REGULATORY PROPOSAL TO THE AUSTRALIAN ENERGY REGULATOR

DISTRIBUTION SERVICES FOR PERIOD 1 JULY 2010 TO 30 JUNE 2015

ERGON ENERGY CORPORATION LIMITED

1 JULY 2009

everything in our power

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OVERVIEW

(O) 1 INTRODUCTION

For regional Queenslanders, providing electricity means more than just keeping the lights on. Ergon Energy's customers value an electricity supply that is affordable and dependable. They also want their supplier to help them manage their electricity use, particularly in an era where awareness of climate change is increasing. Our customers' expectations are driving Ergon Energy's planning for the future, as reflected in this Regulatory Proposal.

(O) 2 OUR REGULATORY PROPOSAL

Our Regulatory Proposal to the Australian Energy Regulator (AER) details the expenditure required to prudently operate our distribution business for the next regulatory control period, 2010-15. If the AER accepts our proposed revenue requirements, then these amounts or the amounts as adjusted by the AER, will be collected via customers' network charges. Ergon Energy's network charges are one of the four components that customers pay for in their retail electricity accounts – the others are wholesale energy, transmission and retail charges.

(O) 3 ABOUT ERGON ENERGY

Ergon Energy is unique in the Australian electricity market in that our supply area, which covers 97 per cent of Queensland, is the largest of all distribution businesses. Our network covers an area that is six times the size of Victoria. Our supply area has one of the lowest densities of customers per square kilometre in the industrialised western world. In particular, western Queensland is characterised by long radial lines and low population density. The Quilpie depot's three employees service an area the size of Tasmania. By contrast, Ergon Energy also supplies some of the fastest growing regions in Australia, including major regional centres along the east coast, and economic hubs that have grown rapidly during the resources boom.

As a Queensland Government-Owned Corporation and an essential service provider, Ergon Energy has a dual role in our communities. We provide electricity to some 653,000 customers, while also sustaining the livelihoods and lifestyles of the 1.4 million people across regional Queensland who rely on our services. This is reflected in our purpose – to enhance the economic and lifestyle aspirations of our customers through sustainable energy solutions.

Our purpose underpins our vision to be a world-class, customer-driven energy business. We plan to achieve our vision in 2020, through a strategy that spans three planning horizons that are aligned with each five-year regulatory control period. Our Regulatory Proposal relates to our second planning horizon, 2010-15. During this period we will lay the foundations to become a distribution business whose customers are empowered to control their energy use through a modern and safe network.

(O) 4 OUR KEY CHALLENGES AND OPPORTUNITIES

As outlined in our Strategic Plan, important drivers of our business direction in 2010-15 will include meeting customer expectations for affordability and dependability, and responding to the issue of climate change. This presents Ergon Energy with new challenges and opportunities.

(O) 4.1 Peak Demand and Affordability

Challenge: Rising customer demand for electricity at peak times is the primary driver of network augmentation costs. Peak electricity demand continues to grow, driven by economic and population growth in regional Queensland and sustained high levels of air conditioning use. At the same time, climate change continues to gather strength as a driver of investment in non-traditional electricity supply options that reduce or avoid greenhouse gas emissions.

Opportunity: Ergon Energy seeks to leverage climate change to deliver dual benefits including carbon reduction and affordable long-term solutions to growing peak demand.

(O) 4.2 Customer Choice

Challenge: The issues of climate change and affordability present challenges that require non-traditional responses to empower customers with greater choice about how they use electricity.

Opportunity: Ergon Energy is seeking to encourage greater competition in the provision of certain services, including customer connections. Climate change is also a driver of greater choice, particularly with regard to how customers procure and use electricity. Ergon Energy seeks to make it easier for customers to connect new technology to the network, including hybrid vehicles and embedded generation devices such as solar photovoltaic systems.

(O) 4.3 Network Safety and Reliability

Challenge: Significant investment is needed to meet increasing reliability obligations and reasonable customer expectations for the safety, quality and reliability of their power supply. This is particularly so for our 65,000 km Single Wire Earth Return (SWER) network, which is under pressure from growing customer demand for electricity. Across our network, we must also respond to ageing assets in an effective and efficient way.

Opportunity: New technology is helping to achieve significant improvements in these areas.

We also face a fourth challenge, amplified by the current financial climate – planning to meet electricity and service demands in an uncertain economic environment.

(O) 5 OUR STRATEGIC RESPONSES

In 2010-15, Ergon Energy will deliver the following initiatives and innovations to address our key challenges and opportunities, and ultimately to meet our customer drivers relating to affordability, dependability and climate change response.

(O) 5.1 Delivering Affordable Solutions to Address Peak Demand

Our strategy to address peak demand by leveraging climate change is supported by the development of a 'smart' network, with significantly expanded functionality. This will facilitate widespread use by customers of innovations such as renewable energy sources, including solar photovoltaic systems and hybrid vehicles.

In 2010-15 Ergon Energy will lay a foundation of technology to support this energy evolution. This includes trialling smart meters, investing approximately $25 million in building the first stage of a critical communications network (UbiNet) and expanding the number of substations and lines under the Supervisory Control and Data Acquisition (SCADA) system. UbiNet will provide better monitoring and control of the network, enabling faster restoration of outages, and later stages will support the continued modernisation of the network.

In addition to technology investments, Ergon Energy will continue to engage customers to reduce their electricity use at peak times through initiatives such as Townsville's Solar City project. Supporting our demand management efforts will be an investment of $61 million in developing non-network alternatives, and a $1 million annual investment through the AER's new Demand Management Incentive Scheme (DMIS) innovation allowance.

(O) 5.2 Expanding Customer Choice

In the current regulatory control period, Ergon Energy has introduced a contestability solution for developers to design and construct urban residential subdivisions. This has provided developers with more choice and control over who builds the electrical infrastructure in their developments and the price they pay for it. Ergon Energy is expanding the range of situations where customers will have a choice about who designs and constructs the electricity assets, including street lighting and new large customers' connection assets.

Expanding the functionality of the network, as detailed above, will also contribute to the range of options customers have for how they procure and use electricity.

(O) 5.3 Delivering a Safe and Reliable Network

Over the past five years, Ergon Energy has greatly improved the reliability of its electricity supply through an unprecedented program of work to upgrade our network. This has resulted in a decrease in average power interruption duration by 25 per cent and a decrease in interruption frequency by 32 per cent. This step change improvement has brought the network up to meet minimum service standards over the past two financial years.

These standards will become increasingly stringent in 2010-15, and will become harder to meet as Ergon Energy addresses the challenges of an ageing network and growing demand on our SWER network. A condition-based assessment will ensure the efficient and effective upgrade of the network through our $664 million Asset Replacement Program. Another $50 million will target specific areas through our Quality and Reliability Improvement Program.

Ergon Energy will also invest significantly in increasing the quality and reliability of power supply of our 65,000 km SWER network, through traditional and non-traditional means. In recent years we have made significant progress towards developing solutions to these challenges and we will continue the rollout of key innovations and initiatives. These include delivering quality improvements through low voltage regulators at customers' premises, enabling faster restoration through electronic reclosers, and improving network resilience to lightning through pole banding, darverters and lightning arrestors.

Significant work will also continue to engage customers in peak demand management initiatives to reduce pressure on the SWER network capacity.

(O) 6 A PRUDENT AND EFFICIENT INVESTMENT

In the current climate of economic uncertainty, the value of sound governance and planning processes becomes paramount. Ergon Energy has established rigorous governance processes to ensure our investment decisions are prudent, and are aligned to our strategic and operational priorities. To ensure our forecasts are as robust as possible, Ergon Energy has engaged external experts to independently validate our predicted demand growth and calculate cost escalations.
Our resource plans ensure we have the capacity to deliver the work forecast in our Regulatory Proposal. Internal checks and processes, as well as new AER incentive schemes, will ensure our work is delivered efficiently and tracked against performance targets.

Upon this foundation of sound decision-making, Ergon Energy proposes to invest $6 billion in capital expenditure projects and $1.9 billion in operating expenditure programs to fulfil regulatory requirements, meet reasonable customer expectations and satisfy peak electricity and service demands in 2010-15.

(O) 7 CONCLUSION

Our customers' expectations are driving our planning for the future. We know our customers value an electricity supply that is affordable and dependable. They also want their energy supplier to anticipate future needs. In an era of climate change awareness, this includes helping customers manage energy use and reduce greenhouse gas emissions through advice and new technology. Our 2010-15 Regulatory Proposal will respond to key opportunities and challenges in order to deliver on our customers' expectations.

Investments in peak demand reduction and non-network alternatives will contribute to improved asset utilisation in the future and therefore a more affordable electricity supply. In the shorter-term, increased contestability in customer connections will drive value through market competition.

Our responses to climate change will seek to reduce peak demand growth and have the additional benefit of reducing carbon emissions. As customers become increasingly aware of climate change, expanded network functionality will empower them to control and reduce their energy use and carbon emissions through education and new technology.

Importantly, that most basic of customer desires – a dependable power supply that keeps the lights on – will be enhanced by continued safety and reliability improvements.

This Regulatory Proposal, aligned with our next strategic planning horizon, is underpinned by our purpose - to enhance the economic and lifestyle aspirations of our customers through sustainable energy solutions - and it will take us one step closer to achieving our vision of being a world-class, customer-driven energy business.

