011/12 summer maximum demand of 660MW, up 3.5% from the previous summer. Winter maximum demand was 678MW, up 7.5% from the previous winter. Over the past five years, the average growth rate for summer and winter respectively has been -0.4% and +2.5%.

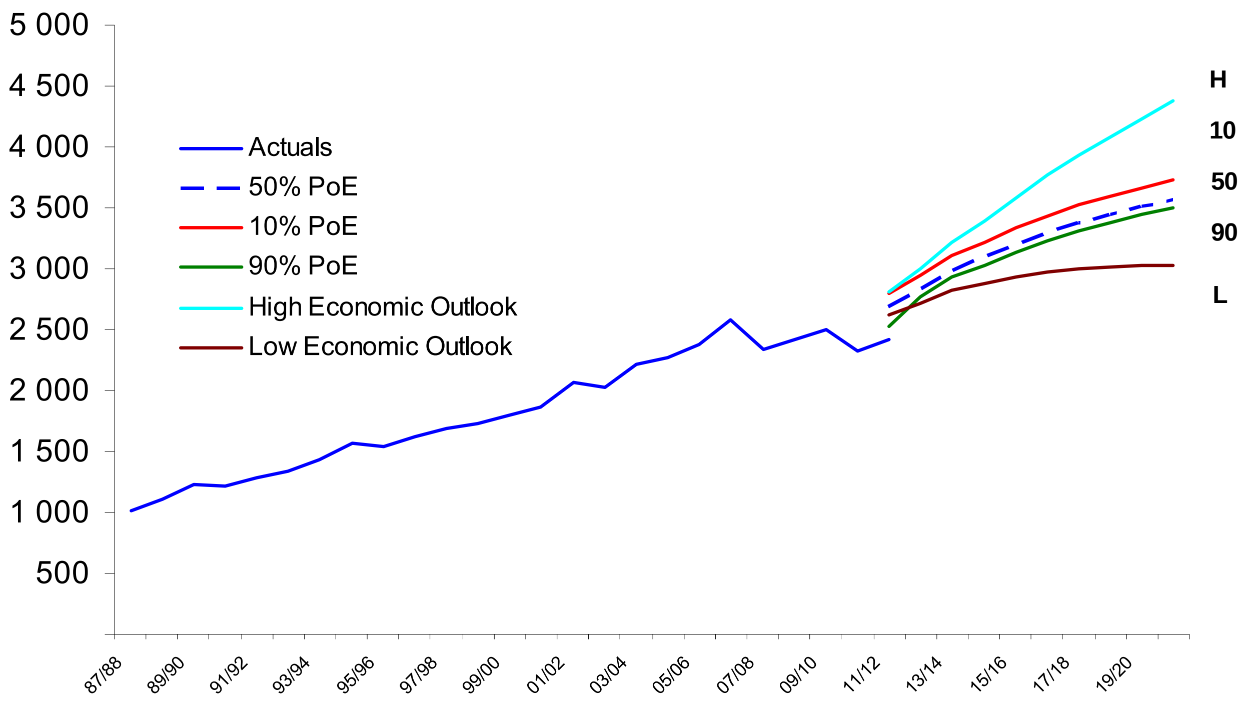
Demand forecast:

The latest maximum demand forecast for the whole of Ergon Energy's grid-connected network (i.e. excluding Mount Isa and the other isolated generation networks) is shown in the following graph. Last year's growth is slowly returning to growth patterns evident before the downturn of 2007/08. However, a full recovery is some way off as the Australian and the Queensland economy continue to be impacted by global economic conditions and terms of trade, as well as the financial burden associated with the severe weather events experienced.

As a consequence, the average growth in system demand over the next five years is forecast at 4.4% a year. The expected increases in coal mining activity within Central Queensland and LNG activity in Central and Southern Queensland are a significant factor in this growth. Graph 9 shows the most likely (50% PoE) forecast for base economic conditions. Mount Isa and the other isolated generation networks are not included.

The highest peak in demand recorded in March 2007 was before the global financial crisis subdued demand.

GRAPH 9: 2011 Ergon Energy total demand forecast



Max. Demand recorded during 12 months ending in July

The total Ergon Energy 10% and 90% PoE lines shown in the forecast are not reflective of the 10% and 90% PoE at each individual site due to a variation of maximum demand days across the state.

The ‘High’ and ‘Low’ trend line are the 50% PoE forecasts for high and low levels of economic growth respectively. For base economic conditions, there is only a marginal difference between the projected demands for 10%, 50% and 90% PoE forecasts.

Ergon Energy’s 50%PoE forecasts are based on historical trends and the forecasts have not been ‘temperature normalised’ prior to compilation. It is considered that the actual long-term demand trends incorporate a degree of temperature normalisation by the fact that they are sampled at the same time as the temperature.

A more formal temperature normalisation process is being developed, but in this report there is no temperature correction in the forecast. However, there is some temperature adjustment in the process to check how well our forecasts reflect actuality. The base power values are for the summer season of the forecast and do not reflect averages for all days of the year.

The biggest influence on future demands will be economic growth levels, as indicated by the ‘high’ and ‘low’ growth trend. Several companies are proposing to develop LNG fields in the Darling Downs and west of Clermont. Some of these developments are of such a scale to require Powerlink involvement, but Ergon Energy demand is still expected to be driven upwards by them, as local supply centres such as Wandoan and Alpha grow significantly to supply accommodation and service industries. Port development is also expected to add considerable load. As well as the influence of market conditions, the scale of demand from these project investments will also be dependent upon the extent of fiscal policy (such as mining tax) and the level of perceived sovereign risk.

Other observations on the impacts to our demand forecast and its relationship to our capital expenditure are listed below:

- Governments have introduced various methods to encourage alternative electrical energy sources and reduced electrical energy usage. These will take time to have a significant impact on electricity demand, although early results are encouraging.
- Power generation embedded within the distribution network will have minimal impact on the total amount of power required but may impact where it is required. The majority of plant that may experience reduced loading is at the interface with the Powerlink network, and is a small proportion of the asset base.
- For some plants such as wind generators, the likely positions of generation points relative to load centres will increase the power flow through some relatively remote sections of the network. This is likely to require increased investment on those sections of the network.
- PV generation will take some time to achieve any significant change to the network demand. As is apparent from Graph 5 above, peak demand for the whole system occurs around 3:00pm when any contribution from PV is reducing, with another substantial peak around 8:00pm when there is no contribution from PV generation.
- While Ergon Energy is collecting data on the size and locations of PV plants connected to the network, Ergon Energy will not have access to information on their maintenance and upkeep as the majority of PV plants are owned by the customer. This will hamper our efforts to track this generation and consequently to track its impact on the system.
- A significant proportion of the generation proposed under the Large-scale Renewable Energy Target (LRET) scheme and the subsequent initiatives are not guaranteed or even scheduled to be commissioned.
- In addition, renewable sources can not guarantee a consistent day time supply. Consequently, Ergon Energy must be in a position to supply power to all sections of our customer base when local renewable generation is not available, so it does not reduce the asset base required. This is likely to result in reduced utilisation of Ergon Energy assets as the capacity required to be held in reserve will not always be needed.

Implications for major customer connections:

The main implication of major customer connections on network capacity is the erosion of spare upstream capacity by catering for that growth. Consequently, additional augmentation works may be required to meet the demand of new major loads.

Implications for the urban networks:

Similarly, the erosion of spare upstream capacity to cater for growth in urban networks results in increasing asset utilisation levels, thereby accelerating the need for network augmentation and potentially delaying customer connection works.

Implications for the rural networks:

The many long radial sections of Ergon Energy's network pose particular capacity problems when required to accommodate changing customer usage patterns, such as those associated with high rates of air conditioner penetration. As outlined in Section 2.3, these systems were designed to supply loads of a type quite different to what has evolved.

However, Ergon Energy is unable to constrain demand growth to existing system capacity. As well, providing extra capacity for the changing load requirements of a limited number of customers for a limited period of peak demand requires construction of extensive new infrastructure at considerable cost. This issue is being addressed initially as part of the SWER project (Section 6.3).

The radial nature of networks in low-density areas means an inherently lower level of supply security because of the lack of alternative supply paths or system redundancy. The supply security in such areas is further compromised when the loads approach capacity limits, with the result being higher outage rates and poorer supply quality.

4.3 Asset age profile

Over the past years, Ergon Energy had steadily consolidated its powerline maintenance programs around a base four-year asset condition inspection program. Data is issued and collected in a Field Mobile Computing (FMC) solution.

As part of this program, all poles are visually inspected and any defects are reported on all associated assets. Defects are then prioritised, packaged and actioned within well-established and strict timeframes.

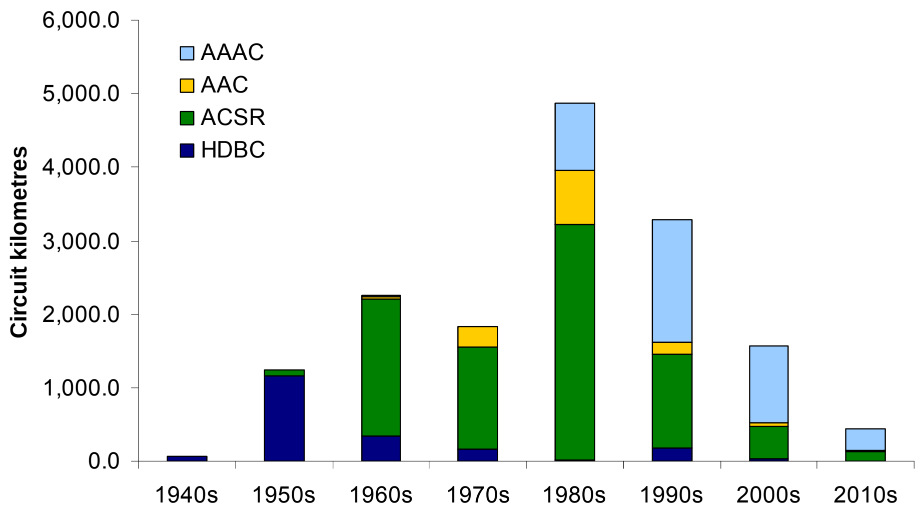
Recently, further work has occurred as a joint workings initiative with Energex to establish a Maintenance Asset Management Framework. This will result in significant change to the well-established Routine Substation Inspection and Maintenance (RSIM) program. The basis of substation maintenance will change to a six monthly Security and Hazard Inspection (SHI), and an In Service Condition Assessment (ISCA) of major plant every 18 months. These programs are being deployed on an FMC platform to improve efficiency, data flow and increase data collection on asset condition.

Concurrently a recognised risk based asset renewal methodology has been delivered through another Joint Workings initiative with Energex. This new Condition Based Risk Management (CBRM) modelling will form the basis of asset renewal decisions. The initial focus has concentrated on the revision of replacement and refurbishment programs for substation plant.

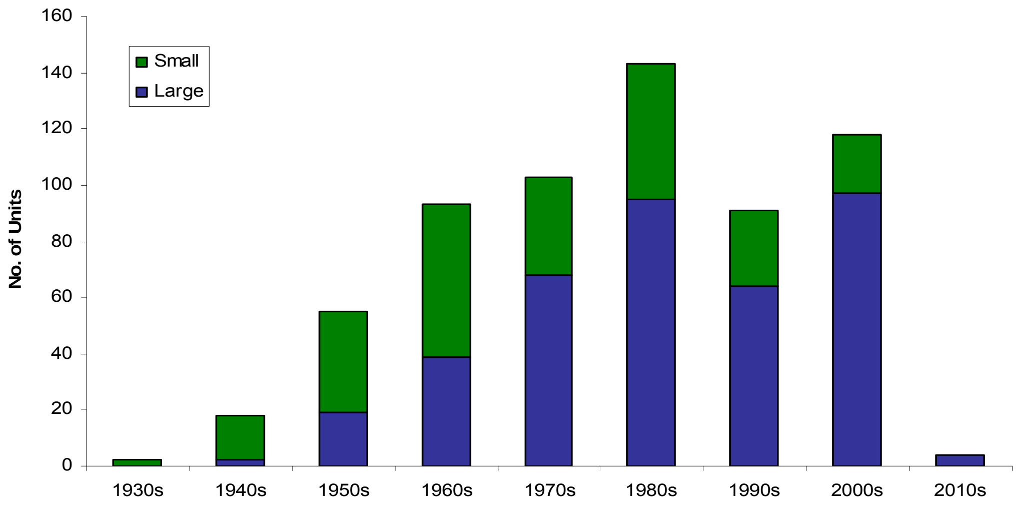
The above initiatives will enable Ergon Energy's maintenance and asset renewal functions to become increasingly condition-based. Nevertheless, Ergon Energy is facing significant ongoing expenditure on assets that are approaching or have reached the limits of their viable lives. Graphs 10 and 11 below show the age profiles for Ergon Energy's overhead subtransmission lines and zone substation transformers respectively.

These graphs illustrate the large volume of assets installed in the 1950s and 1960s and their condition is a major driver for increasing refurbishment and replacement expenditure.

GRAPH 10: Conductor type age profile (subtransmission lines only)



GRAPH 11: Zone substation transformer age profile



Note: Small refers to transformers that have a name plate rating 5MVA and under. Large refers to transformers with a name plate rating greater than 5MVA.

Some of the challenges associated with Ergon Energy's asset age profile include:

- uncertainty in the nominal life for overhead conductor and risk of an increasing failure rate of small copper and galvanised steel conductor
- uncertainty in the nominal life of underground cable, particularly early XLPE cables
- ramping up the power transformer dry-out and replacement programs within the next five years to forestall an increase in failures as a result of age and condition
- the implementation of programs to replace a greater proportion of all substation plant asset classes that CBRM modelling is showing to represent significant future risk if unaddressed, and
- effectively managing the large expenditures on the replacement of Ergon Energy's ageing secondary systems (protection, communications and control) field equipment over the next four to five years.

4.4 Remote systems

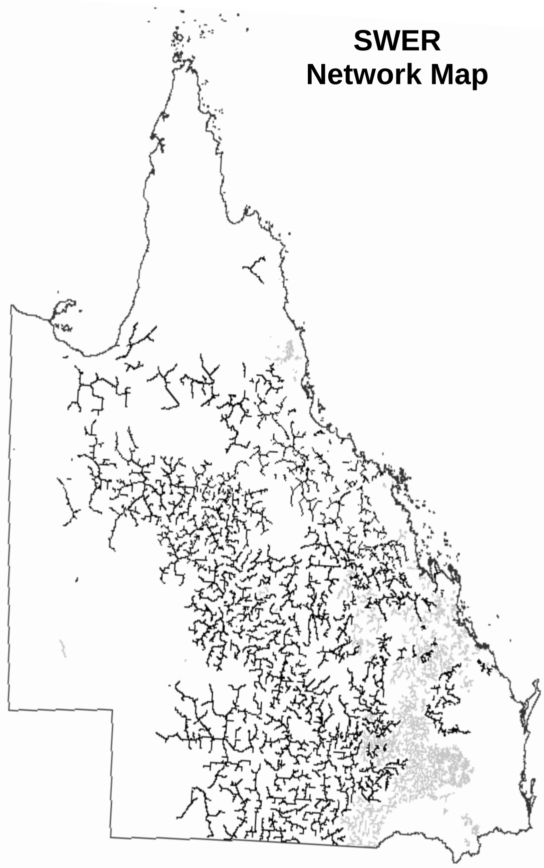
The network operated by Ergon Energy includes around 65,000 kilometres of Single Wire Earth Return (SWER) lines with one of the lowest customer densities in the western world.

As well, Ergon Energy uses a range of non-grid technologies to address the challenges associated with remote supply, including isolated generation and stand-alone power supply solutions.

4.4.1 Single Wire Earth Return (SWER) network

The SWER network design provides a relatively low-cost but limited capacity construction that has facilitated the electrification of much of regional Queensland. However, this network poses unique challenges in its ability to provide a secure and reliable electricity supply, particularly in light of shifts in end-usage patterns to include larger loads (e.g. air conditioning) and sophisticated electronic equipment (discussed in Section 2.3).

The adjacent map shows the extent of the SWER network throughout the Ergon Energy supply area. The SWER network extends from coastal regions to remote inland areas and generally is serviced by higher-capacity three-phase backbone feeders.



The SWER network constitutes an integral part of the supply networks developed by Ergon Energy's predecessor electricity distribution boards to supply customers across the sparsely populated areas of regional Queensland.

Operating at three voltage levels (11, 12.7 and 19.1kV), it supplies around 26,000 customers. Of these customers, 72% are supplied from systems defined as long rural feeders. Energy consumption on the SWER network has been growing at an average of 3% a year despite limited population growth.

Providing and maintaining a supply system that performs at modern standards of quality and reliability over this vast low customer-density network poses a unique challenge.

4.4.2 Isolated generation

Ergon Energy's isolated power stations are in remote areas of the Torres Strait, Cape York and Gulf of Carpentaria, Palm Island and western Queensland. To supply these isolated communities not connected to the main grid, Ergon Energy owns and operates 33 isolated power stations with localised distribution networks.

One of the major challenges Ergon Energy faces in continuing to supply these communities is the ability to meet the growing demand for electricity at the optimum asset life cycle cost. Other challenges are:

- **Diesel Fuel Pricing:** The primary fuel for electricity generation in these isolated communities is diesel. The cost of diesel has increased significantly in recent years (rising dramatically since 2004, in line with instability in the Middle East), making it more difficult for Ergon Energy to provide cost-effective electricity supply.

The likely long-term outlook is for more increases in the diesel fuel price, potentially to a level where it will be more economical to use renewable and alternate technologies rather than diesel. Ergon Energy considers the potential for future diesel fuel price increases to be a major risk to the long-term use of diesel-powered generating plant.

- **Greenhouse Gas Emissions:** Diesel-powered generation in isolated communities is a major contributor to Ergon Energy's GHG emissions. Ergon Energy is committed to reducing the level of emissions from isolated generation by reducing its reliance on fossil fuels for electricity generation.
- **Project Costs:** The costs of capital works have increased significantly over the past five years. These continuing cost pressures are having a major impact on the type of assets Ergon Energy is constructing in remote and isolated regions, and the company is continuing to look to alternative methods to deliver these projects in a cost-effective manner.

5. PLANNING POLICY AND COMPLIANCE

Ergon Energy undertakes comprehensive network planning and load forecasting to deliver on its corporate strategy and ensure that customer expectations and the requirements of the Code and Rules in relation to service standards are met. The Rules also includes provisions relating to the magnitude of power frequency voltage, voltage fluctuations, harmonic distortion and unbalance.

5.1 Planning process

Ergon Energy's planning process involves producing numerous, detailed long-term strategic network development plans that describe the electricity supply infrastructure requirements for defined areas based on 'most likely' 20-year load growth projections. Where appropriate, scenario planning is also used to obtain alternative development plans for a range of possible outcomes (e.g. high growth, more intense weather patterns). Demographic studies based on local government plans are carried out to help indicate the likely very long-term distribution of electricity demand, and these too include scenario modelling to test various outcomes such as high or low customer response to demand management and carbon dioxide abatement initiatives.

The purpose of these plans is to ensure the prudent management of and investment in network infrastructure in both the short and long term. These plans aim to avoid situations where:

- works are scheduled too early, resulting in resources and investment being directed away from areas of greatest need, and
- works are scheduled too late, thereby exposing customers to the risk of contingency events or reduced quality of supply.

The scope of Strategic Network Development Plans is being broadened to support improved integration of projects and coordination of project programming and will include all infrastructure drivers, including reliability performance, sustained climate change response and ageing asset considerations.

In the shorter term, studies are conducted to identify all existing and anticipated network limitations within a five-year horizon. The results are combined with the long term plans to produce firm five-year development plans for augmentation projects, together with a further five-year projection of probable works.

Augmentation projects are identified and scoped in accordance with defined planning criteria as detailed in Section 5.2 below.

5.2 Planning criteria

Ergon Energy is in the process of finalising changes to the security criteria it uses for planning purposes.

From a planning perspective, Ergon Energy has implemented the EDSD recommendation that 'N-1 security levels' be maintained at all bulk supply substations, major-critical zone substations and subtransmission feeders; this simply means that supply can be maintained when a single system element is lost. 'N' is when there is no redundancy built into the system on standby.

To implement the EDSD recommendations, the modified more stringent security criteria was reviewed by independent engineering consultants who concluded that they met the EDSD requirements generally, were conservative and would achieve outcomes consistent with general industry practice.

Over recent years, Ergon Energy and Energex have worked together with consultants to further revise the security criteria, with the aim of targeting our network maintenance and upgrade budget to better meet the needs of different sections of the community. This has been in response to concerns associated with the increasing cost of electricity.

Security of supply is most critical in our commercial and industrial supply areas, as a supply disruption for these businesses will affect both workers (including in severe cases employment/take-home pay) and the consumers of the associated goods and services. In contrast, a disruption to supply in the residential sector does not have such a severe impact. Rather, our ability to maintain reliability standards cost-effectively is more important for the residential sector.

The new revised criteria developed were approved as part of the ENCAP Review in February 2012, and now applies to both Ergon Energy and Energex. Going forward Ergon Energy will continue to monitor the cost-effectiveness of works required to fully meet the criteria and explore alternative solutions when the costs of fully meeting the criteria are considered excessive when compared to the community benefit.

The key impacts of the revised criteria are associated with the security of supply for zone substations and distribution feeder maximum load levels. For zone substations a relaxation of the security standard is applicable for those substations with a mixed but predominately residential load category. N -1 security standard is now stipulated where loads are greater than or equal to 15MVA, where as the previous threshold was 5MVA. The revised standard provides indicative time frames applicable for urban and non urban situations in which all supply is to be restored through network switching and or use of mobile generation. Where the load category is mixed but has significant commercial and industrial load, the threshold remains at 5MVA for the provision of N -1 security standard. For urban category distribution feeders, the maximum load level has increased from 0.67xNCC to 0.75xNCC equivalent to a ‘4 into 3’ target security level. These key changes have resulted in the delay of some future augmentation projects thereby reducing the capital expenditure required.

The new criteria are summarised below.

Practical security levels

‘Security level’ denotes the inherent security of supply provided by major network components as determined by the extent of duplication or redundancy of primary serial elements and their associated secondary protection and control systems.

Target security levels

The following are the planning targets, which will be used in producing future Ergon Energy five-year development plans and against which the status of network capacity and security levels are reported in this NMP. Note, however, that the more detailed plans discussed in Part B of this report were prepared using the previous criteria as described in Part B, which did not discriminate between commercial and residential loads.

Target security levels provide an objective framework within which network development can be planned and against which overall security levels can be assessed and reported. They do not preclude the need for detailed analysis involving reliability assessment and economic viability in the preparation of planning reports and business cases for specific projects.

Full N-1 for lines may be provided via a highly meshed sub-transmission network.

TABLE 4: Security Levels – Planning targets for transmission and sub-transmission

Plant	***Category***	***Indicative Load (MVA)***	***Base Security***	***Applicable Forecast***
Subtransmission & Transmission Lines	Commercial & Industrial	5 and above	N-1(A)	50PoE
		Less than 5	N	50PoE
	Residential	15 and above	N-1(B)	50PoE
		Less than 15	N	50PoE
Bulk Supply Substations	Commercial & Industrial	Any	N-1(A)	50PoE
	Residential	15 and above	N-1(B)	50PoE
		Less than 15	N	50PoE
Zone Substations	Commercial & Industrial	5 and above	N-1(A)	50PoE
		Less than 5	N	50PoE
	Residential	15 and above	N-1(C)	50PoE
		Less than 15	N	50PoE

Notes:

1.	N-1(A)	A system which has the capability to withstand a credible single contingency involving an outage of the largest and most critical system element (transformer, feeder etc) without an interruption to supply of greater than one minute for loads up to 50PoE.
2.	N-1(B)	N-1(A) except that all 50PoE load can be restored in 30 minutes by remote switching.
3.	N-1(C)	N-1(A) except that up to 6MVA of load can be curtailed as long as it can be restored in three hours for urban and four hours for non urban by remote and manual switching.
4.	N	Possible loss of supply for single contingency of up to eight hours urban and 12 hours non urban while the network is reconfigured or repaired or mobile equipment (such as generators) is deployed.
5.	10PoE Forecast	Peak load forecast which has a 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. 10PoE forecast load is not to exceed NCC for system normal (network intact) in all cases excepting distribution substations network element category.
6.	50PoE Forecast	Peak load forecast which has a 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.
7.	C&I	Where the load contains a significant proportion of Commercial and Industrial customers
8.	Res	Where the load is predominantly residential customers.

9.	It is recognised that some remote zone substations in Ergon Energy's and Energex's area of supply will have negligible transfer capacity to adjacent zone substations and alternate supply cannot be economically justified. Under these circumstances, the residual load at risk will be the full load of the substation and the supply restoration time will be either the repair time or the time taken to install temporary generation or mobile substation.
10.	For determination of optimum reinforcement timing, energy-at-risk analysis should be conducted before allowing any system element to exceed the specified security standard shown in the table above, and as qualified by these notes.
11.	This standard does not apply to interim/staged supplies (i.e.: prior to completion of the entire development).
12.	Residual load at risk to be covered by generation to generally not exceed 5MVA after load transfers undertaken.
13.	The 0.75NCC, 50PoE forecast loads for distribution feeders is applicable to the majority of these feeders. However, there will be a limited number of situations where it is appropriate to vary this requirement based on good engineering practice, network configuration or customer requirements.
14.	Where load is curtailed, operational schemes should be in place to ensure that supply is maintained to critical load where possible e.g. high rise.
15.	These standards generally apply to shared assets. Where a single large customer is supplied from dedicated infrastructure or the major user of the infrastructure, the security standard applicable to that infrastructure shall be established by commercial negotiation.

*Note: Customer outages as a result of major substation plant or subtransmission line failure are rare. Restoration times above are Ergon Energy's internal targets. They do **not** represent customer guarantees.*

The restoration targets have been established to ensure that appropriate contingency plans are in place and to ensure that restorations are, where possible, well within the Guaranteed Service Levels (GSLs) applicable under the EIC. They are consistent with Ergon Energy's risk management framework and with customer expectations as determined from detailed customer research. Actual restoration times will be based on ensuring staff safety and being able to access and address the asset related issues.

Security levels – planning targets for distribution network

Urban N: 50PoE forecast not to exceed 0.75 x Normal Cyclic Capacity (NCC) rating
Interruption to supply, all supply restored in three hours by remote or manual switching (where possible) except faulted area which is best practice repair time

Rural N: 10PoE forecast not to exceed 1.0 x NCC rating
50PoE forecast not to exceed 0.90 x NCC
Interruption to supply, all supply restored in four hours by remote or manual switching (where possible) except faulted area which is best practice repair time.

In most cases, an urban feeder is essentially a radial feeder with open circuit ties to adjacent radial feeders. After an interruption to supply, switches can be operated to isolate the faulted section and restore supply to un-faulted sections via available ties, provided the feeders are not overloaded. Rural feeders are also radial feeders, but usually do not have ties available to adjacent feeders, so often cannot be reconfigured in a contingency situation. Where a rural feeder does has alternative supplies they will of course be used when required.

If a feeder is much more reliable than other feeders tied to it, its Target Maximum Utilisation (TMU) may be increased to the maximum value of 0.90 at 50PoE, provided that the TMU for each of the tied feeders is reduced to 0.70 at 50PoE. 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 other combinations are possible to optimise network reliability. This can occur when there is a mix of overhead and underground construction.

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

Allowable loading levels:

Substations

N-1 Substations: The maximum allowable loading for planning purposes is the Emergency Cyclic Capacity (ECC) rating of the remaining transformers following loss of the largest unit (the ratings of other necessary serial elements are required to match the applicable transformer ECC ratings).

N Substations: The maximum allowable loading for planning purposes is the NCC rating of the transformers (the ratings of other necessary serial elements are required to match the transformers' NCC rating).

Notes:

1. *The ECC rating of a transformer is the peak load of the daily load profile for which the transformer uses one month of its design life for each day of service without exceeding certain specified design criteria.*
2. *The NCC rating of a transformer is the peak load of the daily load profile for which the transformer uses one day of its design life for each day of service without exceeding certain specified design criteria.*

Lines

N-1 Transmission and Subtransmission Lines: The maximum allowable loading for planning purposes is the contingency rating of the remaining line(s) following loss of the highest rated line.

N Transmission and Subtransmission Lines: The maximum allowable loading for planning purposes is the normal rating of the line.

Notes:

1. *For any given construction arrangement, the rating of an overhead line is a function of the effect of the prevailing ambient conditions on the temperature of the conductors.*
2. *The normal rating of a line is defined in terms of the maximum allowable current that can flow without causing conductor deterioration or statutory clearance problems. Line ratings used for planning purposes are calculated for summer and winter, noon and evening and are based on the likely ambient conditions prevailing in the geographical area during those periods.*
3. *The contingency rating of a line is defined in a similar way to the normal rating, but allows for slightly more favourable ambient conditions, in recognition that the probability of less favourable conditions coinciding with a system contingency is small.*
4. *All powerlines are also rated according to the maximum allowable voltage drop to maintain statutory voltage regulation at customers' terminals under contingency conditions for 'N-1' configurations and normal conditions for 'N' configurations.*
5. *Security levels for lines assume that the lines have good reliability performance i.e. are in good operating condition, are well maintained and conform to current design and construction standards (e.g. sub-transmission lines of concrete pole OHEW design).*

Fault ratings

The fault ratings of network assets are to be sufficient to withstand prospective fault currents under all foreseeable circumstances.

Load forecasts

Transmission and sub-transmission network assets are required to be capable of supplying the maximum MVA demand at the 'base' economic condition and 10% PoE with the network intact.

For those parts of the transmission and sub-transmission network where redundancy is provided (i.e. where N-1 criteria are applicable), estimates of future loads used in assessing projected security levels employ the forecast maximum MVA demand at the 'base' economic condition and 50% PoE.

Distribution network assets are required to be capable of supplying the maximum MVA demand at the 'base' economic condition and 50% PoE, with the network intact.

5.3 Load forecasting

Effective network planning requires reliable load forecasts, accurate asset data and the ability to simulate and analyse future scenarios using appropriate network modelling.

Ergon Energy produces 10-year maximum demand forecasts using regression techniques based on the available recorded data. The availability of data can vary from up to 15 years at Bulk Supply Point (BSP) level to only a few years in the case of some zone substations, where minimal metering was installed by legacy corporations. Maximum demands are extrapolated with adjustments to accommodate confirmed and anticipated developments and other known local factors, with prospective major customer developments handled based on their probability.

Forecasts are produced for all zone and bulk supply substations and for various regional and whole-of-network aggregations.

The forecasts produced are intended to reflect the 'most likely' or 'base' case for 'average' weather conditions and are for practical purposes 50% PoE forecasts, i.e. there is a 50% probability that an actual peak demand will exceed the forecast value.

As described in Section 5.2, the use of 10% PoE forecasts is one way of reducing the risk that actual peak demands will exceed forecast. At Ergon Energy's bulk supply substations where the connected loads display temperature sensitivity of demand, 10% PoE forecasts may be up to 6% higher than 50% PoE.

Accordingly, 10% PoE forecasts are employed for planning purposes in circumstances where the transmission or sub-transmission system is radially configured and 'N-1' security is not available, and where the meshed transmission or sub-transmission system is at high risk.

An independent, national forecasting company is retained annually to produce independent forecasts at bulk supply point level using 'top down' techniques. These are then used to validate the internally produced forecasts. These forecasts are produced for base, high and low economic conditions, as well as for 50% and 10% PoE.

The annual review of load forecasts is conducted post-summer reflecting the fact that the network experiences summer annual peaks. As part of that review, actual readings are temperature corrected to see how well they matched the previous forecasts. It is intended to continue application and development of temperature correction techniques for accuracy review purposes.

Ergon Energy has developed forecasting methods using demographic and other spatial data, in particular town planning reports. These forecasts are very useful in indicating the likely ultimate load of an area and potential location for proposed new substations. At this stage, however, the more traditional regression analysis methods are still more useful for determining the timing of the load growth.

Following Ergon Energy's submission to the AER in 2011, the AER expressed concern over Ergon Energy's forecasting methods. This led to the AER issuing instructions for Ergon Energy to implement econometric methods and temperature corrected values in future forecasts. Ergon Energy is working with Energex to implement those directives.

5.4 Compliance

An audit of the existing and forecast state of the supply network with respect to the planning criteria and timing of proposed works has been undertaken and is summarised in Section 11.5.

The capital expenditure program aimed at achieving compliance with the planning criteria is implemented by prioritising individual projects in accordance with the risk management framework outlined in Section 11.1. Works are then scheduled in line with resource availability and budgets.

By 2016, it is anticipated that the percentage of the total number of bulk supply substations not matching the security criteria will reduce from the present level of 38% to 11% and that zone substations will reduce from the present level of 10% to 5%. In addition, the total number of distribution constraints as a percentage of total feeders is anticipated to reduce from the present level of 44% to 11%.

6. ASSET MANAGEMENT POLICY AND COMPLIANCE

Ergon Energy has continued the development of an annual Asset Management Plan, which is reflective of the joint Ergon Energy and Energex Network Vision Outlook to 2030. This body of work is complementary to the NMP.

Ergon Energy's goal is to manage the network to best meet our stakeholders' requirements – now and in the future – in the face of varying demand and considerable risk from natural disasters. Ergon Energy is all about delivering a secure, reliable and quality electricity supply for our customers, wherever they are in regional Queensland, which effectively balances both commercial and customer perspectives without sacrificing safety.

Asset management is all about balance – between 'investing in' and 'driving value' from an asset. Our strategic focus on excellence in this area recognises that this balance can only be achieved with a full understanding of the overall health of the network. Ergon Energy's infrastructure network is vast and complex – while individual assets have a finite life, our electricity supply network must perform at a consistent standard day in day out, despite the many individual components being at different stages in their useful life.

This is where asset management becomes central to our meeting our stakeholders' expectations. By better optimising lifecycle management we can enhance customer satisfaction through enhanced and reliable network performance, as well as improved safety and environmental outcomes, and deliver sustainable development that is within our funding constraints, which ultimately optimises our return on investment.

The following key asset management objectives have been set to ensure that corporate requirements are met:

- Safety – Network asset safety risks are managed within corporate risk tolerance levels throughout their service life.
- Customers – Networks assets are managed to deliver and maintain customer value.
- People – Ensure the workforce possesses the skills and capability to deliver the business requirements.
- Financial Performance – Network assets are managed within budgetary provisions and in a prudent, efficient and responsible manner. The asset manager will seek to minimise costs across the whole of the asset life cycle.
- Network Performance – Network performance is managed in terms of security, quality, reliability and availability to prescribed standards.
- Operational Excellence – Corporate, customer, legal and regulatory requirements and constraints are recognised, understood and incorporated into systems for managing the assets.
- Environment – Asset management activities are environmentally sustainable throughout the asset life cycle.
- Asset Management Standards Compliance – The Asset Management System shall be developed based on compliance with Publicly Available Specification PAS 55:2008 Asset Management.
- Asset Information – Asset data records shall be of sufficient quantity and quality to meet the ongoing needs of the Company.
- Compliance – Processes for the management of network assets are adhered to and the compliance is verifiable.

The health of our network has many dimensions, which are all interrelated, the obvious ones being reliability and quality of supply.

These also include our performance against our social responsibilities, notably the challenge of electricity affordability and the need to demonstrate environmental stewardship. The network also needs to be both resilient and responsive when external events occur, such as the numerous natural disasters that we faced over recent years, and the potential for dramatic changes in demand, while achieving the level of utilisation that is vital to meeting our financial obligations.

To ensure the health of the network, our response can either include initiatives associated with the asset itself, such as changes to practices or the use of new technologies (discussed in this section), or draw on suite of non-traditional demand-side solutions (discussed in more detail in the next section). Both are about providing a more cost efficient, sustainable and dependable service for our customers.

6.1 Maintenance and replacement/refurbishment

The key objectives for the maintenance function have been set to ensure that Network Asset Management objectives are met. These objectives are as follows:

Network Asset Management Objectives	Network Maintenance Objectives	Replacement/Refurbishment Objectives
<u>Safety</u> Network asset safety risks are managed within corporate risk tolerance levels throughout their service life.	Maintenance activities shall ensure the risk of equipment failure is kept within tolerable limits throughout the service life of network assets. Network assets shall be maintained in a manner to ensure the health and safety of employees and the public.	Refurbishment and replacement activities shall ensure that equipment related safety risks are maintained below tolerable limits where this cannot be cost effectively achieved by other means such as inspection and maintenance.
<u>Customers</u> Network assets are managed to deliver and maintain customer value.	Maintenance shall ensure that network assets remain serviceable and fit for purpose throughout their service life consistent with delivering customer value.	Refurbishment and replacement programs are designed to provide required levels of customer service in the most cost efficient manner possible.
<u>People</u> Ensure the workforce possesses the skills and capability to deliver the business requirements.	Maintenance shall be managed and carried out by trained and competent staff.	Refurbishment and replacement decisions and programs shall consider the present and future availability of workforce skill and capabilities.

Network Asset Management Objectives	Network Maintenance Objectives	Replacement/Refurbishment Objectives
Financial Performance Network assets are managed within budgetary provisions and in a prudent, efficient and responsible manner. The asset manager will seek to minimise costs across the whole of the asset life cycle.	Maintenance shall deliver 'value for money' and contribute to the lowest whole of life cost.	Refurbishment and replacement programs shall be optimised with respect to cost and risk and financial performance. Programs will be integrated with other network development programs and be documented so as to demonstrate the prudency and efficiency of refurbishment and replacement investment.
Network Performance Network performance in terms of security, quality, reliability and availability is managed to prescribed standards.	Maintenance regimes shall contribute to ensuring acceptable levels of network security, quality, reliability and availability. Maintenance shall ensure the inherent reliability of electrical network assets achieves national or international benchmarks for similar asset classes / types. Maintenance induced failures shall be eliminated.	Refurbishment and replacement programs shall ensure that equipment condition related network outage events are within target levels.
Operational Excellence Corporate, customer, legal and regulatory requirements and constraints are recognised, understood and incorporated into systems for managing the assets.	Network assets shall be maintained in accordance with the requirements of all relevant Acts, Regulations, Standards and Specifications defined in this document.	Asset refurbishment and replacement plans reflect best practice in terms of optimisation of performance and cost, the management of risk and integration with network development. Refurbishment and replacement programs will support the company's long term vision for future network architectures and capabilities.
Environment Asset management activities are environmentally sustainable throughout the asset life cycle.	Maintenance shall be managed to minimise the risk of environmental damage. Maintenance shall contribute to reducing the carbon footprint of the company.	Asset refurbishment and replacement programs will seek to address known asset related environmental issues and minimise the potential for future environmental liabilities.

Network Asset Management Objectives	Network Maintenance Objectives	Replacement/Refurbishment Objectives
Network Asset Management Standards Compliance The Asset Management System shall be developed with an aspiration to achieve compliance with Publicly Available Specification PAS 55:2008 Asset Management.	Maintenance activities shall be systematically planned, implemented, monitored and reviewed to achieve continual improvement consistent with the principles of Publicly Available Specification PAS 55:2008 Asset Management.	Refurbishment and replacement activities shall be systematically planned, implemented, monitored and be consistent with the principles of Publicly Available Specification PAS 55:2008 Asset Management.
Asset Information Asset data records shall be of sufficient quantity and quality to meet the ongoing needs of the business.	Asset condition and failure data shall be collected during maintenance to facilitate maintenance optimisation and the needs of asset management.	Sufficient data of appropriate quality is available to support the analysis and optimisation of asset replacement and refurbishment programs using methods such as condition based reliability management. Accurate network records are maintained following refurbishment/replacement activities.
Compliance Processes for the management of network assets are adhered to and the compliance is verifiable.	Maintenance processes and activities shall be documented and recorded for audit purposes.	Refurbishment and replacement processes and activities shall be documented and recorded for audit purposes.

Plans have been developed to achieve balanced, efficient and effective maintenance and replacement of Ergon Energy's network assets.

Maintenance work is categorised under the operating expenditure activities of preventive, corrective and forced work, while replacement work is categorised as capital expenditure defect refurbishment.

A risk assessment of all classes of network assets has resulted in the establishment of a number of preventive maintenance programs covering substation, line, protection, communications, control system and metering assets, as well as vegetation management. These programs are based on a mix of time intervals, event intervals and condition-based approaches consistent with EDSD recommendations.

Under the Joint Workings project, Ergon Energy and Energex are aligning their Asset Management Policy, Network Maintenance Protocol, maintenance standards and job cards for all line, substation, protection and control system assets and related tools, equipment and consumables. This work has been done with Energex to ensure commonality of standards and to realise efficiencies in work practices, training and documentation. It also aligns with PAS55, which defines best practice asset management techniques. Implementation of the joint maintenance standards and job cards is currently underway. The maintenance and refurbishment initiatives of the Joint Workings project are:

- Maintenance Framework – development and implementation
- Distribution Defect Classification Manual
- Substation Defect Classification Manual

- Condition Monitoring Strategy
- Strategic Sparing Strategy and Implementation, and
- Condition Based Reliability Management (CBRM).

Every effort is made to coordinate the preventive maintenance programs for both substation and line assets to ensure both overall efficiency and that each asset site is visited with appropriate regularity.

For line assets, the asset inspection program is the flagship program. About seventy-five full-time crews routinely inspect poles, cross-arms, pole-top hardware, conductors, pole-mounted equipment, customer service lines, underground pillars, padmount substations and ground mounted switches across the network. Any defects identified are classified, prioritised and recorded electronically in accordance with the Lines Defect Classification Manual, a document originally developed by Ergon Energy but now jointly managed and reviewed with Energex. The serviceability of poles is assessed within the timeframes specified in the Code of Practice Works 2010.

The program began in April 2003 and was initially based on a nominal three-year interval. In July 2006, the interval was changed to a nominal four-year interval. Extension of the interval to 4.5 years is currently being considered on the proviso that the risk to network assets and public and staff safety is acceptable and can be managed and compliance to the frequency of inspection of supporting structures for lines, defined in section 5.1.2 of the Code of Practice Works 2010, is maintained.

In the initial three-year inspection cycle, there were 6,297 priority (P1) defects and 140,352 other defects (known as P2) identified and remediated. These included replacement of 10,595 poles, nailing of 19,959 poles and replacement of 18,031 cross-arms.

From 1 July 2006 to 30 June 2010, 1,097,369 inspections were completed. Improved processes, a broader inspection scope and more stringent criteria identified and remediated 10,432 P1 defects and 212,549 P2 defects. These included 6,857 poles replaced, 12,242 poles nailed and 23,235 cross-arms replaced.

From 1 July 2010 to the end of June 2012, 537,428 inspections were completed, 8,670 P1 defects were identified and remediated, 165,254 P2 defects identified and 139,640 P2 defects have been rectified. These included 2,534 poles replaced, 5,582 poles nailed and 10,873 cross-arms replaced. These elevated figures include the remediation work completed following Cyclone Ului (March 2010). Due to the extent of network damage following Cyclone Yasi, a similar inspection and remediation program was not conducted after the event.

Routine testing of SWER and CMEN-MEN earthing systems is included as part of the asset inspection contract to manage compliance with the Code of Practice Works 2010. Processes have been established to allow some minor remediation work to be conducted by suitably qualified SWER Earth Test officers followed by retesting of the earthing system. This process reduces the number of P2 defects that need to be attended by Ergon Energy crews and therefore improves efficiency for field staff.

For substation assets, moisture and oil assessment of power transformers and instrument transformers is a key preventive maintenance program.

The life of a transformer primarily is determined by the condition of its internal paper insulation and the integrity of associated components. Assessing oil samples of transformer dielectric systems is used to:

- predict the useful remaining life of transformers
- determine the risk of transformer failure
- determine power transformer in-service rating limitations
- determine condition-based transformer maintenance

- determine transformer replacements
- manage transformer contingency
- manage transformer spares, and
- improve transformer specifications.

Monitoring and assessing asset condition (for all asset classes) under the Preventive Maintenance Programs for both lines and substations determines the need for operating expenditure corrective maintenance and capital expenditure defect refurbishment-replacement work. Through the Joint Workings Maintenance Framework project, job cards have been established to support the delivery of all maintenance programs.

Ergon Energy supports and participates in maintenance-related research by external bodies and uses the outcomes of that research to improve its processes and methodologies. Some examples are the Termite Treatment Trial (Energy Networks Australia), 11kV Switchboard Condition Assessment (CIGRE), and the use of Vegetable based dielectric fluids in transformers.

Further, a Substation Contingency Asset Management System (SCAMS) has been developed as a condition-monitoring tool and has been interfaced to our Ellipse Enterprise Resource Planning (ERP) system. This application has the ability to perform complex condition calculations on substation equipment, which Ellipse does not have the functionality to perform. Examples of these calculations include:

- a variety of calculation to assess water content of insulating paper
- derivation of flash temperature
- determination of International Electro-technical Commission (IEC) and Institute of Electrical and Electronics Engineers (IEEE) incipient faults
- calculation of transformer oil thermal time constants
- calculation of age-based parameters
- derivation of oil saturation calculations
- calculation of gas evolution rates
- mass of PCB (polychlorinated biphenyls), and
- age and condition-based reports for end of life assessment.

A key aspect for on-going management of the preventive maintenance programs has been continuous improvement focused on process design, technology, data and people. This capability is reflected in the frequency of process-system upgrades (approximately every three months).

Formal methodologies such as Reliability Centred Maintenance (RCM), Failure Modes, Effects and Criticality Analysis (FMECA) and Condition Based Risk Management (CBRM) are being increasingly used to define and optimise maintenance, aged asset replacements and refurbishment activities and frequencies. RCM, FMECA and CBRM analysis will deliver five principal outcomes for the network:

- greatly enhanced understanding of how assets work
- a better understanding of how assets fail
- an optimal costing model for assessing the refurbishment or replacement of aged assets,
- identify tasks for ensuring the adequate future performance of the assets, and
- greatly improved teamwork across different areas of the business.