GLOSSARY

AARR	Aggregate Annual Revenue Requirement
ABARE	Australian Bureau of Agricultural and Resource Economics
ABS	Air Break Switch
AC	Alternating Current
ACCC	Australian Competition and Consumer Commission
ACG	Allen Consulting Group
ACSR	Aluminium Conductor Steel Reinforced
ADMD	After Diversity Maximum Demand
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEP	Asset Equipment Plan
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
AMP	Asset Management Plans
APIA	Australian Pipeline Industry Association
ARR	Annual Revenue Requirement
ASIC	Australian Standard Industrial Classifications
ASX	Australian Securities Exchange
ATSI	Aboriginal and Torres Strait Islander
B2B	Business to Business
BLR	Bulk Lamp Replacement
BPPA	Basis Points Per Annum
BRW	Burns and Roe Worley
BSP	Bulk Supply Point
CAC	Connection Asset Customer
CAG	Cost Allocation Guideline
CAIDI	Customer Average Interruption Duration Index
CAM	Cost Allocation Method
CAPM	Capital Asset Pricing Model
CARE Program	Cyclone Area Reliability Enhancement Program
CATS	Consumer Administration and Transfer Solution
CBD	Central Business District
CEG	Competition Economists Group
CIA	Corporation Initiated Augmentation
CICW	Customer Initiated Capital Works
CMS	Customer Management System
COAG	Council of Australian Governments
CPI	Consumer Price Index

CPP	Community Powerline Project
CT	Current Transformer
DC	Direct Current
DINIS	Load Flow Model
DLC	Direct Load Control
DME	Department of Employment, Economic Development and Innovation - Mines and Energy
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNAP	Distribution Network Augmentation Plan
DNSP	Distribution Network Service Provider
DRP	Dividend Reinvestment Plan
DUOS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
EDSD Review	Electricity Distribution and Service Delivery Review
EE	Ergon Energy Corporation Limited
EECL	Ergon Energy Corporation Limited
EEPL	Ergon Energy Pty Ltd
EEQ	Ergon Energy Queensland Pty Ltd
EET	Ergon Energy Telecommunications Pty Ltd
EG	Embedded Generator
ENA	Energy Networks Association
ERA	Economic Regulation Authority (Western Australia)
Ergon Energy	Ergon Energy Corporation Limited
ERP	Enterprise Resource Planning
ESO	Electrical Safety Office
Excel	Microsoft Excel
F&A	Framework and Approach
F&A Stage 1	Framework and Approach Stage 1
F&A Stage 2	Framework and Approach Stage 2
FFA	Field Force Automation
FIT	Feed-in-tariff
FRC	Full Retail Competition
FSA	Future State Assessment
FTE	Full Time Equivalent
GOC	Government-Owned Corporation
GSL	Guaranteed Service Level
GSP	Gross State Product
GST	Goods and Services Tax
GW	Gigawatt
GWh	Gigawatt hour
ICC	Individually Calculated Customer
ICSS	International Customer Service Standard
ICT	Information Communication and Telecommunications
IEEE	Institute of Electrical and Electronics Engineers
IRC	Investment Review Committee (of Ergon Energy)
IT	Information Technology
JIA	Joint Industry Association
KPI	Key Performance Indicator
kV	Kilovolt

kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt Hour
LGA	Local Government Authorities
LNG	Liquefied Natural Gas
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MAMP	Metering Asset Management Plan
MCE	Ministerial Council on Energy
MDA	Meter Data Agent
MDI	Maximum Demand Indicator
MDM	Meter Data Management
MDP	Meter Data Provider
MRP	Market Risk Premium
MSATS	Market Settlement and Transfer Solution
MSS	Minimum Service Standard
MTA	Minimalist Transitioning Approach
MVA	Megavolts-ampere
MVAR	Megavar-reactive component of power
MW	Megawatt
MWh	Megawatt hour
NARMCOS (Data Model)	Network Assets Replacement Maintenance Capex Opex Summary
NCC	National Contact Centre
NCP	Network Connection Point
NDM	Network Demand Management
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industrial Research
NIRC	Network Investment Review Committee (of Ergon Energy)
NMI	National Metering Identifier
NMP	Network Management Plan
Nominal	With respect to dollars – means dollars-of-the-day. In this Regulatory Proposal Nominal dollars are dollars as at 30 June of the financial year of which the dollars relate.
NPD	Network, Planning and Development (Business unit of Ergon Energy)
NPV	Net Present Value
NTER	National Tax Equivalent Regime
NUOS	Network Use of System
O&M	Operating and Maintenance
PC	Personal Computer
PCB	Polychlorinated Biphenyl
PDA	Powerdirect Australia Pty Ltd
PE	Photo Electric
POE	Probability of Exceedance - means the likelihood that a forecast value will be exceeded by the actual value. For example, for an annual forecast a 50 per cent POE is likely to be exceeded once every second year, whereas a 10 per cent POE is likely to be exceeded once every 10 years.
PPS	Pricing Principles Statement
PTRM	Post Tax Revenue Model
PV	Photovoltaic

QCA	Queensland Competition Authority
QGM	Queensland Government Marketplace
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
Real	With respect to dollars – means constant dollars at a specific date. In this Regulatory Proposal where 'real' dollars are used, they are 2009-10 dollars unless otherwise stated.
RFM	Roll Forward Model
RIN	Regulatory Information Notice
RIO	Regulatory Information Order
RMU	Ring-main unit
RoLR	Retailer of Last Resort
SAC	Standard Asset Customer
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCI	Statement of Corporate Intent
SCO	Standing Committee of Officials
SEO	Seasoned Equity Offering
SFG	Strategic Finance Group
SKM	Sinclair Knight Mertz
SLA	Service Level Agreement
SNAP	Sub-transmission Network Augmentation Plan
SPARQ	Sparq Solutions Pty Ltd
SoRI	Statement of Regulatory Intent
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
SWOT	Strengths – weaknesses – opportunities - threats
Synergies	Synergies Economic Consulting
TaDS	Transmission and Distribution Services
TNSP	Transmission Network Service Provider
TRR	Total Revenue Requirement
TUOS	Transmission Use of System
TWI	Trade Weighted Index
UbiNet	Ubiquitous Network
UCA	Ergon Energy Union Collective Agreement 2008
UMS	UMS Group Incorporated
URD	Urban Residential Development
V2C	Value to Customer
VAR	Volt Ampere Reactive
VCR	Value of Customer Reliability
VT	Voltage Transformer
WACC	Weighted Average Cost of Capital
WIGS	Wholesale, Interconnector, Generator and Sample NMI Procedures

REGULATORY PROPOSAL NARRATIVE

(N) 1 ABOUT ERGON ENERGY

(N) 1.1 Our Vision

Ergon Energy's vision is to be a world-class, customer driven energy business. This is supported by the organisation's purpose "to enhance the economic and lifestyle aspirations of our customers through sustainable energy solutions".

To achieve its vision and purpose, Ergon Energy has adopted a three-horizon strategic model, where each horizon aligns with successive regulatory control periods. This is shown in Figure 1 and can be summarised as follows.

Secure the business – this refers to the merger of six regional Queensland electricity corporations to form Ergon Energy in 1999 and the subsequent work to develop a cohesive, single distribution business and to bring its service provision up to an acceptable standard.

Horizon One (H1) – this refers to the current regulatory control period 2005-10, where the focus is to improve efficiency (get fit), to improve safety performance, to take a lead role in responding to climate change and to complete the investment necessary to bring the network up to appropriate operational standards.

Horizon Two (H2) – this refers to the next regulatory control period 2010-15 and it is this period to which this Regulatory Proposal relates. In Horizon Two, Ergon Energy will move towards becoming a customer-driven organisation, which will understand the underlying needs and existing behaviours of its customers and identify and predict customer requirements. This knowledge will be used to develop products and services that go beyond the meter and give customers choice and control over their energy use. Ergon Energy will continue to focus on safety, with the aim of being recognised as an industry leader in safety practice and management both for employees and the public. Ergon Energy will leverage the skills and experience gained in Horizon One to develop innovative products that help customers to reduce their carbon emissions. Linked with this will be the expansion of network functionality to improve supply quality and energy management through tools such as smart meters, a ubiquitous communications network (UbiNet) and enhanced Supervisory Control and Data Acquisition (SCADA). The work around smart meters in 2010-15 is focused on conducting pilots and trials and does not include any major rollout to customers.

Horizon Three (H3) – this refers to the 2015-20 regulatory control period. It is in Horizon Three that Ergon Energy will achieve its vision of becoming a world-class customer-driven energy business. Customers will have greater choice and control over the source of their electricity and their consumption. Customers will be empowered. Ergon Energy will fully understand its customers' needs and expectations and have a variety of tailored service options to suit them.

Figure 1: *Ergon Energy's Strategic Planning Horizons*

(N) 1.2 Our Key Challenges

Our Strategic Plan outlines important drivers of business direction in 2010-15 that include meeting customer expectations for affordability and dependability, and responding to the issue of climate change. This presents Ergon Energy with new challenges and opportunities, including:

- Delivering affordable solutions to address peak demand;
- Expanding customer choice; and
- Delivering a safe and reliable network.

In responding to these challenges and opportunities, Ergon Energy will seek to deliver on our customers' expectations. Investments in peak demand reduction and non-network alternatives will contribute to improved asset utilisation in the future and therefore provide a more affordable electricity supply. Increased contestability in customer connections work will drive value through market competition. Expanded network functionality will empower customers to control and reduce their energy use and carbon emissions through education and new technology. Customers will also benefit from continued safety and reliability improvements.

(N) 1.3 A Unique Operating Environment

Ergon Energy's distribution network covers around 97 per cent of Queensland, spanning diverse landscape and climates. Approximately six times the size of Victoria, Ergon Energy's service supply area is one of the largest covered by a single electricity distribution business in the western industrialised world. It also has one of the lowest customer densities.

Geographic and environmental variations influence the design criteria for infrastructure, as well as the ability to respond to incidents on the network. The vast geographical spread of Ergon Energy's service area has a number of impacts on network performance.

Ergon Energy's service area is highly exposed to cyclones, storms and lightning, heavy rainfall and flooding. It also experiences significant summer-winter and day-night temperature variations which make demand difficult to predict.

Relatively low customer numbers in Ergon Energy's western zone limits the cost effectiveness of depots that service a region. In the South West, the Quilpie depot's three employees manage a grid-connected network across a region the same size as Tasmania. These distances have an impact on the ability to maintain reliability and quality of supply. Ergon Energy also faces the unique challenges of providing electricity to island communities in north Queensland and the Torres Strait, although this is outside the network regulated by the Australian Energy Regulator (AER).

Resource industries are regarded as both customers and competitors of Ergon Energy. While the resources boom in the current regulatory control period has had a significant impact on the network, it has also had an impact on employee attraction and retention. Ergon Energy competes as an employer of choice with the mining and resources industries, who employ people with similar skill sets in remote and regional Queensland areas.