The Enterprise Resource Planning (ERP) system is configured to support an RCM-FMECA-CBRM regime and has improved the management of corrective maintenance and defect refurbishment-replacement work, particularly through improved availability of timely data. The configuration of the ERP is currently being reviewed in order to support the outcomes of the Joint Workings Maintenance Framework project.

The principal measures of the effectiveness of the preventive maintenance programs are:

- safety and environmental performance of the network related to maintenance issues
- reliability performance of the network related to maintenance issues
- compliance with regulatory inspection and maintenance requirements
- customer and community satisfaction with network performance related to maintenance, and
- the extent of forced maintenance work resulting from unassisted asset failures.

The efficiency of preventive maintenance is measured by the unit cost of work and comparison of standard job hours versus actual job hours.

Corrective maintenance and defect refurbishment/replacement work arises from inspections and assessments carried out under the preventive maintenance programs.

Asset replacement plans are prepared for zone substation assets both by substation and asset class, based on the data collected from the individual substation preventive maintenance programs.

Refurbishment/replacement plans for transmission, sub-transmission and distribution lines are based on data obtained from a number of line preventive maintenance programs, defect classification reports, reliability statistics and CBRM analysis.

Defects, identified and classified in accordance with the relevant Defect Classification Manual, are packaged for field staff to rectify.

There are set timeframes, some of which are specified in the Code of Practice Works 2010, to rectify priority defects. Compliance to these timeframes is measured and reported and forms part of the Key Performance Indicators (KPIs) for responsible managers.

Forced maintenance work arises from asset failures and impact damage, such as vandalism (human impact) and lightning (nature impact).

Resources and processes have been put in place to investigate network asset-related incidents, such as outages resulting from asset failures. Particular effort is devoted to investigating Significant Electrical Incidents (SEIs), Dangerous Electrical Events (DEEs), significant outages where asset failures have been a contributing cause, poorly performing assets and high incidence fault types. Trends are monitored and analysed and used to drive improvements in maintenance and replacement strategies and plans. The eSafe Incident Management System is used to monitor and report performance and/or non-compliance for such safety incidents.

The ERP Ellipse, GIS (Geographic Information System), Google Earth and FdrSTAT (network outage information) systems are configured to allow improved analysis of forced maintenance work and development of proactive maintenance strategies to mitigate the need for reactive work.

Contingency plans are in place for the failure of critical network assets and strategic spare parts have been identified and either delivered or ordered. A Joint Workings Strategic Spares program has been put in place to further support holding a wide range of strategic spares. This project allows the sharing of strategic spares across both Ergon Energy and Energex and has an added benefit of reducing inventory costs.

Maintenance and replacement plans have been developed for each asset class. These plans summarise the maintenance (preventive, corrective, forced) and replacement strategies adopted and the funding requirements for the next 20 years. They take into account such factors as manufacturer, age, condition, importance and level of risk.

Each maintenance and replacement plan for the different asset classes is continually refined to ensure it adheres to policy and meets or exceeds industry best practice.

Prudent management of the network requires considered assessment of present and future needs of the network assets. Expenditure projections are based on a combination of known issues (e.g. outdated Supervisory Control and Data Acquisition (SCADA) equipment requiring replacement and Air Break Switch models prone to premature failure), asset condition analysis and anticipated increases in expenditure as the network ages.

Asset failure is predicted using statistical analysis of asset condition and failure data or manufacturer or industry mortality data. This data also provides a valuable input to the CRBM modelling so that trends in failure rates can be used to trigger a preventative refurbishment or replacement program.

Ergon Energy has a target of zero for both public and environmental safety incidents. Progress towards this goal is assisted by the risk management methods outlined above.

6.2 Vegetation management

Ergon Energy's vegetation management program is showing positive signs of reaching maturity, with the program becoming more stable and predictable. Continual improvement of cycle times, treatment methods and reporting is the result of increased knowledge of vegetation-related risks facing the overhead network, as well relying on the Ellipse ERP as the central point of program management. This increased knowledge of vegetation condition across the network will be enhanced by data from the ROAMES (Remote Observation Advanced Modelling Economic Simulation) initiative. This initiative is using high-tech observation aircraft to capture precision network related condition data from a significant altitude using laser scanners, digital cameras and a flight assist system. This condition data, combined with assessment of the environmental factors affecting tree growth and network performance will enable a more strategic approach to risk management of vegetation to be adopted.

From September 2008 to June 2010, a revised operational strategy focused on the highest priority vegetation to mitigate safety risks that existed across the network and to maintain compliance with legislative requirements. This required change to the Vegetation Clearance Profile Standard to reduce unit costs and increase speed of treatment to ensure all parts of the network was treated as soon as possible within the constraints of budgets available at the time.

In October 2009, it was estimated that a rural backlog over approximately 58,000 km (300,000 spans) needed to be addressed at an estimated cost of approximately $67 million to improve network reliability and safety. A number of additional lump sum contracts were let at the end of 2010 in Central and Southern Regions to speed up treatment of backlog areas. Treatment of these backlog areas was completed by 30 June 2012 as programmed. Following a mid-year revision of the budget and program in which the budget was increased and treatment of several vegetation zones was deferred to the following year, the Vegetation Management Program for 2011/12 was completed at 0.3% over plan and 2.8% over budget.

The Vegetation Management Strategy and Vegetation Clearance Profile Standard are in the process of being revised to reflect a future focus on rural maintenance. The revised Vegetation Management Strategy will focus on optimisation of treatment cycles, movement towards greater understanding and determination of Ergon Energy's risk appetite, improved auditing and reporting, and finding efficiencies, while improving electrical safety and reliability.

The Vegetation Clearance Profile Standard will be revised to reflect a move back towards a sustainable long-term maintenance program with emphasis placed on finding cost and productivity efficiencies in treatment methods and clearance profiles.

Where the current version of the Vegetation Clearing Profile Standard restricts treatment in rural areas to only vegetation that has the potential to impact electrical safety and reliability during the current treatment cycle, and not vegetation which is likely to grow and pose a significant threat and cost in future treatment cycles, the revised Standard will focus on removing that threat when the vegetation is immature, smaller and cheaper to treat. Greater emphasis is also placed on identifying and mitigating risk, with new measures introduced to treat fast growing vines on stay wires, as well as reviewing easement widths in areas of high bushfire hazard and where surrounding vegetation height, density and mortality presents a higher risk to the network.

While unit costs of vegetation management are still predicted to decrease over time as the program reaches maturity, several issues are currently resulting in short-term cost increases.

An increased level of rainfall and favourable seasonal conditions since early 2010 has resulted in increased vegetation growth rates and vegetation density across most parts of the state. Subsequently, many regions are experiencing increased costs in rural areas to clear more vegetation within the regrowth zone to ensure vegetation will not grow into the clearance space before the next cycle. In urban areas, where aesthetics require that treatment methods need to be less invasive, cycle times have been shortened to account for this increased growth rate. This increased vegetative growth is also occurring within grassland areas, resulting in increased risk of bush fire to network assets.

The past two fire seasons have seen a dramatic increase in the number of fire related incidents and a corresponding loss of power poles to fire. During 2011/12 summer season, 257 poles were lost through grass and bush fires. A significant percentage of these incidents were started by land managers deliberately burning paddocks and bushland which have large volumes of rank grass growth as a result from the increased rainfall experienced in recent years. With this in mind, combined with the flow on implications of the Victorian ‘Black Saturday’ bushfires of 2009, Ergon Energy has revised the Bushfire Mitigation Strategy. The revised strategy and associated Action Plan identifies those parts of the network most at risk of starting, or being impacted by bushfire, because of high bushfire hazard, or fire history.

The strategy details the measures to mitigate those risks, and which sections of the organisation are responsible for implementing those measures. Comprehensive targets, timeframes and estimated costs are to be included in the Action Plan. These measures and any new processes will be integrated into existing Summer Preparedness Plans and Disaster Management Plans.

With changes expected to the Vegetation Clearance Profile Standard and Vegetation Management Strategy, as well as the re-integration of the backlog areas into routine maintenance, the total volume of work is expected to increase in rural areas. This is primarily due to re-expanding rural corridor widths on selected line voltages to more sustainable long-term dimensions aimed at preserving reliability and the need to treat the vegetation which was left in the previous cycle. On ground efficiencies provided by residual herbicide application and more effective contract management should moderate any increase in expenditure.

The ROAMES initiative is also expected to help deliver efficiencies both on the ground and at the desktop. While delivery has been delayed, the data that it is currently being gathered on the condition of vegetation around the overhead network, including images and condition data, is now being utilised. As Ergon Energy staff and contractors begin to gain confidence in the imagery and condition reports, efficiencies and budget savings will be able to be made in scoping and auditing activities.

Management of vegetation zones and work planning using the Ellipse ERP has been successful, with monthly reports and budget analysis based on work orders created for inspection and treatment for each vegetation zone capturing costs for each area as it is completed. Continuing improvements in data quality have also assisted in the smooth transition to management of the program in the Ellipse ERP.

Review of vegetation standards and publication of new processes has clarified roles and responsibilities for delivery of the vegetation program and more consistent application of different vegetation management techniques.

This year marks the 10 year anniversary of the Plant Smart partnership with Greening Australia Queensland. Plant Smart continues to educate the community about the management of trees near powerlines by engaging councils, nurseries, schools and community groups and informing them of low-growing species suitable for their local area. Over 150 plant nurseries around the state are now involved with Plant Smart, and the strength of the program continues to grow. A number of significant reports have been presented by the Plant Smart team, including one on susceptibility of tree species to cyclones following Cyclone Yasi. This report provides recommendations on appropriate street tree plantings in cyclone-prone areas, to reduce the future risk of tree-caused outages and vegetation maintenance expenditure.

The focus and structure of the program has recently undergone a review to ensure Plant Smart continues to deliver positive outcomes for Ergon Energy in terms of safety, reliability and reduced vegetation maintenance costs. Technical studies currently being undertaken by Plant Smart staff include: research into alternative treatment technologies aimed at slowing vegetation growth and reducing treatment costs; measuring plant growth rates to better develop risk models and to calibrate ROAMES reporting; and, development of training packages tailored to the needs of Ergon Energy staff and contractors to improve knowledge and skills relating to vegetation management.

The partnership continues to provide information on low-growing species in different regions so contractors can more readily identify these species and not cut or remove them, and also continues to provide information and advice on how to manage threatened species found in the field to ensure compliance with the Nature Conservation Act. Monitoring trials of different herbicide applications have also been established to measure long-term effects of treatment on species

6.3 Remote Systems

6.3.1 Single Wire Earth Return (SWER) strategies and policies

Ergon Energy and the Queensland Government have a joint taskforce responsible for the improvement to the quality and reliability of SWER supply, in line with EDSD recommendations to lift SWER performance.

Ergon Energy is updating and implementing their 20 Year SWER Improvement Strategy to ensure the SWER network is managed and maintained in line with our corporate vision and purpose.

Embedded renewable energy generation, may provide viable solutions for network support and energy delivery to customers. Ergon Energy continues to investigate and support niche investment opportunities in renewable energy technologies, including customer owned PV systems along with distributed generation options to enhance supply quality on SWER networks.

For the small number of customers who need a higher quality of supply than the SWER network can deliver, Ergon Energy is exploring options with a view to establishing value-added services, such as the installation of integrated utility service technology. This technology provides a range of distributed solutions to improve supply quality at the customer installation.

These customers may need to contribute towards the cost of improving their supply reliability and quality by purchasing relatively inexpensive auxiliary appliances, such as uninterruptible power supplies and/or voltage regulators, and by participating in demand-side management programs.

A very small number of extremely remote SWER lines may be considered unsuitable for the ongoing distributed supply of electricity to our customers due to their length, supply reliability, capacity constraints, limited customer base and cost. If this happens, Ergon Energy will examine and report on the financial and social implications of replacing or supplementing these networks with stand-alone power system technology as it becomes practical. The results of this examination would be reported to stakeholder groups at significant points during the trials.

We also have an internal SWER Working Group responsible for managing a number of initiatives in line with the SWER Strategy to improve the overall safety, security, quality, reliability and access to electricity supply on SWER lines. These initiatives are outlined below.

SWER action plan:

An action plan of capital works and maintenance initiatives to deliver essential improvements to safety, network security, power quality, supply reliability and system access through improved SWER management was developed and is being implemented as part of the SWER Strategy. So far, planned actions include:

- expanded capital works program to address overloading issues and improve reliability
- low-voltage regulator implementation to improve voltage levels in problematic areas
- install medium voltage regulators, use of Line Drop Compensation and transformer taps to improve SWER voltage regulation
- reconductoring to improve feeder capacity and voltage quality
- improve power quality monitoring to help identify unacceptable quality performance
- data management upgrades to improve SWER management
- embedded generation trials to improve load management and supply security
- investigate a range of new technologies to focus on demand management, momentary outages and supply quality improvements.
- develop demand management strategies for SWER capacity enhancement
- develop SWER strategies to support isolation and improve reliability including:
    - reliability improvements through installation of automatic reclosers, sectionalisers and line fault indicators
    - vegetation management
    - asset inspections
    - defect refurbishment
    - deep drilled earths
    - reclosers with remote control for remote fault integration and faster supply restoration
    - pole-banding programs, and
    - upgrade un-isolated SWER.

Since the commencement of the SWER taskforce group in 2005 this action plan is being progressively implemented with short and longer-term development program outlined as follows:

Actions completed:

SWER networks are inspected in the network asset inspection and defect management cycle. Ongoing maintenance programs include preventative maintenance, vegetation management, earth inspections, protection equipment checks and incident investigations.

With safety one of the key objectives the SWER Working Group a number of the Action Plan items were given precedence to enhance the protection of Ergon Energy personnel, the public and property. This has included the progressive upgrading of un-isolated SWER, this is continuing along with the deep drilled earth program. These initiatives along with regular earth checks, protection reviews and plant overload reduction aim to improve the safety of SWER networks.

Biodiversity initiatives are in place whereby vegetation is managed according to vegetation growth rate and feeder criticality to maintain appropriate vegetation clearances from SWER conductors. This is being supported by environmental awareness training.

Capital works to date have included a number of major SWER line upgrades, the provision of additional protection equipment, upgrading existing capacity or splitting up heavily loaded SWER systems and extending the Distribution System Automation (DSA) program for improved monitoring and control.

Progress has been made in developing and testing the new technologies in preparation for their inclusion for SWER improvement. Programs to date have included the mass rollout of low voltage regulator technology on SWER; the establishment of energy storage trials using Grid Utility Support System (GUSS); and the use of Redflow energy storage technologies.

Actions current:

Along with the continued maintenance and capital works programs, the focus remains on implementing and refining new technologies and load demand management in areas where poor performance still exists. This program is addressing customer issues remaining after the major capital works have been completed or where traditional technologies have struggled to provide the required improvement.

New technologies, including energy storage devices and renewable solutions, such as the customer-driven solar energy program, continue to be assessed or implemented with engineering expertise being directed toward embedding these technologies successfully into the existing network and providing reports and guidelines to support their successful application.

The acquisition of data also remains a priority to assess the effectiveness of past focus improvement programs. This will allow more specific reliability assessment of each SWER area as well as a continuing and more resilient capability review program to assess remaining capacity overloads and voltage quality areas. These assessments will help direct and refine capital improvement and maintenance programs for maximum benefit.

The continued demand management program includes expanded trials and assessment of specific SWER areas where overload or voltage quality are problematic. Supporting this is the establishment of detailed metering points to assess the impact of demand management trials leading to a range of programs available for widespread application on SWER.

Safety continues to remain our major SWER focus with programs such as pole-banding, vibration damping, asset inspection, equipment testing, overload reduction, improved protection along with upgraded construction standards being implemented.

6.3.2 Isolated generation

To meet the challenges of isolated supply, Ergon Energy has developed the Isolated Systems Strategy which focuses on the following areas:

- energy conservation
- renewable energy generation
- improved operational efficiencies
- improved maintenance efficiencies
- improved asset performance
- improved safety performance, and
- research and development opportunities.

This strategy will ensure Ergon Energy can provide long-term, cost-effective, legislatively compliant and reliable utility-grade electricity supply to the remote communities served by Ergon Energy's isolated generation plant.

In addition, Ergon Energy has developed Operational and Design Standards, Capital and Maintenance Plans and strategies for the implementation of alternative generation technologies. Ergon Energy is also continuing to develop detailed Maintenance Strategies and Construction Standards for isolated generation.

Ergon Energy is ensuring that the optimum technology and fuel source is used in these locations. This is seeing alternative generation technologies adopted (such as renewable energy technologies and energy sources like wind, solar, geothermal and biodiesel), as well as the application of energy efficiency and demand management measures through targeted programs.

This strategy, combined with period supply contracts for major plant (generators and fuel tanks) and consumables (fuel and lubricants), will enable Ergon Energy to increasingly provide a cost-effective solution to supplying reliable electricity to isolated customers.

Power station assets are managed using the business-wide asset management database, Ellipse. The Ellipse ERP provides the ability to track assets, link maintenance policies to particular plant, create work orders and log the history of planned and unplanned maintenance.

Maintenance policies and work instructions have been developed for all generation assets requiring maintenance. Further work is being done to reduce maintenance requirements using a risk-based approach.

To ensure high performance of these assets, the systems are monitored using the latest power station SCADA system developed by Ergon Energy. This SCADA provides accurate performance data that assists Ergon Energy in identifying opportunities for improvement. Ergon Energy is upgrading the SCADA systems to improve system response and increase reliability of supply for isolated customers.

6.4 Compliance assessment

Ergon Energy sets its annual maintenance and capital works plans from its asset management policies, including the planning policy. Asset inspection, vegetation management and routine cyclical preventive maintenance are key components of the annual maintenance plan.

The annual capital plan focuses heavily on ensuring that adequate system capacity and security is available to meet customer requirements. It also includes works to address reliability and aged asset issues.

In any year, the final content of the maintenance and capital plans is dependent on the financial constraints of the business as well as having both the internal and external human resources available to do the work.

Works are prioritised in accordance with the risk management framework outlined in Section 11.1, which ensures that the most pressing work is done first.

Ergon Energy is meeting its statutory obligation under the *Electricity Act* to inspect poles at intervals not exceeding five years and works to rectify identified defects within internally set timeframes per defect classification.

The replacement of ageing 7-.064 copper conductors on the low-voltage network is being addressed through augmentation works to improve voltage conditions and capacity issues. Some aged copper conductors are also being replaced through augmentation of distribution lines. At the end of June 2012, expenditure on replaced 7-.064 copper conductor was $40 million involving 343km of replaced conductor.

Each year, as part of the summer preparedness planning, any system risks from aged asset failures are assessed and contingency plans put in place until replacement works can be undertaken. This may include having adequate system spares and access to temporary generating capacity or mobile substations.

7. DEMAND MANAGEMENT

7.1 Introduction

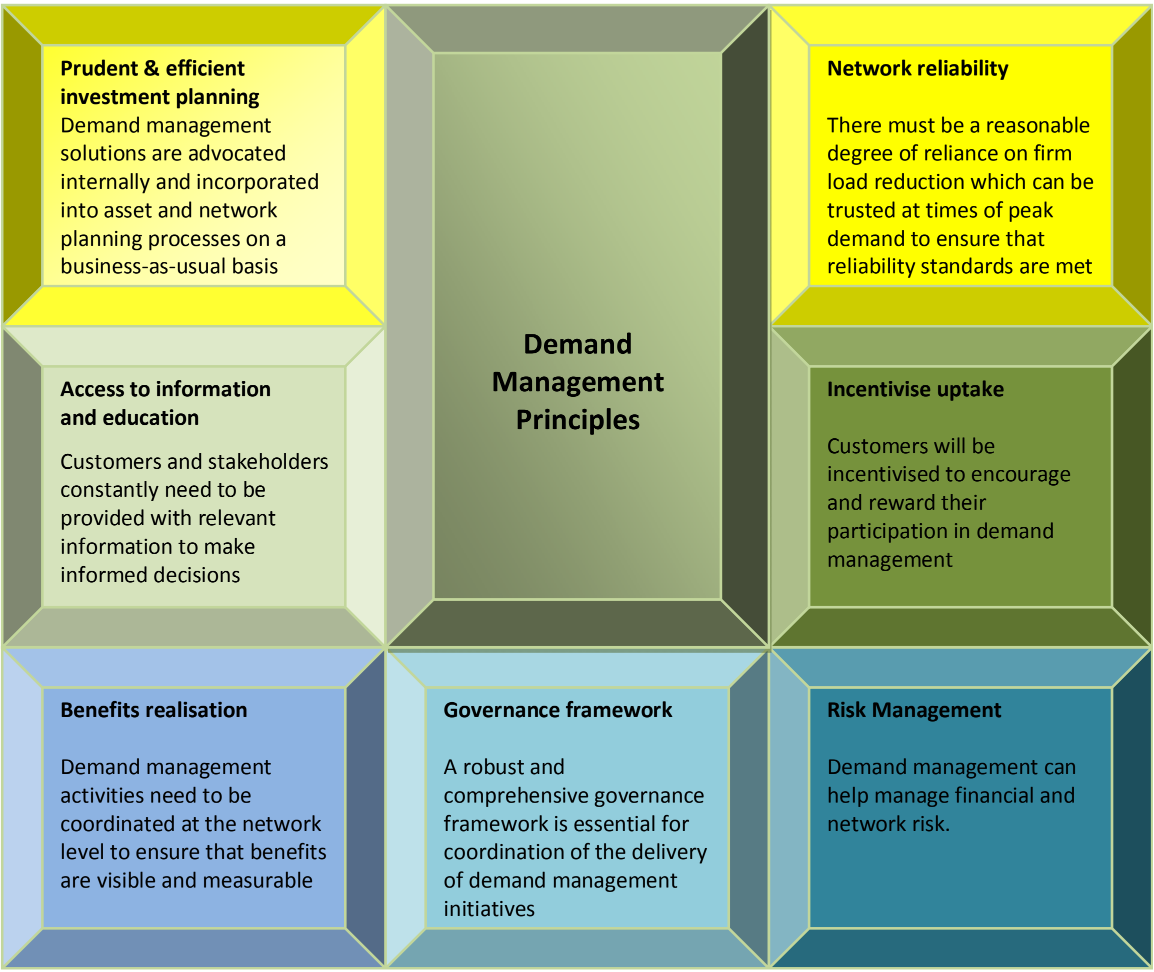
Ergon Energy is committed to implementing demand management alternatives to network augmentation where the alternative solutions are cost effective and provide value to customers.

Ergon Energy defines demand management projects or programs as measures undertaken to meet customer demand by shifting or reducing demand for standard control services through non-network alternatives, or the management of demand in some other way, rather than increasing supply through network augmentation.

Tackling the issues of peak demand, electricity affordability and climate change have been the key considerations in developing Ergon Energy's demand management principles and long-term strategy.

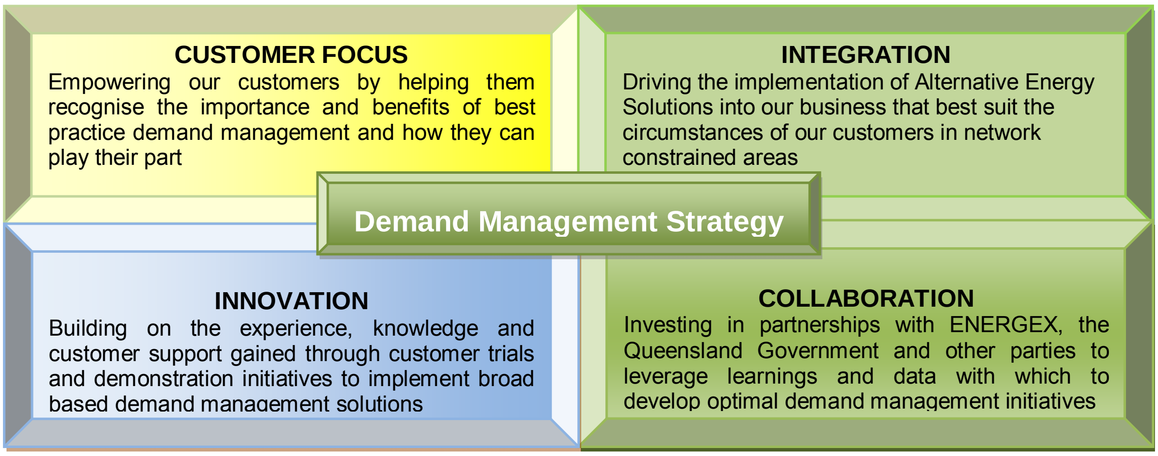
Ergon Energy's guiding principles for the demand management plan are similar to those that apply to its 2030 Network Vision, which was jointly developed with Energex.

The guiding principles are presented below:



7.2 Long-term demand management strategy

Ergon Energy's long-term demand management strategy is summarised in the diagram below. It has been updated recently to recognise the importance of our external partnerships with parties such as the Queensland Government, Commonwealth Government, Energex, research institutions and other parties who have similar goals relating to energy efficiency and peak demand.



Ergon Energy's Demand Management Strategy will be further developed in 2012/13 in response to environmental, technological and internal developments, such as the Demand Reduction Potential Review and Data Strategy.

Demand Reduction Potential Review

In 2012/13, Ergon Energy will undertake a Demand Reduction Potential Review to develop estimates of electricity demand reduction potential and assess a broad range of demand management options, such as demand reduction technologies, behaviour and lifestyle changes, small-scale renewable energies and fuel switching.

The Demand Reduction Potential Review will assist Ergon Energy to:

- Understand available demand savings
- Understand economically achievable savings given current available demand management technology and measures
- Prioritise demand management program resources for different customer segments, and
- Understand the potential impact of demand management on Ergon Energy's future load forecasts.

It is anticipated that the findings from the review will be used to identify efficient scenarios to reducing demand on Ergon Energy's distribution networks.

Data Strategy

Most electricity distribution companies are finding it difficult and expensive to power a 21st century world using networks, technologies, and management tools from the 20th century. It is evident that what Ergon Energy has done in the past may not sustain it into the future and Ergon Energy, in partnership with Energex, has recognised the need to modernise the network. Thus, there is an increasing move towards an intelligent network, a concept that is being actively pursued by Ergon Energy. An intelligent network increases the connectivity, automation and coordination between generators, transmission companies, distributors and customers, bringing the network into the 21st century.

Customers' changing needs and energy consumption patterns are driving changes in how Ergon Energy manages the network and the development of new, innovative products, processes and services. An intelligent network will be critical in achieving this as it is designed to enable us to better meet and manage growing customer requirements and the growing electricity demand, without dramatically affecting customer affordability. Ergon Energy is aware that it must also involve its customers on the journey to an intelligent network by increasingly working collaboratively on solutions beyond the meter.

Part of this intelligent network requires demand data in a timely manner, which can only be achieved with interval meters. Victoria is currently the only state to mandate a state-wide roll-out of 'smart' meters with other jurisdictions awaiting the outcomes before deciding whether to follow suit.

In the shorter-term, however, Ergon Energy is continuing to develop its existing data sets. For example, Ergon Energy recently undertook a project that allowed for network assets (distribution feeders and distribution substations) to be segmented according to predominant customer types. This data enables Ergon Energy to determine which demand management programs will be most effective for a particular area, given the predominant class of customers for each feeder and substation in that area. A Google Earth tool was also developed to view this information spatially at an entire network level.

These types of data tools are informing Ergon Energy's demand management strategy.

7.2.1 Achievements to date

Ergon Energy is delivering against its demand management commitments. Peak demand reductions for the 2011/12 year of 35.7MW were achieved against a target of 25MW. The North Queensland Harmonisation project contributed 15MW to the achieved peak demand reduciton. This builds on the 17MW of demand reductions achieved in 2010/11.

The Energy Sense Community program, a demonstration site in the global Electricity Power and Research Institute (EPRI) Smart-Grid demonstration program, is now being implemented in Townsville. The program is expected to deliver 9MW of demand reductions over three years and inform the next regulatory determination regarding non traditional solutions.

More broadly, our leading demand management trial and pilot outcomes are being integrated into business-as-usual activities, including:

- Townsville Network Demand Management and Power Factor Correction pilot outcomes are being implemented in Bohle (Townsville), Cairns, Mount Isa, Ingham, St George and Charleville together contributing to deferrals of some $280 million of planned capital investment
- Energy Savers pilot and the Solar City outcomes soon to be implemented across Townsville in residential programs targeting some 6,000 households as part of the Energy Sense Community program
- Pool pump trial outcomes are being implemented across the network in the 'save a bomb' pool pump program now delivered to almost 4,000 households
- The successes of the *powersavvy* pilot are being extended to the remaining isolated communities. Plans are also underway to implement the lesson learnt across appropriate SWER networks.

7.3 Initiatives and sub-projects for 2012/13

The Ergon Energy Demand Management Plan for 2012/13 includes a wide range of projects and initiatives, across Ergon Energy's distribution area.

Further, Ergon Energy's demand management related initiatives are at various stages of development, trial or implementation.

All are designed to improve our access to real time information or provide signals, options and alternatives to customers to manage overall network demand and energy consumption. Ergon Energy's five year Demand Management program will continue to be informed and developed by the outcomes of initiatives occurring in the coming financial year.

7.3.1 Townsville: an Energy Sense Community

The Energy Sense Communities program is integrating and further developing the demand management program in Townsville. It involves a suite of 'Smart Asset Management' and 'Network of the Future' initiatives that will further pilot and trial demand management techniques and technologies.

Phases 1 and 2 of this program have been completed. These phases included detailed analysis, scoping and approval of the individual project business cases. Phases 3 and 4 focus on the solution deployment and monitoring, measurement and analysis of all the individual projects contained within the program.

The program consolidates existing and planned Ergon Energy projects into a common delivery program, and includes:

- Townsville Queensland Solar City project (see below)
- The projects aimed at deferring the requirement for proposed zone substations at Bohle Plains and Mount Saint John, including a:
    - range of large customer peak demand initiatives, and
    - residential customer demand management program.
- Other innovation, research and development programs; and
- Other network initiatives.

The aims of this program are to:

- Trial the use of smart asset management techniques and technologies to defer planned network investments
- Gather necessary Smart Grid related evidence to support business cases for the next regulatory control period (2015-20), and
- Maximise the business learning outcomes from the existing and planned 'smart network' related initiatives within Ergon Energy. Integrating these learnings will accelerate the transition of initiatives from pilot to business-as-usual operations.

7.3.2 Townsville: Queensland Solar City Project

The *Townsville: Queensland Solar City* project, an official Australian Greenhouse Office Solar City project, was designed to explore options to address a number of challenges in delivering sustainable energy outcomes in Australia. The project is now in its final monitoring and measurement stage.

The project involves distributed solar technologies, energy efficiency, load management, smart meters, cost-reflective pricing and community engagement strategies relying on Community Based Social Marketing (CBSM) and Thematic Communication principles.

The aim of this project is to:

- Demonstrate the economic and environmental benefit of cost reflective pricing with the concentrated uptake of solar generation, energy efficiency and demand management, and
- Identify and implement options for addressing barriers to distributed solar generation, energy efficiency and electricity demand management for grid connected urban areas.

7.3.3 *powersavvy Mark II*

powersavvy Mark II follows on from the *powersavvy* pilot project which trialled community engagement and energy conservation strategies for customers connected to three of Ergon Energy's isolated networks.

The aim of this project is to extend the *powersavvy* model to more of Ergon Energy's isolated generation communities to deliver customer savings, diesel fuel cost saving and greenhouse gas reductions.

In addition to the wider roll-out, a 'sustain' phase is being implemented in the pilot area communities, to ensure changes in behaviour and thus energy and diesel savings, are maintained.

7.3.4 Other large customer peak demand initiatives

The objectives of the large customer peak demand initiatives are to:

- Encourage commercial and industrial customers to participate in demand management programs that provide a net financial benefit to Ergon Energy through deferred network expenditure, and
- Gain an understanding of the costs and benefits of implementing demand management solutions for a wider range of commercial and industrial customers to inform future program frameworks.

The 2012/13 Large Customer Peak Demand initiatives consist of both continuing and new demand management initiatives, including:

- Power Factor Correction
- Townsville Network Demand Management Pilot
- Townsville CBD District Cooling, and
- Commercial and industrial initiatives (e.g. Bohle Industrial Demand Management; Cairns Northern Beaches; and Moranbah Demand Management).

Power factor correction:

The Power Factor Correction Pilot is a continuing demand management initiative in Toowoomba, Dalby, Warwick and Oakey, which provides financial contributions to large customers to install power factor correction equipment.

The aims of this initiative are to:

- Develop and test a power factor incentive model which could, if commercially viable, be applied to reduce load in constrained areas of the network
- Identify motivations and barriers for improvement of power factor at the customer premise and ways to overcome the barriers
- Obtain a better understanding of the cost and benefits of power factor correction at customers' premises to:
    - Add power factor to the demand management and energy conservation tool kit
    - Inform the development of potential policy changes, and
    - Inform the development of a mechanism to ensure customers meet legislated minimum power factor requirements.

- Determine the level of financial contribution required to incentivise customers to install and maintain power factor correction equipment above the legislated minimum (0.8 LV and 0.9 HV) in the absence of kVA tariffs.

  Ergon Energy is currently developing a Network Pricing Strategy which will consider all possible future network pricing structures to provide appropriate signals to customers to assist with managing network costs and peak demand. This strategy is planned to be completed by the end of October 2012 and Ergon Energy will consider the introduction of a kVA tariff should it be supported by the Network Pricing Strategy. In the mean time Ergon Energy will continue with its direct action program.

Townsville Network Demand Management Pilot:

This is an ongoing pilot project which is based on commercial and industrial (and government) customers in Townsville entering into contracts to reduce their network loads in exchange for financial payments from Ergon Energy.

The project gives Ergon Energy hands-on experience in the technical, commercial and funding aspects of network demand management, enabling Ergon Energy to gear-up to maximise the opportunities presented as demand on the network continues to grow.

The aim of the Townsville Network Demand Management pilot project is to enable Ergon Energy to develop the tools and expertise to proactively implement network demand management arrangements with its customers through a targeted program, deferring the need for network upgrades. The program targets a range of differently sized commercial and industrial customers across different industries looking at a diverse range of solutions for demand management.

Townsville CBD District Cooling Project:

Stage 1 of the Townsville CBD District Cooling Project is a new initiative that proposes Ergon Energy facilitates the development of a chilled water system that will provide chilled water for air conditioning to a number of buildings in the Townsville CBD.

The recommended commercial model is a ’tolling‘ model where a non Ergon Energy company or consortium finances, builds, owns and operates chilled water production and distribution systems in the Townsville CBD.

The model requires the owner/operator of the facility to convert electricity supplied by Ergon Energy to chilled water for a toll. Ergon Energy would then ’retail‘ the chilled water to the end customer.

The aims of the initiative are to:

- Significantly reduce peak demand in the Townsville CBD
- Reduce customer bills
- Decrease GHG emissions, and
- Develop an unregulated business opportunity.

Commercial and Industrial Initiatives:

Commercial and Industrial initiatives involve reducing large customers’ individual demand requirements from constrained areas of the network during peak periods.

The initiative operates such that:

- Ergon Energy identifies customers where demand can be actively managed to reduce the peak demand on the network

- Ergon Energy undertakes an assessment of the possible drivers for the customers concerned, with a view to approaching those customers, and
- Following negotiations, and commercial and engineering assessments by Ergon Energy, a contract is negotiated whereby the customer agrees to reduce its load during peak periods as well as their overall demand for electricity. Mechanisms to achieve this reduction can include the replacement of inefficient equipment; the use of power factor correction on certain appliances; and the customer actively shifting electricity use to off-peak periods.

The individual network demand management projects that comprise the Commercial and Industrial Initiatives include the following:

- Bohle Industrial area
- Cairns Northern Beaches
- Moranbah
- Mount Isa, and
- Ingham.

7.3.5 Embedded Generation Initiative

This initiative seeks to reduce peak load through the use of standby, peaking or renewable generators that are directly connected to Ergon Energy's network.

The embedded generation plant can be owned and operated either by Ergon Energy (covering the capital cost and associated operating costs of the generator) or by a third party, whereby Ergon Energy makes network support payments to the third party.

The aims and benefits of embedded generation programs are to:

- Manage peak demand and therefore defer network augmentation
- Manage network security and provide better response capability
- Support power quality and reliability, and
- Obtain optimal commercial benefit by obtaining energy trading value through periods of volatility in the National Electricity Market.

Customer Embedded Generation:

Customers with onsite standby generation can provide a financial and operational network benefit at a minimal cost to Ergon Energy.

Customer Embedded Generation (CEG) can be used to manage peak demand and therefore mitigate the pressure on electricity prices from the augmentation of the network, manage network security, support power quality, improve network reliability and provide improved planned, unplanned and disaster response capability across Ergon Energy.

The aim of the initiative is to engage where viable CEG as a Non-Network Alternatives (NNA) to overcome network constraints and will be achieved through contracts negotiated with relevant customers.

The CEG initiative potentially adds both short-term capital and ongoing operational costs, however, the aim is to utilise this option at significantly less cost than that associated with network augmentation.

Network and Other Embedded Generation Solutions:

The strategic placement of generation within the sub transmission and distribution network can provide a financial and operational network benefit at minimal cost to Ergon Energy.

This Network Embedded Generation (NEG) can be targeted to respond to specific network constraints, manage network security, support power quality, improve network reliability and provide improved planned, unplanned and disaster response capability across Ergon Energy.

7.3.6 Residential Customer Demand Management Initiative

This program seeks to increase the number and range of residential appliances under load control so that electricity supply to these appliances or the appliances themselves can be controlled during peak demand periods. In a constrained area, network augmentation can be deferred when sufficient forecast load has been curtailed through active intervention.

The major individual projects that comprise the Residential Customer Initiative are:

- North Queensland Load Harmonisation Project
- Air conditioning Direct Load Control
- Pool Pump Filtration and Direct Load Control
- Residential Brownfield
- New Business Models – Residential, and
- Hot Water Direct Load Control.

North Queensland Load Management Harmonisation Project:

This project aims to better align the operation of North Queensland's Tariff 33 load control for electric hot water systems with network demand management requirements. Estimates predict that this project through improved control capability would reduce residential peak demand by 30MW.

To date the project has successfully separated customer's hot water loads from other loads (e.g. air conditioning) enabling these hot water channels to be switched off over peak periods for an extended period. Over the coming months this could see switching of up to six hours in accordance with Tariff 33 conditions

Customer communication and stakeholder engagement has been used to support the implementation of a program so that the increased control of hot water loads in North Queensland, and control of peak demand, can be achieved with minimal customer impact.

Air conditioning direct load control:

The growing penetration of air conditioning units by residential customers is placing a large burden on the Ergon Energy network, due to both the high energy intensity of the appliances and their pattern of usage, which predominantly occurs during peak periods. The ability to widely control this load at peak periods would decrease pressure on the network and defer network augmentation.

It was quoted in the Australian Financial Review (6 February 2010) that when a $1,500 air conditioning system is installed in Australia it costs on average $7,000 to upgrade the network to accommodate it.

This project aims, with Energex, to connect 'peak-smart' residential air conditioning units to allow these units to receive a signal to operate at a lower electrical input during peak periods when required, in return for financial incentives such as rebates.

Pool pump filtration and direct load control:

Pool filtration systems make a significant contribution to peak load due to their high energy consumption and customers' lack of understanding of using a load-control tariff option. The average pool filtration system contributes an average of 1.1kW to network load and is frequently operated during peak demand periods.

Early trials investigated the effectiveness of retrofitting systems. Through customer and pool industry feedback, two load control rebate products were developed:

- Rebate for an economy tariff connection, and
- Rebate for newly developed variable speed drive (energy-efficient) pumps.

These rebates are designed to encourage customers to connect pool pumps and filtration systems to load control tariffs allowing for these to be switched off during certain peak periods in return for financial incentives paid by Ergon Energy. Alternatively customers are invited to install an energy-efficient pool pump which also significantly reduces load on the network.

Residential brownfield initiative:

This initiative plans to take the best of Ergon Energy's lessons learnt from Solar City, *powersavvy* and Energy Savers, and tests different customer engagement methods throughout Townsville to determine the best value approach.

The scope of the initiative includes:

- Tariff information and education
- Incentives to replace old appliances with new appliances
- Incentives to change over pool pump tariff, and
- Customer engagement tools and options such as the bill benchmarking product (messaging, household comparison, third party offers).

The key aim of this initiative is to develop solutions which can be deployed throughout the whole of Queensland that helps Ergon Energy customers reduce their energy use (kWh) and therefore their bill and also assists Ergon Energy in reducing peak demand (kW).

New Business Models – Residential Developments Initiative:

This initiative involves the development of a range of measures to create a new connection process for new residential estates, which will provide a commercial and administrative platform to ensure energy efficiency/demand management measures are incorporated into new homes in an estate providing firm reductions in maximum demand.

The scope of this initiative encompasses:

- Asset planning processes for new residential estates
- Developing terms of agreement with property developers
- Developing industry partnerships
- Influencing government policy and programs with respect to building and development, and
- Ongoing community engagement.

The hypothesis of this initiative is that an effective new connection process, supported by the appropriate energy conservation/demand management measures, can ensure that new estates can be connected to the network based on a lower, bankable reduction in Average Daily Maximum Demand (ADMD).

Hot water direct load control:

Approximately 69% of existing homes in Ergon Energy's network take advantage of an off-peak retail tariff (Tariff 31 or 33, or a combination of these tariffs). However, less than 10% of new homes connected to Ergon Energy's network take advantage of off-peak tariffs.

Given the significant number of new customers not connecting to an off-peak tariff, the aim of this project is to increase customers' and electricians' awareness of the off-peak tariffs and the associated value propositions. Ergon Energy has raised awareness of the benefits of connecting to off-peak tariffs through its collaboration with industry publications and electrician education.

7.3.7 Smart Network and Pricing Signals

This program comprises a number of existing and new initiatives aimed at influencing customers' electricity use. The major initiatives include:

Reward Based Tariffs Pilot:

The Reward Based Tariffs (RBT) pilots a collaborative project between Ergon Energy and Energex to investigate how tariffs may be used to encourage customers to reduce power use during peak periods.

Customers who volunteered for the trials are able to make informed decisions about when they use power by receiving signals that the price of electricity is changing due to peak periods. Volunteer customers are advised in advance of an anticipated network peak day.

Two types of trials are being tested:

- Consumption Tariff Trial – This tariff structure comprises a combination of a Time of Use and Dynamic Peak Price. The Time of Use signal operates every day of the year, to encourage customers to use power during off-peak periods, while the Dynamic Peak Price tariff is used for short periods (four hours) on maximum demand peak days (15 days each year) to motivate immediate reduction in power use on those days, and
- Capacity Tariff Trial – This is a capacity tariff that encourages customers to maintain their total power usage below a pre-agreed level on four hours on 15 maximum demand peak days of each year. These customers receive an indicator to assist in tracking their electricity usage.

The RBT Pilot seeks to investigate the impact of alternative tariff options on residential customers and use those findings to assist in informing future Queensland tariff policy. The trial aims to deliver on the following objectives:

- Creating community awareness and discussion
- Improving the understanding of customer behaviour towards time-varying tariffs
- Understanding of the actions taken by volunteers in response to these price signals
- Estimating potential network benefits of tariffs, and
- Guiding Queensland distribution network policy development.

Energy Information Portal:

The Energy Information Portal (formerly the Energy Information One Stop Shop) is a website that will:

- Promote energy issues specific to the Ergon Energy network and educate interested customers on the benefits of implementing demand management and energy conservation measures

- Provide consistent advice and messages in relation to energy issues to limit customer exposure to incorrect advice or advice that is incompatible with Ergon Energy's priorities
- Establish Ergon Energy as an authority on energy matters and encourage customers to approach Ergon Energy to participate in demand management and energy conservation initiatives, and
- Positively influence customer electricity use and behaviour to reduce peak demand and overall electricity consumption thereby benefiting the Ergon Energy network.

The Energy Information Portal is being developed in conjunction with Energex.

The project aims to establish a single reference point for energy information that would dispense free advice and customer education on a diverse range of issues including:

- Climate control and air conditioning issues
- Energy efficient lighting
- Hot water systems alternatives and load control options
- Swimming pool pumps
- Energy efficient house wiring, and
- Solar photovoltaic purchase and connection.

7.3.8 Sustainable Residential Development Project

This project implements an integrated approach to motivating residential developers, builders and customers to adopt a suite of energy conservation and demand management options in new developments that will provide a greater level of certainty in reducing current ADMD planning standards. The project was developed in partnership with the Urban Land Development Authority (ULDA) and has received grant funding by the Department of Energy and Water Supply.

While the project is based on the ULDA residential development at Oonoonba in Townsville, it is anticipated that the scheme will form the basis for a Greenfield residential demand management program to be applied across the wider business.

This project aims to:

- Develop an incentive scheme that will motivate the adoption of a suite of energy conservation and demand management options that are effective in lowering peak household demand as well as overall energy consumption
- Provide data on the impact of these measures to reduce overall demand and ADMD and to reduce energy infrastructure
- Educate builders on the value of energy saving and off-peak products (tariffs, demand-ready appliances) to their customers
- Encourage and incentivise builders to develop energy saving designs and products
- Educate potential new home buyers on the benefits of low energy home designs and features, and
- Assess the costs and benefits (to Ergon Energy, ULDA, builders and customers) of air conditioner load control and incorporating energy saving features into new homes.

7.3.9 QUT Australian Research Council linkage study:

This project involves the Queensland University of Technology (QUT) undertaking research to develop control strategies for household appliances (including electric vehicles) and statistical models considering price, convenience and charging strategies.

The research will increase the Ergon Energy knowledge base and inform investment decisions in load control initiatives and non-network alternatives with new customer insights. The project will benefit Ergon Energy by contributing to its capacity to reduce the capital investment required to meet growing peak electricity demand.

The researchers will survey and test 2,000 households to enhance Ergon Energy's knowledge and understanding of:

- Load control management at a household level
- Load control application to emerging electric vehicle technologies, and
- Understanding customer load control preferences and acceptances.

The aims of this project are to:

- Develop models to predict the expected change in load in an electricity network which would be enabled by domestic demand side management, and the variability of this prediction
- Develop control strategies for household appliance controllers that optimise the network performance gains from domestic demand side management
- Develop control strategies for all-electric or plug-in hybrid electric vehicles that optimise network performance through demand side management, and
- Determine community levels of acceptance for different domestic demand side management strategies based on trade-offs between price and convenience.

7.3.10 Demand Management Innovation Allowance

The AER in its Final Determination allowed Ergon Energy a Demand Management Innovation Allowance (DMIA) to recover $1 million per annum over the five years to test the commercial viability of emerging and innovative demand management solutions. These initiatives are intended to expand Ergon Energy's demand management capabilities and provide long-term benefits to customers.

Ergon Energy is progressing a range of innovative initiatives that meet the DMIA funding criteria. These projects were subject to a screening process and a subsequent cost benefit analysis to identify the most feasible projects based on their ability to reduce demand and consumption; community acceptance; implementation risks and other appropriate factors.

The individual projects that will comprise the 2012/13 DMIA Program include:

- Grid Utility Support System (Phase 2)
- Automated Demand Response Trial
- Low Voltage Static Compensators
- Transformer Chilled Water Cooling Trial
- Smart Voltage Regulator Validation
- Passive Air Cooling Trial
- Smart Camp Feasibility (for temporary mining camps), and
- Stockland North Shore Living Display Centre.

Many of these projects are in their early stages, require small amounts of funding compared to other demand management projects and do not have any specific MVA reduction targets. The findings and results of these initiatives are published annually and shared nationally under the AER's Demand Management Incentive Scheme.

7.4 Responding to climate change

Ergon Energy is considered a leader in responding to climate change and its associated business risks and opportunities. Our responses have now largely been embedded into business-as-usual activities across the organisation. They may be categorised as either mitigation of GHG emissions, adaptation of the network to physical risks or leveraging of stakeholder responses to climate change for mutual benefit.

Ergon Energy takes a long-term view of the inevitability of changes in the way electricity is generated, delivered and used. It seeks not only to respond effectively to current energy reform but to actively participate in and lead industry discussion on the future of the Australian energy market, particularly in distribution sector forums.

Specific areas of focus for Ergon Energy include:

- improving GHG emissions reporting and compliance with requirements of the *National Greenhouse and Energy Reporting Act 2007.* Attention is being focused on improving the business systems for accurate measurement of GHG emissions.
- preparing to commence reporting in accordance with the *Energy Efficiency Opportunities Act 2006* on generation energy use and network losses by end December 2012.
- taking actions across the business in response to the introduction of a federal Carbon Price Mechanism (CPM) from 1 July 2012, even though Ergon Energy is not a liable entity under the *Clean Energy Act 2011*.
- outworking recommendations of our Climate Change Network Adaptation Plan, jointly developed with ENERGEX.
- increasing our capability to provide non-traditional network solutions to deliver emissions reduction, manage network demand, broaden customers' choice of products and services and integrate low emission, renewable technologies (e.g. solar hot water and heat pumps, distributed renewable generation) with the network.
- developing and implementing energy conservation and community education programs that assist our customers' response to climate change.
- actively working with our communities, governments and other key stakeholders to develop and deliver effective energy programs and contribute to positive energy outcomes in building design, appliance standards, commercial development and energy management.
- future proofing our business by developing our skill sets, improving business practices, securing the value and performance of our assets, implementing forward thinking network technology strategies with world-class partners and ensuring ongoing alignment with customer and community attitudes on energy issues.

8. 2011/12 GENERAL PERFORMANCE

This section provides a summary overview of the general performance of key programs and the network for the 2011/12 financial year. The first two subsections highlight the progress made against the 2011/12 NMP key capital and maintenance programs. The third subsection provides a summary of network performance, including reliability and quality of supply (a more detailed analysis on reliability performance is provided in Section 9). Finally, an update is also provided on the status of remote systems.

8.1 Capital program expenditure

Ergon Energy's capital expenditure is reflective of its commitment to providing a safe, adequate and reliable electricity supply across regional Queensland.

The key capital project achievements for the year include:

- provision of SCADA at 16 zone substations associated with the SCADA acceleration program
- the establishment of new 11kV feeders to the townships of Springsure in Central Queensland and Seaforth in the Mackay area
- increase of 35MVA of installed transformer capacity involving the Kelsey Creek and Mundubbera zone substations
- completion of the redevelopment of the Lannercost zone substation, Ingham and the re-development of the Dalby Central zone substation and Roma Bulk Supply Point both nearing completion which will provide an additional 23.5MVA of installed transformer capacity, and
- replacement of generating sets at Pormpuraaw, Gununa, Camooweal, Bedourie, Birdsville, Dauan Island and Stephens Island.

8.1.1 Customer-initiated capital works

The actual end of year expenditure is slightly lower than originally budgeted, with demand for new connections impacted by recent economic conditions and the legacy of the global financial crisis. This has resulted in a $23.6 million underspend for the customer-initiated capital works (CICW) program overall. Table 5 indicates the actual expenditure for the various key CICW programs compared to budgeted expenditure for 2011/12. Although the total expenditure of $197.2 million is an increase of $6.9 million compared to 2010/11, it is the second lowest level of expenditure since 2005/06.

TABLE 5: 2011/12 CICW Expenditure

Customer Initiated Program	Budget 2011/12 $'000	Actual 2011/12 $'000
Main System		
Commercial & Industrial	107,201	96,467
Domestic & Rural	44,139	48,739
Other	67,960	48,811
Total Main System	**219,300**	**194,016**
Isolated Generation	**1,513**	**3,158**
Total Expenditure	**220,813**	**197,174**

8.1.2 Network (Corporation)-initiated capital works

The actual 2011/12 expenditure on Network-initiated Capital Works (NICW) was $542.9 million compared to a budgeted amount of $549.1 million and represents a $71.9 million increase over the 2010/11 expenditure. The table below shows the forecast expenditure against the various key NICW programs compared to budgeted expenditure for 2011/12.

TABLE 6: 2011/12 NICW Expenditure

Corporation Initiated Program	Budget 2011/12 $'000	Actual 2011/12 $'000
Main System		
Asset Replacement	203,300	251,473
Augmentation	188,700	162,749
Reliability Improvement	22,100	26,297
SWER Scheme Improvement	18,293	16,544
Other	82,679	62,901
Total Main System	**515,071**	**519,963**
Isolated Generation	**34,087**	**22,889**
Total Expenditure	**549,159**	**542,852**

Programs where expenditure is more than 10% above or below budgeted amounts are discussed below:

- **Asset Replacement:** Actual expenditure for 2011/12 is $48.2 million above the budgeted amount of $203.3 million. This is due to additional capital expenditure of $54.9 million associated with defect rectification works as a result of additional inspections undertaken following the floods last year as well improvement in the delivery of replacement of defective ABSs. This was offset by an under expenditure of $6.7 million on asset replacement works although the actual expenditure on asset replacement works of $93.3 million is the highest achieved for these works.
- **Augmentation:** Although $31.9 million of expenditure has been incurred with works continuing into 2011/12 that was not originally budgeted for, overall under expenditure of $26 million compared to the budgeted amount has occurred for this program. The underspend is associated with the following works: zone substation site and line route easement acquisition works; the establishment of a 33kV feeder Columboola to Miles, the establishment of a 66kV switching station at Cannonvale; and transformer augmentation works at the Mona Park, Chinchilla, Gootchie, Black River, Biloela and Gladstone zone substations.
- **Reliability Improvement:** The overspend of $4.2 million is primarily associated with works continuing into 2011/12 that were not originally budgeted for, such as the SCADA Acceleration program.
- **Other**: The forecast underspend of $19.8 million is associated with protection upgrade works, the Operational Cellular Data Network project and delays with the construction of CARE projects.
- **Isolated Generation:** The underspend of $11.2 million is predominately associated with the planned Birdsville Geothermal plant project, replacement of the wind turbines on Thursday Island, replacement of generating sets at Thursday island, Hammond Island, Coen and Kowanyama, and the provision of a new power station at Murray Island.

At the end of June 2012, 18 of the 43 priority projects in the 2011/12 works program were completed with a further eight expected to be completed by end of December 2012. Of the remaining 17 projects, 10 have been further delayed as a result of resource constraints, six as a result of project scope issues and one as a result of property issues.

There have been two primary reasons regarding the resource constraints in the last 12 months that have impacted on the delivery of the capital program. The first has been the Central Queensland mining boom drawing on internal and external field resources. To alleviate this Ergon has sourced additional contract construction resources outside of Queensland, leading to longer than expected project delivery times. This is being managed through closer working partnerships with major existing suppliers to ensure continuity in contract labour requirements.

There has also been a significant constraint within test and commissioning work groups. Nationally this is a high demand competency group that has proven difficult to source. To manage this Ergon is sourcing short term supplementary specialists, as well as targeting expansion in existing contractor test capability. Longer term sustainable internal capacity is being increased through para professional training and development programs.

As a result of the delay being incurred in the implementation of some works as outlined above, a review of relevant network constraints is undertaken to ensure associated network risks are appropriately managed.

8.1.3 Operating and maintenance program

Actual end of year expenditure is $412.3 million compared to the budgeted amount of $384.5 million. The table below shows the actual expenditure against the various key programs compared to budgeted expenditure for 2011/12.

TABLE 7: 2011/12 Operating and Maintenance Expenditure

OPERATING EXPENDITURE	Budget 20111/12 $'000	Actual 2011/12 $'000
Maintenance		
Embedded Generation	4,418	4,971
Lines	147,325	148,785
Vegetation	93,628	104,571
Substations	41,779	36,473
Streetlights	11,718	11,820
Meters	5,355	4,941
Total Maintenance	**304,224**	**311,561**
Operations		
Network Operations	27,337	31,395
Customer Service	17,146	22,895
Alternative Control Services - General	22,186	33,231
Meter Reading Mass Market	13,580	13,244
Total Operations	**80,249**	**100,764**
Total Opex	**384,473**	**412,325**

The end of 2012/13 saw a good result for maintenance in terms of both budget and delivery of the major programs. The “all but” recovery of the asset inspection program reflects concerted efforts by Maintenance Programs and Works Contracts teams focused on a common goal. This was also the case with vegetation management with completion of the Backlog Program ahead of time.

It was a year not without issues with significantly higher costs in the vegetation area seeing a reprioritisation of the program present some challenges for the future. The conscious overspend in vegetation was a decision taken to achieve program delivery in light of underspend in other operational areas. Similarly delivery (resource), shortfalls in some of other lines inspection programs continues to cause concerns with interaction between programs and defect delivery.

Network Operations is cause for concern with budget levels not reflective of the growth in communications operations.

Work continues now on a revised program for the remainder of the regulatory control period in order to meet the overall determination financial allowance.

8.2 Preventative maintenance works

The actual end of year preventative maintenance expenditure associated with key network assets was $190.7 million compared to the corresponding budgeted amount of $192.4 million. Table 8 provides a breakdown against the key maintenance programs.

TABLE 8: 2011/12 Maintenance Expenditure

PREVENTATIVE MAINTENANCE PROGRAM	Budget 2011/12 $'000	Actual 2011/12 $'000
Lines	74,722	62,412
Vegetation	93,628	104,571
Substations	14,601	14,899
Street Lights	6,475	6,030
Metering	2,975	2,739
Total Maintenance Expenditure	**192,401**	**190,651**

8.2.1 Line inspections

Asset inspection delivery improved significantly during 2011/12 with the carry over amount reducing to approximately 10,000 down from 40,000 the previous year.

The most significant shortfall in delivery lies with the Pole Top Inspection program in Far North. This program is resourced by Live Line crews which are in high demand across all of Australia. The risks associated with non delivery of the Pole Top Inspection Program in Far North have been mitigated by prioritising the worst performing feeders and optimising the link to the Ground Line Inspection Program. To date no serious reliability issues have surfaced and resourcing is in place for delivery of the entire program in 2012/13 consisting of both the 2012/13 planned works as well as the carry-over works from 2011/12.This will result in a remodelled program for 2012/13.

Table 9 compares progress made on asset inspections against program targets as at end of June.

TABLE 9: Asset inspections 2011/12

Asset Inspection Program YTD June 2012	Pole Inspectons		Underground Inspections	
	Target	Actual	Target	Actual
Northern	76,902	75,796	12,861	12,812
Central	89,009	85,494	8,884	8,836
Southern	138,370	132,605	9,141	9,009
Ergon Energy	304,281	293,895	30,886	30,657

8.2.2 Vegetation management

The vegetation management program inspected and cleared 517,389 spans at the end of June 2012 against a planned target of 515,618 spans. The vegetation backlog program was completed by 30th June 2012, six months ahead of the target date.

Vegetation management costs remain a focus with the increases experienced across all regions during the year. Integration of ROAMES data will assist greatly with this.

8.2.3 Other key preventative maintenance

The following table shows actual key maintenance tasks completed at the end of June 2012 compared to planned tasks.

. **TABLE 10: Completed Maintenance tasks at end of June**

Maintenance Program YTD June 2012	Target	Actual
LINES OTHER	144,355	135,944
SUBSTATIONS	6,250	6,039
METERS	1,977	1,804
COMMS	3,113	2,843
PROTECTION AND CONTROL	1,013	1,044

8.2.4 Special maintenance programs

Oil Filled Ring Main Units (RMU):

This program has been completed with the exception of two units in Gladstone that are linked to a customer driven project. The units have been tagged out and present no risk from a safety or reliability perspective. Replacement will be completed with the customer project.

Zone Substation Air Break Switches (ABS):

This program relates to 65 ABS' in 15 zone substations with 'strung bus' across all regions and was targeted for completion by the 31 December 2010. Although Far North and North Queensland have been completed there have been some delays experienced with the other regions and at the end of June 2012, 59 units had been replaced. Replacement of the remaining six units in Central is hampered by difficulties in securing electrical access to the relevant substations.

Lines ABS:

A data capture exercise identified approximately 2,500 ABS' of interest with some 1,600 units being of the types that require replacement. While some strategically important switches have already been replaced by Operations' staff, the bulk of the program will be resourced under ABS Inspection, Maintenance and Replacement contracts. The program targets replacement of 600 units per year with completion over a three year period.

This programme is to be delivered by contract in all regions except Far North which is fully resourced internally.

The progress of this program continues to be hampered by the availability of live line resources with delivery of 304 replacements during 2011/12. 2012/13 is the final year of this program and significant pressure is being placed on contract resources to deliver the balance. Initial signs are encouraging with delivery ramping up in past months.

Asbestos management program:

An inspection program of zone and distribution substation buildings was initiated to ensure compliance as per the Code of Practice for the Management and Control of Asbestos in Workplaces (NOHSC: 2018 (2005).

Initial inspections of all sites across Ergon have been completed. Tasks for re-inspection of all sites with asbestos containing materials (ACM) have been established and budgeted for the 2012/13 year. The 2012/13 year program has been modified to accommodate new inspection and audit requirements put in place by changes to legislation.

Pole Top Inspection Program:

This program suffers similar issues to the Air Break Switch Replacement program targeting live line resources. Additional contract teams have been engaged and while delivery for the year just gone has been well below target – 7,500 against a plan of 12,000, improvement during the last three months increased confidence for 2012/13.

8.2.5 Asset replacement and refurbishment

The following table shows forecast expenditure at the end of June 2012 compared to budget for assets replacement, defects and refurbishment.

TABLE 11: Asset replacement and refurbishment expenditure 2011/12

	Budget 2011/12 $'000	Actual 2011/12 $'000
Line Refurbishment	103,300	158,211
System Asset Replacement	100,000	93,262
Total Asset Replacement & Refurbishment	**203,300**	**251,473**

Line refurbishment reflects defect rectification works associated with the Asset Inspection and Defect Management strategy. The over expenditure is due to additional expenditure associated with rectification works as a result of additional inspections undertaken following the floods last year as well improvement in the delivery of replacement of defective ABSs.

8.3 Network performance

8.3.1 Reliability of supply performance

Ergon Energy uses a statistical approach to reliability performance measurement to support the assessment of reliability and report the performance of its vast complex 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 relevant period.
- **System Average Interruption Frequency Index (SAIFI).** This reliability performance index indicates the average number of occasions the system is interrupted during the relevant period.
- **Customer Average Interruption Frequency Index (CAIDI).** The average duration of interruption for customers affected by outages (not all customers are impacted by outages). This reliability performance index indicates the average restoration time for each event and is used as a measure of a utility's response time to system contingencies. CAIDI can be improved by reducing the length of the interruption but also can be reduced by an increased number of short-duration interruptions. Hence, a disproportionate improvement in either SAIDI or SAIFI may result in a CAIDI value that is counterintuitive to the reliability improvement.

Ergon Energy's overall End of Year (EoY) reliability performance by feeder category for 2011/12 is shown in Table 12 below. Ergon Energy has delivered reliability performance favourable to five out of six MSS limits for 2011/12 with Long Rural SAIDI as the only measure unfavourable to the year-end MSS limit. The EoY performance (both SAIDI and SAIFI) for Urban feeders show significant improvement compared to the previous regulatory year.

Short Rural SAIDI has also improved considerably from the previous year with the Short Rural SAIFI remaining static to 2010/11 year. Long Rural feeder performance has been less favourable compared to the previous year.

TABLE 12: Network Reliability Performance

Normalised Performance		2010/11 EOY	2011/12 EOY	MSS 2011/12
SAIDI	Urban	148.88	136.28	148
	Short Rural	425.74	391.65	418
	Long Rural	827.35	1041.58	948
SAIFI	Urban	1.628	1.413	1.96
	Short Rural	3.532	3.549	3.90
	Long Rural	5.266	7.019	7.30

The following table shows the EoY feeder category performance for 2011/12 for Ergon Energy overall and its legacy supply regions. It should be noted that MSS limits identified above apply to Ergon Energy's overall normalised reliability performance. The breakdown by legacy region is provided for information only and to demonstrate the regional variance in reliability performance.

TABLE 13: Feeder category normalised performance per region June 2011/12

		Actual Regional Network SAIDI, SAIFI, CAIDI						
		EE	**FN**	**NQ**	**MK**	**CA**	**WB**	**SW**
SAIDI	All	373	306	379	432	390	332	432
	Urban	136	116	128	135	106	117	225
	Short Rural	392	366	482	552	275	335	384
	Long Rural	1,042	940	1,709	1,227	1,153	749	947
SAIFI	All	3.17	2.70	3.22	3.59	3.30	2.77	3.68
	Urban	1.41	1.10	1.38	1.65	1.40	1.17	1.96
	Short Rural	3.55	3.58	4.23	4.46	2.87	2.79	3.72
	Long Rural	7.02	5.92	10.09	5.29	7.60	5.95	6.64
CAIDI	All	117.65	113.39	117.87	120.31	118.14	119.51	117.14
	Urban	96.42	104.93	93.05	81.41	75.36	100.09.	114.98
	Short Rural	110.43	102.36	113.91	123.95	95.71	120.02	103.29
	Long Rural	148.40	158.71	169.33	207.22	151.76	125.88	142.58

Notes: Excludes major event days. MSS limits are only applicable to overall Ergon Energy column.

Regionally, the Urban feeder SAIDI performance is favourable for five out of six regions, with the exception being the South West region. All regions are currently below the MSS limits for Urban feeder SAIFI performance.

Four out of six regions (except Mackay and Northern Queensland have the Short Rural SAIDI and SAIFI performance favourable to the end of financial year MSS limits.

Far North, Wide Bay and South West are the only three regions that are favourable to the end of financial year Long Rural MSS SAIDI limit. All of the regions are tracking favourably with the end of year MSS SAIFI limits for the Long Rural feeder.

Historically, Urban and Short Rural performance have been a challenge for Ergon Energy especially during the second and third quarters of a financial year which mark the storm season in northern Queensland.

Despite the increased volumes of weather related events in 2011/12, Ergon Energy's overall performance for Urban and Short Rural feeders has been good for the December and March quarters of 2011/12 when compared to the previous year. This is reflective of Ergon Energy's continuous combined focus on its asset and operational strategies targeted towards reliability improvement. Both Urban and Short Rural feeders have met the MSS limits (both SAIDI/SAIFI) for 2011/12.

However, Long Rural performance for 2011/12 has been highly influenced by adverse weather, with EoY Long Rural SAIDI performance remaining unfavourable to the MSS limit. Long Rural customer minutes and interruptions due to bad weather conditions like storms, floods and lightning strikes increased, on average, by 53% and 45% respectively during 2011/12 compared to the previous year.

This resulted into additional 147 SAIDI and 1.46 SAIFI attributable to the adverse weather for Long Rural feeders. Impact from bushfire and adverse weather on Long Rural feeder performance for the quarters up to the storm season are detailed below.

September quarter for Long Rural feeders

- Damage to infrastructure caused by extensive bushfires in Capricornia supply region and summer storms in the South West and Wide Bay supply regions adversely impacted Ergon Energy's unplanned outage performance for the Long Rural SAIDI feeder category during the first quarter.
- Customer minutes lost due to weather triggered outages in the South West supply region increased by approximately 2600% compared to the September 2010/11 quarter.
- Customer minutes lost due to bush fire triggered outages in Capricornia region increased by almost 1500% compared to the September 2010/11 quarter.

December quarter for Long Rural feeders

- Long Rural customer minutes and customer interruptions were impacted by adverse weather conditions and storm activities; increasing by 34% and 75% respectively compared to December 2010 quarter. This has resulted in an increment in Long Rural SAIDI and SAIFI attributable to storms activities by 64 SAIDI minutes and 0.63 SAIFI respectively compared to the same quarter last year.
- In particular, the unplanned customer minutes and customer interruptions attributable to lightning strikes for Long Rural feeders increased by 60% and 145% respectively compared to the December 2010 quarter.

March quarter for Long Rural feeders

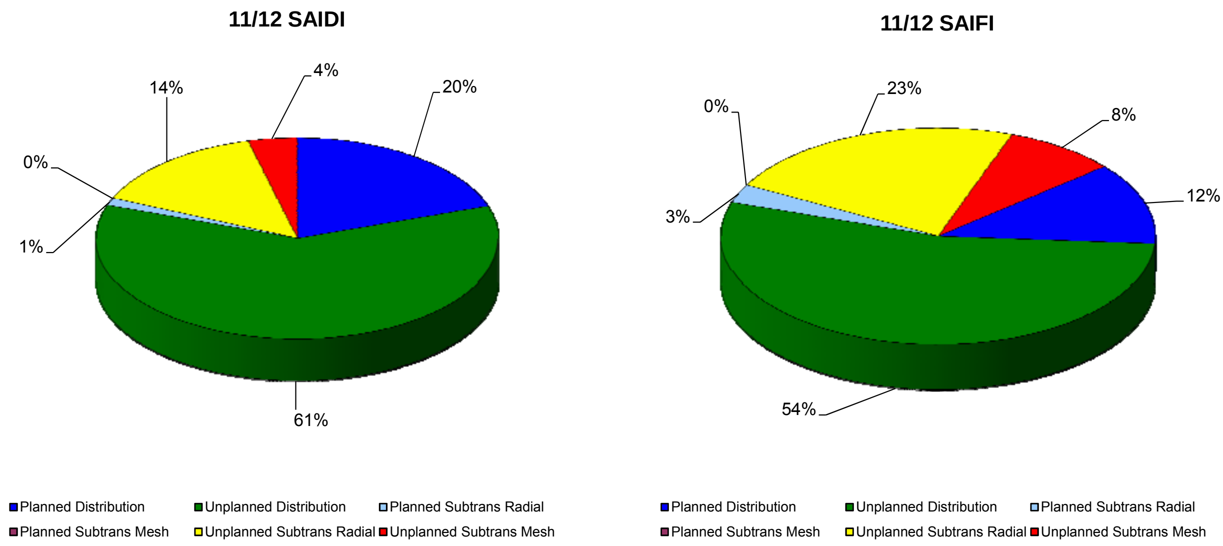
- The March quarter witnessed continuous negative impact from adverse weather on Long Rural performance with customer minutes and customer interruptions attributable to weather increasing by 36% and 12% respectively compared to March 2011 quarter. This has resulted in an increment in Long Rural SAIDI and SAIFI attributable to storms activities by 40 SAIDI minutes and 0.07 SAIFI respectively compared to the same quarter last year.

The compound effects of the bushfire and adverse weather throughout 2011/12 are reflected in the EoY reliability performance for Long Rural SAIDI.

In 2011/12, unplanned subtransmission outages contributed to nearly 18% of overall SAIDI (4% from meshed and 14% from radial) and 31% of overall SAIFI (8% from meshed and 23% from radial). Graph 12 provides a breakdown of planned and unplanned outage contributions to network performance for 2011/12 financial year.

Major Event Days (MEDs), those days on which the impact of an interruption is statistically greater than normal, are excluded from the reportable MSS results under clause 2.4.3(c) of the Code.

GRAPH 12: Contribution to Ergon Energy's 2010/11 SAIDI and SAIFI performance



Planned Outage Performance:

Ergon Energy maintained the improvement levels in its planned performance during 2011/12 compared to the previous year's planned performances. The sustained improvement in planned outage performance is demonstrated in Graph 13.

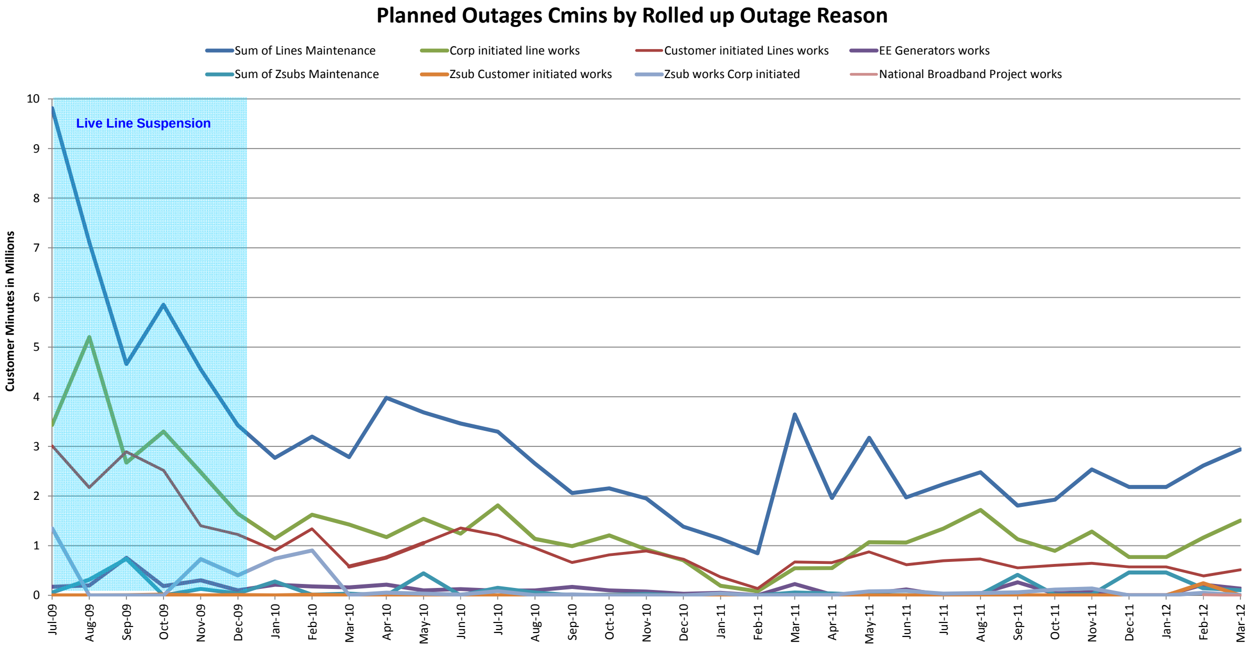
The graph illustrates the contribution of distribution line defect maintenance to the planned outage performance over the past three years (i.e. work required to maintain compliance with the Code of Practice, works under the *Electrical Safety Act 2002* and to minimise unplanned outages/safety risks). This encapsulates the period during which Ergon Energy enforced a ban on live-line work practices, which saw planned outage customer minutes due to line maintenance peak at record high values between March and October 2009.

Since that time it shows how Ergon Energy has demonstrated continual improvement in the area of planned outage performance.

This result is largely due to the reinstatement of live-line working practices between September and November 2009 and the progressive replacement of defective line and substation Air Break Switches. However, additional benefits have been realised from the improvements to the management of outage events. Improvement measures in the operational response have included a major effort centred on planned and unplanned outage management, including improvements to works scheduling and packaging, reporting processes and tools, and increasing the use of mobile generators.

The results have been achieved despite the challenges associated with addressing the outstanding planned works that were deferred due to remediation works post Cyclone Yasi in 2010/11.

GRAPH 13: Planned outage customer minutes by standard outage reason



Operational Limits on Air Break Switch (ABSs):

In 2008 a ban was placed on the operation of pole mounted ABB ‘R’ and ‘U’ series and UniSwitch Air Break Switches (ABSs). In November 2009 this ban was lifted following the implementation of a safe work practice that provided a more detailed safety inspection process prior to operating, and the acceleration of a program to replace these ABSs.

In 2010 it was identified that the operation of these particular ABSs within the confines of a substation presented an additional safety risk to the operator. The risk was highlighted by an incident in March 2010 when the porcelain insulator mount on an ABS failed. In response to this incident Ergon Energy immediately implemented an operating ban on these devices within a substation yard. As a longer term control measure it was determined that the wholesale replacement of all at risk ABSs located in a substation yard was the most sensible, prudent and cost effective manner in which Ergon Energy could achieve its long-term operational requirements without compromising its overarching safety imperatives.

With this ban in place, the ability to isolate sections of the network to carry out planned maintenance was reduced and larger network sections, and consequently customer numbers were impacted for each event. As an example, routine maintenance on a zone substation feeder circuit-breaker, where the line isolator within the substation yard cannot be operated, required isolation from a point further out in the network, thus having an impact on any customers supplied in the first section of network from the substation to the point of isolation. The network had been designed and constructed such that these customers would not normally be impacted.

Ergon Energy is currently outworking its ABS replacement strategy targeting replacement of 65 substation switches and 1,500 line ABSs by 2013. 30% of the defective line of ABSs targeted by the strategy are installed on our Urban feeders, 60% on Short Rural feeders and the remaining 10% installed on our Long Rural feeders.

With the relatively higher densities of customers on the Urban and Short Rural feeders, the operational limitations on ABSs would have a noticeable influence on customer minutes and interruptions.

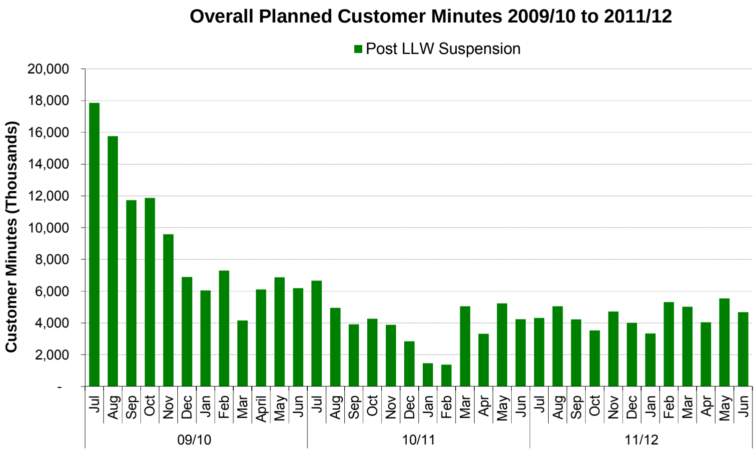
The 2010/11 and 2011/12 delivery of ABS replacements in line with the strategy has suffered significant slippage as a result of influence of the extended wet period, resource commitments to cyclone Yasi recovery and the inability of an engaged contractor to deliver on the terms of the contract in the Southern regions. Six of the 65 units of substation switches remain outstanding as at the end of June 2012.

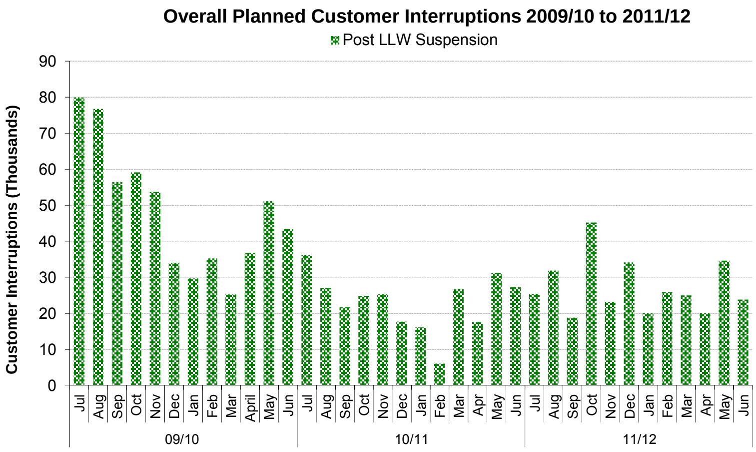
During 2011/12 304 line switches were replaced. Those not delivered during 2010/11 and 2011/12 have now been rolled into the 2012/13 Plan. Delivery shortcomings are being addressed and it is anticipated that the three year targeted total replacement of 1600 will be achieved by the end of June 2013.

While the quantification of impacts on reliability outcomes from the operational ban on the ABSs is not feasible, it is considered that better results for all six reliability measures, especially Urban and Short Rural SAIDI and SAIFI would have resulted without the ABS issues.

The progressive ABS replacement, as well as the reinstatement of the live-line work practices over the December 2009 quarter, has supported the improving trend in planned outage performance as evident in Graph 14.

GRAPH 14: Monthly Planned Outage Performance





Unplanned Outage Performance:

The management of the unplanned outage performance during the storm/flood season continue to provide a challenge to Ergon Energy to meet its reliability targets.

Historically, the summer storm season has considerable influence on the end of year reliability performance results. 2011/12 again witnessed the adverse impact of the storm and wet season on distribution feeder performance. As per previous years, the flooding of access routes gave rise to extended restoration timeframes for unplanned outage events due to the difficulties associated with gaining access to identify faulted assets and to carry out repairs. Ergon Energy continued its practices to safely manage the operation of its high-voltage network during the adverse weather conditions by taking precautionary actions, which may have impacted the performance level received by our customers. The affects in this area were more pronounced in the performance of the Long Rural networks in the Ergon Energy supply regions.

The extreme weather observed in 2011/12 resulted in three Major Event Days (MED). On 15 October 2011, there were extensive storms, hailstorms and bushfires across all regions.

On 5 March 2012 there were heavy rain, damaging winds and flash floods in the southern regions, and on 17 March 2012 a mini tornado occurred in Townsville causing concentrated but major damage to the local network.

Through the exclusion provisions of the Code all interruptions that commenced on a MED are excluded from the calculation of Ergon Energy's SAIDI and SAIFI for all feeder types.

The quantum of interrupted customer minutes and interrupted customer numbers is provided for each MED in Table 14.

Table 14: Major Event Days for 2011/12

DAYS	CUSTOMER MINUTES	CUSTOMER INTERRUPTS	SAIDI	SAIFI	COMMENTS
15/10/2011	5,959,944	45726	8.903	0.0683	Declared MSS MED due to Bushfires, Storms & Hailstorms across All Regions
5/03/2012	6,574,525	22321	9.771	0.0332	Declared MSS MED due to Heavy rain, damaging winds and flash flooding in Southern Region
20/03/2012	9,543,670	13974	14.183	0.0208	Declared MSS MED due to Heavy Rain & Tornado-like winds in Townsville NQ

Though the impact of the most severe weather events have been excluded from the reported reliability statistics, there remains a portion of events resulting from extreme natural events that adversely impact the reliability performance as they sit beyond the reach of the existing exclusion mechanisms of the Code.

The slow moving floods that usually pass through central and southern Queensland from December through to the end of January every wet season is one such event. Ergon Energy has very low customer density and the wide geographical spread of its major customer groups makes it difficult to trigger a Major Event Day at the whole of system level for Ergon Energy.

The first quarter of 2011/12 also had three days where the daily SAIDI on average measured up to 70% of the MED Threshold of 8.17 SAIDI minutes, but the days were not high enough to qualify as a MED. The recent storm season also witnessed five extreme weather days where the daily system SAIDIs measured, on average, up to 70% of the MED Threshold.

Supply interruptions occurring in the flooded areas during March also saw extended restoration timeframes as a result of the condition of access routes that imposed safety risk to both Ergon Energy's staff and its customers. Ergon Energy used its best endeavours to ensure the duration of these interruptions were minimised but they have undoubtedly had an impact on the reported reliability statistics for reasons beyond the control of a distribution entity.

A more in-depth analysis of Ergon Energy's reliability performance is provided in Section 9.

In addition to specific targeted works, network augmentation, asset replacement and refurbishment expenditure and virtually all corporation-initiated network capital and maintenance expenditure have a positive impact on reliability performance. Specific reliability improvement capital expenditure is expected to meet budget for the remainder of the regulatory control period.

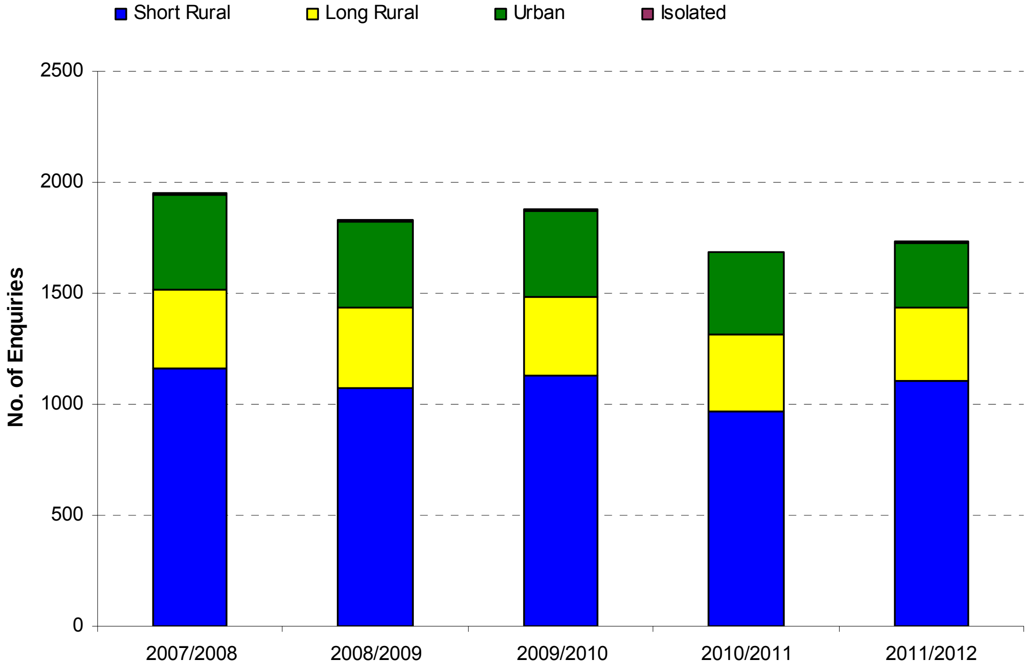
Ergon Energy is committed to implementing policies and strategies to improve the delivery of quality and reliability of supply on its distribution network. Section 10.2 provides information on policies that underpin the Ergon Energy Network Performance Future Vision.

8.3.2 Quality of supply

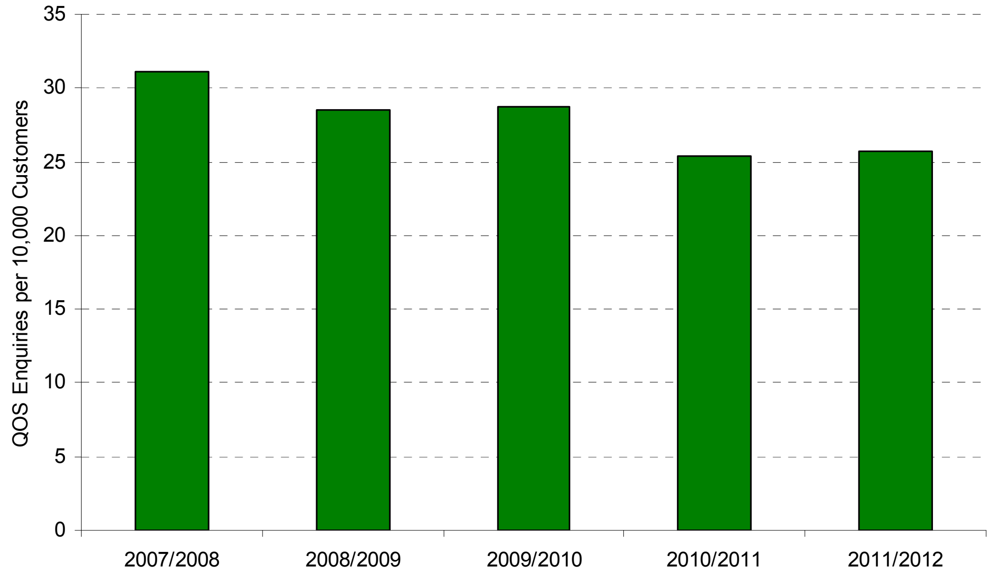
Quality of supply enquiries occur when a customer contacts Ergon Energy with a concern that their supply may not be meeting standards. Quality of Supply issues are selected from the following at the initial contact; low supply voltage, voltage dips, voltage swell, voltage spike, wave form distortion or unbalance, TV or radio interference or unbalance and noise from appliances.

The number of Quality of Supply enquiries received for the 2011/12 year has seen a increase from 1,690 to 1,741 when compared to the previous year. These figures are shown in Graph 15 relative to feeder types and Graph 16 as per 10,000 customers.

Graph 15: Total Number of Power Quality Customer Enquiries by Year



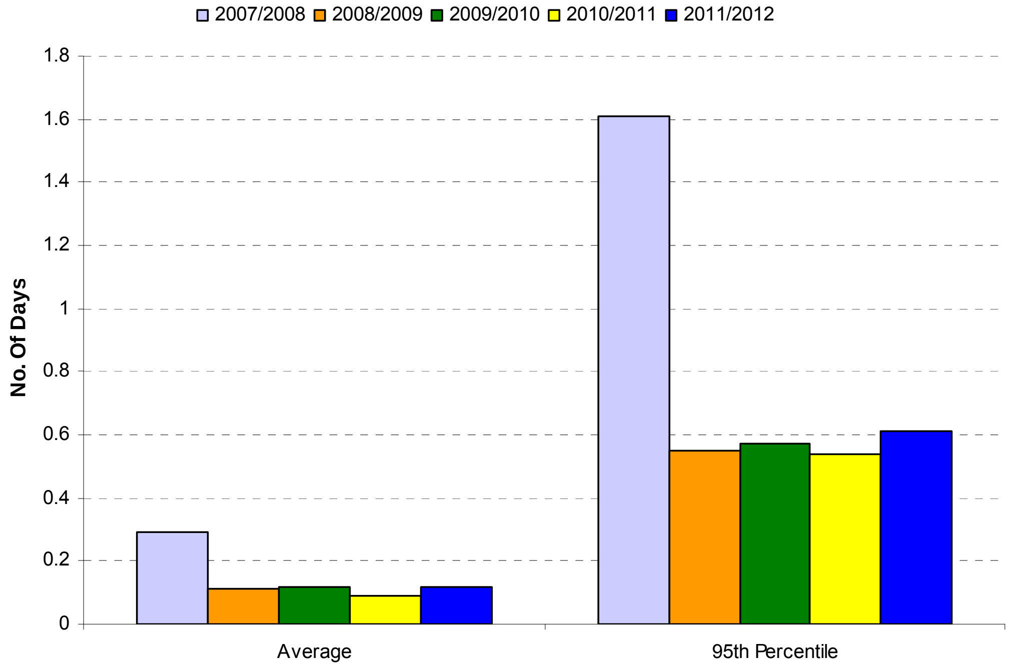
Graph 16: Quality of Supply Enquiries per 10,000 Customers



When an enquiry is received there are three levels of measure on how field staff respond to Quality of Supply issues: acknowledge, dispatch and action. Action refers to when the issues are completed or linked or moved to a new or current asset event.