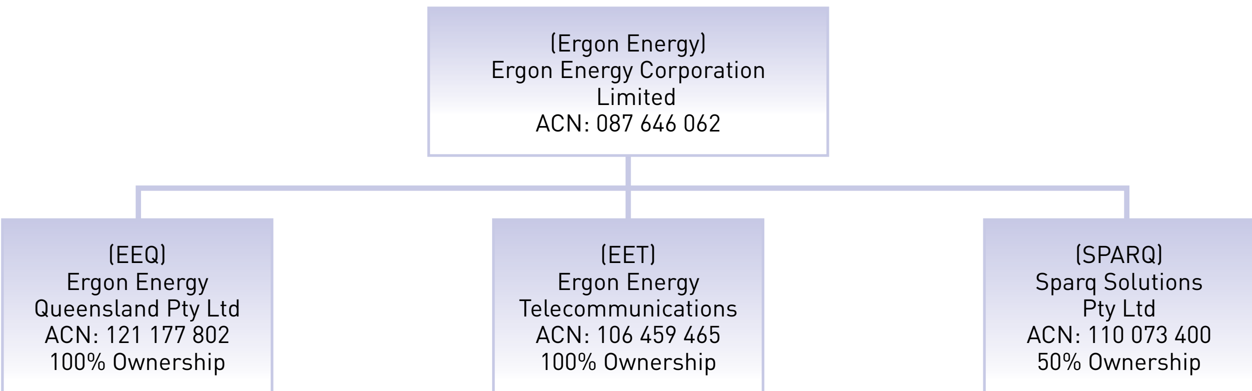
Environmental challenges in our service area include:

- Significant summer-winter and day-night temperature variations, which translate into large variability in seasonal and daily electricity demand, although Ergon Energy's peak demand tends to occur in summer;
- High rainfall and prolonged flooding, which can adversely affect asset condition and restrict access to them;
- Extreme winds and lightning, including summer storms and cyclones;
- Vegetation whose types, density and growth rates adversely affect the operation of assets; and
- Heritage-listed rainforests and wet tropics environmental obligations which add to the costs of work in these areas.

(N) 1.4 Operating Structures

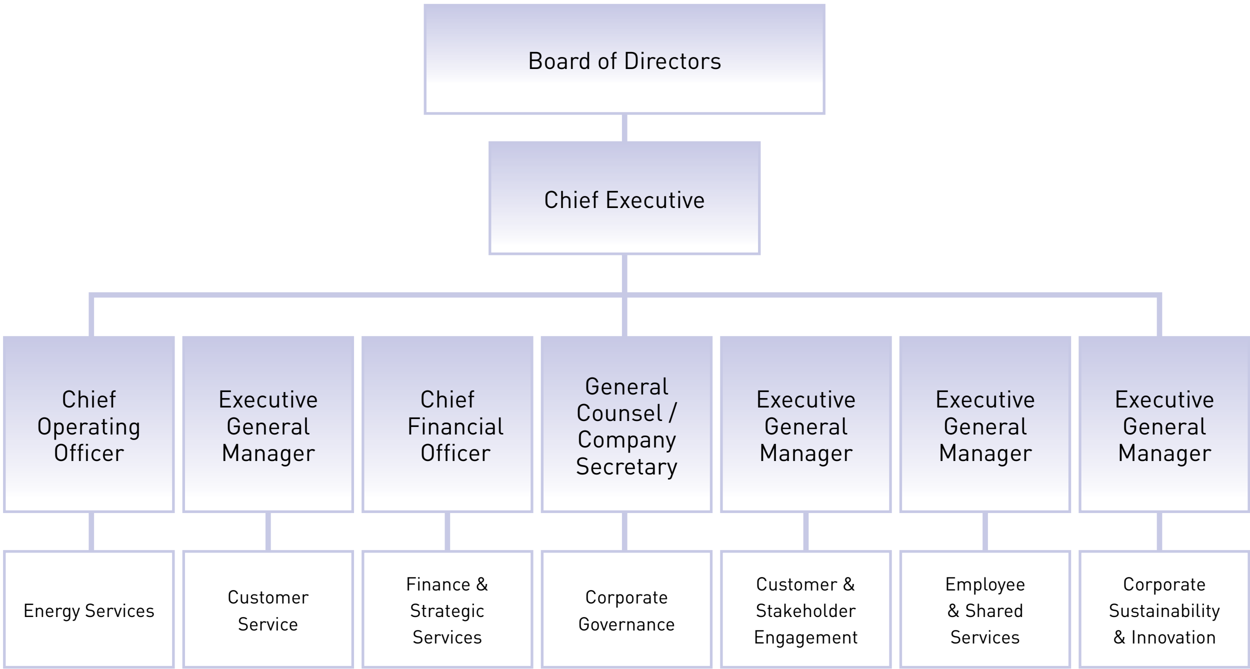
The Ergon Energy group of companies is shown in Figure 2.

Figure 2: *Ergon Energy Group Structure*



The Ergon Energy Group organisational structure is shown in Figure 3.

***Figure 3:** Ergon Energy's Organisational Chart*



(N) 1.5 People

Ergon Energy seeks to be a preferred employer in regional Queensland and to this end effectively competes with the mining and resources industries for the limited resources with the required skill sets to service our customer and network requirements.

The majority of Ergon Energy's people work in the Energy Services business unit, which delivers frontline customer service and network operations. Six other business units provide essential support to these operational units.

Table 1 details Ergon Energy's employees and contractors on the basis of headcount as at 30 June 2008. It is noted that in this table, 'employees' comprise permanent and fixed term employees of Ergon Energy, and 'contractors' comprise labour hire, project resources, consultants and external trainees and apprentices, but do not include core tendered contractors (such as vegetation management contractors, pole inspection contractors etc).

***Table 1:** Ergon Energy's Employees and Contractors as at 30 June 2008*

Business Unit	Employees	Contractors	Total
Office of the Chief Executive			
Energy Services			
Customer Service			
Finance and Strategic Services			
Corporate Governance			
Customer and Stakeholder Engagement			
Employee and Shared Services			
Corporate Sustainability and Innovation			
Total	**4,489**	**320**	**4,809**

Note – Data is presented on the basis of headcount not full time equivalent employees and does not include vacancies.

CONFIDENTIAL INFORMATION

(N) 2 CUSTOMER VALUE

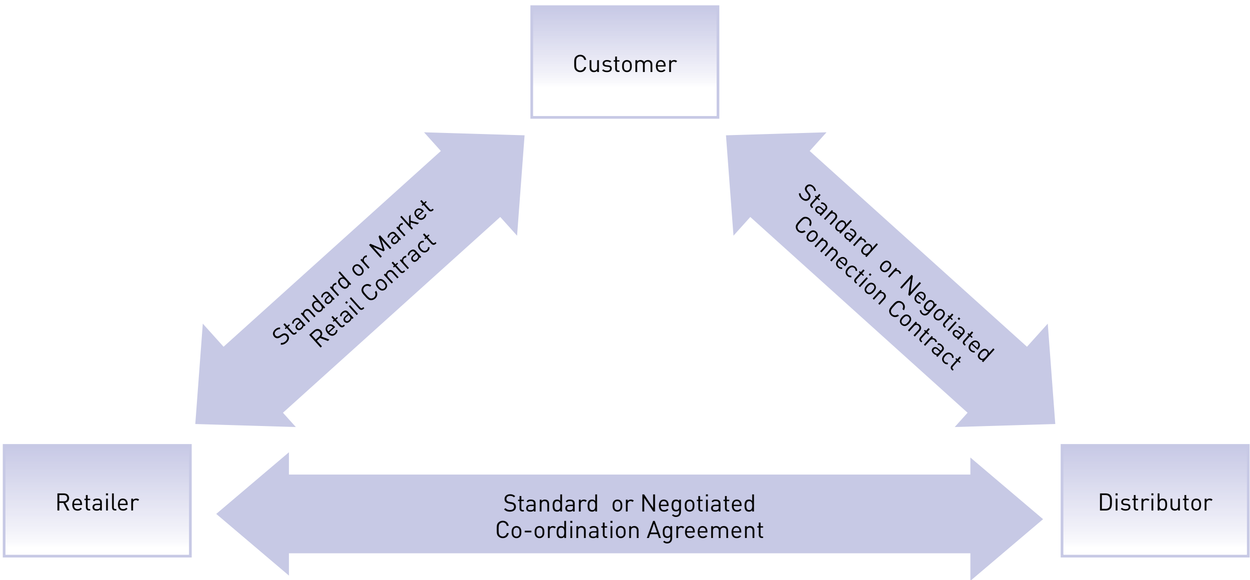
(N) 2.1 Customers and Community

Ergon Energy has the dual responsibility of meeting reasonable customer expectations for service delivery and choice, while also delivering economic and social benefits to the community. This is reflected in Ergon Energy's purpose to enhance the economic and lifestyle aspirations of customers through sustainable energy solutions.

As an essential service provider and a major regional Queensland employer, Ergon Energy is helping to sustain livelihoods and lifestyles for many people in regional Queensland communities. Ergon Energy strengthens local economies and communities through infrastructure investment, as well as through everyday actions such as local purchasing. Community consultation ensures infrastructure is delivered in line with community needs. This includes engagement with local councils, local residents and businesses and other infrastructure providers.

About 1.4 million[1] people currently rely on Ergon Energy every day for the safety, quality, reliability and availability of their electricity supply. Ergon Energy provides its distribution services to electricity retailers, the community and end-use customers. As at June 2008, Ergon Energy had 653,221 end-use customers (excluding street lighting customers). A tripartite relationship between customers, Ergon Energy and retailers was formed as a result of the introduction of Full Retail Competition (FRC) in Queensland on 1 July 2007. The nature of this relationship is illustrated in Figure 4.

***Figure 4:** Tripartite Contractual Relationship*



(N) 2.2 What Customers Value

Ergon Energy has a customer insights program that highlights the points of value to customers, in relation to electricity supply and services. Electricity is recognised by customers as being highly important as it underpins both their social and economic lifestyles. The basic customer requirement is an affordable price and dependable service. Beyond this basic expectation, customers' requirements of a 'best imaginable' supplier include being responsive to customers' needs, being proactive in helping customers to reduce their consumption, providing real-time consumption information and helping customers to be sustainable. This can otherwise be described as providing 'smart options'. Put into practice, the things that customers value include:

- Delivery of a safe, secure and reliable electricity supply;
- Providing good value for money; and
- Providing appropriate mechanisms and support to help customers to better manage their electricity use, particularly in an era of climate change awareness.

(N) 2.3 Delivering Value to Customers

Ergon Energy has made significant progress in the current regulatory control period towards delivering outcomes that are of value to customers. As part of the strategy of being customer-driven, Ergon Energy will focus on the services that are valued by customers.

[1] Derived from information contained at http://www.oesr.qld.gov.au/queensland-by-theme/demography/population/index.shtml

Delivery of a safe, secure and reliable electricity supply

Over the past five years, Ergon Energy has reduced average system interruption duration by 25 per cent and decreased interruption frequency by 32 per cent. Through its capital and operating expenditure programs in 2010-15, Ergon Energy will continue to strive to meet minimum service standards and improve reliability for customers. Ergon Energy will also continue its focus on safety with the aim of being once again recognised as an industry leader in this area.