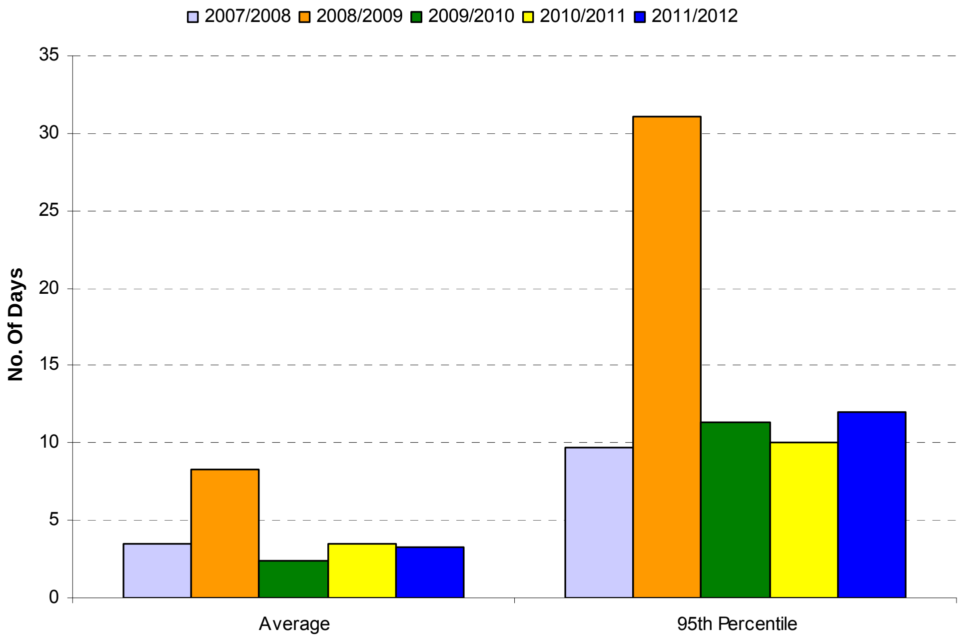
Ergon Energy is meeting the time to acknowledge of one hour as per Graph 17.

Graph 17: Customer Quality of Supply Enquiries – Time to Acknowledge



The time to dispatch has a target period of seven days. During 2011/12 the dispatch period averaged 3.54 days as shown in Graph 18. The average period has remained steady for the year. However, there is need for improvement for some individual regions and depots with the 95th percentile increasing to 13.74 days.

Graph 18: Customer Quality of Supply Enquiries – Time to Dispatch



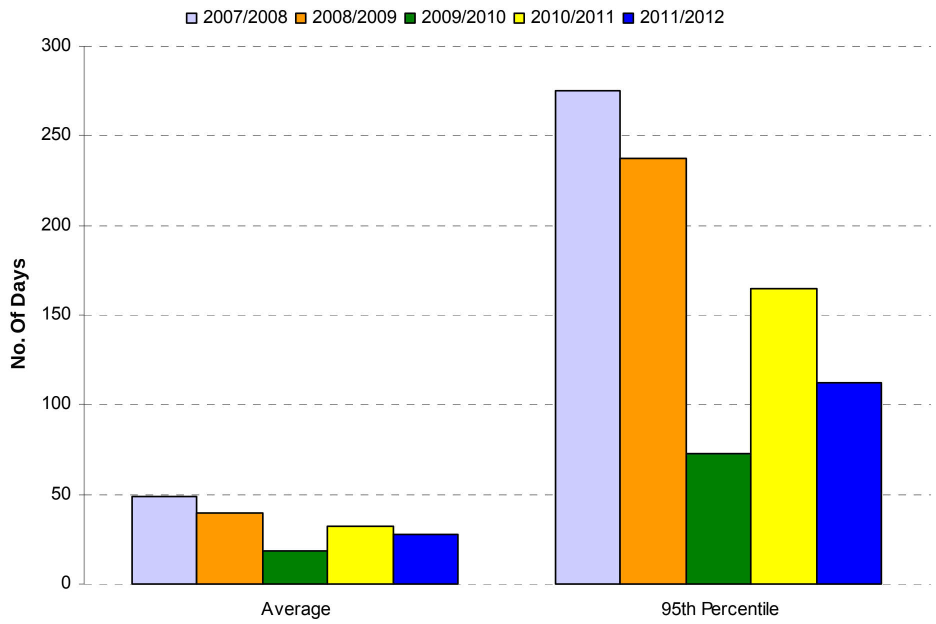
As a result of the increased dispatch time, time to action has also increased. The time to action for 2011/12 averaged 29.58 days as per Graph 19. This period is just within the recommended 30 days as per the current Quality of Supply process.

Again the variation is considerable across regions and depots, with the 95th percentile value at 125.5 days.

When discussing the situation with depots and how Ergon Energy is required to report on quality of supply enquiries, the common reply is that the connection of PV / Inverter Energy Systems (IES) systems and current work plans are impacting on Quality of Supply work times.

An improved Quality of Supply process has also been developed and is being deployed. The aim is to highlight the importance of resolving all Quality of Supply enquiries and to ensure consistent targets are met.

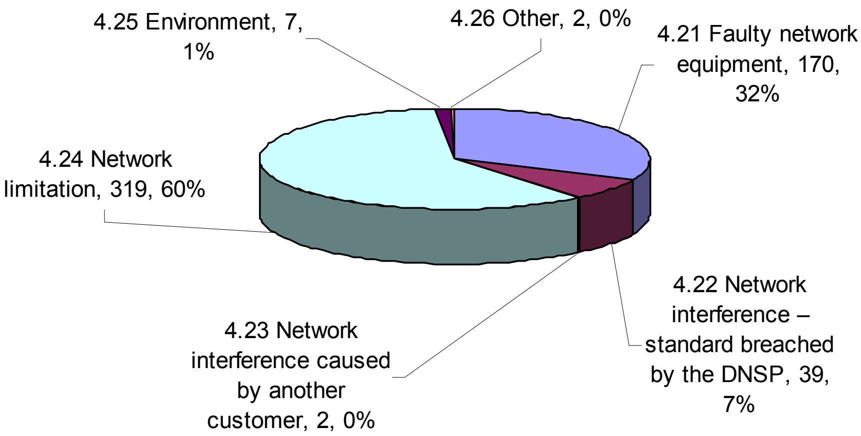
Graph 19: Customer Quality of Supply Enquiries – Time to Action / Complete



When a quality of supply enquiry is completed it is catalogued as the per QCA listing. The two main categories noted for investigation reasons were: Network Limitation and Faulty Network Equipment.

Network Initiated resolutions noted as Network Limitation, Faulty Network Equipment and caused by Ergon Energy contributed to 92% of customer initiated investigations for the year. The remaining 8% of complaints were related to issues on the customer side of the meter, no cause found or supply quality acceptable, environmental, other customers or not a quality of supply problem. Graph 20 shows a break down of the categories. Work is continuing to ensure greater awareness of quality of supply issues so that correct recording of issues is performed.

Graph 20: Customer Initiated Asset Events – Investigation Reasons



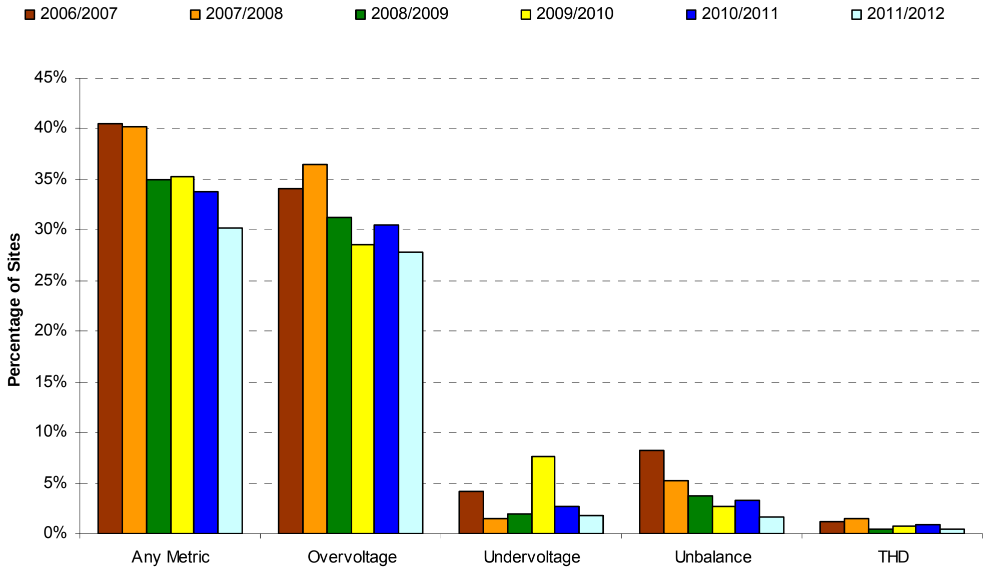
8.3.3 Power Quality parameters

Ergon Energy now has 1,789 Power Quality Monitors connected throughout the network. The monitors give an indication of the state of the network and can be used to draw conclusions for the other parts of the feeder. The data obtained from the units indicated the following:

- Ergon Energy is trending favourably with steady state voltage control for over-voltage (OV). 27.7% of sites recorded voltage outside of regulatory limits.
  The number of sites recording under-voltage (UV) issues has decreased on 2010/11 figures with 1.8% of sites having under-voltage outside of regulatory limits.
- The number of sites showing unbalance for the year has trended favourably. The data is showing that 1.8% of three-phase sites are outside standard. A continuation of work is required to balance the loads on the low voltage distribution network to improve voltage unbalance with particular emphasis on the rural feeders which are harder to balance with seasonal changes and SWER loads.
- There has been a small decrease in the number of sites recording total harmonic distortion (THD) levels greater than the regulatory limits. The number are from a very low base, however, considering the increase in the connection of electronic equipment onto the network, the data indicates that the equipment is largely confirming with Australian standards for harmonics emissions. Ergon Energy will continue to be vigilant to ensure that potential harmfully harmonics are not present on the network.

Refer to Graph 21 for the power quality profile for 2006/7 to 2011/12.

Graph 21: Power Quality Parameters



8.4 Summer preparedness

As required by Section 2.2.1 of the Code, Ergon Energy established a Summer Preparedness Plan for 2011/12, which was published on our website, and provided a report to QCA on the effectiveness and Ergon Energy's compliance with the implementation of the plan.

As in previous years, our Summer Preparedness Plan focused on three key areas:

– continued investment to improve our network to minimise the potential for outages
– enhancing our emergency response capability
– keeping our customers and communities informed on the challenges experienced in the summer period.

These preparations have proven pivotal to delivering on our service commitment to the communities and people of regional Queensland.

Although we did not experience weather events of the same magnitude as in 2010/11, significant tracks of Central Queensland were impacted by bushfires and several towns across the state's south, including Charleville, Mitchell, Roma, and St George, experienced major flooding, which affected our network and the supply of electricity to customers. These events were followed by a significant weather event that occurred in Townsville on the 17 March 2012, which saw tornado type winds of up to 170 kilometres per hour develop from the severe weather system affecting the whole of northern Queensland. The power supply to over 7,800 properties was impacted mainly in the residential suburbs of Aitkenvale, Vincent, Gulliver and Mundingburra. In addition to the damage to the main lines supplying the area, as a result of flying debris, there were approximately 200 service lines down.

The experience gained from past summers was clearly visible in the effectiveness of our response to these natural disasters – again allowing us to demonstrate the professionalism of our emergency response and customer communication capability, and in many ways the increasing resilience of the network.

The lessons learnt from this summer will be incorporated in the Summer Preparedness Plan 2012/13, as we focus on strengthening our network to reduce the potential for storm related outages and continue to improve our demand management capability.

Maintenance Works Pre-summer:

Through a well-developed Asset Inspection and Defect Management program, Ergon Energy has achieved a minimum rating of 100% of P1 (priority) defects and 98% of P2 defects repaired within set policy timeframes. The program has resulted in increased performance, safety and reliability of the network. Table 15 demonstrates the number of defects repaired at both the beginning of summer (end of November 2011), as well as at the end of summer (end of February 2012). It also highlights selected items in the annual maintenance program.

Table 15: Planned Maintenance Works

KEY PARTS OF MAINTENANCE PROGRAM	Planned July to 1 December 2011	Actual July to 1 December 2011	Actual July to end February 2012
Vegetation management – no. of spans cleared	240,000	223,339	323,699
Poles replaced	498	480	882
Poles nailed	802	1,261	1,748
Cross-arm replacements	3,506	2,557	3,986
Pole top repairs	21,832	16,706	27,900
Repairs to services	4,607	4,301	6,364
KEY ITEMS OF INSPECTION PROGRAM	**Planned July to 1 December 2011**	**Actual July to 1 December 2011**	**Actual July to end February 2012**
Feeder Patrols - Spans	122,000	100,832	119,973
Thermo scanning Inspections	600	5,623	5,623
Pole Inspections	116,976	133,762	196,802
Pole Top Inspections	3,570	2,579	3,660

Note: The planned July to December figures were the best forecasts. The actual physicals are an outcome of conditions based assessments.

The main issue that has impacted delivery of the maintenance program pre-summer was resource constraints, in particular in the live line area. The constraints specifically impacting Ergon Energy are due to the availability of staff and contracting issues as a consequence of the significant demand for resources by contractors and distributors alike. Ergon Energy is investigating alternatives to reduce the demand on resources including a focus on prioritising and restructuring work programs to assist the constrained resources in the short term. Ergon Energy is also investigating the use of new inspection technology to assist with the long-term planning.

Since the beginning of December 2011, however, we have largely surpassed the program's pre summer target.

Ergon Energy's ongoing CARE program has continued to progressively address the need for undergrounding of key distribution assets in cyclone-prone areas of northern Queensland. Expenditure on the CARE program pre summer 2011/12 totalled $2.5 million. The following major CARE projects were completed or significantly progressed in the following areas:

- West Mackay Hume St – Under construction
- Cairns Masonic Nursing home – Under construction
- Townsville – Cranbrook – Completed
- East Ayr – Completed.

8.5 Remote Systems

8.5.1 SWER status

Overall Ergon Energy has 758 SWER systems providing 253MVA of connected customer transformer capacity and supplying 25,532 customers. Power system simulation assessments made in 2012 indicated that 12% of these systems may be overloaded while a further 10% are at or near full cyclic capacity. System studies have also identified 17% suffering voltage quality constraints with a further 5% nearing voltage limits.

Although these values do not appear to have fallen significantly since 2007 additional data along with improved system modelling, tighter design limits and training continue to establish a more complete picture of the SWER problems. The implementation of a power quality (PQ) monitoring program has also significantly contributed to the more accurate modelling and to tighter voltage planning limits for SWER. As voltage problems on SWER schemes could be related to voltage regulation issues on 'parent' distribution feeder, improved analysis of the network are continuing to define areas of voltage constraint on SWER systems.

There are presently 73 unisolated SWER networks (down from 98 in 2011) supplying 10.66MVA of connected customer capacity still operating and inhibiting the application of Sensitive Earth Fault (SEF) feeder protection needed for improving public safety. Current programs support the provision of isolating transformers on of these networks.

Since the intensified SWER improvement program started in 2005/06 an average of 5MVA of additional SWER customer transformer capacity (1.6%) is being added annually. To meet this requirement an increase in isolation transformer capacity and associated system augmentation is being provided annually both to help meet this additional diversified load growth and to reduce the present overloading.

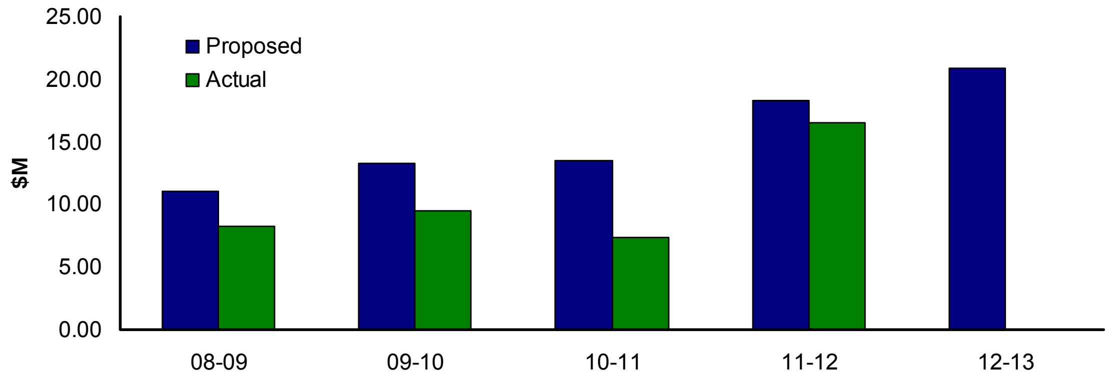
System modelling indicates that, if no corrective action is taken, the present overloading issue and associated voltage problems would almost double in 10 years. As part of our response to this, the 2012/13 works program prioritises upgrades of the current overload and voltage constraints. This will be followed by more upgrade work in the following years supported further by the establishment of NDM load reduction programs.

The 2011/12 capital works program included the identification and staged upgrading of isolating transformers to address unisolated or overloaded SWER systems, upgrading of protection equipment, extension of three phase to replace some SWER network, reconductoring of existing lines and provision of additional voltage regulators to provide further improvements.

There continues to be a strategic focus on: safety, isolator transformer loading; reliability, protection and voltage quality improvements; emerging technology trials; conversion of SWER to three-phase; program upgrading of unisolated SWER schemes; and, upgrading small conductor to larger capacity conductor to continue improving the SWER network. As well, Ergon Energy is providing a greater focus on replacing deteriorated conductors throughout the regions and work to identify those conductors is ongoing.

The following graph indicates the extent of actual improvements identified in the SWER strategy and completed as at the end of June 2012. Actual expenditure achieved in 2011/12 was $16.5 million which was a significant improvement in expenditure compared to previous years where expenditure levels were impacted by delays in getting programs established and the procurement of new equipment such as LVRs as well as resource constraints especially in the southern region. Significant progress has been made in addressing these issues and going forward this higher level of expenditure is expected to continue.

GRAPH 22: SWER scheme improvement capital works



An investigation is under way to identify a range of emerging technologies to help improve existing SWER network performance. This investigation includes low-voltage regulators (LVR), VAr control systems, integrated utility system devices and the incorporation of distributed generation technology for SWER support. Each of these projects is being researched, with a view to progressing worthwhile solutions to a trial stage in line with the SWER Action Plan.

Low-voltage regulator: The overall program has issued 1,012 LVR units for installation across SWERs in localised, or cluster arrangements. Extending on from this program is a series of trials to examine both the energy conservation potential of the LVR and its ability to improve regulation on three-phase low-voltage networks. A smarter version of the LVR labelled an SVR is about to undergo investigation and trial.

VAr Control systems: Shunt reactor switching or Statcom devices are expected to improve SWER system capacity and voltage levels, leading to supply quality and network capacity improvements. Work is continuing on a switched shunt reactor trial, with the monitoring of a prototype to allow technical designs to be tested and refined under live SWER network conditions. Investigations have commenced into Statcom benefits for SWER networks.

Integrated utility system devices: An examination of Integrated Utility System devices are under way, including a trial of battery powered peak load-lopping devices. 5kW flo-battery devices (Redflow) are on trial on the Wambo Creek SWER systems in south-west Queensland while a trial of larger capacity 25kW devices (GUSS) are underway on SWER systems in the Atherton Tablelands area in Far North of Queensland. Work is under way to implement monitoring and control programs to help support and integrate these utility systems. The success of this initiative eventually will help provide important peak load demand reduction and supply quality improvements.

Protection review impact for SWER: Protection studies previously have identified essential equipment upgrades for inclusion in the five-year works program. Periodic protection reviews focus on improvements to SWER performance and safety as defined areas of poor protection are brought up to meet design standards. Research into the availability of new technologies for improved protection operation to detect fallen SWER conductors is proposed. In addition to this all new SWER intermediate poles, with no other constructions on them, are being fitted with gapped bands. Over time as the SWER network becomes populated with gapped bands there will be a reduction in dangerous electrical events (DEEs) and damage caused by lightning, thus reducing the number of faults requiring clearance by protection operation.

SWER monitoring program: An extension to the existing power quality monitoring program is being implemented to monitor the performance of the SWER networks and identify those systems not meeting acceptable performance. The existing proposed works are being reviewed as information and viability assessments become available.

Upgraded SWER modelling: Work is under way to improve and upgrade the data available for modelling the electrical power network to help deliver an electrical network with the capacity to support growing load demands and improve supply quality to meet standards.

A roll-out of computer simulation software was completed, along with a continuing training program focused on improving the general understanding of complex SWER design and new technology implementation such as the LVR used to improve SWER performance.

SWER reliability improvement trials: In previous years, field trials were established to look at ways of improving SWER reliability by introducing vibration dampers, gapped bands darverters, surge arrestors and other design modifications to increase the SWER network resilience to lightning and other damage.

Based on the success of these trials, new design standards now include these upgrades and support other reliability improvements being implemented through introduction of electronic reclosers with Distribution System Automation capability to allow for faster supply restoration.

8.5.2 Isolated generation

Difficulties continue to be experienced in obtaining materials, equipment and adequate contractor services in the isolated generation areas with a premium being paid for contractor resources when obtained. The actual expenditure including CICW for 2011/12 was $26 million compared to the budgeted amount of $35.6 million.

Significant achievements for the year have been the replacement of generating sets at Pormpuraaw, Gununa, Camooweal, Bedourie, Birdsville and Dauan and Stephens Islands.

9. FIVE-YEAR HISTORICAL RELIABILITY PERFORMANCE

9.1 Introduction

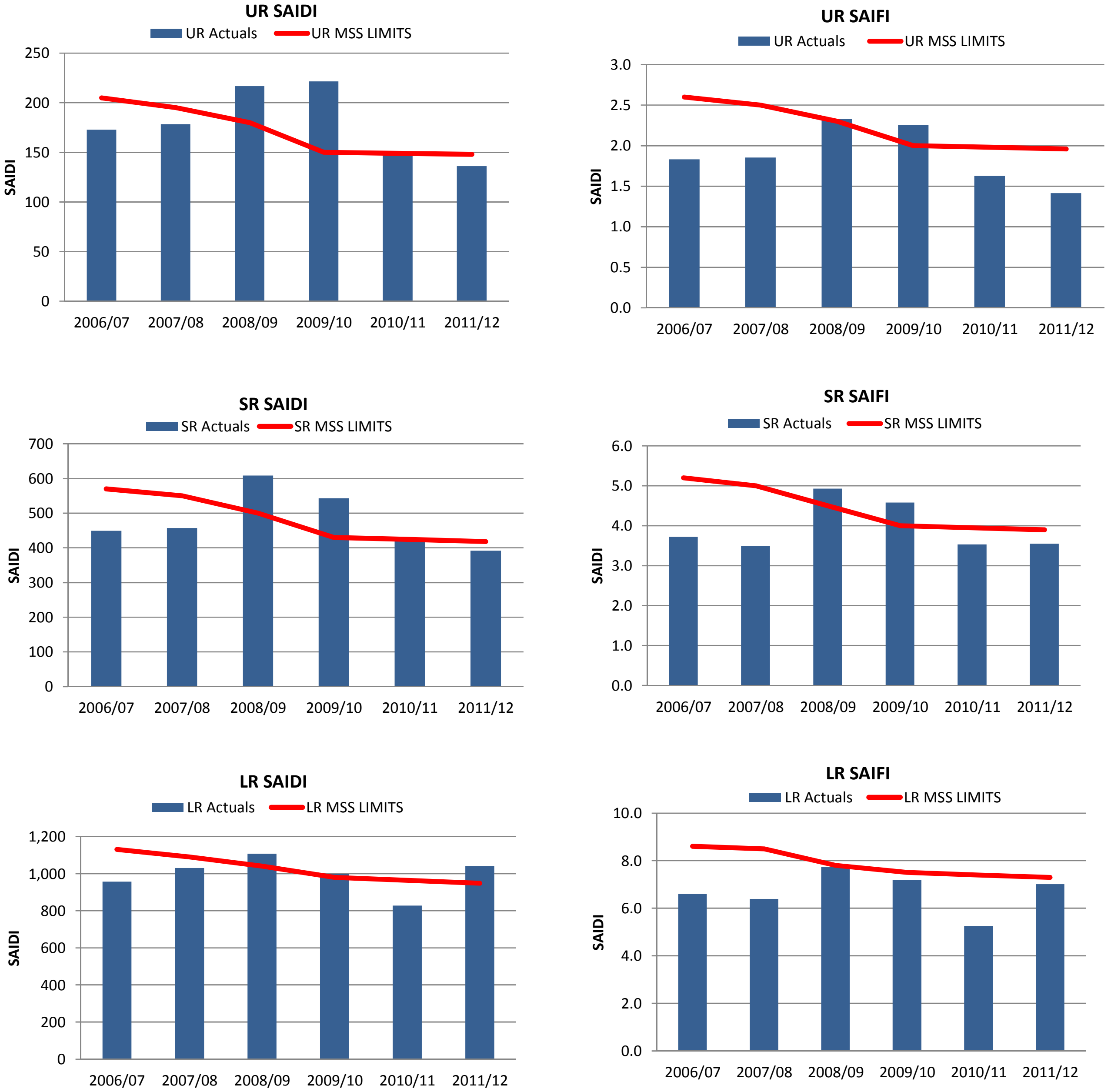
The following section builds on the appraisal of Ergon Energy's reliability performance in the previous section for the 2011/12 financial year. Ergon Energy has adopted analysis that supports the assessment of key elements of the delivery chain to review the contribution of these to the overall performance.

9.2 Reliability performance

Graph 23 shows the past six years' SAIDI and SAIFI performance. The negative impact on the reliability performance stemming from the live-line working ban and the operational restrictions applied to the ABB ABSs is evident in the years 2008/09 and 2009/10 (both SAIDI and SAIFI) for all three feeder categories. The performance improvement since the reinstatement of the live-line working practices and the progressive replacement of ABB ABSs, compound with the impact of Ergon Energy's reliability improvement initiatives, is demonstrated across all three feeder categories for both SAIDI and SAIFI for the year 2011/12.

Ergon Energy's extensively radial supply network is highly exposed to the environment and is subject to adverse weather conditions. This has a direct impact on the statistical variability of the network reliability measure indices and has been reflected in Ergon Energy's network performance results for the past few years. Since 2003, with the exception of those years influenced by live-line bans and ABS operating restrictions, all three feeder categories have recorded a gradual improving trend in outage frequency and duration. This improvement is attributed largely to the benefits of the asset inspection, defect remediation program, network augmentation and in recent years to an increased focus on the management of planned outage performance.

GRAPH 23: Network performance by feeder categories – SAIDI and SAIFI Limits 2006/2012 and Actuals 2006/2012



Graph 24 shows the contributions from planned and unplanned outages to Ergon Energy's SAIDI/SAIFI performance for the three distribution feeder categories. Graph 24 also provides a comparison of the overall performance for each year to the MSS. YTD performance in 2011/12 continues to show improvement in the area of planned outage performance across all three feeder categories and to a lesser degree in the area of unplanned outage performance. It is also noted the YTD Long Rural SAIDI and SAIFI performance are unfavourable to the end of year SAIDI/SAIFI performance for 2010/11.The unfavourable performance for Long Rural Feeder category is largely due to the outstanding increase in volume of outages attributable to the adverse weather conditions.

Ergon Energy places a high priority on achieving the MSS and continues to use its best endeavours to meet its annual MSS obligations. We continue to monitor, assess, analyse and undertake any necessary action to ensure performance levels that will achieve the MSS in 2012/13 and in future years.

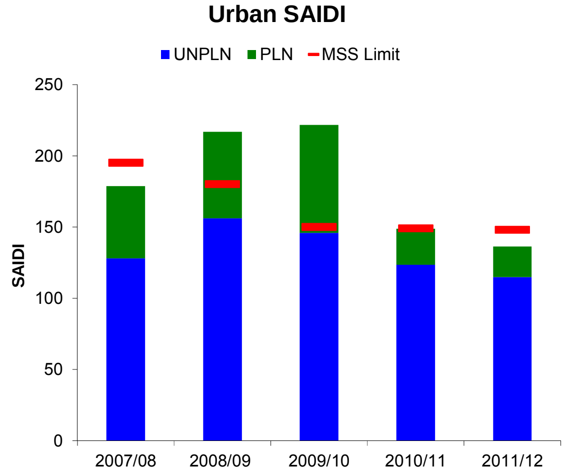
However, Long Rural performance for 2011/12 highly reflects the adverse weather as outlined in Section 8.3.1, with End of Year Long Rural SAIDI remaining unfavourable to the MSS for 2011/12. Long Rural customer minutes and interruptions due to bad weather conditions like storms, floods and lightning strikes increased, on average, by 53% and 45% respectively during 2011/12 compared to the previous year. This resulted into additional 147 SAIDI and 1.46 SAIFI attributable to the adverse weather for Long Rural feeders.

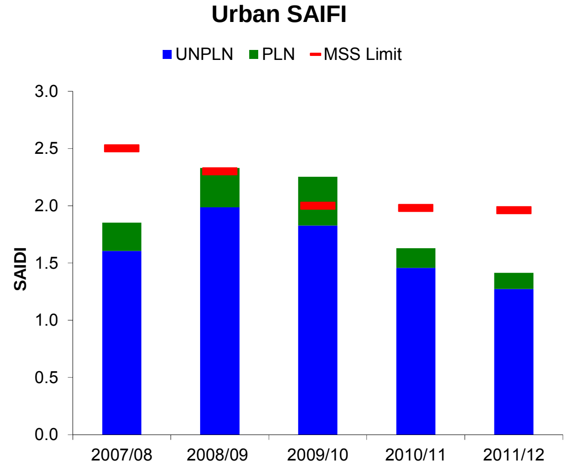
Ergon Energy's overall performance continues to be hampered by the ongoing operational limitations of the line and substation ABSs in its network. The performance implications of this operational restriction will diminish over the next two years as the population of ABB ABSs in the Ergon Energy network is reduced.

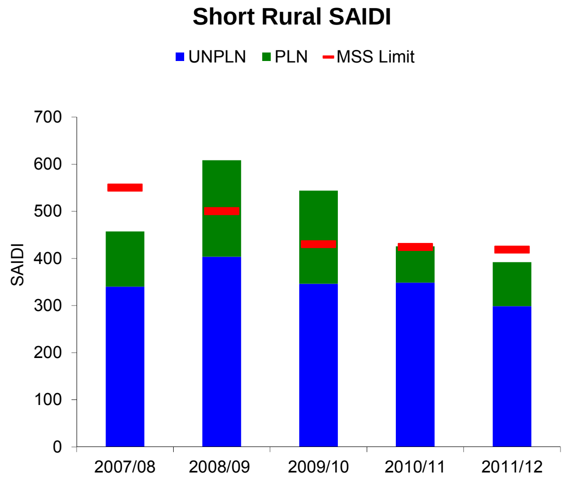
While quantification of the impact on the reliability performance attributed to the operational ban on ABSs is not possible, it is reasonable to expect that Ergon Energy would have delivered better results for all six reliability measures without the ABS issues.

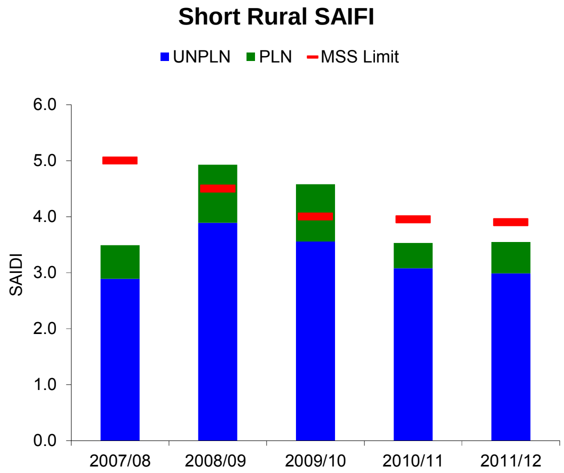
GRAPH 24: Contribution to outages from planned works to distribution feeder categories

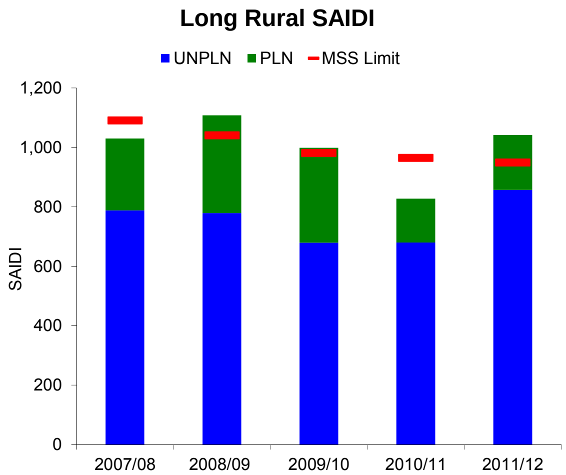
Data supporting Graphs 23 and 24 are provided in the following tables:











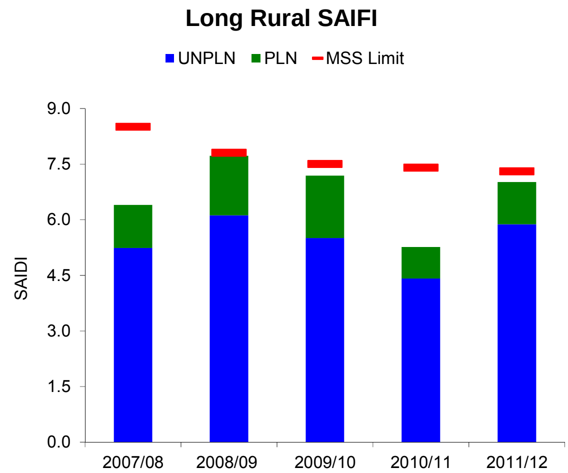


TABLE 16: Historical planned, unplanned and overall SAIDI compared with MSS

	SAIDI - 5 yrs historical Planned & Unplanned performance vs MSS					
		2007/8	2008/9	2009/10	2010/11	2011/12
Urban	Planned	51	61	76	25.33	21.47
	Unplanned	128	156	146	123.55	114.80
	2009/10 Est. LLW Cont			35		
	MSS Limit	195	180	150	149	148
Short Rural	Planned	117	205	197	77.41	93.02
	Unplanned	340	404	346	348.33	298.93
	2009/10 Est. LLW Cont			58		
	MSS Limit	550	500	430	424	418
Long Rural	Planned	242	330	319	147.13	185.23
	Unplanned	788	778	680	680.22	856.35
	2009/10 Est. LLW Cont			72		
	MSS Limit	1090	1040	980	964	948

TABLE 17: Historical planned, unplanned and overall SAIFI compared with MSS

	SAIFI - 5 yrs historical Planned & Unplanned performance vs MSS					
		2007/8	2008/9	2009/10	2010/11	2011/12
Urban	Planned	0.25	0.34	0.43	0.170	0.141
	Unplanned	1.61	1.99	1.83	1.458	1.273
	2009/10 Est. LLW Cont			0.20		
	MSS Limit	2.50	2.30	2.00	1.98	1.96
Short Rural	Planned	0.60	1.04	1.02	0.451	0.562
	Unplanned	2.89	3.89	3.56	3.081	2.988
	2009/10 Est. LLW Cont			0.23		
	MSS Limit	5.00	4.50	4.00	3.95	3.90
Long Rural	Planned	1.16	1.61	1.68	0.848	1.141
	Unplanned	5.24	6.12	5.51	4.417	5.878
	2009/10 Est. LLW Cont			0.42		
	MSS Limit	8.50	7.80	7.50	7.40	7.30

Supply chain contribution:

The majority of the interrupted customer minutes of supply were due to incidents on the high-voltage distribution lines. The extensive radial nature of Ergon Energy's network makes it more susceptible to outage durations (both planned and unplanned).

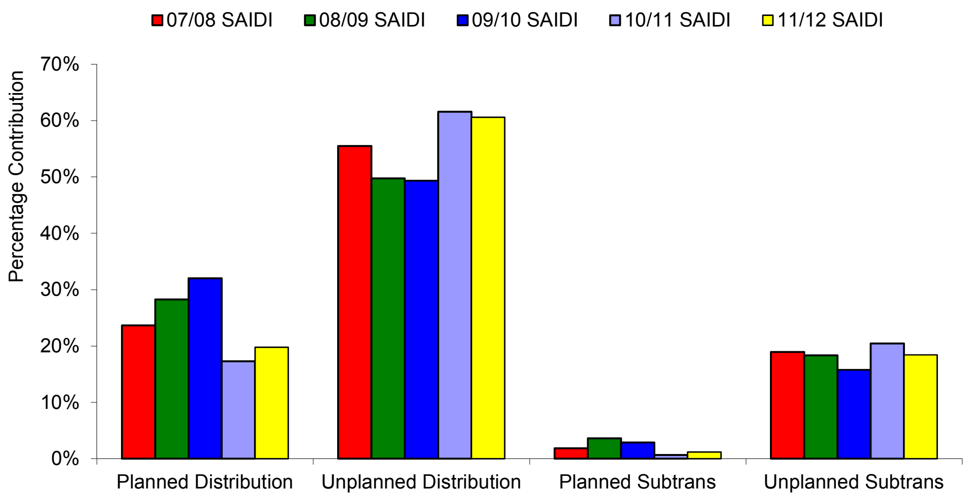
The actual frequency of outage events per unit length of subtransmission feeders is favourable to industry benchmarks for most voltage levels. Notwithstanding, the low frequency of outages, the contribution to Ergon Energy's SAIDI-SAIFI performance by the subtransmission system is inordinately high by industry standards. This is a reflection of the radial nature of Ergon Energy's subtransmission system compared to other Australian distributors.

Graphs 25 and 26 provide the supply chain contribution trends to Ergon Energy's SAIDI and SAIFI for the past five financial years. The SAIDI and SAIFI contribution from the subtransmission segment has remained fairly static during that time. This is indicative of the radial network approaching its service capability. Further step-change in the contribution from the subtransmission segments to network performance is not likely to be viable without substantial further investment in the redundant network infrastructure. Such investment is most likely to be economically unviable.

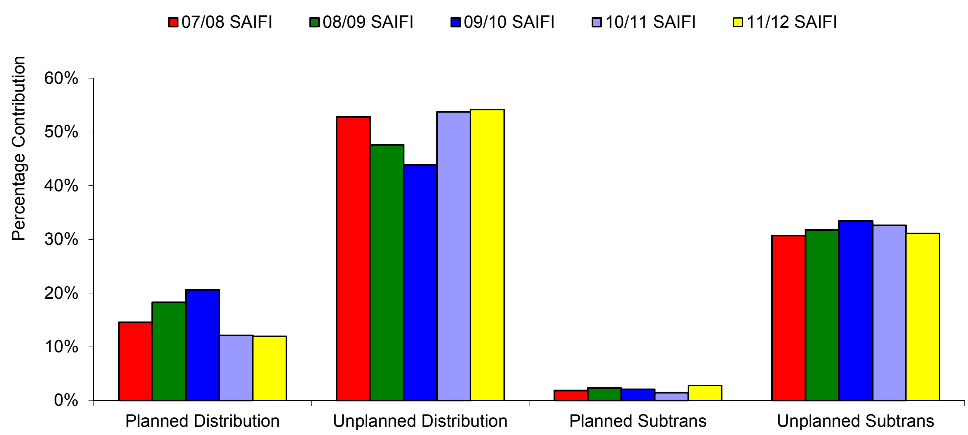
Graphs 25 and 26 further demonstrate the improvements that Ergon Energy has made in the management of planned works and their effect on the continuity of supply to our customers.

The reintroduction of the live-line work practices during 2009/10 and to a much lesser extent the progressive replacement of defective line and substation ABSs are primary reasons for the reduced contribution from planned works to the overall reliability performance.

Graph 25: Contribution to Ergon Energy's 2007/08 to 2011/12 SAIDI performance



Graph 26: Contribution to Ergon Energy's 2007/08 to 2011/12 SAIFI performance



Analysis of the outages for 2011/12 indicates that equipment failures, transient faults, planned works and weather initiated events are the dominant causes of outages across all three feeder categories. The impact of equipment failures reinforces the importance of the current asset inspection and defect remediation program in the prevention of network outages. Addressing the duration and frequency of interruptions resulting from transient faults is a focus of the Reliability Improvement Plan, discussed in Section 10.4. Increased network supervision and control along with the deployment of additional Automatic Circuit Reclosers will assist in the managing the effects of transient faults on the overall network performance.

Weather-related outages have contributed significantly to the reliability performance of all three feeder categories. This is largely because of the exposed and radial nature of much of Ergon Energy's rural network and indicates the importance of developing a network resilient to the weather. The extensive storms and floods during the second and third quarters of 2011/12 greatly influenced the overall network performance experienced by our customers.

The network reliability performance (SAIDI-SAIFI) by month, highlighting seasonal effects, and comparison of monthly performance from each of the past five financial years is shown in Graphs 28-30 below for each of the Urban, Short Rural and Long Rural feeder categories. Also shown are actual EoY 2011/12 performance curves.

The pronounced impact that the wet season has had on the reliability performance is evident in Graphs 27-29. December 2011 especially witnessed some extreme weather days where the daily system SAIDIs measured, on average, up to 70% of the Major Event Day (MED) Threshold of 8.17 SAIDI minutes, but the days were not high enough to qualify as a MED. These extreme weather event days have had a significant adverse impact on Ergon Energy's network reliability measures across all three feeder categories, especially the outage duration (SAIDI). As a result, the Urban category feeders recorded the worst December SAIDI and SAIFI performance for the past five years.

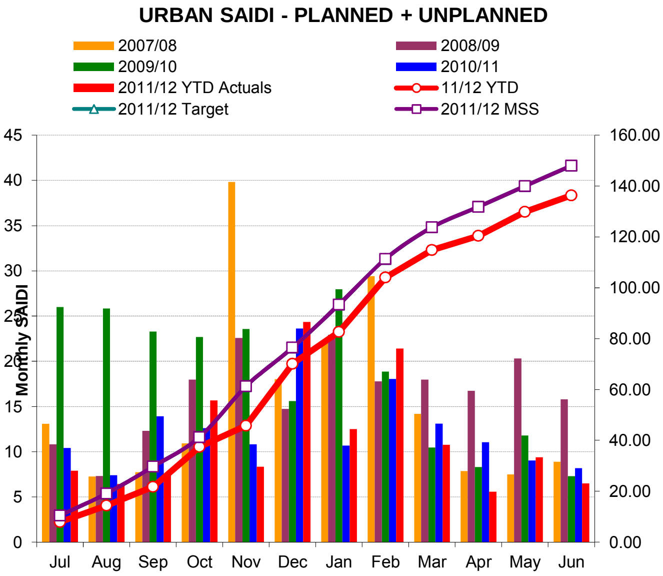
The Short Rural category feeders recorded the second worst monthly SAIFI performance for the past five years for December. The SAIDI performance of the Short Rural feeders, however, was not exceptionally high by comparison to the previous four years.

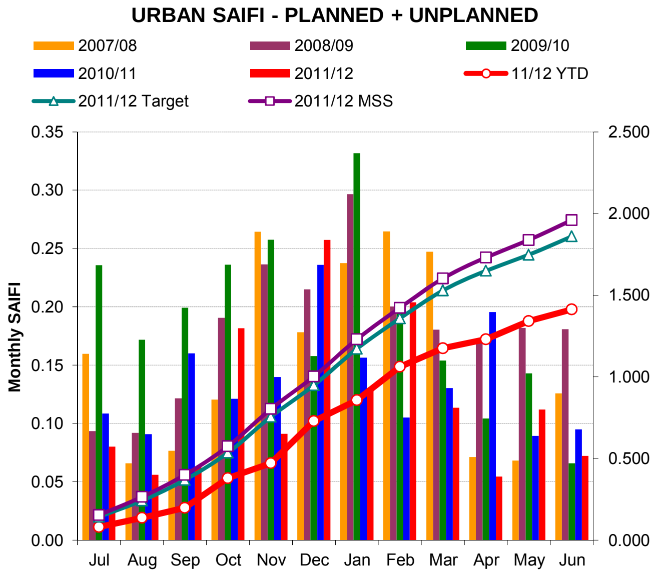
Damage to infrastructure caused by extensive bushfires in Capricornia supply region and summer storms in the South West and Wide Bay supply regions adversely impacted Ergon Energy's unplanned outage performance for the Long Rural SAIDI feeder category during the first quarter which is mainly reflected in the overall performance for September.

Long Rural customer minutes and customer interruptions were impacted by adverse weather conditions and storm activities; increasing by 34% and 75% respectively compared to December 2010 quarter. The Long Rural category feeders recorded the worst monthly SAIDI and SAIFI performance for the past five years for the month of December.

The March quarter continued to experience continuous negative impact from adverse weather on Long Rural performance with customer minutes and customer interruptions attributable to adverse weather increasing by 36% and 12% respectively compared to the March 2011 quarter. The Long Rural feeder category had the worst SAIDI for the month of January 2012. The pronounced impacts on SAIDI indicates that the flooding impacted a lower proportion of the customers supplied by the Long Rural feeders but those impacted suffered extended interruption duration.