Providing value for money

Ergon Energy seeks to provide customers with value for money by ensuring its investments are sound and ensuring it is operating efficiently. In addition, it is exploring more affordable alternatives to the primary driver of network costs – peak demand. In the next regulatory control period, Ergon Energy will invest almost $70 million[2] in peak demand reduction non-network alternatives, in addition to leading numerous demand management trials focused on households and businesses. Exploring non-traditional solutions, such as renewable energy sources, has the potential to increase customer choice and reduce regulated network costs.

Helping customers better manage electricity use

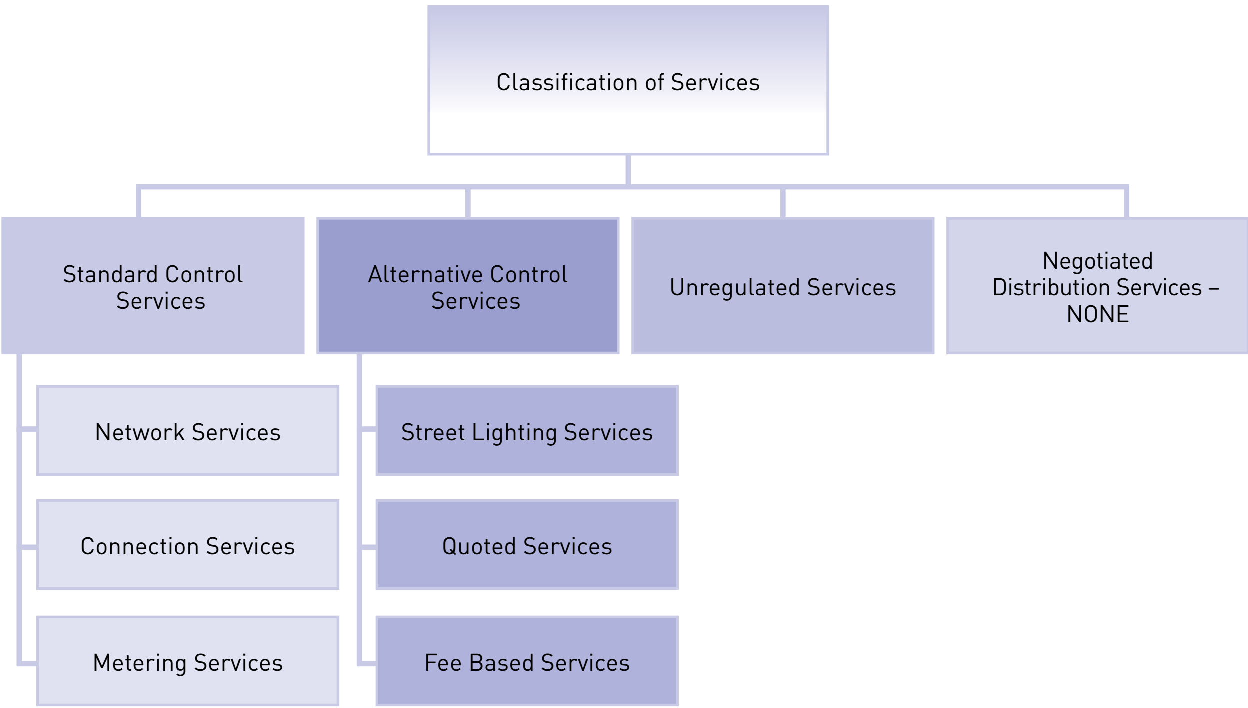
In an era where climate change and affordability are key issues, Ergon Energy provides programs to help customers manage their electricity use. Ergon Energy will continue to refine and expand these programs into the next regulatory control period. These programs include broad campaigns, offering energy saving advice to all customers, and also targeted trials, such as Townsville's Solar City project, which combines smart meters, renewable energy and behavioural change initiatives to help customers reduce their electricity use.

(N) 3 OUR SERVICES AND SERVICE PERFORMANCE

(N) 3.1 Classification of Services

Ergon Energy accepts the AER's likely classification of Ergon Energy's services for the next regulatory control period as outlined in the AER's Framework and Approach Stage 1 (F&A Stage 1) that was released on 27 August 2008. Network services, connection services and metering services will all remain revenue capped under the Standard Control Service classification. A change will occur to street lighting and new large customer connections, which will be price capped under an Alternative Control Service classification. There will also be a range of other Quoted Services, which will be price capped as Alternative Control Services. Fee Based Services, such as disconnections and reconnections, will also continue to be price capped under the Alternative Control Service classification. The Classification of Services is shown in Figure 5.

Figure 5: *Classification of Services*



[2] This is a combination of operating expenditure and Demand Management Innovation Allowance.

(N) 3.2 Service Performance

Ergon Energy participates annually in the International Customer Service Survey (ICSS). In 2008, Ergon Energy received a score of 7.63 out of 10, placing it in the top 5 per cent of organisations certified through the International Customer Service Standard (ICSS) globally.

Ergon Energy's Value to Customer (V2C) key performance indicator provides insights into how, from a customer's perspective, it delivers value across a range of customer services, covering both the distribution and retail businesses. It benchmarks Ergon Energy's performance against selected similar electricity service providers. This independently conducted research highlights that Ergon Energy consistently outperforms the average of other service providers across a range of measures, including electricity supply, customer interaction experience, corporate social responsibility and cost/affordability. The overall V2C score for Ergon Energy in November 2008 was 7.3.

(N) 4 ASSETS AND NETWORK PERFORMANCE

(N) 4.1 Distribution System

Ergon Energy's distribution system is built to accommodate, as well as possible, its environmental challenges. The distribution system is characterised by a large radial network, including approximately 65,000 km of Single Wire Earth Return (SWER) lines. Over 68 per cent of Ergon Energy's powerlines are classified as non-urban. While vast distances and low customer density characterise large parts of the service area, Ergon Energy's network also supplies electricity to rapidly growing population and economic centres throughout regional Queensland.

Details of Ergon Energy's network are summarised in Table 2.

Table 2: *Features of Ergon Energy's Distribution System*

Item	Value / Unit
Network service area (square kilometres) [1]	1,698,100 sq kms
Total length of lines (kilometres) - distribution and sub-transmission [1]	146,339 kms
Customers per kilometre of line [2]	5.2
Total distribution customers: [3]	632,196
Urban feeder [3]	251,213
Short rural feeder [3]	307,124
Long rural feeder [3]	69,985
Number of poles [1]	939,227
Distribution losses [1]	6.50%
Number and capacity of transformers (MVA):	
Sub-transmission [1]	628 / 7,508 MVA
Distribution [1]	85,034 / 6,099 MVA

[1] Source: Ergon Energy, Annual Service Quality Report (July 2007 – June 2008), found at http://www.qca.org.au/files/E-SerQual-Ergon-AnnRep0708-0409.pdf

[2] Source: QCA – Ergon Energy's Financial and Service Quality Performance 2007-08 (March 2009), found at http://www.qca.org.au/files/E-SerQual-QCA-ErgonAnnRep0708-0409.pdf

[3] Source: Ergon Energy, Quarterly Service Quality Report (October - December 2008), found at http://www.qca.org.au/electricity/service-quality/qtrservqualrep.php

(N) 4.2 Approach to Planning

Ergon Energy uses a strategic planning model that spans three horizons, each corresponding to a new regulatory control period. The Strategic Plan, currently extending to 2010, aligns with other long term planning documents, including the Network Vision to 2030, to provide an overarching framework to guide network planning and investment decisions. Ergon Energy's Asset Management Plan (AMP) and Network Management Plan (NMP) are used to guide shorter-term decision making and are key inputs for determining the capital and operating expenditure programs for the next regulatory control period.

The Asset Management Plan for 2009-10 to 2014-15 provides a framework for the efficient management of Ergon Energy's electricity infrastructure assets over their life cycle. It balances costs against service obligations and stakeholder expectations, including expectations of customers, regulators and Ergon Energy's Shareholding Ministers. The NMP is a rolling five-year plan, prepared in accordance with section 2.3 of the Queensland Electricity Code. The NMP is a public document that is published annually following approval by the Queensland Competition Authority (QCA). It 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. The NMP is built up from other Ergon Energy annual planning documents such as:

- Sub-transmission Network Augmentation Plans (SNAPs), which are prepared annually for each region. These plans describe the capital works that are needed to meet the augmentation requirements of the sub-transmission network to accommodate normal load forecasts for the next 10 years; and
- Distribution Network Augmentation Plans (DNAPs) which are prepared for each region, listing in Excel spreadsheets a description of the capital works needed to meet the augmentation requirements of the distribution network for the next 10 years, based on normal load growth.

(N) 4.3 Demand Forecasts

To effectively plan to meet electricity demand, Ergon Energy prepares annual demand forecasts of system demand (MW). It then engages the National Institute of Economic and Industrial Research (NIEIR) to prepare an independent top-down forecast of maximum demand in order to validate Ergon Energy's internally produced forecasts.

During the next regulatory control period, peak demand for electricity – the primary driver of network augmentation costs – is forecast to rise by an average of 2.93 per cent per annum. In the first year alone, it will jump by 3.68 per cent on the back of new customer connections, including 12 known new large customers and an expected 11,000 small customers, comprising households and small to medium-sized businesses. Ongoing demand forecasts are based on experts' predictions of continued population growth, commercial and industrial developments and increasing air conditioning use. It is expected customer numbers will continue to grow, increasing by a forecast 8.14 per cent over the next regulatory control period.

Ergon Energy notes that, while it is useful to gain a high level understanding of Ergon Energy's likely operating environment, the concept of 'average peak demand' cannot be used to understand network augmentation requirements, which must consider site-specific information. During the current regulatory control period 'average' peak demand of 4 per cent has been less than the forecast of 4.38 per cent in 2007-08 and 2008-09 due to mild summers. But Ergon Energy's maximum demand growth at many of the main growth points in the network has been higher than forecast. It is the peak demand at specific locations that causes network constraints and the need for augmentation, such as new substations.

Total energy consumption is forecast to rise from 15,870.51 GWh to 17,887.16 GWh per annum. However, Ergon Energy does not use energy consumption for its capital expenditure forecasts as the network must be built to cope with peak demand – the period when demand for electricity is highest.

Table 3 shows Ergon Energy's forecasts of its potential peak maximum demand, energy throughput and customer numbers for the next regulatory control period.