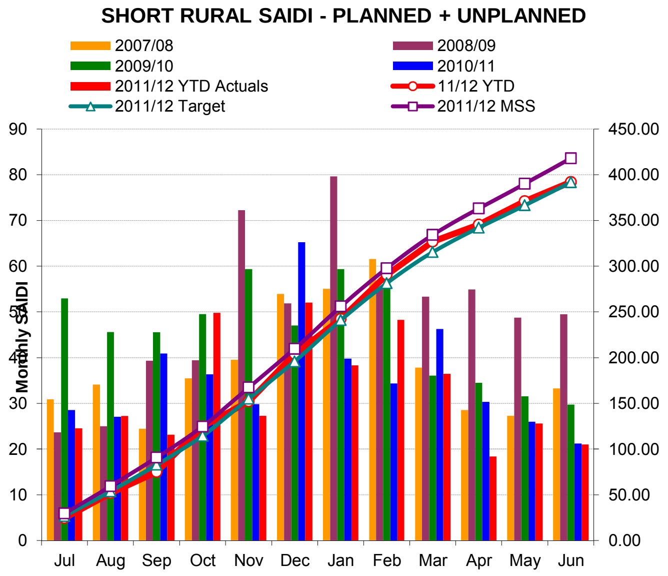
GRAPH 27: Reliability performance – urban category

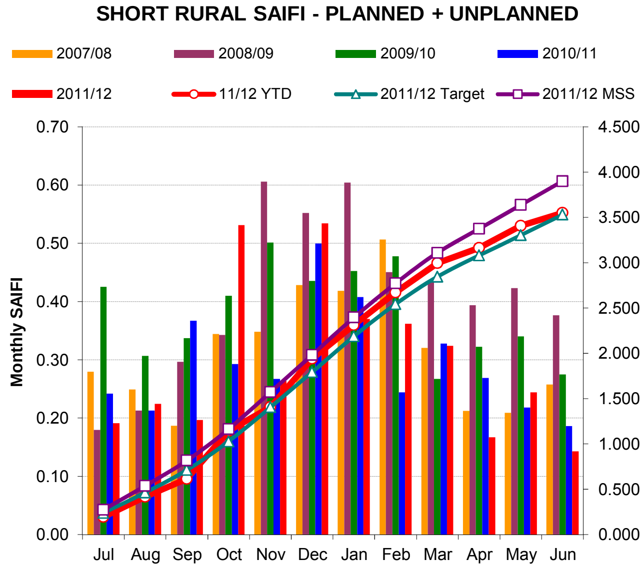




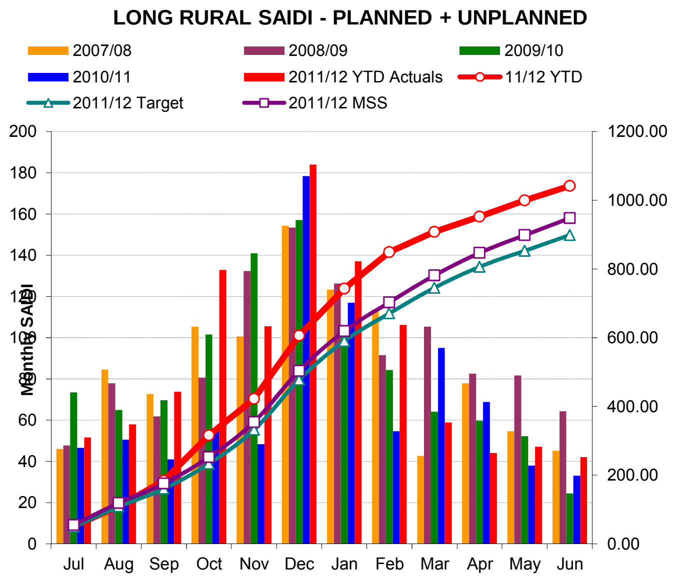
Note: The numbers are adjusted for Major Event Day exclusion events.

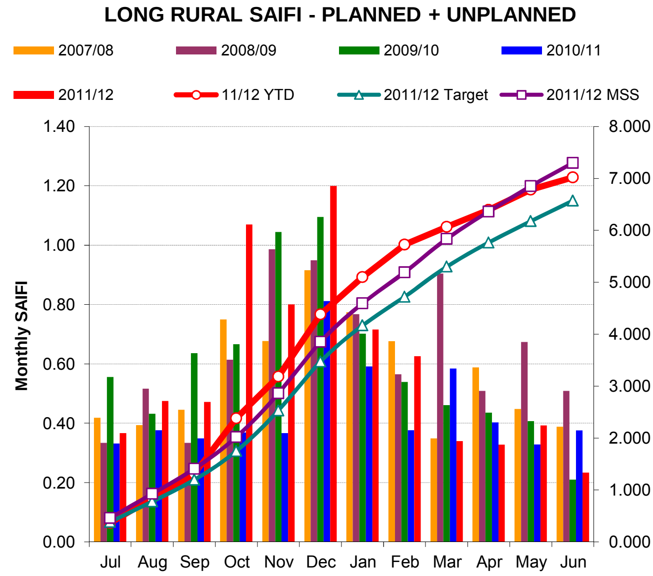
GRAPH 28: Reliability performance – short rural category





GRAPH 29: Reliability performance – long rural category



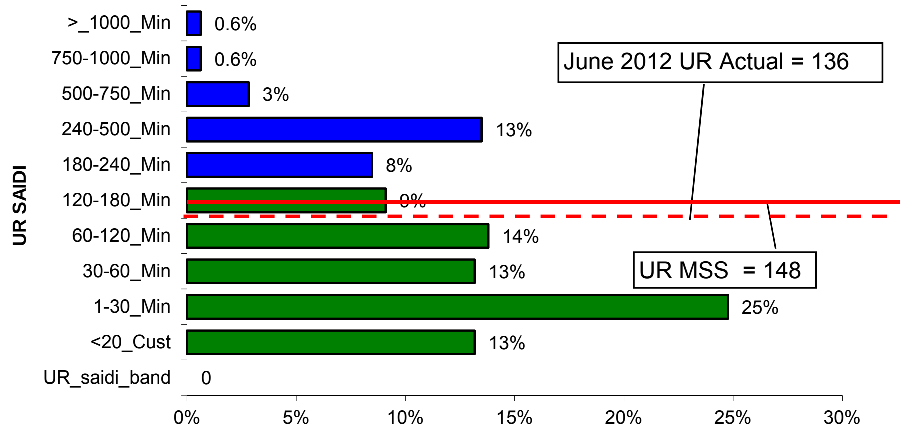


Band Analysis of SAIDI and SAIFI by feeder category:

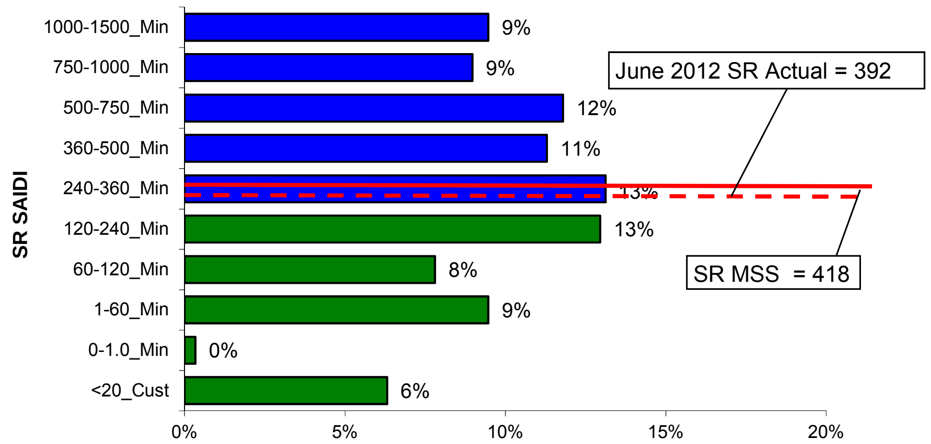
The performance of Ergon Energy distribution feeders (Urban, Short Rural and Long Rural) for 2011/12 follows. The feeder performance is based on the SAIDI and SAIFI for individual feeders in each category and is represented by various SAIDI and SAIFI bands. This allows Ergon Energy to identify the percentage of its feeders above MSS, with different degrees of severity and impact on customers.

The graphs below also indicate the percentage of feeders with fewer than 20 customers for the Urban and Short Rural feeder categories. There are no Long Rural category feeders supplying fewer than 20 customers.

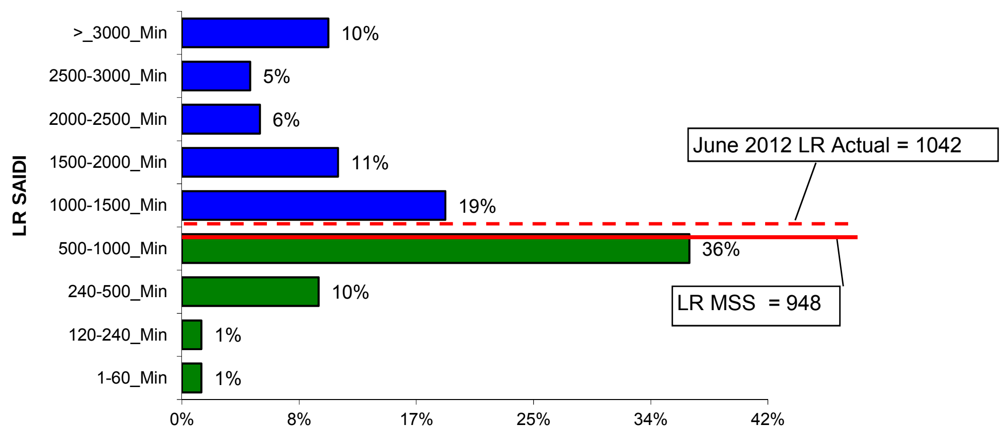
GRAPH 30: Urban SAIDI 2011/12



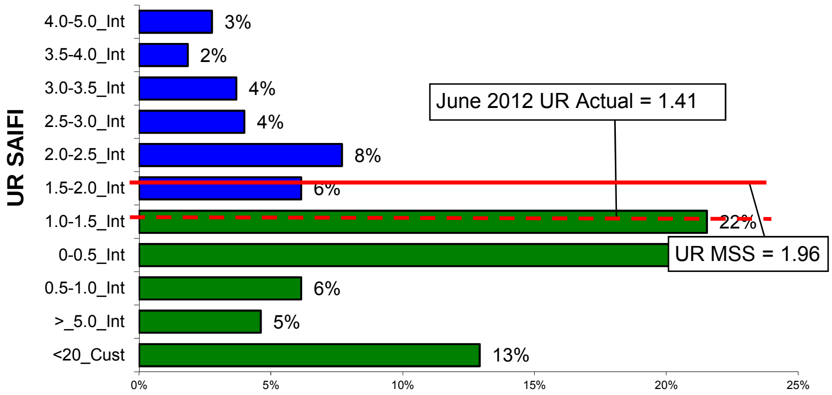
GRAPH 31: Short Rural SAIDI 2011/12



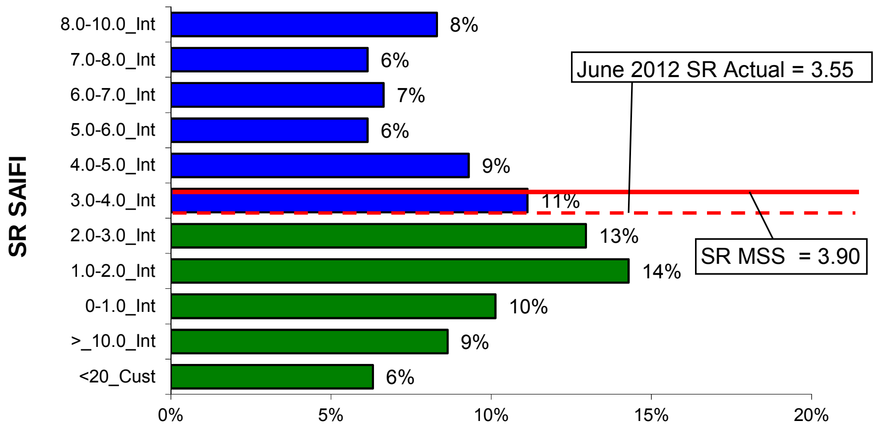
GRAPH 32: Long Rural SAIDI 2011/12



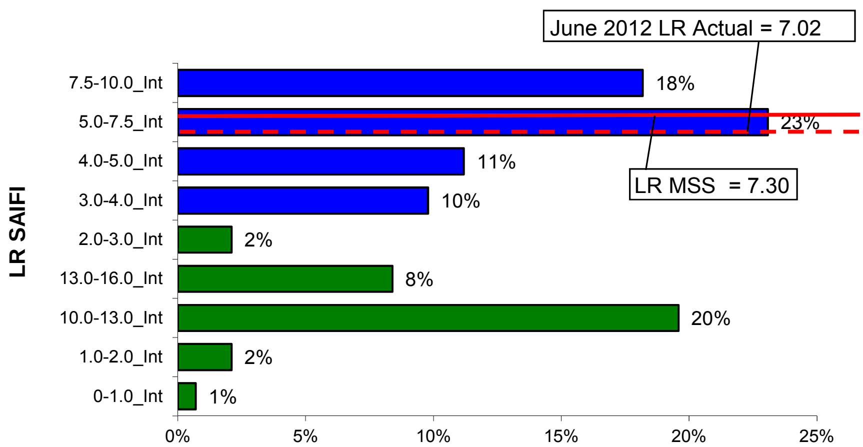
GRAPH 33: Urban SAIFI 2011/12



GRAPH 34: Short Rural SAIFI 2011/12



GRAPH 35: Long Rural SAIFI 2011/12



9.3 Reliability reporting – data quality

Ergon Energy continues to further explore and materialise the opportunities to further improve the accuracy of its reported performance statistics.

For this regulatory control period, Ergon Energy has been utilising an independent external data auditor on an annual basis to audit its reported reliability performance. The audit includes a review of the systems and processes used by Ergon Energy to capture, collate and report the information, and an audit of the integrity of the underlying datasets used to calculate the performance indices.

Consistent with the previous three years, the summary of the 2010/11 audit concluded that Ergon Energy's network performance data for the review period is of a very high quality and consistency and that the systems and processes used by Ergon Energy in maintaining and reporting this data are robust and sufficient to achieve the ±5% accuracy required under clause 2.6.3(b) of the Code. Table 18 presents the last four years of data audit history.

The Code requires an annual independent audit of a distribution entity's performance reporting against the MSS until it can be verified that the reported performance is within ±5% accuracy. To meet this requirement, Ergon Energy is obliged to seek an independent audit of its processes of data capture, systems and calculations of network reliability performance.

TABLE 18: Overall Reliability Performance Variance

	Published statistics variance	
Reporting Year	Minimum (Overestimation)	Maximum (Underestimation)
2010/11	-1.06%	+2.54%
2009/10	-0.25%	+ 0.46%
2008/09	-0.4%	+ 0.4%
2007/08	-2.1%	+ 3.7%

9.4 Reliability supply expenditure

The following table shows forecast expenditure for 2011/12 and projected spends for the following five years.

TABLE 19: Direct Reliability Capital Expenditure

Direct Reliability Capital Expenditure	Actual	Forecast				
	2011/12 $'000	2012/13 $'000	2013/14 $'000	2014/15 $'000	2015/16 $'000	2016/17 $'000
Reliability Improvement	26,297	26,588	34,399	37,652	19,505	20,288

Notes: The above financial information reflects escalated (nominal) dollars for each financial year.

The actual expenditure in 2011/12 and over the following five years is significantly increased compared to past years and is consistent with initiatives being implemented to address network performance and ensure conformance with MSS limits as outlined in Section 10.4.

In addition to these direct reliability works, network augmentation, asset replacement and refurbishment works, along with the majority of all corporation-initiated network capital and maintenance works have a positive impact on reliability performance.

9.5 Power quality – introduction

Ergon Energy is committed to not only a reliable supply for all customers but also ensuring that there is minimal impact from poor power quality. Ergon Energy is working to ensure that all customers supply is within the specified ranges for all power quality parameters. Power quality encompasses the parameters of steady state voltage levels, voltage dips (sags), voltage surges (swells), harmonic content, flicker and unbalance of voltages for three-phase supply, noise on power supply.

Customer expectations regarding the reliable operation of the ever increasing number of sensitive consumer goods and the substantial increase of electronic control in industry has raised the importance of good power quality.

Ergon Energy continues to face significant challenges within the area of network power quality. These include:

- continuing embedded generation on the distribution network creating voltage management challenges
- load growth on the distribution network which require significant lead times for augmentation due to limited resources
- managing the implications of disturbing loads connected to weak parts of the network
- restricted resources to address power quality due to competing issues, such as maintenance, asset replacement and customer connections
- increasing customer expectations due to the proliferation of devices and appliances that are perceived to be more sensitive to network power quality issues, and
- the requirement to investigate and develop achievable power quality minimum service standards prior to the next regulatory determination period.

9.6 Power quality strategies

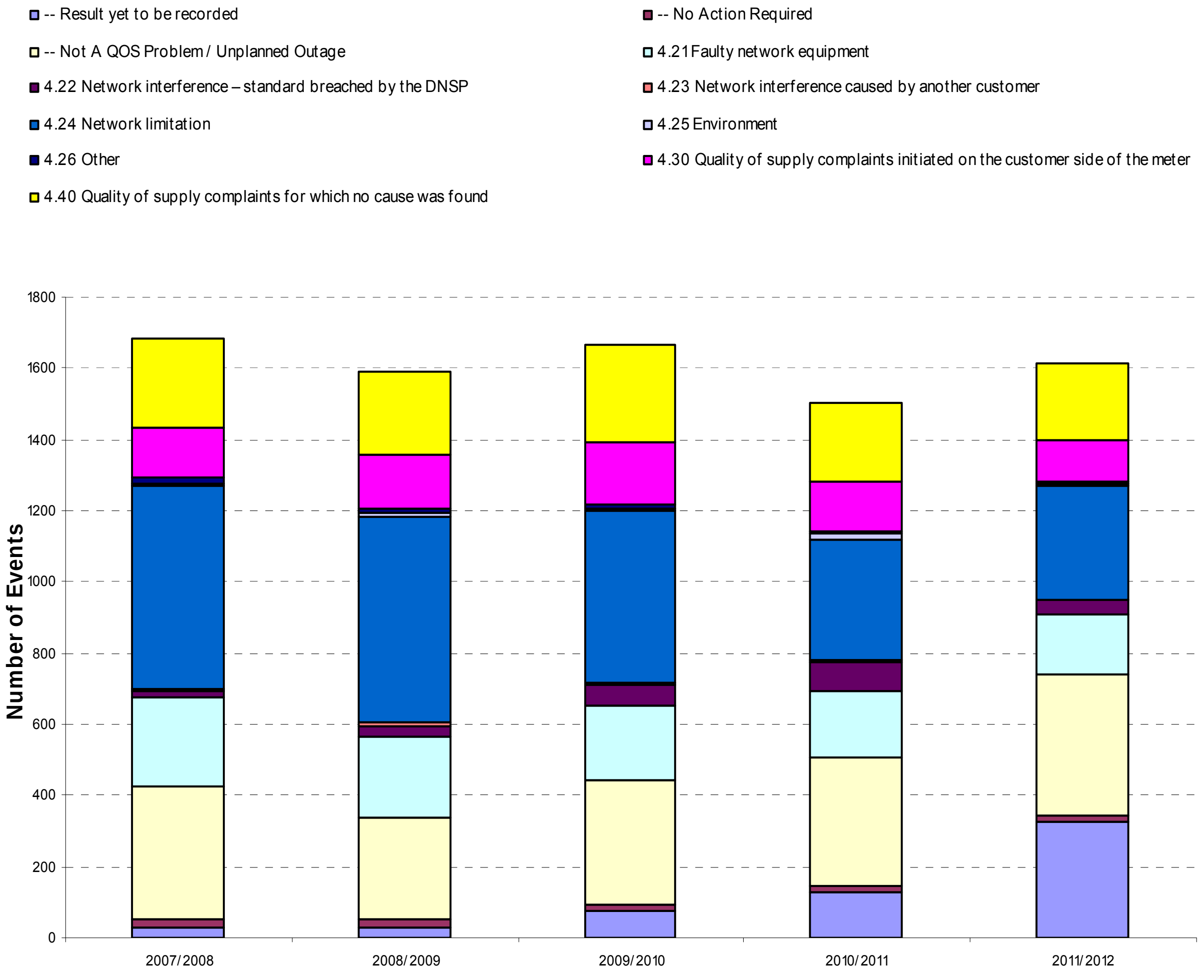
The majority of the network power quality is a continuing focus and many of its improvement strategies are focused on establishing a capability to assess power quality, implement solutions to improve and implement processes to ensure equipment that has the potential to cause poor power quality are not connected. Ergon Energy has considered the following strategies and will consider further developments in 2012/13.

9.6.1 Quality of supply management process

Ergon Energy is continuing to refine and develop an end-to-end process which enables the rapid identification of network quality of supply issues, their investigation and deployment of appropriate solutions. This initiative is targeted at ensuring that Quality of Supply issues raised by customers, internally by personnel and remotely by the power quality monitoring program are dealt with in an efficient, consistent and auditable process. This process includes thorough investigation, application of options and delivery of desired improvement outcomes. Ergon Energy will be working to implement an improved Quality of Supply process from the one developed as part of joint working with Energex in 2009/10.

As previously indicated, Quality of Supply enquiries to Ergon Energy have trended in a favourable direction for 2011/12 year and are the lowest figures for the previous six years as per Graph 36. The majority of enquiries are still taking place in and around major regional centres. The time it is taking to resolve quality of supply enquiries will continue to be a priority in the coming period.

GRAPH 36: Customer initiated asset events – investigation reasons



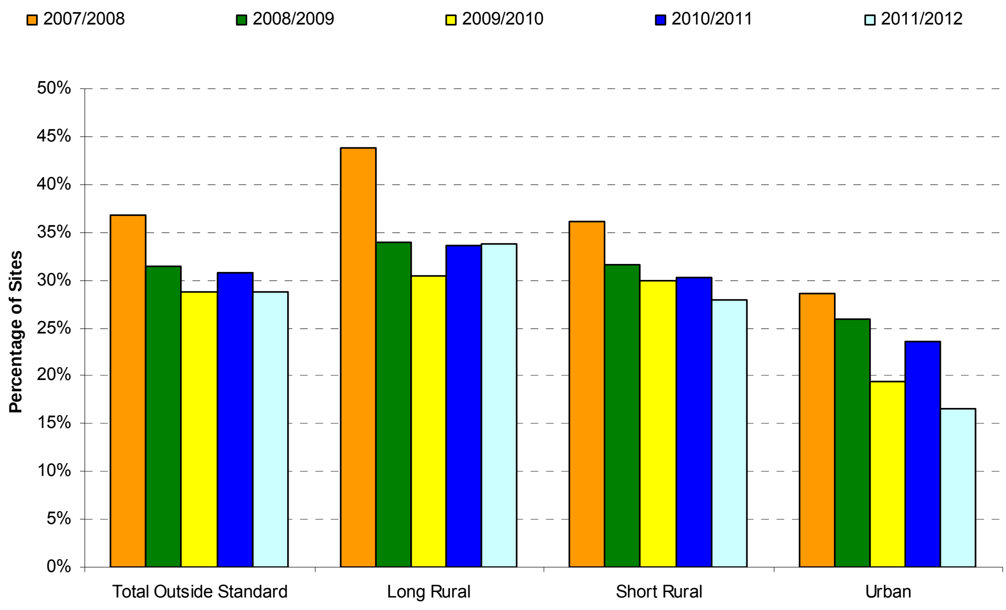
9.6.2 Power quality parameters

Ergon Energy now has 1,789 network monitoring units installed throughout the network. The result is that a comprehensive profile can now be obtained of the power quality parameters on the network.

As indicated in Graph 37, Ergon Energy is trending favourably for over voltage for the Short Rural and Urban feeder categories while the Long Rural feeder category remains static. Graph 37. Further work is required in voltage management including automatic voltage regulation (AVR) settings and tap plans in order to reduce the total outside standard to below 27%. Power Quality is finalising the Voltage Management Plan which is a strategy that will include the review of the current process for voltage management.

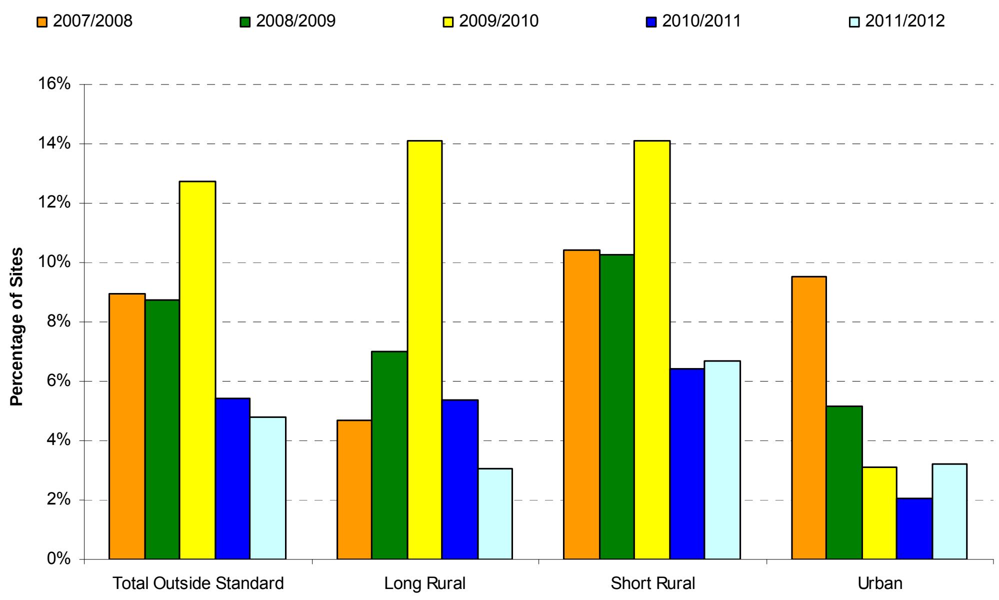
During 2011-12 time was spent cleaning and auditing the data that had been previously entered in the PQ database. It was found that a number of sites were either incorrectly entered, or not entered in all fields. The result is that there will be changes in the profile for previous years. During the cleansing it was also found for unbalance that the total number of sites were used, instead of only the three-phase site.

Graph 37: Over voltage by feeder type for 2007-2012



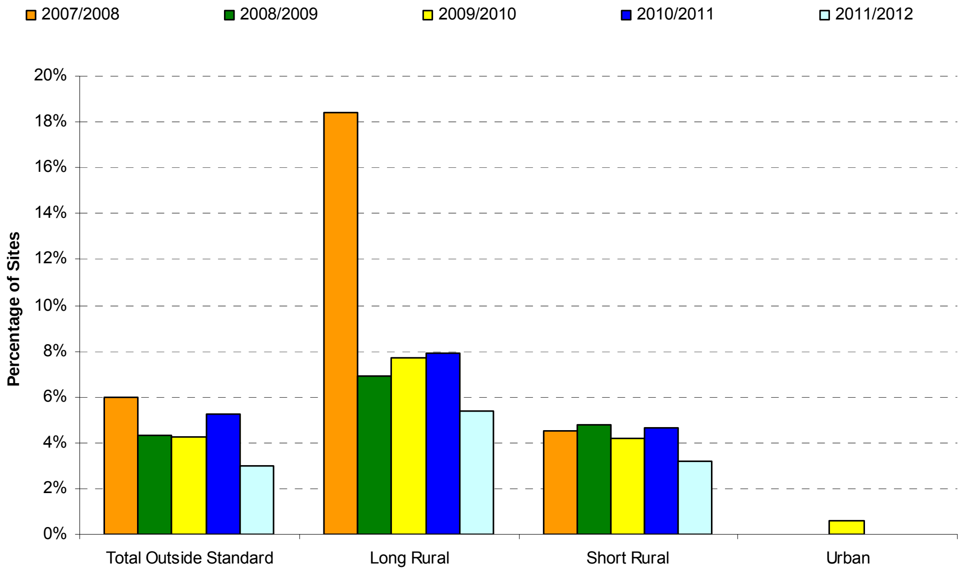
Ergon Energy is showing an overall improvement for under voltage however there has been an increase in the short rural and urban feeders as per Graph 38.

Graph 38: Under voltage by feeder type for 2007-2012



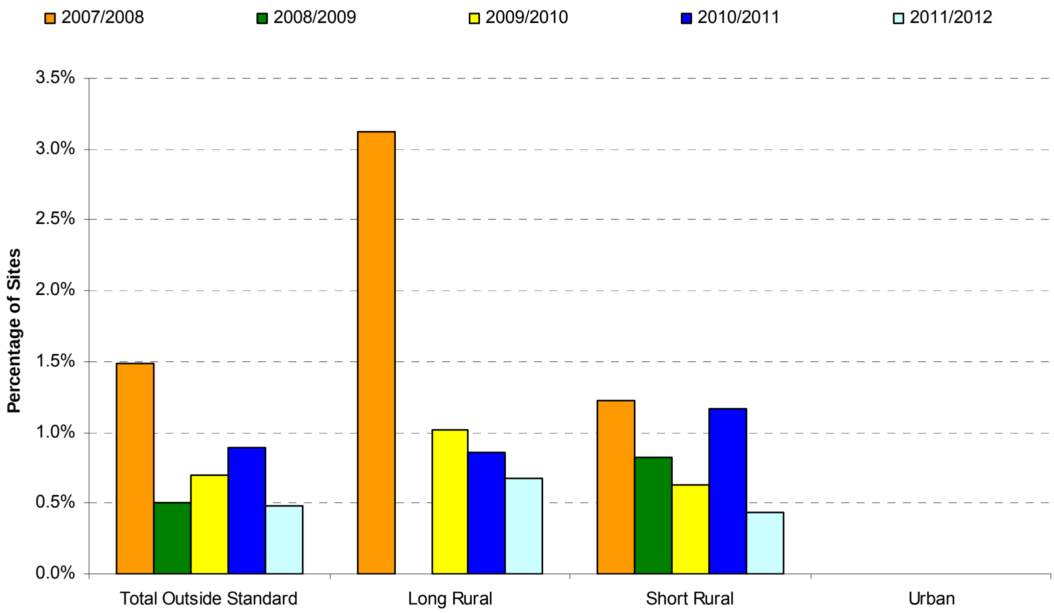
Ergon Energy has trended favourably for all feeder categories for voltage unbalance as per Graph 39. The seasonal and SWER loads will require continual vigilance to ensure the unbalance remains within standard.

Graph 39: Unbalance by feeder type for 2007-2012



As shown in Graph 40, Total Harmonic Distortion (THD) levels are under the Australian Standards limits in over 99.5% of sites, but vigilance will be required to ensure modern electronics equipment does not provide an increase in harmonics levels on the network.

Graph 40: Total Harmonic Distortion (THD) by feeder type for 2007-2012



The network monitors have been found to provide not only power quality data on excursions from regulatory limits and asset failure issues in the network but is assisting in identifying issues for planning and augmentation work.

9.6.3 Develop practical standards and measures

Ergon Energy will continue to look for opportunities with Energex on developing standards for Quality of Supply and Power Quality. The previous work on the joint Network Performance Standard and Voltage Management Standard will be reviewed towards the end of 2012/2013 financial year. These standards provide guidance to specialists in the planning and asset management to better manage steady state voltages and power quality parameters

As a follow up from the joint working, the monthly report will continue to be refined and developed to ensure it meets the needs of the business. The report identifies sites that have exceeded the regulated limits for a given period and provides support to assist staff in assessing and mitigating issues more effectively.

9.6.4 Monitoring the network

As stated previously Ergon Energy has installed 1,789 network monitoring units. There are approximately 35 units that communicate via the mobile phone network still to be installed in the 2012/13 year. Ergon Energy also plans to install 150 units in isolated areas that will communicate via satellite communications once the technology was been finalised. The aim is for Ergon Energy to have 2,000 power quality network monitors recording power quality data and providing the business with base line data to proactively develop solutions and strategies to improve power quality.

Ergon Energy is a contributor to the Long Term National Power Quality Survey run by the University of Wollongong.

The yearly benchmarking report monitors Ergon Energy's performance in managing power quality, provides independent analysis of the Ergon power quality data and benchmarks Ergon Energy against other Australian and New Zealand distributors.

The results of the 2010/11 survey placed Ergon second overall of the eight distributors in the survey, however, the ranking moved to seventh for overvoltage.

Power Quality group has gained preliminary approval for the installation of 100 Power Quality analysers to monitor feeders at zone substations. The feeders being monitored have been selected due to the potential of the loads on the feeder having an impact on power quality.

9.6.5 Proactively manage network voltage

The Power Quality group are currently finalising a Voltage Management Plan for implementation starting in July 2013. The plan was instigated to re-develop modelling tools, user guidelines and training to 'up-skill' Ergon Energy to more effectively maintain the steady state voltages within the network.

The impact from multiple connections of photovoltaic embedded generation in the low voltage networks has identified an area of the voltage management strategy with traditional methodology. Power Quality is involved in the development of a process for issues associated with the connection of PV systems. The advert connection of PV systems has resulted in issues where some PV systems are unable to connect or disconnect due to either possible network or customer premises issues. The process will enable field crew to determine the correct solution.

9.6.6 Research, Training and Innovation.

Ergon Energy is committed to working with other members of the Energy Networks Association (ENA) Reliability and Power Quality Committee (RPQC) to develop policies and processes which will give a uniform approach for Australian distributors.

Power Quality will continue to offer placement for University undergraduate students and Ergon Energy graduates during their rotation periods. Graduates and students always provide a new prospective on issues and are often used to undertake research and develop solutions.

The training of field and operational staff will continue by way of face to face training for the use the powermonics equipment and the supply of specialised power quality analysis equipment.

10. RELIABILITY IMPROVEMENT PROGRAMS

10.1 Network performance

The key purpose of prudent asset management is to have serviceable assets that meet customer expectations in the most optimal manner. Previous sections in the NMP have outlined how Ergon Energy will strive to provide an appropriate level of electricity availability, meet customer electricity demand in a sustainable manner and provide a level of electricity power quality to meet customer needs. This section specifically focuses on network reliability improvement initiatives that are targeted to deliver reliability performance consistent with MSS.

To deliver Ergon Energy's purpose we need to secure efficient performance of the network on a sustainable basis. This sets an expectation that network reliability and power quality performance will be optimised from a customer perspective through the practical management of assets, appropriate operational methods and prudent investment of network capital using strategies suited to the Ergon Energy service area.

Ergon Energy measures and reports reliability performance (interruptions) to an industry recognised set of customer proportioned macro indices, namely SAIDI and SAIFI.

10.1.1 Challenges

Reliability performance of the supply network depends on:

- network configuration and inherent security level
- load growth rate
- design and age of network assets
- maintenance level and effectiveness (including vegetation management)
- environment, climate and weather patterns
- remote communication and control facilities, and
- operational processes and available field resources.

Ergon Energy's challenges in this area over the five-year planning horizon are characterised by factors common to the electricity supply industry, as well as factors inherent from the corporation's unique history, geography, network topology and customer density.

The extent of asset exposure is a key means of differentiating Ergon Energy's situation from that of other distributors. Much of Ergon Energy's network reliability performance is a function of the infrastructure technology used for low load densities and the expanse of the areas served. This results in very extensive radial runs of line which service few customers, combined with the extreme geographical and climatic environment. Response times in isolated areas are an obvious additional challenge.

Ergon Energy recognises that its long radialised rural systems were designed as low-cost systems to meet what were initially basic customer load requirements. At the time of construction in the 1960s, 1970s and 1980s, the designs and configuration did not take into consideration the extent of the now emerging electronic economy and the growth in thermal (air conditioning) loads.

Analysis of network performance indicates that reliability challenges are widespread across the entire system, both along the coastline and in western parts. Many parts of the eastern networks, while not as extensive as the western systems, also are radialised due to relatively low customer densities.

This illustrates that the main reliability performance challenge is the higher level of exposure due to significant radial line distance from a bulk supply or zone substation to the customer. Approximately 30% of Ergon Energy's customers are fed from radial subtransmission networks, where a loss of one line will result in significant loss of supply.

With 68% of zone substations being radially fed (which in turn feed 50% of all distribution feeders), there is a substantial contribution to overall reliability performance from subtransmission networks, as demonstrated in Graphs 25 and 26 on page 89.

The majority of distribution feeders are radial and where interconnection exists, an outage is required to restore supply to alternate feeders.

While augmentation, maintenance and replacement programs all contribute to reliability improvement, it is anticipated that customers' expectations will continue to rise thus widening the probable gap that will need to be bridged by additional reliability and quality of supply improvement initiatives including the introduction of new technologies.

10.2 Reliability targets for the regulatory control period

Reliability performance is subject to MSS and GSLs mandated through the Code.

The MSS define the reliability performance levels required of Ergon Energy's network and include provisions for managed improvement of performance over time. The Code states that Ergon Energy must use its best endeavours to ensure that it does not exceed in a financial year the MSS for SAIDI and SAIFI applicable to its feeder types.

During April 2009, the QCA issued its Final Decision on the Review of the MSS and GSLs to apply in Queensland from the 1 July 2010. The reliability limits for years 2010-2015 have been sourced from the Code, Tenth Edition, August 2011, and are indicated in the following tables. Tables 20 and 21 also display Ergon Energy's performance to the MSS for the previous five years including the 2011/12 performance.

TABLE 20:

SAIDI Minimum Service Standards											
Category		2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
UR	MSS	215	205	195	180	150	149	148	147	146	145
	Actual	219	168	179	217	222	149	136			
SR	MSS	590	570	550	500	430	424	418	412	406	400
	Actual	593	452	457	609	544	426	392			
LR	MSS	1150	1130	1090	1040	980	964	948	932	916	900
	Actual	1323	946	1030	1108	999	827	1042			

TABLE 21:

SAIFI Minimum Service Standards											
Category		2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
UR	MSS	2.70	2.60	2.50	2.30	2.00	1.98	1.96	1.94	1.92	1.90
	Actual	2.26	1.81	1.85	2.33	2.25	1.63	1.41			
SR	MSS	5.40	5.20	5.00	4.50	4.00	3.95	3.90	3.85	3.80	3.75
	Actual	4.96	3.74	3.49	4.93	4.58	3.53	3.55			
LR	MSS	8.75	8.60	8.50	7.80	7.50	7.40	7.30	7.20	7.10	7.00
	Actual	9.41	6.49	6.40	7.73	7.19	5.27	7.02			

The legislated MSS is a framework that helps ensure Ergon Energy's average underlying reliability of supply is statistically improving over time. To ensure that the MSS are successfully met or to manage the risk of not meeting the MSS, Ergon Energy sets internal targets for all of the three feeder categories i.e. Urban, Short Rural and Long Rural.

However for this regulatory control period, it has not been feasible to set any gaps between the MSS SAIDI/SAIFI limits and internal targets for Urban feeders.

This is mainly to allow for the planned program of works to be delivered whilst managing the more stringent levels of MSS for Urban feeders compared to other categories.

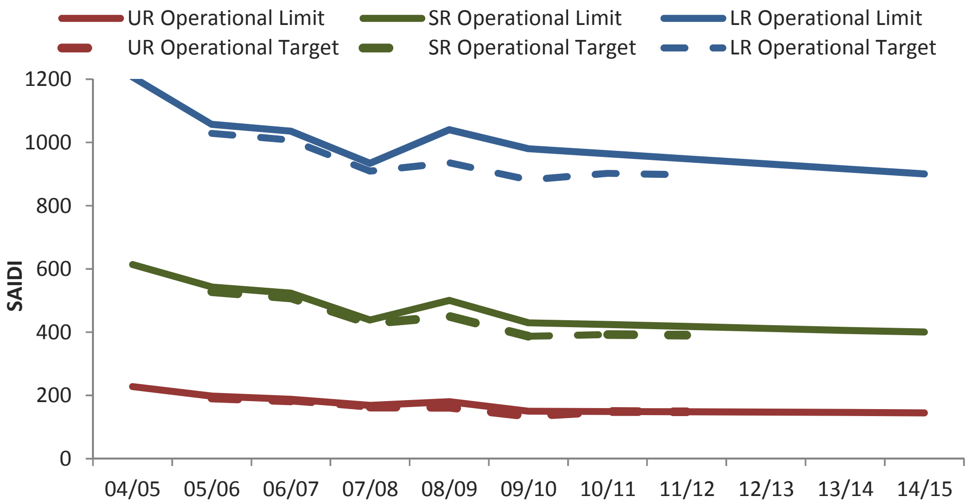
Ergon Energy has been putting additional focus on operational response in the urban areas for the unplanned outages as well as planned outage mitigation methods. This is reflected in the Urban performance which have been favourable to the MSS limits for the last two years.

For example, unplanned performance targets are set at a higher level during the storm-flood season in the tropics as opposed to relatively benign weather seasons.

Ergon Energy designs its specific performance improvement strategies to improve its underlying performance to below MSS to ensure that with statistical variation the internal targets and hence MSS will still be met. Ergon Energy also focuses on the delivery of the program of works targeted towards network capacity, security, safety and network assets as the major contributor to meeting the MSS limits for the SAIDI and SAIFI. These include our augmentation, asset replacement and refurbishment and all corporation-initiated network capital and maintenance works.

Ergon Energy continues to target reliability performance to a level that is compliant with the requirements of the Code in terms of the MSS obligations. The targeted performance levels for the remainder of the current regulatory control period are shown in the following graph.

GRAPH 41: Ergon Energy's Internal Reliability Targets against MSS Limits



In determining whether Ergon Energy has exceeded the MSS, the following events are excluded:

- an interruption of a duration of one minute or less (momentary)
- an interruption resulting from
  - load shedding due to a shortfall in generation
  - a direction by AEMO, a system operator or any other body exercising a similar function under the Electricity Act, National Electricity Rules or National Electricity Law
  - 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
  - a failure of the shared transmission grid, and
  - a direction by a police officer or another authorised person exercising powers in relation to public safety.

- any unplanned interruption to the supply of electricity which commences on a Major Event Day, or
- an interruption caused by a customer's electrical installation or failure of that electrical installation.

10.2.1 Determining Major Event Days

Ergon Energy identifies MEDs using the IEEE 1366: 2.5 Beta Method, an international standard that uses five years of daily SAIDI data to calculate the MED threshold (T_{MED}).

A MED under the 2.5 Beta Method is one in which the daily total system SAIDI value exceeds the threshold. The threshold applied for the financial year 2011/12 for Ergon Energy was 8.17 system minutes and was based on five years of accurate daily data. This saw three MEDs excluded from the 2011/12 MSS result under clause 2.4.3(c) of the Code, as discussed earlier.

10.2.2 Guaranteed Service Levels

GSLs applicable to the reliability performance experienced by individual customers were implemented under the Code from 1 July 2005. The GSLs relate to both the duration of individual outages and the number of interruptions (SAIFI with exclusions) in a financial year.

These GSLs provide for the payment of rebates to individual customers who suffer excessive outages. The following is an extract of Clause 2.5.9 of the Code relevant to Ergon Energy's reliability GSLs:

(a) Subject to paragraphs 2.5.9(b), *a small customer* is eligible for a GSL rebate of $104 from its *distribution entity* in either of the following circumstances:

(i) each *interruption* to its *premises* which, if connected to:

- an *urban* or *short rural* feeder – lasts longer than 18 hours; or
- a *long rural* or *isolated feeder* – lasts longer than 24 hours,

("*interruption duration GSL*"); or

(ii) once that *customer* experiences the relevant number of *interruptions* at its *premises* in a *financial year* as set out in the following table ("*interruption frequency GSL").*

TABLE 22: GSL entitlements

GSL entitlements per feeder category	
Feeder category	**Interruptions in a financial year***
Urban	13
Short rural	21
Long rural	21
Isolated	21

** A customer is not entitled to more than one GSL rebate under Clause 2.5.9(a)(ii) in a financial year.*

The legislated GSLs provide a 'safety-net' to individual customers and highlight areas of excessive poor performance. The 2011/12 GSL payments made by Ergon Energy's legacy regions and by GSL category are provided in Tables 23 and 24.

TABLE 23: GSL claims processed 2011/12

	FN	NQ	MK	CA	WB	SW	Total
Planned Interruption (Bus)	41	225	249	88	47	153	**803**
Planned Interruption (Res)	655	1004	1794	384	981	1014	**5832**
Connection	13	18	113	25	12	23	**204**
Wrongful Disconnection	32	26	17	26	23	14	**138**
Reconnection	14	5	4	7	4	6	**40**
Hot Water	0	3	4	1	0	0	**8**
Appointments	15	39	16	40	20	18	**148**
Reliability of Supply (Frequency)	19	137	93	261	0	11	**521**
GSL Ex Gratia Payment	1	0	1	0	1	2	**5**
Reliability of Supply (Duration)	79	1199	171	655	65	252	**2421**
	869	**2656**	**2462**	**1487**	**1153**	**1493**	**10120**

TABLE 24: GSL payments made 2011/12

	FN	NQ	MK	CA	WB	SW	Total
Planned Interruption (Bus)	$ 2,665	$ 14,625	$ 16,185	$ 5,720	$ 3,055	$ 9,945	**$ 52,195**
Planned Interruption (Res)	$ 17,030	$ 26,104	$ 46,644	$ 9,984	$ 25,506	$ 26,364	**$ 151,632**
Connection	$ 2,028	$ 1,924	$ 23,296	$ 3,796	$ 1,456	$ 4,004	**$ 36,504**
Wrongful Disconnection	$ 4,160	$ 3,380	$ 2,210	$ 3,380	$ 2,990	$ 1,820	**$ 17,940**
Reconnection	$ 780	$ 520	$ 572	$ 716	$ 260	$ 520	**$ 3,368**
Hot Water	$ -	$ 156	$ 312	$ 416	$ -	$ -	**$ 884**
Appointments	$ 780	$ 2,028	$ 832	$ 2,080	$ 1,040	$ 936	**$ 7,696**
Reliability of Supply (Frequency)	$ 1,976	$ 14,248	$ 9,672	$ 27,144	$ -	$ 1,144	**$ 54,184**
GSL Ex Gratia Payment	$ 26	$ -	$ 156	$ -	$ 350	$ 230	**$ 762**
Reliability of Supply (Duration)	$ 8,216	$ 124,644	$ 17,784	$ 68,120	$ 6,760	$ 26,208	**$ 251,732**
	$ 37,661	**$ 187,629**	**$ 117,663**	**$ 121,356**	**$ 41,417**	**$ 71,171**	**$ 576,897**

10.3 Service Target Performance Incentive Scheme

Ergon Energy came under the economic regulation of the AER and its Service Target Performance Incentive Scheme (STPIS) from 1 July 2010.

The AER's STPIS seeks to provide a financial incentive for Ergon Energy to maintain and improve its service performance. The STPIS is designed to reward or penalise an energy distributor for its network performance relative to a series of predetermined service targets.

The incentive rates within the STPIS for the reliability performance are primarily based on the value that customers place on supply reliability, referred to as the 'Value of Customer Reliability' (VCR), energy consumption forecast by feeder type and the regulatory funding model. The VCR value used in the STPIS is $47,850-MWh.

The STPIS encompasses reliability performance and customer service parameters and operates in parallel with the MSS and GSL schemes which apply to Ergon Energy under the Code. GSLs are not included in the STPIS and as such continue to operate from the Code.

Quality of Supply does not apply as a service quality measure in the STPIS for the 2010/11 to 2014/15 regulatory control period.

Reliability of supply parameters:

- Unplanned SAIDI (normalised but inclusive of Service Fuse and Beyond outage events)
- Unplanned SAIFI (normalised but inclusive of Service Fuse and Beyond outage events).

Customer service parameter:

- Telephone answering (normalised for Major Event Days).

The reliability performance targets are applied separately for each feeder category (Urban, Short Rural and Long Rural). The customer service performance targets, however, are applied to distribution network as a whole. Service performance targets for all the parameters are determined at the beginning of a regulatory control period.

Under the scheme, Ergon Energy is required to meet the service performance targets in order to avoid the penalty in the form of an Annual Revenue Requirement (ARR) decrement. Delivery of the service performance results better than STPIS targets will yield reward for Ergon Energy in the form of an ARR increment. For this regulatory control period overall revenue at risk is capped at ±2%, inclusive of a ±0.2% for the telephone answering parameter.

With the advent of STPIS, Ergon Energy is required to report on its service quality measures to the AER on an annual basis.

STPIS SAIDI/SAIFI targets for Ergon Energy (as determined by the AER) and the actual results against them for this regulatory control period are shown in Tables 25 and 26 below. The annual Telephone Answering Target has been fixed at 77.3% for each of the regulatory years in 2010-15.

STPIS financial outcomes are influenced by the quantum of differences between the targets and actuals i.e. by how much the targets have been met or missed. The incentive rates for outage frequency (SAIFI) are much higher than the outage duration (SAIDI).

End of Year STPIS results for 2010/11 (the first year of application of the scheme) were favourable for two out of six measures - Urban and Long Rural SAIFIs. Urban and Long Rural SAIDIs and Short Rural SAIFI were only marginally unfavourable to the STPIS targets. The Telephone Answering result was 78% against the annual target of 77.3%. The resultant STPIS penalty based on 2010/11 reliability and customer service performance was $13.5 Million which would be applied in the year 2012/13.

Ergon Energy has delivered considerable improvement in the STPIS SAIDI/SAIFI results for 2011/12 as shown in Tables 25 and 26 below. Urban SAIDI/SAIFI and Short Rural SAIFI were favourable to the EoY targets. Short Rural SAIDI is only marginally favourable to the EoY target. Telephone Answering result also improved to 84.6% for 2011/12. The estimated STPIS outcome for the improved performance in 2011/12 is a reward sum of $1.8 Million.

TABLE 25:

SAIDI STPIS						
Category		2010/11	2011/12	2012/13	2013/14	2014/15
UR	STPIS	129	128	127	127	126
	Actual	131	122			
SR	STPIS	296	291	287	283	279
	Actual	365	294			
LR	STPIS	699	687	675	664	652
	Actual	713	853			

TABLE 26:

SAIFI STPIS						
Category		2010/11	2011/12	2012/13	2013/14	2014/15
UR	STPIS	1.69	1.68	1.66	1.64	1.63
	Actual	1.55	1.35			
SR	STPIS	3.06	3.02	2.98	2.94	2.91
	Actual	3.24	2.93			
LR	STPIS	5.59	5.52	5.44	5.37	5.29
	Actual	4.63	5.84			

10.4 Reliability improvement strategies

Ergon Energy's reliability improvement strategies aim to provide distribution network reliability performance that keeps pace with rising customer expectations. In 2010/11 a reliability improvement plan was developed that complements the existing reliability specific programs and aims to deliver short and long term operational and asset focused reliability improvement initiatives.

Initially Ergon Energy expects that the reliability performance gains will primarily be delivered by the initiatives focused on improving its operating practices and beyond that through the implementation of the asset focused initiatives.

The operational practice improvement initiatives aim to achieve a more effective response to unplanned interruptions and an increased focus on improved management of planned work. Much of this work surrounds procedural and practice improvements within the two operations control centres.

As well as this a number of opportunities to improve the tools and other resources available to the control centres to more effectively dispatch and coordinate response crews have been identified and solutions to these are being outworked through an Operations Control Centre Program of Works.

While operational practice and procedural improvements offer the ability to achieve performance improvement within a short timeframe, the delivery of the asset focused initiatives will mainly deliver performance improvement toward the later years of this current regulatory control period.

The asset focused reliability enhancement initiatives aim to achieve improvements in planned and unplanned outage performance through improved performance of the installed network assets. This is being achieved through a detailed and in depth analysis of asset failures to determine targeted, reliability focused maintenance and improvement programs of work. Existing refurbishment and maintenance programs have been reviewed and adjusted to achieve reliability performance gains earlier. A number of reliability initiated projects and programs for the distribution and subtransmission networks have been identified and included in the program of works for delivery in the future years of the current regulatory control period. These projects and programs will deliver improved network performance through network segmentation, increased visibility of installed network devices and improve the resilience and capability of the network.

In addition, Ergon Energy is looking forward to new and emerging technologies that have the potential to improve reliability performance. New 'smart' technologies such as intelligent gas switches, communications capable Line Fault Indicators and Fuse Savers have all been identified and either included in a full deployment program of works or included in a preliminary investigation and trial through a limited population deployment.

The integration of these 'smart' devices coupled with those devices already installed with these capabilities into the existing SCADA and any future Distribution Management System will aid Ergon Energy's achievement of network resilience and performance capable of meeting the current and future customer expectations and regulatory obligations.

Considering the need to address adverse network reliability performance in a more sustainable manner, Ergon Energy has adopted the following approach to improving its network reliability performance.

Our strategies are structured around a three tiered approach to address unplanned outages:

1. Reduce Events
2. Reduce Impacts
3. Improve Response.

As well as a four tiered approach to address planned outages:

1. Reduce Events
2. Reduce Impacts
3. Minimise Duration
4. Meet the customer commitments.

The key strategies that address the key challenges facing Ergon Energy's network business are listed below.

- Set reliability performance criteria and determine internal targets in terms of the frequency and duration of interruptions to customers.
- Assess segmented customer performance to ensure specific segmented needs are considered. The ultimate outcome of this initiative is to migrate to service offerings for customer segments requiring higher levels of reliability.
- Monitor, investigate and report on customer reliability of supply performance
- Identify areas of worst performance and contributing network elements and justify reliability improvement solutions, and
- Develop and deploy the reliability standards through effective communication, training and coaching in the areas of
  - network configuration
  - augmentation and supply security
  - structural and asset standards
  - protection and control development
  - operation of the network and response standards
  - network maintenance standards, and
  - data collection and reporting of reliability performance.

Along with the asset performance improvement initiatives, Ergon Energy is adopting a number of operational initiatives and targeted measures for better planned outage management and improved unplanned outage response times to overcome the current performance gap in order to meet the MSS in this regulatory control period. The asset performance and operational initiatives are discussed in details in the following sections.

Delivery chain analysis and management:

Ergon Energy has undertaken an analysis of each of the elements of the supply chain across the distribution network as a means of providing a balanced approach to managing network reliability performance. The Reliability Improvement Program specifically targets adversely performing distribution feeders through performance analysis and consideration of the segments of the delivery chain above the distribution feeders.

By splitting the delivery chain into logically distinct segments and evaluating the performance of each, as well as their contribution to the overall network performance indices, Ergon Energy has been able to better identify the opportunities to be embedded across the entire network to assure optimal reliability performance.

The outcome of the delivery chain analysis has been fed into the various reliability improvement strategies-program discussed in this section. Ergon Energy intends to continue with this initiative in the 2012/13 financial year to make informed decisions on the performance improvement investments.

System, processes, data and reporting:

Ergon Energy's network reliability team reports on network reliability performance and initiates and coordinates reliability improvement initiatives and projects.

The group currently provides monthly summary reports of reliability performance. These reports contain SAIDI, SAIFI, CAIDI, planned and unplanned distribution feeder performance, historical data and significant event analysis.

The group also is responsible for the quarterly and annual reporting on reliability performance to the QCA and Department of Energy and Water Supply.

Ergon Energy has consistently recorded five full years of reliability performance data. Work is continuing on developing robust facilities for the collection, storage and retrieval of network reliability data and enhanced reliability performance reporting.

This includes consolidation of more comprehensive outage cause codes, automation of data mining capability, spot checking of outage data, reliability analysis along the delivery chain, documentation of reporting processes and scripts and a data warehousing capability. Providing accurate reliability analysis allows the business to make more informed decisions regarding investment, planning and operational issues.

Planned outage management:

Ergon Energy is in varied stages of delivering and implementing the following strategies and improvements to assist in managing the duration and impact of planned outages across the network:

– The operational response has included a major effort centered on planned outage management, including improvements to works scheduling and packaging, reporting processes and tools, and increasing the use of mobile generators.

  Generation Resource Co-ordinators are being appointed in each of Ergon Energy's supply regions to manage the deployment of embedded generation for planned and unplanned work. Outage Mitigation Officers are being recruited across the state to better manage the co-ordination and consolidation of outages, plan temporary generation and other available options to minimise both the customer interruption duration and frequency. Ergon Energy is reviewing its asset inspections works to co-ordinate all work by feeder, to reduce the number of planned outages.

– A greater emphasis is also being placed on returning key out-of-service plant to service and reduce network risk whilst weather forecasting services are being used to predict storm activity and prepare additional resources to respond to faults. Aerial patrols are used to identify faults and speed up restoration.

– Following the bush fire events in Central region during the September 2011 quarter, Ergon Energy held meetings with Queensland Fire and Rescue Service (QFRS) for better management of bush fires. Control Centres now use the Google Earth fire overlay to monitor fire progress. The aerial patrol of the lines in affected areas is used during fires to identify the location so lines can be isolated and pole fires extinguished. QFRS are advising fire permit recipients to clear around poles and monitor fires.

– Ergon Energy continues to monitor vegetation management practices to ensure that outages resulting from vegetation management activities are minimised. Where possible vegetation work is conducted in conjunction with outages planned for other work. In addition, a review has been conducted of the vegetation program for opportunities to focus on poor performing feeders (particularly radial and non N-1 subtransmission lines). These reviews have maintained Ergon Energy’s focus on minimising the duration and frequency of planned and unplanned vegetation-related outages on all feeder types; the ‘default’ arrangement for all work within approach limits is for the use of live-line. Trials of Jarraf operation and remotely controlled equipment that allows operation within approach distances continues in an effort to minimise the need for outages associated with vegetation control.

– Develop high voltage injection capability. This strategy involves the procurement of three 1.25MW mobile/rapid deployment containerised high voltage generating units. These new additional high voltage generators will complement the existing fleet of LV generators and assist by minimising or in some instances eliminating the impact of planned outages. The three high voltage injection units are currently being developed. The first unit is due for commissioning by mid June 2012 with the remaining two anticipated to be commissioned by August 2012.

A number of additional low voltage generation units to complement the existing fleet are also currently under procurement process. This includes 6x150kVA, 3x300kVA and 1x500kVA generation units.

- Optimise the packaging of defect remediation works that require planned supply interruptions in order to carry out the work. This strategy aims to package numerous defect repairs across a radial distribution feeder into a single unit of work so as to undertake planned interruptions at a reduced frequency and to reduce the impact of those planned outages in rural areas.
- Identifying initiatives for attracting and retaining live-line workers in western areas to ensure that Ergon Energy's workforce maintains the capability and skills to perform live-line work in rural areas.
- Replacement of faulty line ABSs and Ring Main Units (RMUs). This strategy aims to achieve a reduction in both planned and unplanned outage performance by increasing the network operability to reduce the customers involved in planned outages and the duration for which they are involved in unplanned outage events.
- Consideration given during the concept development phase of capital projects to the mitigation of planned interruptions through the delivery and construction phases of the project. This strategy aims to reduce the frequency and duration of planned interruptions required to deliver augmentation and refurbishment projects by considering outage mitigation options in the concept phase and including the works required to deliver the mitigation option within the project scope where appropriate.
- A planned outage calculator software application has been deployed in well supported by the operational arms of the organisation.

  This tool was developed in the first quarter of 2010/11 and has provided increased visibility of the impacts of planned interruptions on overall network performance (SAIDI/SAIFI) with the intention of bringing into focus planned outage mitigation opportunities provided by such things as the deployment of generation or the bundling of works to reduce the frequency and duration of planned interruptions.
- Organisation Structure Review of the current network operation business unit to establish a more stringent governance model to drive the control of planned outages.

The predominantly radial topology of Ergon Energy's supply network makes it more susceptible to longer planned outage duration. Ergon Energy, however, takes all reasonable action possible to minimise the disruption of these outage events on the customers.

Where possible and appropriate, planned outages are scheduled at times that minimise the inconvenience to customers while still delivering cost-effective outcomes for customers. This includes undertaking planned work:

- during the day or late at night for residential areas when people are away from their homes or sleeping
- during weekends or night for industrial – commercial areas when businesses are closed, and
- during off-peak periods when road lane closures are needed.

Unfortunately, the MSS do not recognise the reduced inconvenience of planned outages scheduled for these times.

Consistent with the strategy set out above, and following the reinstatement of live-line practices, Ergon Energy will continue to carry out live-line works and deploy mobile generators where appropriate to minimise outage impacts. However, it is anticipated that the ongoing operational limits on certain makes of ABSs and Ring Main Units will continue have a detrimental effect on the planned performance through 2012/13.

Unplanned outage management:

Ergon Energy is implementing systems to better manage unplanned outages through prepared contingency plans, and already has contingency plans for critical network areas. Customer operating protocols for major customers sites are being reviewed and updated within the contingency planning framework. Ergon Energy is continuing to explore and investigate new fault isolating and locating devices and development of a strategic direction for automation and control of our network using reclosers, sectionalisers and remotely controlled gas switches.

Ergon Energy is varied stages of delivering and implementing the following strategies and improvements to assist in managing the duration and impact of unplanned outages across the network:

ABS replacement strategy:

Ergon Energy has a large population of ABSs identified as defective and as such they are subject to an operational ban. The limited use of these ABSs has had a detrimental effect on the reliability performance (both planned and unplanned), especially for the Urban and Short Rural feeders, in recent years. To recover from this situation Ergon Energy has implemented a strategy to deliver replacement of the entire population of defective ABSs over this regulatory control period.

The program consists predominantly of replacement of ABB (R, U, S and Uniswitch series) switches and consists of:

- Substations – 65 switches are targeted for replacement by the overall program, six units of which remain outstanding as the end of June 2012.
- Lines – 1,600 switches are targeted for replacement by the overall program. During 2011/12 304 line switches were replaced. Those not delivered during 2010/11 and 2011/12 have now been rolled into the 2012/13 Plan. Delivery shortcomings are being addressed and it is anticipated that the targeted program replacement of 1600 switches will be achieved by the end of June 2013.

To aid with the delivery of this program, non essential maintenance programs in Central and Southern regions have been temporarily suspended to allow resources to focus on ABS replacement and outage negotiations have been escalated for instances whereby live line techniques cannot be utilised.

Improved remote control initiatives and data acquisition – SCADA Acceleration Strategy:

Ergon Energy's Strategic Horizon Two (2010/11 to 2014/15) is to support its customers by continuing to develop its network to expand the network functionality. One of the key initiatives to enhance the network functionality includes the extension of the remote control capability further into Ergon Energy's supply networks. This strategy aims to provide more timely response to outage events and will ultimately provide significant improvement to outage duration.

SCADA (Supervisory Control and Data Acquisition) is a system that provides remote control and monitoring of electrical equipment at Ergon Energy's regional substations. It enables the operational control centres to monitor loads and other system parameters and to carry out remote switching to, in some cases, avoid outages and to remotely restore supply in the quickest possible manner following an interruption.

In this way we are able to restore supply to many customers on the network whilst minimising the field staff involvement.

It is anticipated that deployment of SCADA will contribute a large proportion of SAIDI minute reductions required for all the Urban, Short Rural and Long Rural feeder categories to remain favourable to MSS limits in future regulatory control periods.

The accelerated upgrade of Ergon Energy's network monitoring and control capability with the installation of SCADA into zone substations is now nearing completion. Under this program 56 regional zone substation sites had been identified for inclusion in the program. The program delivery was delayed by Cyclone Yasi. Nevertheless, as of the end of June 2012, 55 out of 56 Zone Substation SCADA projects were delivered under this program. An additional six SCADA projects were completed within other Zone Substation projects.

The extended coverage of SCADA facilities will assist Ergon Energy to enhance network performance and deliver shareholder and customer value through cost reductions and performance improvements. It also will provide the foundation for operational integration of the current and future Distribution Management System (DMS) capability across the corporation.

Expansion of auto-reclose functionality at zone substations:

Ergon Energy is currently expanding the Auto Reclose functionality at its zone substations. The delivery of this program is provided in two stages.

Stage 1 is focused on the zone substations in the Townsville area of the North Queensland supply region with Stage 2 expansion to encompass the remaining zone substations in the North Queensland supply region and Stage 3 to encompass remaining substations in other regions.

The program is aimed at achieving feeder performance improvement through reduced feeder outage duration and frequency, to achieve improved SAIDI and SAIFI. The Stage 1 Townsville area works will mostly influence the urban and short rural feeder performance in Townsville local area.

With the expanded delivery of Stage 2 the influence of the program will extend to urban, short rural and long rural category feeders across the entire North Queensland supply region. By doing this, the specific contribution from the feeders to the overall Ergon Energy performance can be significantly reduced, thereby improving customer service and achieving performance within boundaries of MSS limits.

Improved application of automatic reclosing on 11kV feeders could potentially reduce the impact of the transient faults that often result from severe weather events by reducing the outage observed by customers to a momentary interruption.

The successful delivery of this program will also result in operational efficiency gains by reducing the strain on Ergon Energy field resources deployed to carry out patrols on faulted feeders before a re-energisation attempt is made.

Eight zone substations have been included in the Stage 1 Townsville implementation phase. At the end of June 2012, of the eight sites included in this program of works, construction has been completed for five sites and design completed for remaining three. All work on the Townsville Stage is targeted for completion before the wet season in 2012/13.

A review of the auto reclose capabilities of the zone substations in the North Queensland supply region was conducted as Stage 2 of the auto reclose program. This review identified two zone substations that did not have auto reclosing capabilities – East Ayr zone substation and Collinsville substation. Both of these substations now have projects scoped and initiated to have auto reclose function provided on their outgoing distribution feeders. The actual work is anticipated to be completed during 2012/13.

Line fault indicator trial:

Ergon Energy is engaged in a trial of conductor clamped Line Fault Indicators (LFIs) on a number of distribution feeders in the southern supply regions. Initially a pilot trial of three different models of LFI was targeted to ensure the most suitable type is selected for Ergon Energy's network and climatic conditions.

Thirty units of conductor clamped LFIs were installed between late 2010/11 and early 2011/12. However, the trial's progress was negatively impacted when the manufacturer identified defects on the installed units. 100% of the defective units have now been replaced. Additional 15 units are planned to be installed during 2012/13.

Trials are also underway with handheld portable Line Fault Indicating units in the Southern region. These devices are intended to assist the field crews in identifying the faulted network section during the investigation phase immediately following an unplanned supply interruption.

Automatic circuit recloser remote communication strategy:

This strategy's goal is to roll-out a uniform approach to remote Automatic Circuit Recloser (ACR) communications across Ergon Energy in order to expand the remote control functionality on existing reclosers of the distribution supply network.

Currently Ergon Energy has approximately 1,850 pole mounted distribution ACRs of which only 550 (30%) have some form of remote communication. The goal of this strategy is to have all ACRs connected to the ABB SCADA system, where beneficial, and also be accessible to engineers via an engineering interface.

It is expected that the timeframe for this strategy will be 10 years with three distinct phases:

Phase 1 – Quick Wins Phase (2yrs): Extend communications to another 167 ACRs and prepare the communication networks for the remaining ACRs. Even though the program of works for phase 1 has the design and material procurement completed, the commencement of the actual construction has been delayed due to issues related to contractor competency. The issue is anticipated to be resolved by the beginning of 2012/13.

Phase 2 – Ubinet Phase 2: Follow Through (2yrs): Target ACRs that are communications ready and in radio reach. It will extend communications principally via Ubinet Phase 2 and follow the Ubinet Phase 2 roll out extending communications to another 277 existing ACRs.

Phase 3 – Installation Phase (8yrs): Provide remote communications to the remaining 1,190 ACRs where it is beneficial to do so. The final cost will be dependent on the implementation methods deployed and level of plant replacement necessary.

This phase of the strategy will also be the catalyst for the replacement of many older mechanical and hydraulic line reclosers that don't have the capability to support a communications interface.

Worst Performing Feeder Improvement Program:

The 'feeder' component of the distribution system is still the overwhelming contributor to the network's overall reliability performance. The Worst Performing Feeder Program aims to deliver improvement by providing targeted solutions to address the underlying causes of historical poor performance in the 50 worst performing feeders in the Ergon Energy distribution network.

In general Ergon Energy aims to achieve improvement in the performance of the distribution feeder segment of the delivery chain and to this end has adopted the following initiatives to manage the distribution feeder performance risk across the network:

– increased application of auto-reclose at zone substations and/or on distribution feeders

(where not presently available but not on feeders that consist predominately of underground cables or traverse high-risk areas)

- manage feeder lengths by capping maximum lengths and reducing the lengths of long poor-performing feeders
- protection review and protective device installation
- smart sectionalising of feeder segments to aid isolation of faulted areas and improve-reduce outage duration and frequency
- strategic interconnection of feeders where practical
- installing intelligent line devices to assist in fault-finding such as information from SCADA, line fault indicators, power quality monitors and reclosers, and installation of HV and LV spreaders, and
- relocation of lines from adverse lightning, high wind and/or vegetation areas.

Automatic Circuit Recloser Strategy:

A program to install additional reclosers on the distribution feeders identified in the Worst Performing Feeder program has been ongoing for many years. The ACR Strategy takes a proactive approach to the installation of additional reclosers rather than based solely on historical poor performance. The ACR Strategy through desk top analysis has identified the distribution feeders that present substantial future reliability performance gains through the installation of additional line ACRs.

The strategy is particularly focused on improving the SAIDI and SAIFI performance of the urban and short rural category feeders through improved device supervision and control and increased feeder/customer segmentation across a single distribution feeder. This strategy aims to provide consistent ratio of customers per ACR across the six supply regions for all three feeder categories. Of critical importance to the achievement of the identified improvements is the installation of ACRs at the boundary of the urban, high customer density section of the distribution and the rural, sparsely populated and exposed section.

Installations at these key locations will prevent the faults that inherently lead to lower reliability performance in the rural type networks from impacting the higher customer density urban portions of the feeder. The result of which will be an overall improvement in urban and short rural performance.

The strategy has identified a total of 428 additional recloser sites and 332 distribution feeders with the potential to deliver future reliability performance improvements. Most of these ACRs (~65%) are targeted to be installed along Short Rural feeders with 27% on Urban feeders and remaining 8% on Long Rural feeders. Subsequent and future detailed assessment will determine the practical suitability of each site. Detailed design and feeder review could also result in some of the identified reclosers being removed from the program.

It is intended to roll out the ACR strategy in conjunction with Remote Control Switch Application Strategy to ensure the strategic placement of the ACR along with the smart switches along a distribution feeder.

Remote Controlled (Gas) Switch Application Strategy:

This final scoping of this strategy has now been completed. This strategy is primarily intended to provide guidelines on installation of gas insulated pole top remote control switches at key points in high voltage distribution feeder backbones, and at key feeder tie points with adjacent feeders capable of supplying the adjacent un-faulted feeder segment. The strategy intends to install approximately a total of 184 remote controlled switches across all three feeder categories during this regulatory control period. The strategy mostly targets Urban and Short Rural feeders and conforms to Ergon Energy future state vision of delivering a ‘smart’ network. The guidelines cover the standard distribution feeder configurations based on feeder type (radial and non-radial feeders).

- Non-radial feeders – remote controlled segmentation and/or sectionalisation of a feeder into equal one third customer number sections, with remote control tie points in segments two and three able to support a one third feeder load shift during peak load periods, where possible, and
- Radial feeders – remote controlled segmentation and/or sectionalisation of a feeder into equal one third customer number sections, with remote control tie points in segments two and three to adjacent feeder/s, where possible.

Installed at key sites these intelligent gas switches have the potential to improve sectionalising the restoration timeframes following unplanned supply interruptions coupled with improved planned outage management and increased operational efficiency. The remote control switches will be integrated into the SCADA system giving the Operations Control Centres increased network visibility to more discretely identify and isolate the faulted segments and restore the unaffected customers via alternate supply route (where feasible with normally open tie points). This strategy will be rolled out in conjunction with the ACR strategy to ensure the strategic placement of the ACR along with the smart switches along a distribution feeder for optimal reliability improvement.

Asset replacement programs:

In addition to the reliability improvement specific strategies, Ergon Energy has increased its reliability focus in connection with asset maintenance and asset replacement strategies and works planning of such.

Some of the asset maintenance and replacement strategies that will either continue to have positive influence on reliability performance or provide additional benefits on reliability performance in the coming years of this regulatory control period are as follows:

- Line defect refurbishment
- Conductor replacement
- Connector and helical splice upgrade programs
- Aged underground cable replacement
- Expanded pole top inspection program and pole top replacement
- Subtransmission line refurbishment and replacement
- Replacement of failed lightning arrestors
- Power transformer dry-out and replacement
- Circuit-breaker condition based replacement
- Substation primary plant condition based replacement, and
- SWER Improvement strategies – pole banding, lightning arrestor installation.

Operational initiatives:

Besides the asset performance initiatives outlined above, Ergon Energy is in varied stages of delivering a number of additional operational initiatives that will result in improved response for the unplanned outage events:

- Implementation of Outage Dashboard (which displays the real-time (or near real-time) effect of critical outages) to enable the Operation Control Centre (OCC) staff and Field Operations Staff to prioritise the restoration of supply to network segments with the most critical impact on network reliability.

  This functional tool was delivered in the first quarter of 2010/11 and has provided a focus through increased real-time transparency to the wider business community of unplanned outage performance and management.

- Review of the current dispatch processes to address responsibilities and accountabilities for managing unplanned events.
- As a result of the progressive delivery of the SCADA Acceleration Strategy, SCADA functionality is being provided in areas that had previously had little or none in the past.

  To provide the familiarity and skill required of the local first response staff in order to deliver the potential benefits of the scheme Ergon Energy has continued to provide training on the practical applications of SCADA to local response staff to enhance their operational capability in minimising unplanned outage times.
- Routine pre-storm aerial inspection of critical radial and non N-1 subtransmission has been considered in the routine annual maintenance programs. These inspections are scheduled such that their timing allows sufficient time to rectify any latent defects before the storm season.
- Review the vegetation program for opportunities to focus on poor performing feeders (particularly radial and non N-1 subtransmission) where no vegetation works were done recently.
- Delivery of major augmentation projects with reliability benefits.
- Development and implementation of a periodical review process for feeder profiles. This will result in reduced repetition of contingency planning/analysis on same assets and improved response time to unplanned outages due to better knowledge/data/information about feeders.
- Ensuring that there are contingency plans in place where augmentation projects are delayed and will not be delivered on time, and
- Develop a prudent and reliability performance considered process and approach to the management of Out of Service Plant and Equipment with a view to increasing control, visibility, and reduction in repair cycle times.

Joint Working initiatives:

During the last the three financial years, Ergon Energy worked with Energex under the Joint Working project to identify the performance improvement opportunities and establish guidelines to assist the respective businesses with the formulation of economical performance improvement strategies and projects. The following are the two key guidelines on network reliability that were developed and are currently being implemented in both of the organisations.

Reliability investment guidelines:

This guideline outlines the requirements for economically justifying a reliability improvement project and includes investment criteria for assessing the economic value to Ergon Energy of a network reliability improvement project. The economic value of reliability is been based on the value of losses incurred by the customer for interruption of electricity supply under the AER's Service Target Performance Incentive Scheme (STPIS).

Reliability planning guideline:

The objective of this document is to provide reliability planning guidelines for the distribution networks of Ergon Energy and Energex. This will be limited to 11kV networks for Energex and would cover 11kV, 22kV and 33kV distribution networks for Ergon Energy. The guideline aims at providing assistance with:

- Understanding key factors affecting reliability performance of distribution networks in Queensland.

- Understanding of Ergon Energy network performance with respect to distribution capability and planning.
- Development and implementation of strategies for long term reduction of the frequency of outages through prudent distribution network planning, and
- Development and implementation of strategies for long term reduction of the duration of outages through prudent distribution network planning.

Network performance modelling:

Ergon Energy continues to investigate the development of performance models of its network to determine intrinsic reliability levels and the impact of the works program on those levels. This will include modelling of: the size of the gap with the future regulatory performance targets; weather impacts; and capability limits due to the radial topology of the network. Ergon Energy has had a preliminary model developed to assess the impact of its ongoing reliability improvement programs on future reliability outcomes against the MSS. This model is intended to be tested and implemented by mid-2012/13.

The network can be reconfigured to reduce losses, improve loading and provide more inter-feeder ties and switches to help manage customer numbers and supply restoration.

Ergon Energy also has simple systems to evaluate the saved customer minutes and interruptions as a result of splitting up feeders and reconfiguration of the network as a means of improving network performance. The capabilities are still being developed and currently have limited application.

Zone substation and subtransmission improvement:

Ergon Energy plans to enhance the performance of its subtransmission system and zone substations through targeted maintenance works, which will include consideration of appropriate insulation coordination, work methods and improved configuration to further mitigate outages.

Ergon Energy has accomplished the following initiatives as a first step:

- **Subtransmission feeder fault rate analysis:** Ergon Energy has established the historical failure rates (faults-100km-yr) for its 132kV, 110kV, 66kV and 33kV subtransmission feeders. The fault rates for all the categories remain favourable to global industry benchmarks *[Ref: Collation of Benchmarked Fault Rate Data for Network Elements – Sinclair Knight Merz, March 2006].*

TABLE 27:

Historical failure rates of Ergon Energy's Subtransmission Lines						
	Failure Rate (F/100km/Yr)					
	2007-08	2008-09	2009-10	2010-11	2011-12	Benchmark
132kV	0.20	0.30	0.13	0.19	0.16	2.90
110kV	1.60	1.83	1.10	0.37	0.18	3.13
66kV	2.50	2.34	2.36	1.84	2.49	3.25
33kV	2.20	3.92	3.06	3.99	4.35	4.34

- **Worst performing subtransmission feeder identification:** Ergon Energy has identified the worst performing subtransmission feeders for all voltage levels based on the faults-100km-yr and impacted customer numbers.

The outcomes of the above initiatives have been fed into Ergon Energy's Asset Replacement Program.

10.5 Worst performing feeder identification and repair

Ergon Energy addresses reliability performance issues on the worst performing distribution feeders via a composite of proactive and reactive reliability improvement programs. The distribution feeders identified as the worst performing feeders are done so, 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 SAIDI ≤ MSS
- yellow feeders have a SAIDI > MSS < 150% MSS
- amber feeders have a SAIDI > 150% MSS < 200% MSS, and
- red feeders have a SAIDI > 200% MSS.

The red feeders in each of the Urban, Short Rural and Long Rural feeder categories are independently analysed to identify outage duration improvement opportunities. These opportunities are then evaluated and where appropriate, projects raised and carried through to the works program to deliver these reliability improvement opportunities.

Based on the rolling average SAIDI performance for three years, red feeders currently contribute 32% and 25% of Ergon Energy's overall customer minutes and customer interruptions respectively. The contribution from the red feeders on reliability performance has trended upward in the last three years due to the additional combined adverse impact from the bans put on live-line work and ABS' operation. Targeted reliability improvement projects will aim to improve the service quality to customers currently supplied on red feeders. By targeting the worst performing feeders with relatively higher numbers of customers, the SAIDI contribution from those feeders on overall feeder category performance will improve.

About 30% of distribution feeders are identified as red (266 in total – 63 Urban, 177 Short Rural and 26 Long Rural). Feeders with fewer than 20 customers are excluded from the worst performing list unless specific issues have been identified. Red feeders are further analysed to identify the top 50 worst-performing feeders, which equal 5% of total distribution feeders. Ten urban, 30 short rural and 10 long rural feeders have been included in the worst-performer's list in Appendix 12.6. A higher number of short rural feeders were included in the list because they are the largest feeder category and service the largest customer base.

The approach for the red feeder performance improvement includes:

Network operation through:

- execution of operational investigation to determine predominant outage cause
- execution of any reliability or operational improvement requirement identified with the investigation of any unforseen major incidents
- improved fault-finding procedures with improved staff-resource availability, training and line access
- improved availability of information to field staff to assist fault-finding, which could include communications, data management and availability of accurate maps and equipment
- contingency planning for known risks until permanent solutions are available, and
- improved-optimised management of planned works.

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, and
- undertaking wildlife mitigation (e.g. birds, snakes, possums, frogs) in the vicinity of red feeders.

Augmentation and refurbishment through capital expenditure by:

- refurbishing/replacing ageing assets (both powerlines and substations), and
- insulation co-ordination exercise/works.

10.5.1 An analysis of worst performing feeders

Appendix 12.6 provides information on the worst performing feeders (WPFs) for each of the urban, short rural and long rural categories for 2011/12. The predominant outage causes for the worst performing feeders are planned work and unfavourable weather conditions (storms/lightning), followed by equipment failure such as broken/burnt poles, broken conductors and broken cross-arms.

The contribution from the subtransmission network to the worst performing distribution feeders, especially for the urban and short rural feeders, is considerably high (more than 50% in most cases).

For 2011/12, most of the worst performing feeders (based on three years' average SAIDI) are in Northern and Central supply regions. This is due to the wider impact from the bans on Live-line work through 2008 to 2009 and the continuation of the operating limitations of ABSs mostly affecting the Urban and Short Rural Feeders in these supply areas. The outliers in the southern regions are mostly due to the radial network area resulting in higher exposure to the adverse environmental elements. Approximately 61% of the customers in the South West supply region are supplied by radial networks. This supply region also has a higher exposure to thunderstorm activity as compared to other regions.

Urban feeders:

The larger customer density on urban feeders contributes significantly to a single outage event and results in a higher SAIDI value for the feeder. Only 10% of urban feeders in this year's worst-performing list carried over from the previous year. The average SAIDI for most of the reported feeders appear to be high due to one-off events (mostly planned and subtransmission) over the past three years with 50% of the feeders included as worst performing feeders showing significant improvement in SAIDI performance in 2011/12.

South West is largely represented in the worst performing feeder list for the Urban feeder category. The number of worst performing Urban feeders in Mackay region has improved compared to the last few financial years. Mackay has very limited SCADA coverage at the urban zone substations and nearly 40% of Ergon Energy's urban feeders with defective ABSs are in the central region. With the recent completion of Ergon Energy's SCADA acceleration strategy and ongoing ABS replacement strategy, it is anticipated to improve the SAIDI performance of feeders in urban areas of Mackay. The full benefits are not anticipated until 2013.

The updates on urban feeders reported in 2010/11 are also provided in Appendix 12.5. Interestingly, 90% of the worst performing urban feeders show significant improvement in the annual SAIDI over the last three years period.

Short rural feeders:

Thirty short rural feeders are on the 2011/12 worst-performing list. 30% of short rural feeders in this year's worst performing feeder list have been carried over from the previous year. 55% of the reported Short Rural feeders show significant improvement on their annual SAIDIs.

The updates on the short rural feeders reported in 2010/11 are provided in Appendix 12.5. 76% of the short rural feeders reported as the worst performing in 2010/11 show significant improvement in the annual SAIDI in 2011/12 when compared to the three year historical average annual SAIDI. South West and Northern Queensland supply regions of Ergon Energy dominate the worst performing feeder list for the Short Rural feeder category. This is because these regions have the highest number of Short Rural feeders compared to other supply regions of Ergon Energy and the category dominates their total distribution feeder base at 57% and 50% respectively. Also, almost 52% of Ergon Energy's Short Rural feeders with defective ABS' are in these regions.

Long rural feeders:

The length of exposure of long rural feeders, coupled with the dispersed geographical locations of attending staff and their subtransmission systems contribute significantly to the adverse performance of these feeders. 60% of the long rural feeders reported in this year's worst-performing list are carried over from 2010/11.

The updates on long rural feeders reported in 2010/11 are provided in Appendix 12.5. 40% of the 10 long rural feeders show improvement in 2011/12 annual SAIDI compared to the average of the previous three years.

The following table provides a regional summary of the worst-performing 10 urban, 30 short rural and 10 long rural feeders.

TABLE 28:

2011/12 Reliability Performance – Worst Performing Feeders			
Region	Urban	Short Rural	Long Rural
Far North	1	3	1
North Queensland	1	18	7
Mackay	3	1	-
Capricornia	-	-	1
Wide Bay	-	-	-
South West	5	8	1

It is expected that the reliability improvement strategies being considered and those already being implemented will provide significant reliability improvement across all feeder categories over the remainder of the regulatory control period.

10.6 Five-year capital expenditure program

Apart from expenditure on capital works specific to the reliability improvement program, capital works associated with other key programs such as network augmentation and asset replacement and refurbishment programs, along with virtually all corporation-initiated network capital and maintenance works have a positive impact on reliability performance. The following sections therefore summarise Ergon Energy's proposed capital and operating expenditure programs for the next five years.

As indicated in Section 2.6, Ergon Energy's revenue requirements for Standard Control Services have been established under the Final Distribution Determination made by the AER for the regulatory control period 2010/11 to 2014/15. The projected expenditure shown in tables following is reflective of strategies and policies previously outlined in this document.

Customer-initiated capital works program expenditure:

The continuing impact of the depressed economy following the global financial crisis on the demand for new connections is evident in the actual 2011/12 expenditure of $191.3 million the second lowest since 2005/06.

The following table shows the forecast for the next five years for the key CICW programs and is reflective of anticipated stronger economic times ahead.

TABLE 29: Forecast CICW program expenditure

Category	Actual 2011/12 $'000	Forecast 2012/13 $'000	2013/14 $'000	2014/15 $'000	2015/16 $'000	2016/17 $'000
Main System						
Commercial & Industrial	96,467	93,788	98,632	103,801	112,156	116,657
Domestic & Rural	44,139	54,550	61,995	93,057	102,403	106,513
Gifted Assets	15,300	14,000	15,100	15,900	16,000	16,400
Other	26,498	31,582	33,188	34,943	39,011	40,576
Street Light Gifted	3,450	2,700	2,000	2,000	0	0
Total Main System - SCS	**185,854**	**196,620**	**210,915**	**249,701**	**269,570**	**280,146**
Major Customer ACS	**2,206**	**28,427**	**27,968**	**29,898**	**34,134**	**35,504**
Isolated Generation	**3,158**	**2,600**	**2,704**	**2,812**	**2,925**	**3,042**
TOTAL	**191,218**	**227,647**	**241,587**	**282,411**	**306,629**	**318,692**

Notes: The above financial information reflects escalated (nominal) dollars for each financial year. As from 10/11dedicated connection assets associated with Major Customer works is handled under Alternative Control Services. Other work associated with Major Customers involving shared assets will be handled either under the Commercial and Industrial category or the Augmentation category under NICW.

Network-initiated Capital Works program expenditure:

The following table indicates the forecast expenditure in key programs for the next five financial years and is reflective of the ENCAP Review outcome of reduced capital expenditure for the current regulatory control period. Ergon Energy is very aware that cost pressures are a very real concern for our customers and a further review is currently being undertaken to ascertain if further reduction in the forecast capital expenditure for this regulatory control period may be possible. This review is expected to be completed by end of September 2012. The final two years of the five year forecast projections are in the next regulatory control period. Forecast expenditure for these two years have been based on expenditure modelling under taken to meet the strategic objective of limiting increases to network charges to CPI -1% and achieving sustainable level of investment in the network.

Even with the adoption of the revised security of supply criteria as an outcome of the ENCAP Review, significant expenditure on the augmentation program will still be required to ensure adequate system capacity is available to meet customer growth and demand for energy. Significant expenditure will also be required on the asset replacement program to address aging asset issues and defect refurbishment requirements.

The minor increase in forecast expenditure for the Reliability Improvement program in 2012/13 compared to the actual expenditure for 2011/12 reflects that the Accelerated SCADA program was completed in 2011/12. A lower level of expenditure has been forecast for 2015/16 and 2016/17 than previous years in anticipation that a review of the MSS limits for the next regulatory control period may result in the MSS limits being flat lined from 2015/16.

TABLE 30: Forecast NICW program expenditure

CAPITAL EXPENDITURE	Actual 2011/12 $'000	Forecast 2012/13 $'000	2013/14 $'000	2014/15 $'000	2015/16 $'000	2016/17 $'000
System Assets						
Augmentation	162,749	225,879	265,082	331,764	243,817	253,602
Asset Replacement	251,473	221,164	274,675	280,569	263,323	273,890
Reliability Improvement	26,297	26,588	34,399	37,652	19,505	20,288
Other	61,162	57,499	39,381	44,371	52,069	54,161
SWER Scheme Improvement	16,544	18,856	17,732	19,422	16,200	16,848
Street Lighting Refurbishment	1,739	-	1,754	1,771	1,951	2,029
Total Main System	**519,963**	**549,986**	**633,023**	**715,549**	**596,865**	**620,818**
Isolated Generation	**22,889**	**37,478**	**38,348**	**40,355**	**36,023**	**37,434**
Total System Capex	**542,852**	**587,464**	**671,371**	**755,904**	**632,888**	**658,252**

Notes: The above financial information reflects escalated (nominal) dollars for each financial year. Isolated Generation is inclusive of CICW.

Priority projects for 2011/12 are defined as those projects with an estimated total project value of more than $1 million and due for commissioning in 2012/13. Appendix 12.4 lists these projects.

10.7 Five-year operating and maintenance program expenditure

The following table summarises Ergon Energy's proposed regulated system assets operating and maintenance expenditure programs for the next five years, as included in the Ergon Energy 2012/13 Corporate Plan. As with the capital budgets, the operating and maintenance budgets for the current regulatory control period are also under review and so these budgets may change. The review is expected to be completed at the end of September. These programs have been developed in accordance with the maintenance strategies outlined in Section 6.2.

TABLE 31: Forecast operating program expenditure

OPERATING EXPENDITURE	Actual 2011/12 $'000	Forecast 2012/13 $'000	2013/14 $'000	2014/15 $'000	2015/16 $'000	2016/17 $'000
Maintenance						
Embedded Generation	4,971	7,202	7,556	7,741	8,410	8,912
Lines	148,785	142,115	132,225	135,735	148,448	152,759
Vegetation	104,571	94,148	88,110	88,618	93,817	85,424
Substations	36,473	38,852	33,714	35,115	34,537	35,572
Streetlights	11,820	10,067	10,945	11,504	11,210	11,287
Meters	4,941	4,909	5,719	5,829	7,470	6,829
Total Maintenance	**311,561**	**297,293**	**278,270**	**284,542**	**303,893**	**300,783**
Operations						
Network Operations	31,395	36,546	35,063	36,434	41,677	44,145
Customer Service	22,895	21,887	21,066	21,923	24,716	25,901
Alternative Control Services - General	33,231	29,842	30,196	31,387	33,589	35,162
Meter Reading Mass Maarket	13,244	14,135	14,325	14,913	15,977	16,747
Public Consumer Safety	856	1,073	1,087	1,131	1,211	1,270
Other	1,606	1,719	1,738	1,806	1,932	2,021
Total Operations	**103,226**	**105,202**	**103,475**	**107,595**	**119,102**	**125,247**
Total Opex	**414,787**	**402,495**	**381,744**	**392,137**	**422,995**	**426,030**

Notes: The above financial information reflects escalated (nominal) dollars for each financial year. Actual and forecast expenditure amounts are for regulated system assets only.

11. RISK MANAGEMENT OF MAJOR CONSTRAINTS

11.1 Risk management

Under the Risk Management Policy approved by the Board in 2001, Ergon Energy has adopted a risk management framework with the following primary objectives:

- ensure that the overall strategic direction of the business is appropriate in view of the external market and the political – regulatory environment in which it operates
- identify business priorities and allocate resources effectively and efficiently
- demonstrate due diligence in discharging legal and regulatory requirements and meeting the expectations and standards of external stakeholders, and
- identify and maximise opportunities for business growth and diversification.

Risk management drives virtually all network activities and programs, including maintenance and replacement, reliability assessment and improvement and network augmentation. Risks are rated according to AS/NZ ISO 31000 Risk Management Principles and Guidelines and are assessed with reference to the Ergon Energy risk management framework and potential adverse impacts on:

- public and employee safety
- customer lost load and supply disruption
- financial performance
- exposure to litigation-prosecution
- the natural environment, and
- Ergon Energy's public reputation.

Risk management considerations have resulted in type-based replacement programs for assets found to pose a safety or fire risk during failure. All asset inspection programs have an implied purpose of assessing risk linked to asset condition.

Assessed risk is the principal driver of priorities for each equipment-based plan. This ensures that individual assets representing the highest risk are managed to mitigate that risk to acceptable levels.

The results of risk assessment studies also helps determine the relative allocations of physical and financial resources among the various asset management programs and support activities.

A joint working initiative with Energex to introduce a common risk based approach to optimise our works programs was implemented in 2009/10 to jointly deliver savings and improve business outcomes. This approach introduces improved accountability, ensures focus on core pieces of work and unlocks resources needed to undertake these works. The key outcomes of applying the methodology are:

- demonstrating that development of our electrical network infrastructure is being managed in a prudent and efficient way
- a formal, defensible and repeatable approach to identifying and managing network risk
- addressing highest ranked network risks first where possible, and
- ensuring that the appropriate management levels are aware of significant identified network risks and are endorsing any remedial actions.