Table 3: *Ergon Energy Demand Forecasts for 2010-15*

	2010-11	2011-12	2012-13	2013-14	2014-15
EE Coincident peak (maximum) demand (MW) – September 2007	2,967	3,063	3,153	3,243	3,330
EE Total energy consumption (GWh)	15,870.51	16,450.40	16,874.17	17,432.66	17,887.16
EE Customer numbers	684,469	695,242	706,204	717,356	728,706

Source: Ergon Energy RIN

(N) 4.4 Planning for Extreme Events

Ergon Energy's NMP, along with its Summer Preparedness Plan, Disaster Management Plan and Emergency Management Plan, set out Ergon Energy's planning processes for extreme events.

A Summer Preparedness Plan is developed each year with the aim of minimising network disruptions in preparation for high storm and lightning activity and cyclones during summer. The need to prepare this Plan arose as a result of recommendations from the Electricity Distribution and Service Delivery (EDSD) Review in 2004 and focuses on:

- Network protection and maintenance;
- Capacity to manage and respond to extreme weather events and emergencies;
- Keeping customers informed;
- Ergon Energy's commitment to safety; and
- Contingency plans to ensure security standards are met.

The Disaster Management Plan documents a process for the rapid response to all large-scale disasters, including the co-ordination of resources to areas affected by a major event. Supply restoration priorities, as detailed in the Disaster Management Plan, have been determined in accordance with statutory disaster management groups and draw upon broad experience in minimising community disruption. The Disaster Management Plan is supported by subsidiary plans from other business units indicating how they will support the restoration process.

An Emergency Management Plan exists for each of Ergon Energy's regions. The Emergency Management Plans are authorised by the relevant General Manager Operations and document the actions required by the key business units in the lead up to, and during, significant network events. Each Emergency Management Plan also has supporting plans based on both business unit and geographic responses.

(N) 4.5 Network Reliability and Performance

Ergon Energy must comply with a series of externally imposed obligations relating to security, quality and reliability of supply, as well as safety and customer service. Chapter 6 of the Rules requires that Ergon Energy's operating and capital expenditure forecasts "maintain the quality, reliability and security of supply of standard control services". In the current and next regulatory control period, specific programs to address network reliability and performance include:

- The Reliability and Quality Improvements program, which targets improved continuity of supply across 50 of Ergon Energy's worst performing feeders; and
- The Asset Replacement program, which incorporates asset replacement determined from condition assessment of assets, along with replacement of assets where defects have been identified.

In addition, it is noted that various other Ergon Energy capital and operating expenditure projects and programs contribute to the improvement of its network reliability and performance.

(N) 4.6 Network Assets that Ergon Energy will Build

Ergon Energy's Regulatory Proposal covers capital and operating expenditure projects and programs that Ergon Energy will undertake to build new infrastructure and to replace existing infrastructure. For example, in the next regulatory control period, Ergon Energy is intending to:

- Build 37 new urban and 19 new rural zone substations in response to demand growth and security standards;
- Build 337 km of new underground cables, many of which are in complex situations such as town centres and urban areas;
- Build 1,430 km of new overhead powerlines;
- Spend approximately $87 million on acquiring new line routes and sites for electricity infrastructure;
- Replacement of assets that are approaching the point where they will fail, with the objective being to replace prior to failure thus preventing outages and safety incidents; and
- Build a significant amount of new customer-specific infrastructure in order to connect new customers.

In addition to the capital expenditure projects, Ergon Energy's operating expenditure program enables the network to be maintained and operated in accordance with good electricity industry practice. Examples of the key operating expenditure programs are:

- Vegetation management beneath and around overhead powerlines to limit the number of outages that are caused by vegetation contacting powerlines, with a focus on rural areas;
- Establishment and maintenance of access tracks so that Ergon Energy can access its electricity infrastructure; and
- Rolling out demand management initiatives in partnership with customers and other innovative companies to reduce peak demand on the distribution system.

(N) 4.7 Service Target Performance Incentive Scheme (STPIS)

The AER's Service Target Performance Incentive Scheme (STPIS) provides Ergon Energy with financial incentives to improve reliability of supply. The measures proposed to be assessed under the STPIS include the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) for each of the feeder types within Ergon Energy's region. Momentary Average Interruption Frequency Index (MAIFI) measures are not included in the STPIS. This is consistent with the AER's Framework and Approach Stage 2 final decision.

(N) 5 WORKS MANAGEMENT AND DELIVERY

(N) 5.1 What Ergon Energy Does

Ergon Energy holds a Distribution Authority issued under the Queensland Electricity Act 1994 and is authorised to build, operate, maintain and protect its electricity distribution network to ensure the adequate, economic and safe supply of electricity to its customers. Ergon Energy has an obligation to provide 'access' to customers to connect their electrical installations to the distribution network.

(N) 5.2 Third Party Providers

Just over 80 per cent of total system capital expenditure is market tested because materials, contractors and other costs are generally provided by third party providers using Ergon Energy's competitive tender process.

Up to 59 per cent of total system operating expenditure is market tested because materials, contractors and other costs are procured from third party providers using Ergon Energy's competitive tender process.

(N) 5.3 Customer Choice of Providers

Ergon Energy's customers are increasingly able to choose their providers for design and construction for connections to the supply network. In the current regulatory control period, developers of urban residential subdivisions have exercised choice about whether they would design and construct the electricity infrastructure within the subdivision, or instead choose Ergon Energy to undertake the work. This 'contestable' approach will be expanded in the next regulatory control period to commercial and industrial customer connections and rural subdivisions. In some cases, large customers have contracted to build their own network assets that have been connected to Ergon Energy's distribution network.

The AER indicated in its F&A Stage 1 that its likely approach will be to classify Street Lighting Services, Fee Based Services and Quoted Services (including the design and construction of new large customers' connection assets) as Alternative Control Services. The AER's approach would result in two significant changes to the way in which these services are currently regulated:

- A separate 'limited building block approach' will be used to regulate Street Lighting Services – currently they are included with the Standard Control Services; and
- The design and construction of new large customers' assets will no longer be regulated under a building block approach, but instead will be regulated by the AER applying a formula-based (i.e. a non-building block) approach to determine the efficient costs of providing this service under a price cap form of control in the first year of the regulatory control period and establishing a price path for the remaining years of the period.

The AER indicated in its F&A Stage 1 that it considers these changes are appropriate for these two types of services because they need not be supplied exclusively by Ergon Energy and there is the potential to develop competition in their supply between service providers. As noted above, Ergon Energy supports these changed service classifications.

Street Lighting Services

Ergon Energy has a legislative obligation to connect street lighting customers to its distribution network, however it does not have an obligation to provide, construct and maintain new street lighting assets. Rather, the legislative obligation to provide or arrange for the street lighting rests with the party responsible for the carriageway/road, which is typically a Local Council or the Main Roads Department.

There are currently three ways in which new street lighting can be developed in Queensland:

- The responsible party can ask Ergon Energy to provide, construct and maintain the street lighting assets;
- A party other than Ergon Energy, such as a developer, can provide and construct the street lighting assets and transfer them to Ergon Energy for it to own and maintain; and
- The responsible party can construct and maintain the street lighting assets themselves, in which case Ergon Energy has no involvement in the provision of any Street Lighting Services, although it is responsible for delivering energy to the customer's street lighting asset using its distribution network.

The party responsible for providing street lighting, as the electricity customer, is currently charged different prices by its retailer depending on which one of these three approaches is used to provide, construct and maintain the street lights. The retail Notified Prices includes Rates 1, 2 and 3, as detailed in the gazetted retail tariffs.

In the next regulatory control period, Ergon Energy will levy:

- Two charges when Ergon Energy provides new assets:
    - → An up-front charge on the street lighting customer for the provision and construction of new street lighting assets, where Ergon Energy competes, or has an arrangement, to provide these assets for the responsible parties. New assets built by Ergon Energy would therefore be included in Ergon Energy's regulatory asset base at zero value, because the cost would already have been fully paid up-front; and
    - → There would also be an ongoing charge to recover the operation and maintenance of the new street lighting assets;

- Ongoing charges to recover the street lighting revenue cap in relation to existing assets owned by Ergon Energy. The revenue cap would reflect a return on, and depreciation of, the existing street lighting assets (which would not grow over time in value, because new street lighting assets would come into the regulatory asset base at zero value) and an operating and maintenance expenditure allowance associated with existing street lighting assets; and
- A Distribution Use Of System (DUOS) network charge for the use of the shared distribution network to deliver energy to the street lighting assets. This would apply to all street lighting customers irrespective of who owns the street lighting assets.

The key change for street lighting customers will therefore be that, from 1 July 2010, they will be charged up-front for the provision and construction of new street lighting assets. Ergon Energy will no longer recover the cost of new assets over time in network charges. Ergon Energy considers that this change is consistent with the approach its competitors would take to charging for new street lighting assets. It also reflects the fact that Ergon Energy is not responsible for the provision of new street lighting assets and that the parties who are responsible have a choice of how new street lighting assets will be provided and constructed.

Design and Construction of New Large Customers' Connection Assets

The AER's F&A Stage 1 distinguishes between "large" and "small" customers on the basis of the "classes of network users" used by Ergon Energy for pricing purposes:

- Large customer connections are Individually Calculated Customers (ICCs) (typically customers consuming more than 40 GWh per annum), Connection Asset Customers (CACs) (typically customers consuming more than 4 GWh per annum) and Embedded Generators (EGs); and
- Small customer connections are Standard Asset Customers (SACs).

In the current regulatory control period, the costs of designing and constructing new large customer connections were reflected in the capital and operating expenditure forecasts used by the Queensland Competition Authority (QCA) to determine Ergon Energy's revenue cap, which is determined by applying a 'building block approach'. Ergon Energy therefore earns a return on, and depreciation of, new large customer connection assets over time and receives and on going allowance for operating and maintaining these assets. Large customers pay individually calculated network tariffs that allow Ergon Energy to recover this revenue over time and have not paid a capital contribution up-front to be connected.

The AER's F&A Stage 1 indicates that its likely approach will be to classify the design and construction of new large customer connections as an Alternative Control Service from 1 July 2010. As a consequence, Ergon Energy's costs of designing and constructing new large customer connections will no longer be regulated under a revenue cap using a "building block approach".

Rather, Ergon Energy's prices for these services will be regulated by the AER under a formula and a price cap, which will cap the charges that Ergon Energy can levy for the services. However, as customers will be able to choose alternative providers, the market will in fact set the price the customer pays.

Importantly, the AER's proposed classification of the design and construction of new large customer connections as an Alternative Control Service does not, by itself, change the 'contestability' of the market for these services. Within the regulatory and legal framework, large customers are able to choose their preferred supplier for the design and construction of connection assets, although Ergon Energy does have an obligation to provide these assets and connect these customers if no-one else offers to perform the work.

Ergon Energy will compete with the private sector to provide design and construction services for new large customer connections and will retain an obligation to provide these assets and connect these new customers if no-one else offers to do so.

Ergon Energy will change its current practice of allowing new large customers to pay for the costs of Ergon Energy providing new assets through an on-going network charge, typically over 30 years. Instead, it will require a full up-front payment of all design and construction costs, in line with the approach that could be expected from Ergon Energy's competitors.

There will be no potential under this approach for Ergon Energy to 'double recover' the cost of assets that have been paid for by customers, because it will not be able to include these assets in its regulatory asset base at value. As a consequence, it will not earn a return on, or depreciation for, these assets. It will, however, receive an allowance in the regulated revenue cap for Standard Control Services for the cost of operating and maintaining new large customer connection assets.

(N) 5.4 Ergon Energy's Procurement Process

Ergon Energy has robust and auditable procurement processes in place, which support and encourage the achievement of competitive prices for the procurement of goods and services. These processes include the application of:

- Queensland Government State Purchasing Policy;
- Procurement policy business rules;
- Guidelines to establish and manage contracts for goods and services;
- Work instructions to manage, extend, re-invite and complete contracts;
- Work instructions to request, prepare and advertise tenders for goods or services;

- Work instructions to evaluate, recommend, obtain approval and award contract; and
- Work instructions to issue tender packs, receive and open tenders.

These procurement processes help to ensure that Ergon Energy acquires its goods and services in a competitive, transparent and efficient manner. This is a key contributor to ensuring that Ergon Energy's unit rates reflect efficient market based costs, particularly for higher value or volume purchases. This is because Ergon Energy procures the majority of its materials from external sources and also outsources a significant amount of work to contractors.

Examples of purchases of materials and services that are made after a public tender process are:

- Key items of equipment such as transformers, poles and cables;
- 'Turn-key' project delivery including civil constructions such as substation buildings;
- Vegetation clearing works;
- Pole inspection works; and
- Purchase of fleet vehicles.

(N) 6 SUSTAINABILITY AND INNOVATION

(N) 6.1 How Ergon Energy Considers Non-Network Alternatives

Ergon Energy has a three stage process to consider non-network alternatives, which is undertaken in conjunction with existing capital works planning and investment approval processes in order to assess whether a suitable non-network alternative is more prudent than a more traditional network augmentation. The three stages of this process involve undertaking a screening test, a feasibility investigation and a business case:

- Screening test – this is a high-level assessment to determine whether undertaking a non-network alternative could be viable and whether further investigations are warranted;
- Feasibility investigation – if a screening test identifies that one or more non-network alternatives may be viable then a feasibility investigation is undertaken. The feasibility investigation is a detailed investigation that details the prospective non-network alternatives' technical requirements and risks, customer agreement terms and supplier quotations; and
- Business case - a business case involves a detailed investigation of the identified non-network alternative option which is incorporated with detailed investigations of the network options and discounted cash flow analysis.

In accordance with the requirements of the Rules, Ergon energy also conducts the Regulatory Test for any network augmentation investment greater than $1 million, and a public consultation about the Regulatory Test for any network augmentation investment greater than $10 million, to allow other providers the opportunity to invest in non-network alternatives.

(N) 6.2 Non-Network Alternative Trials

Ergon Energy's non-network alternatives program for the next regulatory control period is $61.248 million (Real $ 2009-10), all of which is operating expenditure.

When combined with projects that provide specific deferral of network augmentation projects that are identified through the Regulatory Test, Ergon Energy's non-network alternatives trials program could reduce peak demand.

The focus of Ergon Energy's current non-network alternatives program is conducting trials and pilot projects in 2008-09 and 2009-10 to develop the necessary skills and expertise before the commencement of the next regulatory control period.

The trials and pilot project programs in the next regulatory control period will establish an evidence base for the future deployment of non-network alternatives as appropriate in regional Queensland whilst not compromising service standards, safety or security. Ergon Energy will continue to work closely with customers in undertaking these activities, as they will need to choose to participate in the programs. The end goal of the non-network alternatives program is to deliver to customers the reliability and security of supply they expect at the lowest cost by enabling customers to participate in non-network alternative solutions. Ergon Energy will seek to do this by providing a low cost, reduced risk solution to traditional supply side solutions.

(N) 6.3 Demand Management Incentive Scheme (DMIS)

The AER has introduced a national DMIS for all distribution businesses. For Ergon Energy, the scheme will involve a Demand Management Innovation Allowance (DMIA) of $5 million being available to be spent by Ergon Energy over the five year regulatory control period. The intention of the scheme is to allow the more risky and innovative demand management initiatives to be piloted and the results to be reported to the AER.

In addition to its own trials, Ergon Energy will be utilising the scheme to prove the viability and sustainability of demand management initiatives.

(N) 6.4 Communications Network

Ergon Energy has begun the first stage of rolling out a contiguous telecommunications backbone network, known as the 'Ubiquitous Network', or 'UbiNet', throughout its distribution area.

UbiNet will have a primary backbone, which will enable the future deployment of a multipoint network solution to service intelligent network devices and deliver enhanced monitoring and control of the distribution network. Where it is not economic to construct the internal telecommunication platform, commercial carrier services, such as satellites, will be integrated into the UbiNet solution.

UbiNet will satisfy a range of Ergon Energy's telecommunications requirements including SCADA, network monitoring and control, fixed and mobile staff communications and, if required, connectivity to customer meters.

UbiNet Stage 1 involves investing in the core telecommunications backbone network across Ergon Energy's distribution area. This stage will be implemented between 2008-09 and 2011-12, which means it is included in forecasts for the first two years of the next regulatory control period. This is the only stage of UbiNet that has to date been approved by Ergon Energy's Board. No other stages of the UbiNet development have been included in the forecast capital expenditure for the next regulatory control period.

In 2010-15, the SCADA program will also be extended to cover about 90 per cent of Ergon Energy's customers. The extended coverage of the SCADA program will focus on providing remote control, particularly in Ergon Energy's South West, Mackay and Wide Bay regions, where there is currently limited SCADA penetration. This will enable Ergon Energy to harness value from the control centre infrastructure installed by the LINK project and will contribute to achieving Ergon Energy's vision and strategy of moving towards a smart grid.

(N) 6.5 Delivering on Climate Change Impacts

Ergon Energy's Climate Change Response Plan forms a key outworking of Ergon Energy's Strategic Plan and Environmental Policy and has been aligned to the Strategic Plan's objectives for 2005-10. This plan provides for a Climate Change Response Framework, which identifies the intended business outcomes for the areas of understanding climate change, building business resilience and proactively capitalising on opportunities. It also identifies a range of climate change strategies and actions, at business unit level, for each of the key areas of response outlined in the Climate Change Response Framework.

The potential effects of climate change, including the likelihood of severe summer temperatures, could increase the uncertainty of load forecasts and reduce the tolerance for error because of the lower capacity ratings of electrical equipment at higher ambient temperatures with flat load profiles.

(N) 7 OUR EXPENDITURE PROGRAM

(N) 7.1 Capital Expenditure for Current Regulatory Control Period (2005-10)

For the current regulatory control period Ergon Energy's total system capital expenditure exceeded the QCA's building block forecasts. This is shown in Figures 6 and 7. It is predominantly driven by the uncontrollable number of new Customer Initiated Capital Works (CICW). New connections to the network also drive expenditure on the shared network in the category of Corporation Initiated Augmentation (CIA). To the extent it could, without compromising the reliability, quality or safety of supply, Ergon Energy has curtailed its more discretionary system expenditure in order to fund and resource new customer connections and to ensure that supply was not interrupted in times of peak demand.

Growth in customer connections has been higher than forecast for this period. Customer numbers were expected to grow at an average of 1.88 per cent from 2005 to 2010. Actual growth for the first three years of the current regulatory control period has been 2.31 per cent and is forecast to slow slightly to 1.6 per cent for the remaining two years. Increases have been seen as resulting from:

- Strong growth in domestic and rural connections;
- Increased subdivision work; and
- Larger commercial and industrial connections linked to the resources boom.

The rising cost of materials and labour resources has had an impact on capital expenditure, and this is also reflected in the 2010-15 forecasts. Labour and contractor costs will increase by 0.5 per cent from 2008 in line with the new Ergon Energy Union Collective Agreement 2008, which provided for an annual wages increase from 4 per cent to 4.5 per cent. Higher contractor rates are reflective of the contractor market tightening during the resources boom. Material costs have also increased significantly, particularly for high volume essential items. The examples shown below are based on the average per annum increases in prices as reflected in procurement contracts over the last four years:

- Padmount transformers – 9.7 per cent;
- Pole mount transformers – 11.6 per cent;
- Aluminium underground cable – 5.6 per cent;
- Copper underground cable – 9.4 per cent;
- Aluminium Conductor Steel Reinforced (ACSR) aerial cable – 2.0 per cent;
- Copper aerial cable – 11.3 per cent;
- Steel cable – 26.0 per cent; and
- Poles – 5.4 per cent.

Non-system capital expenditure also required investment above the QCA's building block forecasts. A contributing factor was the investment of $70 million in Project Jet, the project which delivered Ergon Energy's enterprise resource planning system (Ellipse).