The project and program investment business case tool was enhanced to include a scoring system pertaining to both risks and benefits to facilitate decision-making associated with project ranking and program of work optimisation.

11.2 Disaster management

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

- ensuring personal safety of both the public and Ergon Energy staff
- protecting equipment and infrastructure from damage
- efficient supply restoration – including meeting the communication requirements of customers and other emergency services, and
- keeping the community informed more broadly.

Ergon Energy primarily applies a whole-of-business Disaster Management Plan that clearly documents its planning, preparation, response and restoration philosophy.

Three Regional Emergency Management Plans (Northern, Central, Southern) support the Disaster Management Plan, documenting the actions required by key business units within regions before, during and after a business disruption event.

These plans detail Ergon Energy's response to a disruption event impacting on the distribution network and Ergon Energy's services. In addition there are supporting plans, based on business units and geographical areas, which detail the services and resources which will be used to assist during a disruption event.

An Asset Management Emergency Management Plan has also been developed, which provides for the provision of resources and the capture of data during a disruption event.

These plans are tested and reviewed at least annually, before the start of each storm/cyclone season. They are also reviewed and amended where necessary after major events.

11.3 Summer preparedness

Ergon Energy understands the importance our customers place on dependable electricity supply. For this reason, we are committed to the maintenance and continued development of a supply network that fulfils their expectations and requirements.

The highest load on the network and the exposure to significant weather events occurs over the summer period, so much of our annual planning and record expenditure is aimed at preparing the network for summer. To minimise the potential for outages arising from storms, cyclone or extreme temperature events, leading into the 2012/13 summer, Ergon Energy will:

- review and update its Network Management Plan, providing customers with transparency and an understanding of our system capacity. The plan is a five-year blueprint outlining our capital works plan to 2016
- continue to gather more comprehensive and accurate information about network assets through our asset inspection cycle
- respond appropriately to priority maintenance items through the defect rectification program. This ongoing program is continually improving the network's reliability as defects are identified and repaired in a timely manner, and
- continue our maintenance commitment. The total allocation for the 2012/13 maintenance program is $297.3 million, with approximately $130.7 million of this work undertaken before the start of December.

11.4 Contingency planning

Each year, as part of the summer preparedness planning, any system risks remaining from plant nearing its expected life or potential capacity overload issues are assessed and appropriate contingency plans put in place until longer-term replacement works can be completed. This may include having adequate system spares, access to temporary generating capacity or mobile substations available.

At present, Ergon Energy has maintained around $20 million worth of strategic spares located in our stores across the state ready for use in an emergency. Access to these supplies proved vital in our response to the events of the summer of 2011/12.

The joint use of common spares with Energex has progressed to the final stages of recommendations, signoff and spares management (intranet site development to manage and book out spares).

Ergon Energy has continued to develop the Temporary Load Support Strategy as outlined in the Summer Preparedness Plan. Progress on the support solutions is shown below:

- **Mobile substations** – the NOMAD substations were located on stand by in Townsville, Rockhampton and Toowoomba during summer
- **Skid mounted substations –** Ergon Energy had two skid mounted substations available and on stand -by during summer
- **Contingency generation** – Ergon Energy has commenced a project to design and manufacture HV injection units to step up the outputs of our generators to enable HV injection into our network. The first of these units is expected to commence field testing/deployment in late June 2012.
- **Detailed monitoring of real time loads** – the SCADA acceleration program is nearing completion with 44 substations now being monitored. The load data obtained is an invaluable aid to managing the network.

Ergon Energy has a large pool of skilled personnel to support contingency plans. In addition, the company has relationships across the industry, as well as contractors to call on to respond effectively to events.

The process for the development and maintenance of the contingency plans is ongoing work, and the resulting documentation is continually updated.

11.5 Asset security levels

11.5.1 Substation security levels

Bulk supply substation summary:

Excluding substations dedicated to single customers, and following the transfer of Chinchilla and Columboola to Powerlink, Ergon Energy now owns 24 bulk supply substations. The current and projected situations for these substations are summarised in Table 32 below. The load forecast used to derive bulk supply substations' security level is the 50% PoE forecast except for those bulk supply substations where the transmission or subtransmission system is radially configured and 'N-1' security is not available.

All 24 substations have adequate capacity to meet the current maximum demands under normal operating conditions. Nineteen of them currently have an N-1 level of security. Five bulk supply substations do not currently have an N-1 level of security. Four others have N-1 security but are in a minor state of non-compliance (they are 'B' and 'C' not 'A').

Ergon Energy has current project plans to construct another three new bulk supply substations over the next five years.

Project plans are in place to bring some of the nine substations currently outside the security targets into full compliance. Of the three substations presently projected to be outside the security targets after the next five years:

- Barcaldine is run as two 1x20MVA substations within the same fence, with the ability to back each other up using remote switching within 30 minutes. It, therefore, achieves N-1(B) security instead of the target N-1(A). This arrangement allows independent control of the sending end 66kV voltage for Blackall and Longreach feeders, which in turn provides better voltage conditions at Blackall and Longreach. Provision of full N-1(A) switching would require significant expenditure for very limited reliability gain, and would reduce voltage quality at the remote substations.
- Warwick achieves N-1 C class security, below the desired A class. The proposed Clifton East zone substation will take a small amount of load off Warwick in about 2017.
- Kilkivan reaches its demand peaks very rarely. Over 2010/12 it had N-1 capacity over 99.3% of the time. Load relief measures are being investigated.

TABLE 32: Security level status and projection for bulk supply substations

SoS		11/12 Achieved Security						16/17 Projected Achieved Security					
Class	Required	A	B	C	N	0	Totals	A	B	C	N	0	Totals
Bulk Supply Substations													
All	N	2	0	2	0	0	4	2	0	3	0	0	5
Bulk	C	0	0	0	0	0	0	0	0	0	0	0	0
Supply	B	1	0	0	1	0	2	2	0	0	1	0	3
	A	10	1	3	4	0	18	17	1	1	0	0	19
			1	3	5	0	24		1	1	1	0	27
		Not matching security criteria				9	38%	Not matching security criteria				3	11%

Table Legend	
X	White on red: Max demand exceeds normal capacity
X	Yellow shading: N-1 Security target applicable but not achieved
X	Cyan shading: N-1 Security achieved but higher class required
X	Green shading: Security Target Achieved
Securtiy Level	
0	Maximum Demand exceeds Rating for System Normal
N	Maximum Demand within Rating for System Normal
C	<3 hrs to restore Maximum Demand after 1st contingency
B	<30 minutes to restore Maximum Demand after 1st contingency
A	No sustained outage for 1st contingency event

Projects will be completed based on priorities set in accordance with Ergon Energy's risk management criteria outlined in Section 5.4.

In addition to the bulk supply substations owned by Ergon Energy, Ergon Energy is working with Powerlink Queensland and Energex to ensure that the equipment they use to supply Ergon Energy's network meets the security requirements of the Rules and specific Connection Agreements. The status of the Energex and Powerlink Queensland owned substations (including plans for additional substations) are the subject of their own respective network management plans and annual planning reports.

Zone substation summary:

The current and projected situations for Ergon Energy-owned zone substations (excluding those dedicated to single customers) are summarised in Table 33. The load forecast used to derive zone substations' security level is the 50% PoE forecast except for those zone substations where the transmission or subtransmission system is radially configured and 'N-1' security is not available.

TABLE 33: Security level status for zone substations

SoS Class	Required	11/12 Achieved Security A	B	C	N	0	Totals	16/17 Projected Achieved Security A	B	C	N	0	Totals
Zone Substations													
All	N	61	1	31	67	2	162	78	1	32	58	0	169
Zone	C	11	0	1	1	0	13	24	0	0	1	0	25
Subs	B	0	0	0	0	0	0	0	0	0	0	0	0
	A	39	1	9	11	0	60	48	1	8	2	0	59
			1	9	12	2	235		1	8	3	0	253
			Not matching security criteria			24	10%		Not matching security criteria			12	5%

Adequate capacity to meet the current maximum demand under normal operating conditions is available at 233 (99%) of the 235 substations. 211 (89.9%) of the zone substations currently meet the specified target security-load levels.

Two zone substations are at risk of exceeding their rated capacity. Of these:

- Distribution works are underway to unload more Highfields load to the new Cawdor zone substation. These two substations provide mutual support, so each of the pair sometimes exceeds their individual firm capacity without exceeding the firm capacity of the combination.
- Mt Mowbullan is overloaded by about 100kVA for the one in 10 year load forecast, and a new transformer is planned for 2014/15. The risk of plant failure due to this potential overload is regarded as acceptable.

A further 12 substations do not have any level of their target N-1 security at peak load. An additional 10 do have a level of N-1 security, but are in a minor state of non-compliance (i.e. ‘C’ rather than ‘A’ or ‘B’).

Based on the current expenditure program, the forecast situation for five years’ time is that 95% of zone substations will be in compliance with the target security levels.

By that time, nine zone substations classed as commercial or industrial are not expected to have the desired A class N-1 security, but should be fully restored within 30 minutes of the loss of the largest single item of plant (C class N-1 security). Two of these are expected to exceed their firm capacity by less than 1MVA, so N-1(A) will be available at those substations most of the time. A new tap-changer controller arrangement is being considered for Rockhampton Glenmore, which will restore N-1(A) to that substation if found to be practical.

Three substations are not expected to have the target B class N-1 security. In one case, the apparent shortfall is due to an expected large customer load. Additional works will be implemented to service that load if it eventuates. Another has a marginal overload and is scheduled to be relieved the following year, while the last planned to be augmented and relieved as part of a program planned for the Toowoomba city area. The individual parts of that program may be rescheduled if necessary, and in any case there is some capacity available from adjacent substations, although it does take some time to reconfigure the network.

In addition to extensive augmentation works in existing substations, there are 19 new zone substations planned for construction over the next five years. An interim 33/11kV installation at Warwick will be retired as the permanent substations in the area are redeveloped. (This does not include substations required to be built for dedicated supply to major customers, or those in the Far North region involving connection to Powerlink Queensland’s 132kV network).

11.5.2 Transmission and subtransmission line security levels

Transmission and subtransmission line security levels:

The process used to identify the transmission and subtransmission lines at risk involves a method based on repetitive load flows using a model covering the entire Ergon Energy transmission and subtransmission network.

The process is being continually developed to improve its accuracy and usefulness as an auditing tool, with the intent being able to report on readily identifiable feeders rather than short line segments. This means that counts of items at risk cannot be directly compared to counts quoted in previous reports. This method presently identifies lines at risk with respect to thermal rating.

This auditing process is conducted in parallel with conventional planning analysis which is carried out by studying in detail the separate defined supply areas throughout Ergon Energy, and from which specific augmentation projects are initiated.

It should be noted that any assessment of the system status at the end of the forecast period depends on the system model accurately representing the system at the end of that period. There are significant difficulties in achieving this, as there are often several options available to address various issues, and it is difficult to incorporate alternatives in the system models. As a result, the assessment of the system status at the end of the forecast period can be pessimistic.

The following table shows an assessment of the number of line segments and lengths at risk during system intact and contingency situations.

TABLE 34:

Lines at risk during System Intact and Contingency situations Summaries

Region	Counts <15MVA Not N	Counts >15MVA Not N	Counts >15MVA Not N-1	Counts Total	Distances (km) <15MVA Not N	Distances (km) >15MVA Not N	Distances (km) >15MVA Not N-1	Distances (km) Total	Notes
Year ending June 2013									
FN	0	0	1	1	0	0	10	10	*1*
NO	0	0	0	0	0	0	0	0	*1*
MK	0	0	0	0	0	0	0	0	*1*
CA	0	1	2	3	0	8	74	81	*1*
WB	0	2	2	4	0	28	16	44	*1*
SW	26	0	0	26	125	0	0	125	*3*
Total	26	3	5	34	125	35	100	260	
	1.6%	0.2%	0.3%	2.1%	1.0%	0.3%	0.8%	2.0%	*4*
Year ending June 2017									
FN	0	0	0	0	0	0	0	0	
NO	0	0	0	0	0	0	0	0	
MK	0	0	0	0	0	0	0	0	
CA	0	0	0	0	0	0	0	0	
WB	0	0	0	0	0	0	0	0	
SW	0	0	0	0	0	0	0	0	
Total	0	0	0	0	0	0	0	0	
	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	*4*

Notes

1. *Projects programmed to address most problems. Some need further investigation.*
2. *System model does not include some elements which may address these problems*
3. *Conservative data assumptions result in significant apparent risks in SW regions. Investigations to date have shown problems are not as severe as indicated. Investigations are continuing.*
4. *Percentages (%) are relative to total transmission/subtransmission segments count & line lengths (approx 1650 & 13200km respectively)*
5. *Changes in the system model results in unavoidable changes in the ways lines are broken into segments, so comparisions to previously reported results can only be made in general terms.*

The headings shown refer to the following situations:

<15MVA, Not N	Load in the line less than 15MVA, line rating may be exceeded under system intact situation.
>15MVA, Not N	Load in the line more than 15MVA, line rating may be exceeded under system intact situation.
>15MVA, Not N-1	Load in the line more than 15MVA, line rating may be exceeded under line outage contingency.

A large number of South West subtransmission lines have been identified as being at risk under system intact (N) situations. The majority of these are older lines which have been conservatively rated for 50ºC design temperature for analysis purposes in the absence of reliable ratings data. This results in very low line ratings.

Line surveys are progressively being undertaken for these lines and projects have been or are being scheduled for the necessary work to increase the ratings as required.

After allowing for both the projected works and forecast load growth, no subtransmission lines are expected to have issues in 2016/17.

11.5.3 Distribution feeder security levels

The following table provides a summary of the results from the 2011 Distribution Capability Review in which all distribution feeders were examined with regard to the planning criteria. Results are presented for all feeders according to whether feeder constraints are exceeded with respect to voltage regulation or capacity.

TABLE 35:

Security level 2011 status for distribution feeders		
Category	**Number**	**%**
Total Feeders	1798	100%
Capacity Constraints	360	20%
Voltage Constraints	435	24%
Total Constraints	795	44%

Note that the term ‘constraint’ in this context refers to non-compliance with the planning criteria. The majority (64%) of the 360 capacity constraints are in fact related to feeder maximum demand loads exceeding the ‘4 into 3’ target security level criterion applicable to the urban environment (i.e. Urban N: 50PoE forecast not to exceed 0.75xNCC rating) rather than feeder ratings being exceeded under normal operating conditions.

Across the entire network and as a result of the reporting criteria changing from ‘3 into 2’ to ‘4 into 3’ target security, there is a significant reduction (from 453 to 360) in capacity constraints from last year.

Whilst this may suggest a considerable decrease in augmentation works, it should be noted that capital expenditure in previous years was not triggered until the ‘4 into 3’ target security was exceeded.

Feeders are deemed to be ‘voltage constrained’ when network modelling indicates that the voltage regulation criteria used in planning the HV distribution network may be violated during the maximum demand period. There was a slight decrease (1%) in ‘voltage constrained’ feeders over last year.

The total constraints are distributed through all Ergon Energy regions. Apart from specific feeder augmentation works, constraints will also be alleviated by new zone substation works which will involve the establishment of new feeders to reduce load on existing feeders.

The following table indicates the projected security levels in 2016 and shows a significant improvement over the present position.

TABLE 36:

Projected 2016 security levels for distribution feeders		
Category	**Number**	**%**
Total Feeders	2,018	100%
Capacity Constraints	97	5%
Voltage Constraints	124	6%
Total Constraints	221	11%

The major improvements projected for the end of 2016 reflect the focus on improving network capacity and security and the high level of augmentation expenditure. This includes the establishment of an estimated 220 new distribution feeders over the next five years.

Approximately 19% of the 2016 capacity and voltage constraints are associated with Urban Capacity Constraints and are predominately related to the ‘4 into 3’ urban distribution feeder security level criteria. As a result of changing the ‘4 into 3’ target security, the number of capacity constrained feeders has reduced considerably (121 to 97) from the previous year.

Further improvement will rely upon a review of feeder ratings (underground and overhead), new technologies as they are accepted and implemented in the network and greater scrutiny of the general network.

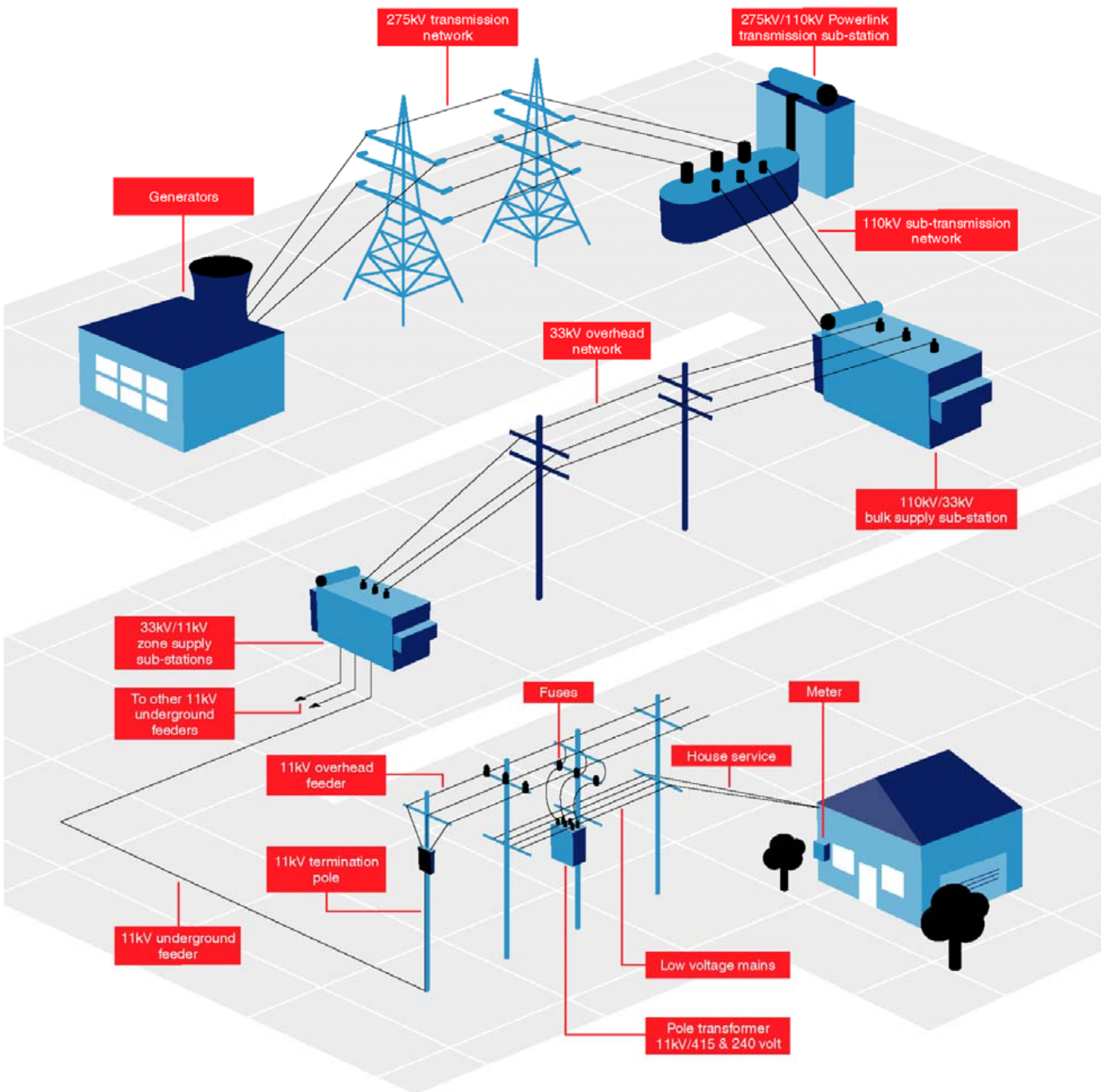
The majority of the balance of the 2016 capacity and voltage constraints are now associated with Rural feeders (i.e. 39%). Ongoing scrutiny of the supply quality in rural areas is required as a greater number of voltage constraints become evident.

From Table 34, it can be seen that Voltage Constrained networks are expected to exceed capacity related constraints by 2016. It is anticipated that ongoing challenges will be experienced as new technology (e.g. solar photovoltaic embedded generation and electric vehicles) penetrates the distribution network and the impacts are managed in a cost effective and equitable manner.

12. APPENDICES

12.1 Role of distribution in the supply of electricity to customers

The following diagram has been extracted from the final report from the Queensland Government independent review of electricity distribution in Queensland – entitled *'Electricity Distribution and Service Delivery for the 21st Century'* (EDSD).



The following definitions provide a brief explanation of key elements of the network:

1. **Transmission Network:** The electricity supply network operating at or above a nominal voltage of 110kV. This term is used regardless of ownership.

2. **Connection Point (CP):** The agreed point of supply established between Ergon Energy's network and Powerlink, an embedded generator or a customer.

3. **Bulk Supply Point (BSP):** A point (normally associated with a bulk supply substation) in the electricity supply network where supply is provided to the subtransmission network.

4. **Bulk Supply Substation:** A site incorporating equipment that provides control and voltage transformation from the transmission network to the subtransmission network, regardless of ownership.

5. **Subtransmission Network:** Ergon Energy's electricity supply network operating and supplying zone substations or customer connection points at a nominal voltage of 33kV or 66kV.

6. **Zone Substation:** A site incorporating equipment that provides control and voltage transformation from the subtransmission or transmission network to the distribution network, regardless of ownership.

   Note: A site that provides supply to both the subtransmission and distribution networks incorporates both functions and therefore is both a bulk supply and a zone substation. Sites that provide supply directly to customers at subtransmission voltage are normally listed with zone substations.

7. **Distribution Network:** Ergon Energy's electricity supply network operating and supplying distribution substations or customer connection points at 11kV, 22kV *or where so designated, 33kV* nominal voltage and including 11, 12.7 and 19.1kV Single Wire Earth Return systems.

   Note: Depending on function, a 33kV line may constitute part of the subtransmission network, the distribution network or both.

   Note: Sites that provide supply directly to customers at transmission voltage are normally listed with bulk supply substations.

8. **Distribution Substation:** An assemblage of equipment providing control and voltage transformation from the distribution network to the low voltage (415-240V) network.

9. **Security Level:** Denotes the inherent security of supply provided by major network components as determined by the extent of duplication or redundancy of primary serial elements and their associated secondary protection and control systems.

12.2 Abbreviations, definitions and units of measure

ADMD	Average Daily Maximum Demand
AIDM	Asset Inspection and Defect Management
AAAC	All Aluminium Alloy Conductor
AAC	All Aluminium Conductor
AEMO	Australian Energy Market Operator (AEMO) (previously NEMMCO)
AER	Australian Energy Regulator
ACSR	Aluminium Conductor Steel Re-enforced Conductor
BSP	Bulk Supply Point-s or Substation-s
CARE	Cyclone Area Reliability Enhancement program
CB	Circuit Breaker (switch in electrical network)
CMEN	Common Multiple Earth Neutral
CICW	Customer Initiated Capital Works
CIGRE	International Council on Large Electric Systems
DLC	Direct Load Control
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DUOS	Distribution Use Of System
DSA	Distribution System Automation
ECC	Emergency Cyclic Capacity
EIC	(Queensland) Electricity Industry Code
ENCAP	Electricity Network Capital Program Review
ERP	Enterprise Resource Planning (Ellipse system)
EDSD	Electricity Distribution and Service Delivery Report
ESAA	Energy Supply Association of Australia
ESO	Electrical Safety Office
GPATS	Global Position and Tracking System
GOC	Government Owned Corporation
GUSS	Grid Utility Support System
GSL	Guaranteed Service Level
GIS	(a) Geographical Information System; (b) Gas Insulated Switchgear
HDBC	Hard Drawn Bare Copper Conductor
IEC	International Electrotechnical Commission
IES	Inverter Energy System
IEEE	Institute of Electrical and Electronics Engineers
ISO	International Standards Organisation
IT&T	Information Technology and Telecommunications
LDC	Line Drop Compensation
MD	Maximum Demand
MED	Major Event Day
MEN	Multiple Earth Neutral
MSS	Minimum Service Standards
NAPM	Network Asset Preventative Maintenance
NATA	National Association of Testing Authorities
NCC	Normal Cyclic Capacity
NDN	Normalised Distribution Network
NEC	National Electricity Code
NEL	National Electricity Legislation
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company

NER	National Electricity Rules
NICW	Network Initiated Capital Works
NIEIR	National Institute of Economic and Industry Research
NMP	Network Management Plan
OGOC	Office of Government Owned Corporations
OHEW	Overhead Earth Wires
OPEX	Operating Expenditure
CAPEX	Capital Expenditure
POE	Probability of Exceedance
URD	Underground Residential Development
QCA	Queensland Competition Authority
RAPs	Remote Area Power Supply system
RCM	Reliability Centred Maintenance
SCADA	Supervisory Control and Data Acquisition
SCAMS	Substation Contingency Asset Management System
SCI	Statement of Corporate Intent
SEF	Sensitive Earth Fault
SPS	Stand-alone Power Supply
S/Stn	Substation
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TMU	Target Maximum Utilisation
XLPE Cable	Cross Linked Polyethylene Insulated Cable
VAr	Volt-amperes reactive (Reactive power)

Network Reliability Measures

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).
CAIDI	*Customer Average Interruption Duration Index* – Network reliability performance index, indicating the interruption duration that each customer experiences on average (minutes) per interruption.
Customer Minutes	Customer minutes is a measure of the number of customers interrupted multiplied by the duration of a power outage or outages, incorporating any staged restoration.

Network Quality of Supply Measures

AVDI	*Absolute Voltage Deviation Index* – AVDI is a measure of the spread of voltage around the middle of the nominal voltage range. AVDI is the maximum of the three (one for each phase) 95th percentile AVD levels at a site. AVDI is expressed as a percentage of the reference voltage.
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.
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.
VUFI	*Voltage Unbalance Factor Index)* – VUFI is the 95th percentile level of measured or calculated unbalance at a site. VUFI is expressed as a percentage.

V	volt	the unit of potential or electrical pressure
A	Ampere	the unit of electrical current
kV	kilovolt	1,000 volts
W	watt	a measure of the rate of flow of electrical energy when a current of one ampere flows under a pressure of one volt
kW	kilowatt	1000 Watts
LF	Load Factor	Average Demand-Peak Demand
MW	megawatt	1000kW or 1,000,000 Watts
VA	volt ampere	a measure of the apparent power flowing for which equipment must be rated
MVA	mega volt ampere	1,000,000VA
kWh	kilowatt hour	The standard 'unit' of electrical energy. One kilowatt hour represents the consumption of electrical energy at the rate of one kilowatt over a period of one hour
MWh	megawatt hour	1000kWh
GWh	gigawatt hour	1000MWh or 1,000,000kWh
HV	high voltage	Alternating current supply at above 1000V

12.3 2011/12 NMP – priority project status – Page 1 of 4

The following tables provide status information on the priority projects.

Region	Project Description	Initial Project Estimate	Original Target Comm. Date	Revised Project Estimate	Revised/Actual Target Comm. Date	Project Status
Far North	Gordonvale, CARE works Stage 3	$1,321,003	May-12	$4,092,250	Aug-13	Delayed due to obtaining QR permits as well as scope issues.
Far North	CARE works Cairns Nth zone S/Stn to Masonic Homes, Whitfield & Brinsmead	$2,384,253	Oct-11	$3,849,133	Jan-12	Completed
Far North	Atherton Rd FDR – Upgrade Copper Conductors	$1,408,719	Jun-12	$1,408,719	Mar-12	Completed
Far North	Feeder development works Kewarra Beach S/stn	$3,488,000	Jan-12	$1,300,000	Jan-12	Completed
Far North	Install SEF protection - Atherton S/Stn	$1,150,117	May-12	$1,109,637	Dec-13	Delayed due to scope review & resource constraints
Far North	Protection upgrade and replacement of RTU at Atherton zone S/Stn	$1,889,470	Feb-12	$1,907,519	Jan-14	Project delayed due to resource constraints
Far North	Refurbishment works – Atherton zone S/Stn	$1,304,857	Dec-11	$516,879	Oct-13	Project delayed due to resource constraints
Northern	CARE works Willows	$943,512	May-12	$943,512	Jun -12	Completed
Northern	Greenvale Zone Sub Transformer Upgrade	$1,130,857	Jan-12	$1,138,445	Jan-14	Project delayed due to resource constraints
Northern	66kV feeder upgrade works Dan Gleeson to Cranborne zone S/Stn	$2,069,054	Mar-12	$1,978,889	Feb-12	Completed
Northern	Provision of 2nd transformer at Kalamia zone S/Stn	$2,204,936	May-12	$1,001,045	Jun-15	Project delayed due to property issues
Northern	Upgrade works at Victoria Milll, Ingham to cater for increased generation capacity	$13,476,000	Dec-11	$15,240,925	Oct-11	Completed
Northern	Distribution feeder augmentation works Frances Street, Mt. Isa	$1,754,395	Dec-11	$1,754,395	Nov -13	Project delayed due scope review and resource constraints
Northern	66kV Protection upgrade works at Merinda zone S/Stn	$1,403,059	Nov-11	$1,708,007	May-14	Project delayed due to resource constraints

12.3 2011/12 NMP – priority project status – Page 2 of 4

Region	Project Description	Initial Project Estimate	Original Target Comm. Date	Revised Project Estimate	Revised/Actual Target Comm. Date	Project Status
Mackay	Install 2nd 33kV fdr from Mackay BSP to Alfred St zone S/Stn	$4,671,218	Nov-11	$3,848,101	Oct-13	Project delayed due to resource constraints
Mackay	New Town feeder Moura	$1,523,983	Jan-12	$2,318,226	Dec-12	Project delayed due to contract issues
Mackay	Provision of 2nd transformer at Jubilee Pocket zone S/Stn	$626,000	Oct-11	$1,995,161	May-14	Project delayed due to major plant issues and impact of resource constraints
Mackay	Mackay BSP – RTU replacement	$2,135,798	Feb-12	$2,162,989	Sep-12	Project delayed due to resource constraints
Central	Establish a new feeder to Springsure from Rolleston	$7,885,535	Mar-12	$6,170,777	Dec-11	Completed
Central	Establish new 11kV Feeder for Gracemere Shoppingworld, Rockhampton	$3,359,000	Oct-11	$2,686,000	Dec-12	Project delayed due to property issues
Central	Proposed Hopper Road 11kV Feeder	$1,586,361	Jun-12	$1,408,090	Nov-12	Project delayed due to delay in obtaining external approval
Central	Establish 66kV transformer bay at Pandoin BSP for PQ transformer	$2,415,653	Dec-11	$3,284,524	Aug-11	Completed
Central	Provision of 66kV connection for Daunia Coal Mine	$1,571,601	Apr-12	$1,881,954	Jan-12	Completed
Central	Increase 66kV feeder rating Egans Hill-Gavial 66kV Line	$1,082,387	Sep-11	$366,306	Oct-13	Project delayed due to resource constraints
Central	Increase 66kV feeder rating Lilyvale-Middlemount 66kV Line	$1,766,914	Oct-12	$890,066	Oct-11	Completed
Central	Glenmore zone S/Stn – Replace LM Controller & SFU	$1,099,956	Jul-11	$2,104,020	Oct-11	Completed

12.3 2011/12 NMP – priority project status – Page 3 of 4

Region	Project Description	Initial Project Estimate	Original Target Comm Date	Revised Project Estimate	Revised/Actual Target Comm. Date	Project Status
Wide Bay	Transformer augmentation at Kilkivan Town zone S/Stn	$2,163,797	Dec-11	$2,030,368	Mar-13	Project delayed due to resource constraints
Wide Bay	Farnsfield zone S/Stn- Install 11kV capacitor bank & upgrade 11kV TF Cables	$1,785,085	Dec-11	$1,046,299	Apr-12	Completed
Wide Bay	Bundaberg 132/66kV BSP – Improvements to transformer bunding and oil containment	$1,500,922	Jun-12	$1,501,924	May-13	Project delayed due to resource constraints
Wide Bay	Provision of 2nd transformer at Mundubbera zone S/Stn	$2,117,608	Aug-11	$1,732,022	May-11	Completed
South West	Redevelopment of Central Dalby zone S/Stn	$19,446,429	Jun-12	$24,082,395	Aug-12	Project delayed due to resource constraints
South West	Undergrounding of 11kV distribution works Ruthven St as part of Toowoomba Gateways project	$1,598,000	Jan-12	$1,598,000	Jun-13	Project delayed due to resource constraints
South West	Toowoomba – street light control wire replacement works	$1,907,879	Jun-12	$4,515,000	Jun-12	Completed
South West	Establish Columboola to Miles 33kV Fdr	$2,808,000	Apr-12	$2,808,000	Jun-13	Project delayed due to scope issues
South West	Replace Nandi/Loudon 33/11kV transformer No.2	$1,034,000	Jun-12	$599,877	Jun-13	Project delayed due to scope issues
South West	Jessie St distribution substation augmentation, Toowoomba	$1,809,004	Mar-12	$1,809,004	Mar-13	Project delayed due to property issues
South West	Protection upgrade South Toowoomba	$1,735,999	Apr-12	$1,737,222	Jun-13	Project delayed due to scope issues
South West	Re-arrange 33 fdrs& regulator connections at Miles zone S/Stn	$1,849,202	Jun-12	$1,849,202	Mar-13	Project delayed due to scope issues

12.3 2011/12 NMP – priority project status – Page4 of 4

Region	Project Description	Initial Project Estimate	Original Target Comm Date	Revised Project Estimate	Revised/Actual Target Comm. Date	Project Status
Generation	Birdsville – Replace Set 1	$1,361,118	Aug-11	$1,445,097	Aug-11	Completed
Generation	Pormpuraaw – New Set 4	$908,942	Jul-11	$1,227,252	Jul-11	Completed
Generation	Gununa – Replace set 2	$1,181,200	Nov-11	$906,405	Oct-11	Completed
Generation	Thursday Island – Replace Set 5	$2,069,594	Nov-11	$1,589,331	May-12	Completed
Generation	Yam Is – Replace gensets	$1,334,672	Jan-12	$2,005,342	Jan-12	Completed

12.4 Priority projects for 2012/13 Page 1 of 2

Region	Project Description	Target Commissioning Date	Total Project Budget
Far North	Redlynch, CARE	Nov-12	$999,568
Northern	66kV Protection upgrade works at Merinda zone S/Stn	May-14	$1,708,007
Northern	Load Management NQ Region	Jun-13	$7,000,000
Northern	Cape River 66kV Protection Upgrade	Dec-12	$1,185,000
Northern	Substation upgrade works Neil Smith Zone S/Stn	Feb-13	$1,101,275
Mackay	New Town feeder Moura	Dec-12	$2,318,226
Mackay	Mackay BSP - RTU replacement	Sep-12	$2,162,989
Mackay	Broadlea - Establish new 132/66kV S/Stn	Mar-13	$48,000,000
Mackay	South Mackay Zone S/Stn Protection Upgrade	Sep-12	$1,070,000
Central	Establish new 11kV Feeder for Gracemere Shoppingworld, Rockhampton	Dec-12	$2,686,000
Central	Proposed Hopper Road 11kV Feeder	Nov-12	$1,408,090
Central	Canning St Zone S/Stn - Establish New 11kV Feeder	Jan-13	$2,178,368
Central	HV Injection Units for Mobile Generating Sets	Sep-12	$4,147,389
Wide Bay	Transformer augmentation at Kilkivan Town zone S/Stn	Mar-13	$2,369,196
Wide Bay	Bundaberg 132/66kV BSP - Improvements to transformer bunding and oil containment	May-13	$1,501,924
Wide Bay	Pt Vernon Zone S/Stn - Replace existing transformers with 32MVA units	Dec-12	$6,017,502

12.4 Priority projects for 2012/13 Page 2 of 2

Region	Project Description	Target Commissioning Date	Total Project Budget
South West	Redevelopment of Central Dalby zone S/Stn	Aug-12	$28,000,000
South West	Undergrounding of 11kV distribution works Ruthven St Toowoomba	Jun-13	$1,598,000
South West	Establish Columboola to Miles 33kV Fdr	Jun-13	$2,808,000
South West	Jessie St distribution substation augmentation, Toowoomba	Mar-13	$1,809,000
South West	Torrington zone s/stn – Install 4 additional feeder bays	Dec-12	$1,174,602
South West	Protection upgrade South Toowoomba	Jun-13	$1,737,222
South West	Re-arrange 33 fdrs& regulator connections at Miles zone S/Stn	Mar-13	$1,849,202
South West	Replace St George Zone S/Stn SVC	Dec-12	$13,341,701
Generation	Coconut Is - Replace sets 1,2 & 3	Jan-13	$1,111,000
Generation	Yorke Is - Replace sets 1,3 & 4	May-13	$1,171,436
Generation	Hammond Is - Replace sets 1, 2 & 3	Dec-12	$1,055,406
Generation	Wasaga - Augment step up transformers	Sep-12	$1,171,000

12.5 Updated Top 10 Urban Distribution Feeders for 2010/11

										Distribution Feeder Customer Minutes by event trigger (including upstream events) - 3 Yr window as a percentage																								
Asset Name	Cust	LINE (km)	Fdr Cat	Region	SAIDI 0809	SAIDI 0910	SAIDI 1011	SAIDI June 2012	Event Type	Animal / Bird	Conductor Connection Failure	Cyclone	Design Fault	Equipment Failure	Fire (External)	Floods	Forced Event	Generation failure - Isolated	Incorrect Phasing	Leakage Pole Top Fire	Lightning / Storm	Load Shed Ergon	No Trigger Found (Not Storm conditions)	Operational	Overload	Planned Event	Trees / Veg	Trip & Auto Reclose	Trip & Manual Reclose	UG Cable / Joint Failure	Unassisted Failure (Apparent defect)	Vandalism	Vehicle / Machinery Impact	Total per Event Type
Depot Hill	401	5.732	UR	CA	19	10	7,206	95	Dist_HV																	0.02								0.02
									Dist_LV		0.04						99.92						0.01			0.01								99.98
Bohle No.08	26	2.935	UR	NQ	4,980	266	158	53	Dist_HV																	3.12								3.12
									Dist_LV								91.40			0.09			0.30		0.07						0.08			91.94
									EE_SubTrans															0.18		4.76					0.00			4.94
Garbutt No.11	380	11.894	UR	NQ	214	328	1,387	111	Dist_HV	18.70							2.71							4.87		15.99			8.86		11.95		7.35	70.41
									Dist_LV	0.31	1.24						0.90				0.31	0.01	0.55			24.35					0.00	0.70		28.37
									EE_SubTrans																	1.22								1.22
Neil Smith No.11	367	6.828	UR	NQ	260	721	103	9	Dist_HV	0.28	29.18						1.76									1.95					11.68		8.34	53.18
									Dist_LV	0.31	0.12						0.63						2.58		0.01	3.08								6.74
									EE_SubTrans														13.21											13.21
									EE_Z_Sub		26.38													0.49										26.87
STEPTOE ST	61	6.989	UR	WB	271	2,031	3	148	Dist_HV																	73.95			16.60					90.55
									Dist_LV														0.04			9.34								9.38
									EE_SubTrans																				0.08					0.08
WHITFIELD	133	18.673	UR	FN	71	1,791	23	-	Dist_HV								26.29									58.04								84.33
									Dist_LV								3.41						0.04		3.75	8.47								15.67
SHINGLEY	659	10.736	UR	MK	478	445	1,098	58	Dist_HV	7.66	11.02						0.68						3.90	2.62		24.54	2.83		5.01	2.77				61.04
									Dist_LV	0.01	0.12	0.18					0.07						0.75			6.56				0.28				7.97
									EE_SubTrans		3.10																		2.37		11.06			16.52
									EE_Z_Sub								7.04			2.50									4.93					14.48
Julia Creek No.03 Town No 1	144	2.406	UR	NQ	1,736	606	432	1,804	Dist_HV	4.62																2.03			1.37		0.85			8.88
									Dist_LV	2.06	0.69												0.45			2.69					0.10			5.99
									EE_SubTrans	24.59							4.80				2.07		2.83		0.19	24.59		0.40			4.91			64.38
									EE_Z_Sub	8.51							5.76				3.13								3.35					20.75
11KV HOMEFIELD FDR	580	5.487	UR	MK	504	481	439	177	Dist_HV		9.08													3.57	2.01	30.45			6.68		8.25		9.30	69.35
									Dist_LV		1.60	0.17					0.90					0.00	2.94		0.00	5.62								11.23
									EE_SubTrans	2.99																7.96								10.94
									EE_Z_Sub	8.48																								8.48
11kV SCHAPERS RD FDR	367	14.239	UR	MK	117	234	874	11	Dist_HV								0.09						2.65			15.19	27.55							45.48
									Dist_LV		0.02						0.08						3.06		0.61	6.32				3.43	0.06		0.15	13.74
									EE_SubTrans		5.90			2.33			1.93									0.25								10.41
									EE_Z_Sub																				20.23		10.14			30.37

Updated Top 30 Short Rural Worst performing Feeders for 2010/11

										Distribution Feeder Customer Minutes by event trigger (including upstream events) - 3 Yr window as a percentage																									
Asset Name	**Cust**	**LINE (km)**	**Fdr Cat**	**Region**	**SAIDI 0809**	**SAIDI 0910**	**SAIDI 1011**	**SAIDI June 2012**	**Event Type**	**Animal / Bird**	**Conductor Connection Failure**	**Cyclone**	**Design Fault**	**Equipment Failure**	**Fire (External)**	**Floods**	**Forced Event**	**Generation failure - Isolated**	**Incorrect Phasing**	**Leakage Pole Top Fire**	**Lightning / Storm**	**Load Shed Ergon**	**No Trigger Found (Not Storm conditions)**	**Operational**	**Other Natural Disaster**	**Overload**	**Planned Event**	**Trees / Veg**	**Trip & Auto Reclose**	**Trip & Manual Reclose**	**UG Cable / Joint Failure**	**Unassisted Failure (Apparent defect)**	**Vandalism**	**Vehicle / Machinery Impact**	**Total per Event Type**
Merinda No.03	29	127.587	SR	NQ	1,234	(blank)	1,128	746	Dist_HV	0.25	1.61						3.21				15.81		1.29				62.78		0.01	0.17		1.62		5.94	92.71
									Dist_LV	0.01	0.14						0.02				0.09		2.35				1.84					0.15			4.60
									EE_SubTrans																				0.02	2.60					2.63
									EE_Z_Sub					0.06																					0.06
Shute Harbour	81	20.235	SR	MK	2,168	2,190	3,059	859	Dist_HV		4.87						0.86										16.88	8.22				8.21			39.04
									Dist_LV		0.01	0.09					0.04				0.01		0.61				0.32				0.03			0.69	1.82
									EE_SubTrans		8.63										1.64		1.04				2.65	14.88		0.39		23.99			53.21
									EE_Z_Sub		3.14						0.10															2.70			5.94
Yarrabee	28	150.727	SR	CA	1,107	1,166	18,286	666	Dist_HV	0.23	5.54					62.95	0.43			1.88	1.14		0.25				4.11			15.75				3.72	96.00
									Dist_LV	0.02					0.00		0.01				0.29		0.21							0.05					0.57
									EE_SubTrans								0.26			2.63				0.10						0.04		0.41			3.43
Barron Pocket	122	190.015	SR	MK	833	1,039	5,343	727	Dist_HV	12.28	14.85						0.80				4.81		3.04				19.37	10.26		11.74		7.48		1.99	86.63
									Dist_LV	0.07	0.02	1.98					0.12				0.11		1.32				0.17	0.00				0.02			3.81
									EE_SubTrans	4.37										2.10	2.88			0.06										0.16	9.57
Millaroo No.2	103	91.724	SR	NQ	5,164	3,188	3,960	1,933	Dist_HV	2.28	0.01						1.99			1.72	3.24		0.36				6.49			4.46		2.11		1.44	24.10
									Dist_LV	0.03							0.25				0.15		0.48				0.01					0.38		0.01	1.31
									EE_SubTrans	1.33							1.52										26.32	0.83		1.75		2.06			33.81
									EE_Z_Sub	0.63				2.74	3.45		0.29				7.05						1.48			12.27		12.88			40.78
COMET RURALS	27	43.444	SR	CA	407	1,370	10,341	1,646	Dist_HV							83.27	0.55						1.04				1.31			0.88					87.05
									Dist_LV	0.09											0.07		0.34				0.06								0.56
									EE_SubTrans								0.04				1.19									6.96		4.20			12.38
Millaroo No.1	46	59.395	SR	NQ	5,226	3,178	3,180	1,804	Dist_HV		4.50						1.41			1.18							10.20								17.29
									Dist_LV								0.07				0.49		0.40				0.59								1.55
									EE_SubTrans	1.40							1.40										28.35	0.91		1.88		2.20			36.14
									EE_Z_Sub	0.68				3.56	3.68		0.32				7.66						2.06			13.15		13.92			45.02
Ross Plains No.14	27	3.301	SR	NQ	(blank)	73	6,030	89	Dist_HV																		71.34								71.34
									Dist_LV		2.89													0.12		3.20	12.05								18.26
									EE_Z_Sub	10.40																									10.40
Rasmussen No.07 11kV feeder	71	26.377	SR	NQ	1,550	691	1,641	22	Dist_HV	9.96							11.43						2.79				37.31	0.16	0.45	6.86					68.95
									Dist_LV	0.07	0.02						0.02						3.56				1.04					0.07			4.77
									EE_SubTrans												25.85		0.43												26.28
NANDI - GRASSDALE	67	64.232	SR	SW	3,274	2,838	4,192	973	Dist_HV	3.30	2.55					37.20	0.92				5.27						1.44			0.89		0.48			52.06
									Dist_LV	0.03	0.09					0.45	0.03				0.21		0.58												1.39
									EE_SubTrans				0.04				3.38			6.35	20.22					0.20	13.45				1.80	0.45		0.68	46.56
Kirknie No.2 / NQEB No.1	74	48.345	SR	NQ	5,987	1,333	2,027	1,248	Dist_HV								44.75				4.32						5.27					10.24			64.58
									Dist_LV	0.05							0.00				0.00		0.36			0.01	0.02								0.45
									EE_SubTrans	2.06							1.80										6.20	1.05		1.08		0.97			13.16
									EE_Z_Sub	0.80					1.56						5.80									8.41		5.24			21.80
Jarvisfield No.4	314	84.190	SR	NQ	2,013	5,922	1,100	1,249	Dist_HV	9.42	23.50						1.39			1.53	3.74		0.13				14.48	1.12		1.28		38.39		2.65	97.63
									Dist_LV	0.03	0.06						0.06				0.12		0.85				0.01	0.01				0.07		1.10	2.32
									EE_SubTrans																		0.05								0.05

Asset Name	Cust	LINE (km)	Fdr Cat	Region	SAIDI 0809	SAIDI 0910	SAIDI 1011	SAIDI June 2012	Event Type	Distribution Feeder Customer Minutes by event trigger (including upstream events) - 3 Yr window as a percentage																									
										Animal / Bird	Conductor Connection Failure	Cyclone	Design Fault	Equipment Failure	Fire (External)	Floods	Forced Event	Generation failure - Isolated	Incorrect Phasing	Leakage Pole Top Fire	Lightning / Storm	Load Shed Ergon	No Trigger Found (Not Storm conditions)	Operational	Other Natural Disaster	Overload	Planned Event	Trees / Veg	Trip & Auto Reclose	Trip & Manual Reclose	UG Cable / Joint Failure	Unassisted Failure (Apparent defect)	Vandalism	Vehicle / Machinery Impact	Total per Event Type
MtFox No.1 SWER	48	73.987	SR	FN	2,687	1,413	4,812	1,678	Dist_HV		4.70										1.89		9.35				8.68								24.61
									Dist_LV								0.03				0.07						0.09	0.35				0.02			0.56
									EE_SubTrans	0.27											0.06														0.33
									EE_Z_Sub		19.70					6.31					6.78						19.78	1.14		3.37		17.42			74.49
11KV LANN-03 FDR	356	130.101	SR	FN	3,951	2,751	1,637	2,661	Dist_HV	1.20	0.83						4.65				4.45		7.20				18.70			1.51		11.57		1.59	51.69
									Dist_LV	0.04	0.35						0.03				0.48		0.31				0.07			0.00		0.36		0.01	1.65
									EE_SubTrans	1.63				2.06									2.53	0.07			1.47			4.17					11.93
									EE_Z_Sub	0.82	2.26			7.24			6.90				2.32											15.18			34.73
TIPTON BRIDGE	45	60.871	SR	SW	1,625	2,934	3,856	1,151	Dist_HV		4.39						1.24				3.85		1.40				5.93			3.40		33.62			53.83
									Dist_LV		0.05						0.08				0.51		3.39									1.11			5.14
									EE_SubTrans												2.79						3.68								6.47
									EE_Z_Sub	1.18	4.59		4.06		0.01		1.10			3.71	3.88		1.57			1.59	3.96			4.80		4.11			34.56
EL ARISH	395	168.993	SR	FN	1,808	1,702	1,203	315	Dist_HV	0.02							2.12				15.52		6.79				31.59	8.91		4.86		11.92		1.49	83.23
									Dist_LV	0.02							0.06				1.12		0.38				1.09	0.16				0.32		0.03	3.17
									EE_SubTrans														3.77	0.23		0.28						2.66			6.94
									EE_Z_Sub	6.66																									6.66
Jarvisfield No.5	240	49.241	SR	NQ	3,451	3,268	902	1,083	Dist_HV	10.68	4.28						2.22				1.24		32.39				40.07					5.13		1.56	97.58
									Dist_LV	0.01							0.05				0.22		0.53				0.17					0.03		0.01	1.04
									EE_SubTrans					1.37													0.02								1.39
Mutarnee No.1	196	60.217	SR	FN	4,551	1,256	1,896	2,621	Dist_HV	0.05	2.46						2.32				25.21		0.72				20.10	9.21		1.71		3.15			64.94
									Dist_LV	0.41							0.06	0.09			0.11		0.45				0.20			0.01					1.33
									EE_SubTrans											5.62	0.07														5.69
									EE_Z_Sub		9.02					3.76					3.85							1.25		1.72		8.44			28.05
11KV LANN-05 FDR	306	96.506	SR	FN	4,213	2,166	1,144	1,111	Dist_HV	0.06	12.31						1.08				0.25		1.48	0.14			23.59					5.44		1.37	45.73
									Dist_LV	0.34	0.20						0.02				0.47		0.39			0.02	0.08	0.00	0.00			0.19			1.72
									EE_SubTrans	1.86				2.31									2.14	0.08			2.64			5.53					14.56
									EE_Z_Sub	0.46	2.35			8.50			8.23				2.42											16.02			37.99
Northern	587	125.897	SR	MK	955	4,143	414	689	Dist_HV		7.13						4.82				1.63					1.59	34.97			1.17	24.39	1.38		0.89	77.99
									Dist_LV	0.06	0.16	0.11		0.00			0.05				0.34		0.75			0.21	1.30	0.00			0.01				2.98
									EE_SubTrans														1.68			0.35	7.81					9.20			19.03
LOUDOUN	44	38.825	SR	SW	3,648	2,789	997	872	Dist_HV	10.47	3.27						1.84				8.53		2.38				4.33					0.23		1.74	32.79
									Dist_LV	0.11							3.37				0.29		0.41				0.03								4.22
									EE_SubTrans				0.05				4.64			8.74	27.31					0.27	17.95				2.47	0.62		0.93	62.98
CLIFTON WEST	291	177.237	SR	SW	2,865	1,572	2,747	2,197	Dist_HV		2.37					32.41	2.58				10.03		1.38				18.11	3.50	0.66	9.66				2.57	83.27
									Dist_LV	0.02	0.11						0.10				2.85		0.48				0.28					0.12		0.09	4.04
									EE_Z_Sub												4.55		1.59				6.55								12.69
Macknade No.09	236	98.814	SR	FN	4,567	646	1,974	1,140	Dist_HV	1.29	2.98						4.59			1.14	29.18		0.21				16.83	0.43	0.02	0.10		2.40			59.18
									Dist_LV	0.03	0.04						0.12				0.06		0.11				0.22	0.03		0.00		0.01		0.01	0.63
									EE_SubTrans	0.36										1.26	2.48						3.19								7.29
									EE_Z_Sub		14.48			2.80			0.48			1.29	1.28						2.78	2.16				2.16		5.46	32.90

Asset Name	Cust	LINE (km)	Fdr Cat	Region	SAIDI 0809	SAIDI 0910	SAIDI 1011	SAIDI June 2012	Event Type	Distribution Feeder Customer Minutes by event trigger (including upstream events) - 3 Yr window as a percentage																									
										Animal / Bird	Conductor Connection Failure	Cyclone	Design Fault	Equipment Failure	Fire (External)	Floods	Forced Event	Generation failure - Isolated	Incorrect Phasing	Leakage Pole Top Fire	Lightning / Storm	Load Shed Ergon	No Trigger Found (Not Storm conditions)	Operational	Other Natural Disaster	Overload	Planned Event	Trees / Veg	Trip & Auto Reclose	Trip & Manual Reclose	UG Cable / Joint Failure	Unassisted Failure (Apparent defect)	Vandalism	Vehicle / Machinery Impact	Total per Event Type
BRUCE HIGHWAY	72	23.820	SR	NQ	782	1,208	1,710	1,005	Dist_HV	7.34	12.07						0.63			8.73							19.32	9.84		8.61		19.79		9.14	95.46
									Dist_LV	0.02							0.19						0.10				3.97	0.20				0.06			4.54
Kungurri	295	138.131	SR	MK	1,082	2,119	2,040	774	Dist_HV	1.58	3.44						12.28				7.86		2.92				32.78	1.64		4.96		8.11		12.46	88.03
									Dist_LV	0.15	0.84						0.29				0.20		1.13				0.13					0.14			2.87
									EE_SubTrans								0.75				0.98									7.37					9.10
Woodstock No.01	226	144.646	SR	NQ	2,278	789	3,631	2,645	Dist_HV	2.76	14.68						3.67				3.39		6.71				16.61	8.50		2.31		8.65		9.05	76.33
									Dist_LV								0.03				0.05		0.35				0.11	0.02				0.16			0.72
									EE_SubTrans		2.87		1.27				2.46			2.56	1.67							2.43		3.19		6.51			22.95
BRYMAROO	103	104.987	SR	SW	3,205	1,875	1,674	1,381	Dist_HV								3.57				12.40						11.59			4.84		0.34			32.75
									Dist_LV	0.02	0.05						0.01	0.36			1.28		0.96				0.41					0.10			3.20
									EE_SubTrans								7.87				0.29		2.62			2.50				2.76				0.00	16.05
									EE_Z_Sub								0.43			5.18	14.10						9.77			4.97		13.54			48.00
Weir	148	69.073	SR	MK	3,146	2,413	1,010	1,250	Dist_HV	2.08	28.76						2.88				0.20		7.22	0.24			20.19			1.03		5.36		7.90	75.86
									Dist_LV	0.03	0.03						0.13				0.03		1.39				0.06								1.67
									EE_SubTrans	0.36	3.44						0.42				3.80			0.03		0.27				8.32		4.94			21.59
									EE_Z_Sub															0.88											0.88
GREENMOUNT	491	153.339	SR	SW	1,407	3,206	709	707	Dist_HV		2.58						1.79				21.80		0.05	0.10		3.24	19.76			5.48		6.02			60.82
									Dist_LV	0.71	0.07						0.03				2.61		0.83	0.14			0.86	0.27		0.00		0.00		0.07	5.59
									EE_Z_Sub												17.16		3.39				13.04								33.59
HOPEVALE	678	139.210	SR	FN	3,414	2,418	708	450	Dist_HV						1.40		5.28			10.54			0.09				48.92	5.30		0.23		7.94	0.69		80.40
									Dist_LV	0.12							0.35				0.25		0.26				0.69	0.01				0.01			1.68
									EE_SubTrans		1.15			0.42			0.18				2.80						0.81			0.12					5.48
									EE_Z_Sub						11.63								0.11	0.11			0.49					0.10			12.44

Updated Top 10 Long Rural Distribution Feeders for 2010/11

										Distribution Feeder Customer Minutes by event trigger (including upstream events) - 3 Yr window as a percentage																									
Asset Name	Cust	LINE (km)	Fdr Cat	Region	SAIDI 0809	SAIDI 0910	SAIDI 1011	SAIDI June 2012	Event Type	Animal / Bird	Conductor Connection Failure	Cyclone	Design Fault	Equipment Failure	Fire (External)	Floods	Forced Event	Generation failure - Isolated	Incorrect Phasing	Leakage Pole Top Fire	Lightning / Storm	Load Shed Ergon	No Trigger Found (Not Storm conditions)	Operational	Other Natural Disaster	Overload	Planned Event	Trees / Veg	Trip & Auto Reclose	Trip & Manual Reclose	UG Cable / Joint Failure	Unassisted Failure (Apparent defect)	Vandalism	Vehicle / Machinery Impact	Total per Event Type
Tanby	136	242.2	LR	CA	842	477	750	191	Dist_HV	0.04	2.41						3.47			7.60	7.44		0.77	0.66			3.98		0.07	13.19		16.21	0.27	6.77	62.88
									Dist_LV	0.32	0.08						0.44			0.00	0.07		1.18			0.16	1.46	0.10				0.40		0.66	4.88
									EE_SubTrans	10.91														0.29							9.48	1.29		3.75	25.72
									EE_Z_Sub											2.58	1.48					0.89				0.28				1.29	6.53
BURKETOWN	64	800.1969	LR	FN	2,435	5,122	6,884	9,989	Dist_HV	7.73	0.06				3.18		7.92			3.13	11.12		4.03				21.39		0.08	12.34		6.98			77.97
									Dist_LV												2.76		1.23				0.24					0.31			4.54
									EE_SubTrans												7.11						2.77			1.00					10.88
									EE_Z_Sub	3.51																	0.59			2.52					6.62
Township No 4	167	595.922	LR	MK	1,355	1,968	1,766	1,103	Dist_HV	24.47	0.29				0.44		1.54			0.36	14.41		0.58			0.77	32.36	0.04	0.00	1.68				4.31	81.24
									Dist_LV	0.02	0.09		0.10				1.51				0.16		0.55				8.29	1.78				0.28			12.78
									EE_SubTrans								0.12				5.42						0.30					0.13			5.98
Julia Creek No.13 SWER - TALDOORA	35	378.2935	LR	NQ	4,734	3,795	3,429	3,177	Dist_HV	1.84	10.58						1.61				36.13		0.33			0.62	7.14	0.59		0.16					59.02
									Dist_LV		0.36						0.05				7.48		1.00				0.18								9.08
									EE_SubTrans	4.94	1.20						1.10				0.50		0.70			0.05	9.38		0.10	0.13		1.15			19.23
									EE_Z_Sub	2.05							1.35				8.35									0.93					12.67
Julia Creek No.08 SWER - CANOBIE	36	312.9121	LR	NQ	4,511	2,321	3,679	4,673	Dist_HV	7.59							0.16				56.39		1.74				2.20			2.48					70.56
									Dist_LV	0.02	0.06						0.08				0.10		2.52				0.03								2.81
									EE_SubTrans	5.47	1.22						1.25				0.56		0.78			0.05	10.64		0.11			1.30			21.39
									EE_Z_Sub	1.77							1.53				0.91									1.02					5.23
Greenvale No.1	208	496.9208	LR	NQ	3,830	2,035	4,749	7,292	Dist_HV		0.75						2.16				14.04		3.49				8.54			4.44					33.44
									Dist_LV	1.44							0.19				0.28		0.13				0.07					0.12			2.23
									EE_SubTrans	0.23											0.05														0.28
									EE_Z_Sub		16.28					5.02					2.83						21.10	0.90		2.66		15.26			64.06
Richmond Nth SWER No.01	30	214.595	LR	NQ	6,996	746	2,051	3,607	Dist_HV		6.33						0.05				53.79						10.47			2.21		16.79		0.36	90.00
									Dist_LV		0.07										0.43		0.65				0.57								1.71
									EE_SubTrans	0.95				0.42			0.27				0.61		0.29			0.06	2.63		0.12			1.40			6.73
									EE_Z_Sub								1.56																		1.56
MUNGALLALA	173	839.8882	LR	SW	3,388	3,269	2,565	2,460	Dist_HV		0.02						3.25			0.70	25.27		1.04				6.88			3.55		6.97			47.67
									Dist_LV	0.04							0.04				2.09		0.82				0.06					0.06			3.11
									EE_SubTrans		6.36						0.14		###	1.49	13.79					0.14	1.73	5.83		1.91		12.71		3.58	49.22
COLLINSVILLE NO 2	135	870.5036	LR	NQ	2,549	4,441	2,453	6,787	Dist_HV	0.96	0.49				16.23		3.12				25.25						13.02			0.52		9.30		1.92	70.80
									Dist_LV	0.16	0.03						0.05				0.75		0.43				0.37					0.44			2.23
									EE_SubTrans	2.96	7.27			0.06	0.25		3.28			0.73	2.84		1.28	0.12			0.55			5.88		1.75			26.97
Elderslie SWER No.01	42	400.5797	LR	NQ	1,823	4,344	2,660	4,622	Dist_HV		2.15						0.10			1.25	51.82						4.63			1.43					61.38
									Dist_LV		0.25						0.06				1.22		0.33				0.05								1.90
									EE_SubTrans		16.02						1.31				0.66		0.33			0.06	8.94		0.11	2.31		1.56			31.31
									EE_Z_Sub								2.24										3.16								5.40

12.6 Analysis of 2011/12 worst performing feeders

Top 10 Urban Worst performing Feeders for 2011/12 (3 year average)

										Distribution Feeder Customer Minutes by event trigger (including upstream events) - 3 year window as a percentage																									
Asset Name	Cust @ June 2012	Line (km)	Fdr Cat	Region	2009/10 SAIDI	2010/11 SAIDI	2011/12 SAIDI	SAIDI 3 Year Average	Event Type	Animal / Bird	Conductor Connection Failure	Cyclone	Design Fault	Equipment Failure	Fire (External)	Floods	Forced Event	Generation failure Isolated	Incorrect Phasing	Leakage Pole Top Fire	Lightning / Storm	Load Shed Ergon	No Trigger Found (Not Storm conditions)	Operational	Other Natural Disaster	Overload	Planned Event	Trees / Veg	Trip & Auto Reclose	Trip & Manual Reclose	UG Cable / Joint Failure	Unassisted Failure (Apparent defect)	Vandalism	Vehicle / Machinery Impact	Total - Event Type / Feeder
Julia Creek No.03 Town No 1	149	2.406	UR	NQ	610	421	1,804	945	Dist_HV	4.83																	2.12			0.50		0.89			8.34
									Dist_LV	2.15	0.72												0.47				3.05					0.11			6.50
									EE_SubTrans	6.19							4.06			17.00	1.43		1.03			0.93	23.57		0.42	1.64		1.32			57.59
									EE_Z_Sub	13.47							7.16				3.27						0.15			3.50					27.55
CECIL PLAINS TOWN	140	2.520	UR	SW	1,006	628	769	801	Dist_HV																		10.58								10.58
									Dist_LV														0.02												0.02
									EE_SubTrans					3.39																4.11					7.50
									EE_Z_Sub	5.60				5.13			27.40			25.86	0.89						0.78				1.85	14.39			81.90
KRATZKE ROAD FDR	613	12.271	UR	SW	949	747	621	772	Dist_HV		7.87						4.13						17.79	0.36		0.49	15.50	13.49		3.92				6.08	69.63
									Dist_LV	0.19	0.36			0.02			0.20				1.38		2.58			0.03	1.42	0.43				0.15			6.76
									EE_Z_Sub																			0.69				8.24		14.67	23.60
WILLOWBURN	966	9.396	UR	SW	601	578	842	674	Dist_HV	18.84	14.69						11.73				5.71						5.10			0.74		13.24			70.05
									Dist_LV	0.22	0.63						0.22			0.09			1.32	1.91			0.89							1.77	7.05
									EE_SubTrans					4.47																0.63		15.74		2.05	22.89
ROMA COLLEGE	636	6.508	UR	SW	213	540	1,256	669	Dist_HV	3.10	26.38															2.05	0.93							17.18	49.64
									Dist_LV	0.28	0.09						0.43				0.17		0.53				0.84					0.01			2.35
									EE_SubTrans								0.20										0.75			1.53		2.61			5.09
									EE_Z_Sub								0.10				21.69					0.62				9.67				10.83	42.91
RUTHVEN STREET	412	4.062	UR	SW	735	207	726	556	Dist_HV		17.43						5.49										24.76			9.24		5.57		4.16	66.65
									Dist_LV								1.25				0.01						2.81								4.07
									EE_SubTrans					5.71																1.35		19.61		2.61	29.28
Industrial	128	9.166	UR	MK	614	577	468	553	Dist_HV	9.44	4.64												10.82			1.88	2.67			6.62	11.29			15.60	62.96
									Dist_LV								0.11						0.32			0.22	4.28				0.11	1.13			6.17
									EE_SubTrans																					6.15		15.25			21.40
									EE_Z_Sub					4.13										1.74						3.57					9.44
CARLYLE ST FDR	197	2.991	UR	MK	1,290	36	261	529	Dist_HV																		2.30								2.30
									Dist_LV																		13.68								13.68
									EE_SubTrans	0.65				6.99								1.88		1.48						0.26	69.77				81.03
									EE_Z_Sub																							2.99			2.99
GORDON ST WEST FDR 11KV	90	4.000	UR	MK	1,002	260	212	491	Dist_HV		5.52													0.54			3.07	14.29		11.18					34.60
									Dist_LV			25.64											3.21				0.78								29.63
									EE_SubTrans	2.46																	33.30								35.76
									EE_Z_Sub																										
COOK NO 3	944	22.154	UR	FN	95	836	508	480	Dist_HV	4.17	6.85						2.85										20.35	26.18		15.23		15.54			91.17
									Dist_LV								0.14						0.77				3.94	0.54						0.07	5.46
									EE_SubTrans					1.62										1.75											3.37

Top 30 Short Rural Worst performing Feeders for 2011/12 (3 year average)

										Distribution Feeder Customer Minutes by event trigger (including upstream events) - 3 year window as a percentage																									
Asset Name	Cust @ June 2012	Line (km)	Fdr Cat	Region	2009/10 SAIDI	2010/11 SAIDI	2011/12 SAIDI	SAIDI 3 Year Average	Event Type	Animal / Bird	Conductor Connection Failure	Cyclone	Design Fault	Equipment Failure	Fire (External)	Floods	Forced Event	Generation failure - Isolated	Incorrect Phasing	Leakage Pole Top Fire	Lightning / Storm	Load Shed Ergon	No Trigger Found (Not Storm conditions)	Operational	Other Natural Disaster	Overload	Planned Event	Trees / Veg	Trip & Auto Reclose	Trip & Manual Reclose	UG Cable / Joint Failure	Unassisted Failure (Apparent defect)	Vandalism	Vehicle / Machinery Impact	Total - Event Type / Feeder
Millaroo No.2	100	91.594	SR	NQ	3,142	4,030	1,933	3,035	Dist_HV	10.91							1.09			2.34	0.25		0.48				5.38			6.05		2.27		2.57	31.34
									Dist_LV	0.05											0.09		0.53				0.02					0.02		0.02	0.73
									EE_SubTrans	3.72							1.78										30.45	1.13		2.38					39.46
									EE_Z_Sub	0.85					4.69						5.37						1.55			6.12		9.87			28.45
Jarvisfield No.4	319	83.630	SR	NQ	5,894	1,107	1,249	2,750	Dist_HV	4.98	25.52						3.54			1.68	2.06		0.05	0.50			13.25			3.10		37.84		4.07	96.59
									Dist_LV	0.12	0.05						0.08				0.06		0.67				0.26	0.01				0.08		0.01	1.34
									EE_SubTrans	1.09																	0.16							0.83	2.08
Millaroo No.1	48	59.395	SR	NQ	3,116	3,208	1,804	2,709	Dist_HV						1.97		1.74			1.66							18.34								23.71
									Dist_LV								0.10				0.69		0.62				0.72							0.03	2.16
									EE_SubTrans	2.32							1.97										34.00	1.27		2.65					42.21
									EE_Z_Sub	0.96					5.17						6.08						1.71			6.87		11.13			31.92
NANDI - GRASSDALE	69	63.486	SR	SW	2,823	4,269	973	2,688	Dist_HV	4.26	0.43					48.01	3.33				4.17		0.39				4.74			1.15					66.48
									Dist_LV	0.05	0.12						0.03				0.19		0.68				0.12								1.19
									EE_SubTrans				0.05				3.00			8.19	6.11					0.25	10.25			0.24	2.32	0.16		0.87	31.44
									EE_Z_Sub																					0.89					0.89
TIPTON BRIDGE	47	60.869	SR	SW	2,945	3,772	1,151	2,623	Dist_HV		5.00						2.63										1.71			3.75		35.49			48.58
									Dist_LV		0.03						0.04				0.65		4.10									0.31			5.13
									EE_SubTrans					2.14													3.88			1.25					7.27
									EE_Z_Sub	1.25	4.84		4.29				1.10			8.84	4.09		1.65			1.67	1.72			5.24		4.34			39.03
MtFox No.1 SWER	46	72.769	SR	NQ	1,428	4,714	1,678	2,607	Dist_HV														10.61				7.29								17.90
									Dist_LV								0.06				0.05						0.09	0.40							0.60
									EE_SubTrans	0.31							1.74			6.88			3.60				5.19					2.09			19.81
									EE_Z_Sub		22.36										3.88						20.33			0.27		14.86			61.70
MYWYBILLA	83	73.388	SR	SW	3,047	1,353	3,351	2,584	Dist_HV	4.53	7.63						1.76				7.02		3.03				11.53					21.62		1.82	58.94
									Dist_LV		0.14				0.01		0.01				0.86		1.48				0.05								2.55
									EE_SubTrans					1.03													2.18			1.23					4.44
									EE_Z_Sub	1.27	4.91		4.35				1.11			9.06	0.91		0.03			1.70	0.96			5.34		4.45			34.09
Hughenden No.20 33kV feeder	26	145.863	SR	NQ	824	1,998	4,811	2,544	Dist_HV	2.81	1.31						5.48			2.24	22.82						6.27			2.95		7.55			51.43
									Dist_LV												0.08		0.45				0.17			0.21					0.91
									EE_SubTrans	0.32				0.69						0.58	15.65		0.32			0.22	0.32	1.42	0.12	6.11		21.89			47.64
CARBINE	612	151.637	SR	FN	4,008	1,025	2,377	2,470	Dist_HV								2.26				1.19		13.04				12.56	8.27				4.37			41.69
									Dist_LV	0.07	0.01						0.11				0.33		0.13				0.27	0.08		0.02				0.01	1.03
									EE_SubTrans	4.37	1.63						0.58			1.34	3.21						2.71			9.12					22.96
									EE_Z_Sub		4.03						1.27				2.10		2.44				7.71	2.81		5.30		6.51		2.13	34.30
CAPEFERGUSON NO.02	334	47.620	SR	NQ	900	1,522	4,810	2,411	Dist_HV	5.80	5.13				0.16		5.74										10.57					12.14			39.54
									Dist_LV	0.01							0.01				0.01		0.20				0.24								0.47
									EE_SubTrans								0.10			5.21				0.39			3.79								9.49
									EE_Z_Sub	1.59					13.19		2.29						2.23				2.48	13.58		0.48		14.66			50.50

										Distribution Feeder Customer Minutes by event trigger (including upstream events) - 3 year window as a percentage																									
Asset Name	Cust @ June 2012	Line (km)	Fdr Cat	Region	2009/10 SAIDI	2010/11 SAIDI	2011/12 SAIDI	SAIDI 3 Year Average	Event Type	Animal / Bird	Conductor Connection Failure	Cyclone	Design Fault	Equipment Failure	Fire (External)	Floods	Forced Event	Generation failure Isolated	Incorrect Phasing	Leakage Pole Top Fire	Lightning / Storm	Load Shed Ergon	No Trigger Found (Not Storm conditions)	Operational	Other Natural Disaster	Overload	Planned Event	Trees / Veg	Trip & Auto Reclose	Trip & Manual Reclose	UG Cable / Joint Failure	Unassisted Failure (Apparent defect)	Vandalism	Vehicle / Machinery Impact	Total - Event Type / Feeder
Woodstock No.01	231	144.225	SR	NQ	790	3,627	2,645	2,354	Dist_HV	7.65	11.07						5.98						4.59	0.04			9.52	7.97		2.17		7.09		8.49	64.57
									Dist_LV	0.01							0.01				0.03		0.45				0.09					0.10			0.69
									EE_SubTrans		2.69		1.19		4.55		7.47			2.40										6.80		9.63			34.73
Woodstock No.02	209	88.032	SR	NQ	1,269	2,468	3,170	2,302	Dist_HV	1.80	2.00						9.12				2.05		4.00				18.31	3.87		7.78		13.47			62.40
									Dist_LV	0.14	0.02						0.01				0.07		1.34			0.01	0.09					0.07			1.75
									EE_SubTrans		0.91		1.20		4.64		7.74			2.54										6.97		11.87			35.87
Gumlu No.1	71	86.841	SR	NQ	1,624	1,637	2,985	2,082	Dist_HV	4.87	9.19						2.43			0.31			1.42				17.62			1.93		14.85			52.62
									Dist_LV	0.04	0.01						0.26			0.01			0.79				0.12					0.03			1.26
									EE_SubTrans						0.61					9.13	14.54		1.34						0.02	5.03		5.19			35.86
									EE_Z_Sub						1.52															6.85		1.89			10.26
11KV LANN-02 FDR	350	145.543	SR	NQ	-	-	1,974	1,974	Dist_HV	3.47	18.75						3.28				2.04		0.27			0.52	40.83	1.98				10.87			82.01
									Dist_LV	0.01	0.09						0.01				0.02		0.43				0.74					0.02		0.12	1.44
									EE_Z_Sub	2.38							14.16																		16.54
Guthalungra No.1	247	125.651	SR	NQ	2,446	723	2,747	1,972	Dist_HV						15.95		0.07						4.13				45.28			3.11					68.54
									Dist_LV												0.45		0.88				1.12								2.45
									EE_SubTrans						0.61					8.66	2.68		1.85						0.02	5.23					19.05
									EE_Z_Sub						1.59															6.26		2.11			9.96
STEWART CREEK	102	76.408	SR	FN	3,045	1,061	1,761	1,956	Dist_HV								7.87				2.12		2.20				25.54	25.49		7.90		10.72		0.73	82.57
									Dist_LV	0.46	0.07						0.15						0.04				2.81							0.02	3.55
									EE_SubTrans	0.84				2.72							4.06									6.25					13.87
									UNPLZCE																										
BALD HILLS	71	82.160	SR	SW	3,753	850	1,188	1,930	Dist_HV								0.71				3.49		5.86				11.94					11.92		4.81	38.73
									Dist_LV		0.02						0.20				0.61		0.79				0.03					0.11			1.76
									EE_SubTrans					1.42													15.21			1.70					18.33
									EE_Z_Sub	1.69	6.46		5.72				1.48			7.02	1.19		0.05			2.23	2.54			7.01		5.78			41.17
Mutarnee No.1	199	63.297	SR	NQ	1,249	1,890	2,621	1,920	Dist_HV	0.12	1.39						3.15				2.28		1.51				34.40			2.28		17.48			62.61
									Dist_LV	0.55	0.05						0.09	0.12			0.09		0.82				0.41	0.02		0.02		0.29			2.46
									EE_SubTrans		1.67						0.05			1.12			5.04									8.94			16.82
									EE_Z_Sub		12.06										5.15									0.35		0.55			18.11
HORRANE	83	79.763	SR	SW	2,896	926	1,741	1,854	Dist_HV		7.24						4.92			8.76			0.50				32.03			0.86				3.18	57.49
									Dist_LV	0.20	0.04						0.04				1.47		2.31				0.13								4.19
									EE_SubTrans					1.46																1.76					3.22
									EE_Z_Sub	2.24				2.25			11.76			11.12	0.39						0.34				0.79	6.21			35.10
EVERGREEN	169	127.706	SR	SW	2,241	1,286	1,960	1,829	Dist_HV					3.69			3.56				4.82		1.46				27.20	2.10		6.07					48.90
									Dist_LV	0.02	0.28						0.07				0.71		0.44				0.13								1.65
									EE_SubTrans									3.89												0.23				4.07	8.19
									EE_Z_Sub											6.17	10.99						9.89			5.98		8.21			41.24
CLARESOUTH NO.04	57	45.569	SR	NQ	2,389	803	2,240	1,811	Dist_HV	3.20	12.92						7.64			32.72							18.36				21.42				96.26
									Dist_LV	0.09							0.03				1.54		1.28				0.02								2.96
									EE_SubTrans												0.38														0.38
									EE_Z_Sub								0.41																		0.41

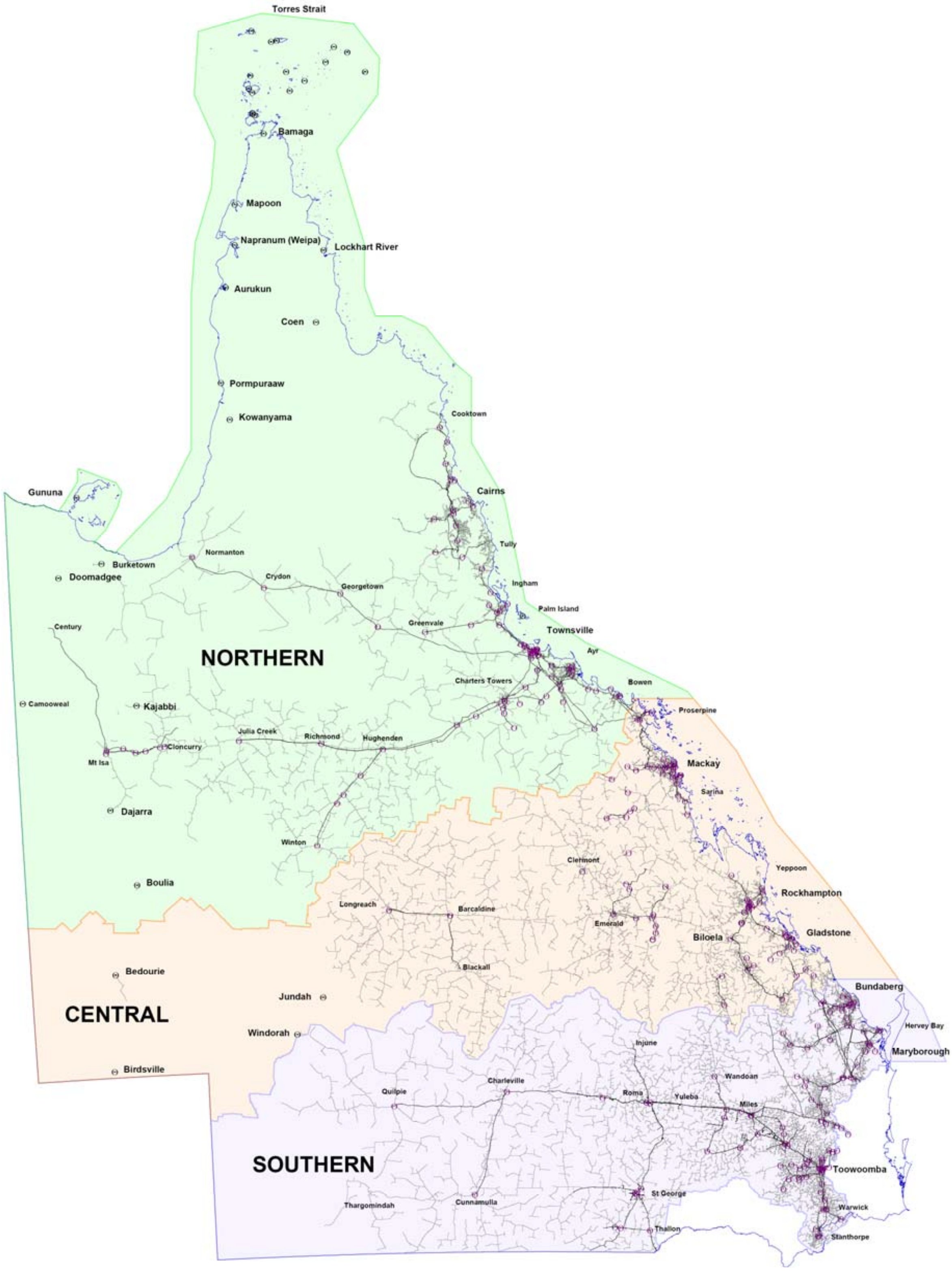
										Distribution Feeder Customer Minutes by event trigger (including upstream events) - 3 year window as a percentage																									
Asset Name	Cust @ June 2012	Line (km)	Fdr Cat	Region	2009/10 SAIDI	2010/11 SAIDI	2011/12 SAIDI	SAIDI 3 Year Average	Event Type	Animal / Bird	Conductor Connection Failure	Cyclone	Design Fault	Equipment Failure	Fire (External)	Floods	Forced Event	Generation failure - Isolated	Incorrect Phasing	Leakage Pole Top Fire	Lightning / Storm	Load Shed Ergon	No Trigger Found (Not Storm conditions)	Operational	Other Natural Disaster	Overload	Planned Event	Trees / Veg	Trip & Auto Reclose	Trip & Manual Reclose	UG Cable / Joint Failure	Unassisted Failure (Apparent defect)	Vandalism	Vehicle / Machinery Impact	Total - Event Type / Feeder
KARUMBA	380	70.404	SR	FN	3,238	821	1,312	1,790	Dist_HV	2.49							2.85				1.06					0.11	16.80			1.82		10.37			35.50
									Dist_LV	0.27	0.01						1.48						0.34				0.09								2.19
									EE_SubTrans												18.73						6.22			6.13					31.08
									EE_Z_Sub	9.35				8.16							0.28						1.57			11.89					31.25
Ravenswood No.1 SWER	50	151.275	SR	NQ	1,304	1,960	2,062	1,775	Dist_HV								5.22				4.37		11.51				8.92			0.58		4.79			35.39
									Dist_LV																		0.18								0.18
									EE_SubTrans	3.08																	2.71			0.46		8.75		3.67	18.67
									EE_Z_Sub	7.96	2.23				0.41					7.36	2.29									17.69		7.83			45.77
Mingela No.2 SWER	41	95.731	SR	NQ	1,208	2,561	1,537	1,769	Dist_HV		0.23						1.93						1.70				15.07			3.76					22.69
									Dist_LV	0.09							0.32				0.29		0.05				0.74								1.49
									EE_SubTrans		1.52		1.62		5.80		22.89			3.22							17.73			7.75		5.98			66.51
									EE_Z_Sub	1.82							0.06				1.89						2.29			3.23					9.29
Mingela No.1 SWER	22	81.032	SR	NQ	647	2,287	2,298	1,744	Dist_HV								2.08										15.49								17.57
									Dist_LV												4.04		0.17				1.07								5.28
									EE_SubTrans		1.53		1.64		5.88		23.24			3.34							17.92			7.91		6.17			67.63
									EE_Z_Sub	1.84							0.06				1.91						2.44			3.29					9.54
NOBBY	441	198.766	SR	SW	2,476	1,019	1,730	1,741	Dist_HV	2.99	13.71						9.67			3.36	19.36		0.32				12.99			6.45		2.13		8.58	79.56
									Dist_LV	0.02	0.07						0.01				0.86		0.80				0.41	0.01				0.11			2.29
									EE_SubTrans																							5.40			5.40
									EE_Z_Sub								0.05				1.05		2.17				8.30			1.18					12.75
Jarvisfield No.5	244	49.141	SR	NQ	3,233	879	1,083	1,731	Dist_HV	10.42	9.37						4.49			1.29	0.70		8.02				49.80			1.00		7.53		2.30	94.92
									Dist_LV								0.10				0.32		0.63				0.25					0.05			1.35
									EE_SubTrans	1.68				2.01													0.03								3.72
FORMARTIN	81	103.920	SR	SW	3,769	459	947	1,725	Dist_HV								4.83				6.26						0.56			5.76					17.41
									Dist_LV	0.08	1.27						0.04				1.39		0.74				0.07					0.35			3.94
									EE_SubTrans					3.30													17.10			1.93					22.33
									EE_Z_Sub	1.87	7.26		6.43				1.65			13.58	6.11		2.53			2.51				7.87		6.50			56.31
HANNANS ROAD	269	141.273	SR	MK	2,262	1,017	1,867	1,715	Dist_HV	3.15	7.86	16.90					1.89			3.73	5.14		3.08				7.06			2.85		13.48			65.14
									Dist_LV	0.39	0.54						0.04			0.02	0.03		6.83				0.91					0.07		0.53	9.36
									EE_Z_Sub	2.16			0.31							0.94	12.73									7.02		2.34			25.50
11kV RO-01 FDR	617	45.557	SR	NQ	2,160	2,227	730	1,705	Dist_HV	8.43	4.36						0.86										29.77			5.14		2.39			50.95
									Dist_LV								0.02				0.19		0.46			0.27	1.72								2.66
									EE_SubTrans															0.27						1.57					1.84
									EE_Z_Sub	4.80	9.50										2.71		1.95							4.22				21.38	44.56

Top 10 Long Rural Distribution Feeders for 2011/12 (3 Year average)

Asset Name	Cust @ June 2012	Line (km)	Fdr Cat	Region	2009/10 SAIDI	2010/11 SAIDI	2011/12 SAIDI	SAIDI 3 Year Average	Event Type	Animal / Bird	Conductor Connection Failure	Cyclone	Design Fault	Equipment Failure	Fire (External)	Floods	Forced Event	Generation failure Isolated	Incorrect Phasing	Leakage Pole Top Fire	Lightning / Storm	Load Shed Ergon	No Trigger Found (Not Storm conditions)	Operational	Other Natural Disaster	Overload	Planned Event	Trees / Veg	Trip & Auto Reclose	Trip & Manual Reclose	UG Cable / Joint Failure	Unassisted Failure (Apparent defect)	Vandalism	Vehicle / Machinery Impact	Total - Event Type / Feeder
BURKETOWN	64	810.056	LR	FN	5,122	6,912	9,989	7,341	Dist_HV	5.02	0.43				9.99		6.14			6.79	13.35		4.97			0.02	14.69		0.02	11.43		5.10			77.95
									Dist_LV												1.57		0.95				4.42								6.94
									EE_SubTrans												4.59						1.49			1.49					7.57
									EE_Z_Sub	2.28				1.94							0.07						0.38			2.89					7.56
Greenvale No.1	205	485.719	LR	NQ	2,118	4,827	7,292	4,745	Dist_HV	0.60	1.78				2.45		1.56				8.04		2.90				4.49			1.38					23.20
									Dist_LV	1.00							0.01				0.03		0.12				0.47					5.70			7.33
									EE_SubTrans	0.17	0.54						0.98			12.76			2.04				1.31					10.25			28.05
									EE_Z_Sub		12.05										2.09						18.34			0.14		8.78			41.40
COLLINSVILLE NO 2	134	858.717	LR	NQ	4,451	2,455	6,787	4,564	Dist_HV	0.33	0.33				15.59		3.11				33.31		0.32				7.64	0.07		0.96		18.40		1.31	81.37
									Dist_LV	0.16	0.02			0.02	0.65		0.04				0.65		0.49				0.28					0.46			2.77
									EE_SubTrans	5.33	1.99			0.04	2.81		2.88							0.08			0.10			2.26					15.49
									EE_Z_Sub								0.13										0.25								0.38
Elderslie SWER No.01	44	399.130	LR	NQ	4,352	2,532	4,622	3,836	Dist_HV		9.70				4.02		0.07			1.42	40.16						3.63			0.13		11.96			71.09
									Dist_LV		0.25						0.04				0.38		0.31				0.16					0.40			1.54
									EE_SubTrans		12.22						0.77			0.37	0.32		0.25			0.17	5.69		0.08	2.18		0.31			22.36
									EE_Z_Sub					0.51			1.71										2.41			0.37					5.00
Julia Creek No.08 SWER - CANOBIE	36	344.287	LR	NQ	2,321	3,679	4,673	3,558	Dist_HV	8.41	8.94				1.24		4.46				31.58		1.71				9.03			2.44					67.81
									Dist_LV	0.02	0.13						0.13				0.56		2.66				0.13					0.29			3.92
									EE_SubTrans	0.54							3.01			4.64	0.38		0.26			0.25	11.27		0.11	0.44		0.36			21.26
									EE_Z_Sub	3.14							1.91				0.90						0.04			1.01					7.00
Julia Creek No.13 SWER - TALDOORA	35	376.053	LR	NQ	3,795	3,429	3,177	3,467	Dist_HV	3.54	13.54			1.39	0.27		1.86				17.57					0.72	6.91	1.00		0.19		3.63			50.62
									Dist_LV		0.30						0.02				8.57		2.21				0.13								11.23
									EE_SubTrans	0.71							3.09			4.76	0.39		0.27			0.25	11.30		0.11	0.45		0.37			21.70
									EE_Z_Sub	3.79							1.96				9.60						0.04			1.06					16.45
Glenelg No.01 Corfield SWER feeder	58	282.541	LR	NQ	3,532	2,520	3,102	3,052	Dist_HV	1.17							1.02				65.61						7.15			0.55		14.84			90.34
									Dist_LV	0.06											0.28		0.90				0.03					0.16			1.43
									EE_SubTrans											0.47	0.39		0.33			0.21			0.10	0.53		0.38			2.41
									EE_Z_Sub								2.29										3.07			0.46					5.82
BINGEGANG RURAL CIRCUIT	95	374.903	LR	CA	2,934	1,635	4,274	2,948	Dist_HV	8.91					10.52		2.87			8.03	25.83		0.91				6.77			0.85		6.24			70.93
									Dist_LV		0.01			0.05	0.08						0.44		0.18				0.40								1.16
									EE_SubTrans								0.56							0.27			2.73			0.65		8.00			12.21
									EE_Z_Sub					0.43				2.53						0.20			4.96					7.56			15.68
Julia Creek No.11 SWER - ORINDI	50	283.829	LR	NQ	994	1,666	5,816	2,825	Dist_HV	1.06	2.31						0.96				25.99		0.21				2.99			7.99		16.64		3.25	61.40
									Dist_LV		0.37						0.07				0.04		0.55				0.25					0.04			1.32
									EE_SubTrans	1.24							3.75			5.87	0.48		0.33			0.31	14.50		0.13	0.56		0.45			27.62
									EE_Z_Sub	4.65							2.42				1.28						0.05			1.26					9.66
QUILPIE RURAL	317	2417.332	LR	SW	2,530	2,708	3,056	2,764	Dist_HV	0.53	4.39				0.15		2.58			2.51	30.69		0.75				10.95			6.45		9.01			68.01
									Dist_LV	0.03	3.09			0.01			0.02				4.07		5.91				0.17			0.07		0.07			13.44
									EE_SubTrans					0.10							0.27						8.04			8.84		0.55			17.80
									EE_Z_Sub												0.59									0.17					0.76

12.7 Ergon Energy's subtransmission and rural distribution network

Ergon Energy's network is dominated by the western system, as shown. The diagram also illustrates the radial nature of the subtransmission and rural distribution networks.



12.8 Tables and graphs