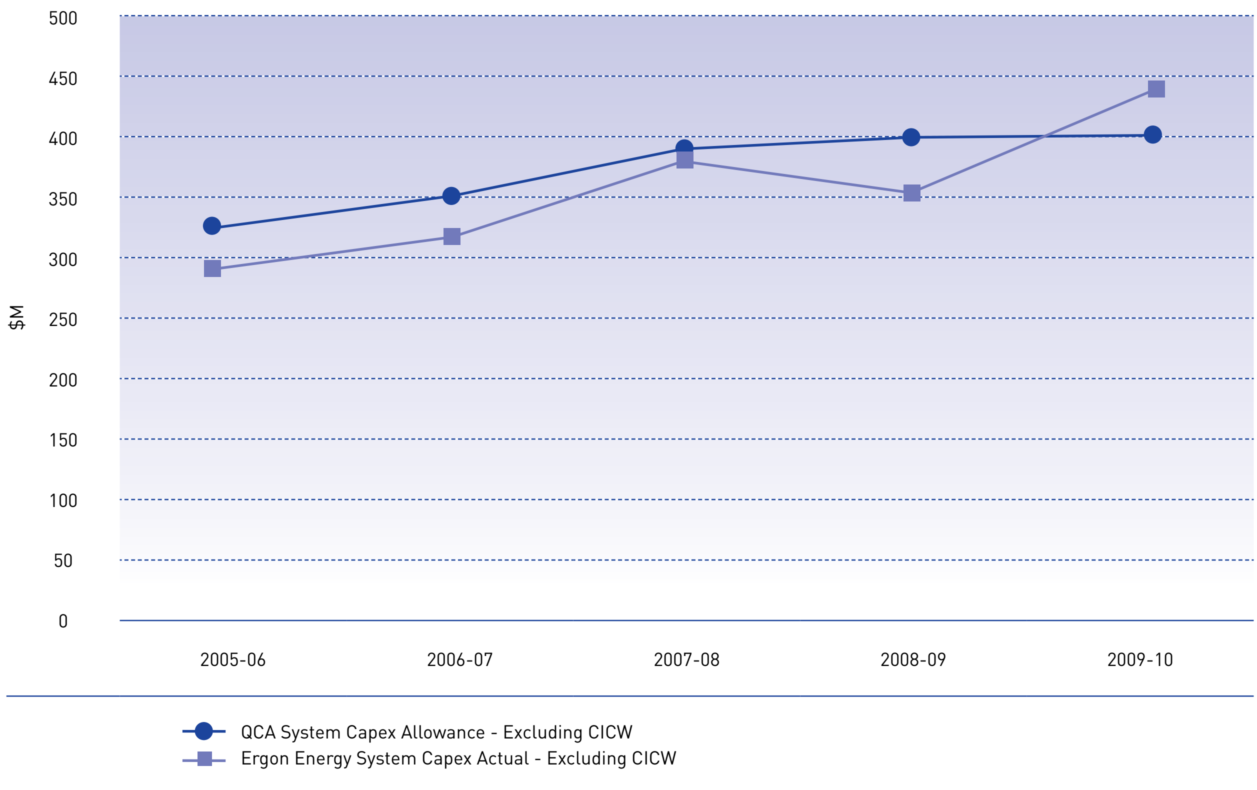
Additional investments in property, fleet and information and communications technology (ICT) were necessary to keep pace with growth in employee numbers, which increased from 3,652 employees in June 2005 to 4,489 in June 2008.

A key contributor to the increase in employees was a commercial drive over the same period to reduce external fixed-term resources, which dropped from 768 to 320, in favour of permanent appointments. More employees were required in the National Contact Centre (NCC) and in Customer Connections, Design and Regional Works Planning to cope with the sharp increase in new customer connections. The NCC employee numbers increased in other areas to cope with more than one million calls annually.

The apparent dip in Ergon Energy's capital expenditure profile in 2008-09 is due to a number of factors including, but not limited to: the delay in UbiNet approval, a change in CICW scoping, estimating and approval process changes, flooding, industrial action, overtime reductions, a drive to reduce leave and an underspend in non-system expenditure (particularly Land and Buildings, Change and Fleet). Ergon Energy plans to recover this over the next three years (2009-10 to 2011-12) and return to the capital expenditure profile seen in the first three years of the current regulatory control period. This profile of expenditure is reflected in the capital expenditure forecasts in this Regulatory Proposal.

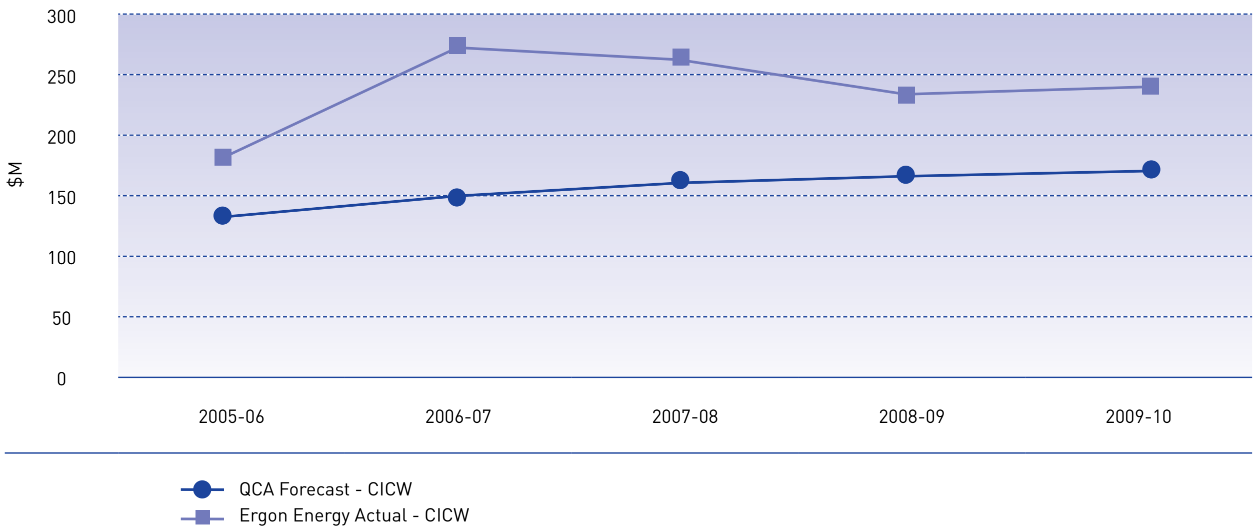
Capital Expenditure including Comparison with QCA Building Blocks

Figure 6: *System Capital Expenditure –*
Excluding Customer Initiated Capital Works (including comparison with QCA Building Blocks) ($M Nominal)



Source: Tables for Proposal N 7.1

Figure 7: Customer Initiated Capital Works (including comparison with QCA Building Blocks) ($M Nominal)



Source: Tables for Proposal N 7.1

(N) 7.2 Operating Expenditure for Current Regulatory Control Period 2005-10

For the current regulatory control period, Ergon Energy's total operating expenditure investment has been higher than the QCA's building block forecasts. This is shown in Figure 8. Key drivers for this additional investment include:

- Improvements to maintenance programs;
- Above-forecast increases in maintenance volumes;
- Higher labour and contractor costs; and
- One-off events including Severe Tropical Cyclone Larry and FRC.

The areas of Corrective and Preventive Maintenance saw significant increases in the volume of work relating to vegetation management and pole inspections. Both areas also saw the introduction of improved maintenance programs relating to pole top inspections and access track establishment and maintenance. Less significant increases occurred across other asset equipment types, due in part to increased material and labour costs. Labour and contractor costs will increase by 0.5 per cent from 2008 in line with the new Ergon Energy Union Collective Agreement 2008, which saw annual costs growth increase from 4 per cent to 4.5 per cent.

One-off events also required additional operating expenditure. Cyclone Larry accounted for $15.8 million in 2005-06. The implementation of FRC accounted for $18.4 million.

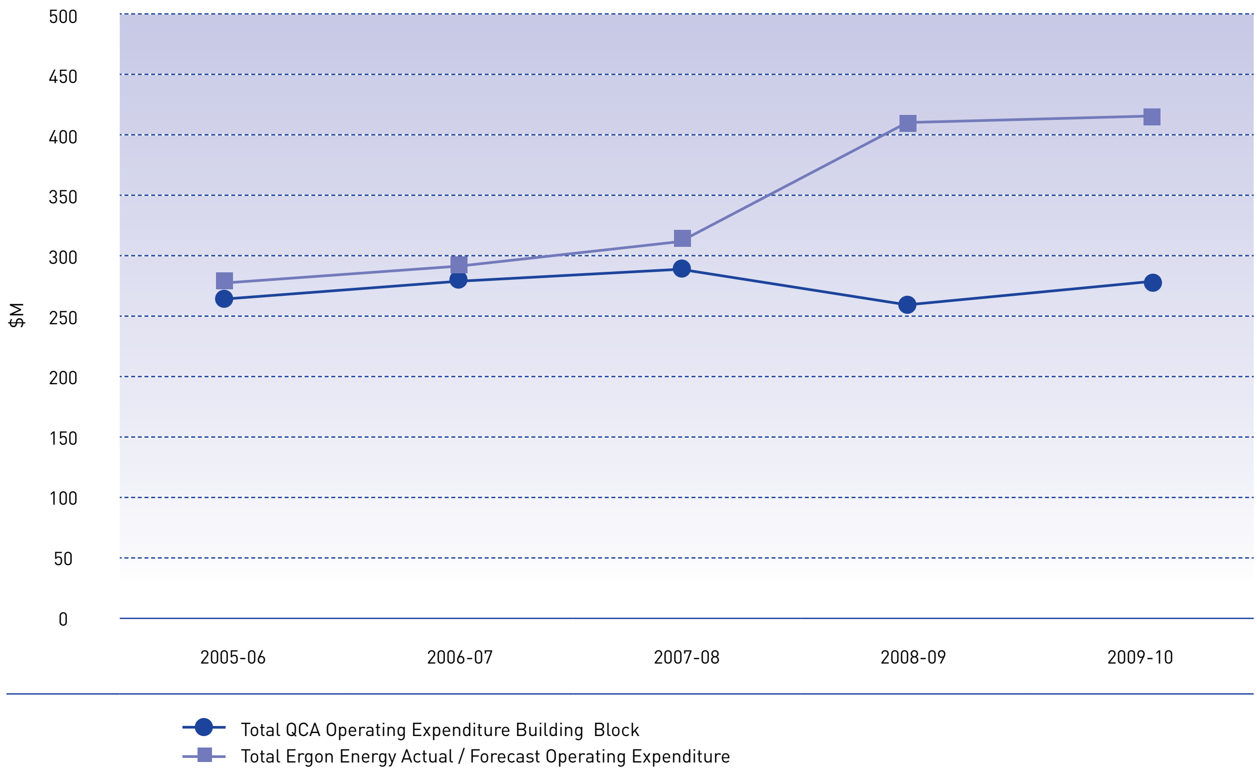
(N) 7.3 Network Performance for Current Regulatory Control Period 2005-10

Over the past five years, Ergon Energy's reliability performance has improved significantly with a decrease in average system interruption duration by 25 per cent and decrease in interruption frequency by 32 per cent. Strong investment in the network has contributed to this step change in performance. Meeting the more gradual, yet increasingly stringent, improvements in the minimum service standards since this step change has been achieved for the past two financial years, but was impacted negatively in 2005-06 by Cyclone Larry.

Despite extreme weather events again in 2008-09, Ergon Energy's 2008-09 Summer Preparedness Report shows improved overall performance from its network over the summer period. Network averages showed a 10 per cent drop in the number of power interruptions compared to the previous summer, even though many parts of the state weathered some of the most significant storm and natural disaster events in decades during the 2008-09 storm season. Exceptional weather events for the summer included severe lightning storms in northern parts and the effects of tropical cyclones Charlotte, Ellie and the Category 5 system Hamish. Reliability figures also show regional Queenslanders received an electricity supply which not only met, but was on average significantly higher than, the regulated minimum service standards. Despite a strong summer performance, a deferral of live line work to enable a review of safety procedures and operating bans on ABB Air Break Switches due to systemic failures, are likely to negatively impact Ergon Energy's ability to achieve its overall minimum service standards for 2008-09. Ongoing compliance with the targets in 2010-15 will require a significant investment in asset replacement.

Work has also been delivered to improve pole reliability and power quality. Based on a three-year rolling average, pole reliability is now at 99.997 per cent, exceeding the minimum standard of 99.99 per cent. Ergon Energy has invested in establishing infrastructure to monitor power quality on a routine basis, providing a foundation for further improvement programs.

Figure 8: *Operating Expenditure (including comparison with QCA Building Blocks) ($M Nominal)*



Source: Tables for Proposal N 7.2

(N) 7.4 Forecast Capital Expenditure for Next Regulatory Control Period 2010-15

Figure 9 details Ergon Energy's forecast capital expenditure for 2010-15 by category driver by year of $6.032 billion.

The increased cost of materials and labour, above that which was forecast for the current regulatory control period, is a driver of the step change increase in capital expenditure for the next regulatory control period. These cost increases were discussed in section (N) 7.2 above. The increase in costs will impact all areas of the 2010-15 capital expenditure program, including major investments in:

- Asset replacement to improve reliability and safety;
- CIA to meet growing demand on the shared network;
- CICW to deliver more new connections;
- Targeted reliability and quality improvements;
- A new communications network; and
- The construction of new buildings to consolidate and upgrade ageing depot and office facilities in major regional centres including Cairns, Townsville and Rockhampton.

Asset Replacement

$1,214.14 million will be invested in improving the reliability of the network. Major reliability improvements have been achieved in the current regulatory control period. However challenges still remain to reduce unplanned outages to meet minimum service standards through asset replacement and refurbishment.

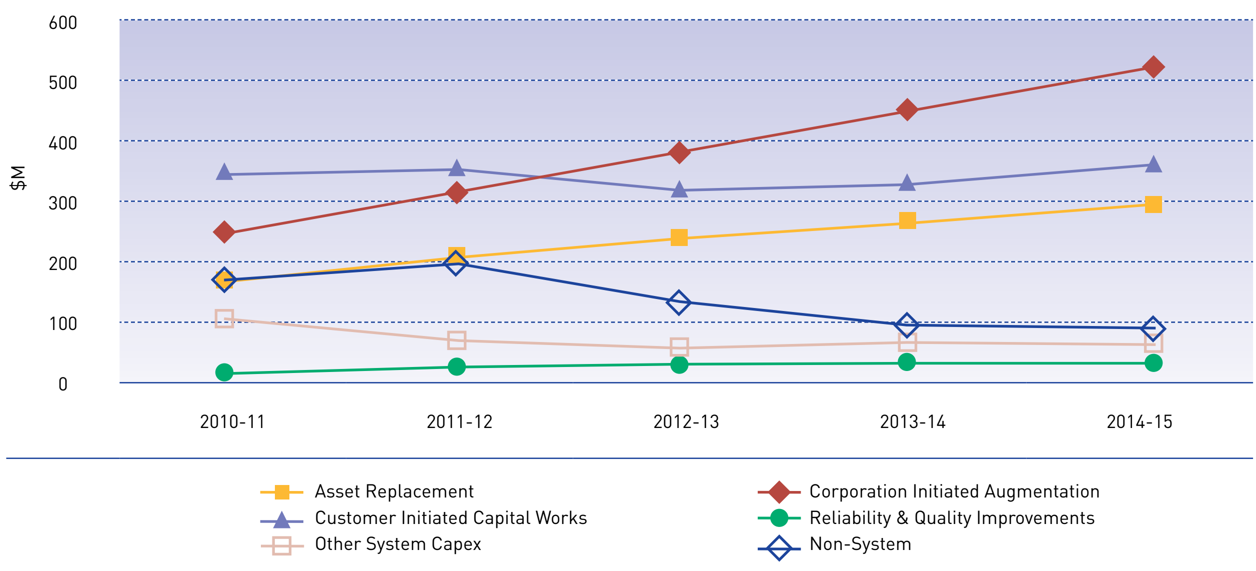
Defect-based expenditure will increase on:

- Pole top replacements to address more unassisted failures and dangerous electrical events relating to cross arms;
- Underground cables to address the large number of high voltage cables that have failed in service and the need to replace high voltage XLPE cables;
- Lightning arrestors as a result of changing the defect classification criteria for failed lightning arrestors;
- Customers' overhead service lines in order to improve public safety;
- Earth remediation in order to address the requirements of the Code of Practice Works under the Electrical Safety Act 2002; and
- The replacement of non-compliant meters in accordance with the Meter Asset Management Plan.

Condition-based expenditure will increase on:

- Overhead conductor replacement in accordance with the recommendations of the EDSD Review and the subsequent Queensland Government initiated 2008 Operational Review;
- The replacement of liquid filled fuses in order to address identified safety risks;
- The refurbishment of sub-transmission feeder pole tops on the basis of condition assessments, feeder performance and assessed risks to the network;
- Sub-transmission line rebuilds relating to sub-transmission lines in order to meet service performance requirements; and
- A variety of substation plant and equipment, including: zone substation transformers refurbishment and replacement, circuit breakers and switchboard refurbishment and replacement, current transformers and voltage transformers, outdoor

Figure 9: *Forecast Capital Expenditure – by Category Driver – 2010-15 ($M Real $2009-10)*



Source: Tables for Proposal 23.1

switchyards refurbishment, capacitors and static Volt Ampere Reactive (VAR) compensators, protection equipment and SCADA and load control equipment.

Corporation Initiated Augmentation

$1,990.95 million will be invested in increasing network capacity to cope with growing peak demand, which is forecast to increase at an average of 3.27 per cent annually over the next regulatory control period. In this time, Ergon Energy has forecast to build 37 new urban and 19 new rural zone substations in response to demand growth and security standards. Expenditure will also be directed at improving security of supply, particularly relating to the network's redundancy provisions in the event of equipment failure.

In particular, CIA expenditure will increase to enable Ergon Energy to:

- Meet the maximum demand/load forecasts, which are expected to be driven by strong population growth, major new industrial or commercial developments, economic growth, climatic effects and air conditioning penetration; and
- Implement its Network Planning Criteria NP02 and Security Criteria NPD05.

Customer Initiated Capital Works

$1,694.99 million will be invested in connecting new customers to the network. Volumes for small and large customer connection works are forecast to fluctuate on a year-by-year basis during the next regulatory control period. However overall volume of customer connection works are expected to continue to increase on average over the five years when compared to the current regulatory control period. Compounding the cost of this increase is the escalation of labour and materials costs above that which was forecast for the current regulatory control period. Materials account for around 40 per cent of CICW expenditure.

Reliability and Quality Improvements

Reliability and quality improvements expenditure of $122.39 million will increase to enable Ergon Energy to meet the increasingly onerous minimum service standard requirements under the Electricity Industry Code and to address its worst performing feeders. The key programs will relate to:

- The rollout of SCADA to around 90 per cent of all customers;
- Actioning the feeder improvement program. Investment in targeted reliability improvements which will focus on improving the worst performing distribution feeders across the network; and
- Extending the network monitoring program.

This work will contribute to meeting the minimum service standards, which will also benefit from investments in asset replacement, corporation initiated augmentation and network maintenance programs.

Infrastructure established in the current regulatory control period to provide routine monitoring of power quality will provide a foundation for further quality improvements in 2010-15.

Other System Capital Expenditure

Other system capital expenditure will increase to $331.38 million and will be invested in:

- Completing the first stage of UbiNet, which will deliver enhanced monitoring and control of the distribution network. UbiNet will allow faults to be more easily identified and repaired, significantly reducing outage durations;
- Improving protection system design to clear faults and dangerous situations in a timely manner in order to ensure public and staff safety and to protect Ergon Energy's assets; and
- Delivering on the 17 strategies for the SWER system that were detailed in the January 2008 document entitled 20 Year Strategic Plan for SWER that was prepared by the SWER Improvement Group. There will also be investment in modernising the SWER network and undergrounding powerlines in key locations, including cyclone prone areas.

Non-System Land and Buildings

Non-system land and buildings capital expenditure of $384.23 million is a key contributor to the increased investment in non-system Capital Expenditure of $679.10 million. This includes the consolidation and upgrade of ageing and outgrown depots and workplaces in major regional centres.

- $60 million for a new Townsville depot to accommodate the significant increase in operational requirements;
- $20 million for a new Cairns depot which will consolidate operations above the tidal surge zone; and
- $54 million for the redevelopment of Rockhampton's ageing Glenmore Road site.

(N) 7.5 Forecast Operating Expenditure for Next Regulatory Control Period (2010-15)

Figure 10 details Ergon Energy's forecast operating expenditure for 2010-15 by category driver by year of $1.898 billion.

Overall, this expenditure will deliver a safer, more reliable network through maintenance programs, as well as ensuring continued efficient delivery of network operations and customer services. It also includes provisions for necessary increases in investment in Preventive and Corrective Maintenance, as well as new schemes to deliver more affordable peak demand reduction solutions. The impact of above-forecast cost increases will also be felt in the operational expenditure program for the next regulatory control period. These cost increases were discussed in section (N)7.2 above. Labour and contractor costs are forecast to increase above CPI in accordance with the Ergon Energy Union Collective Agreement 2008, which will be renegotiated in 2011.

Preventive Maintenance

New inspection programs are being introduced across all asset equipment types. Each program will see a relatively small increase in work, however, the combined effect will require an increase in expenditure compared to forecasts for the current regulatory control period. Additional work is also arising from Preventive Maintenance inspections for meters, distribution services, underground cables and joints, vegetation scoping work, outdoor switchyards, communications and protection.

Preventive Maintenance expenditure will increase in order to:

- Improve supply reliability by reducing pole top and cross arm failures through a combination of mast-mounted cameras, aerial helicopter inspections and elevating platform vehicle inspections;
- Commence an overhead customer service inspection program on a 12 year cycle;
- Introduce a full program of internal inspection of underground pillars on an eight year cycle from 2010-11;
- Commence a new ring-main unit inspection program on a 12 year cycle from 2010-11;
- Upgrade the vegetation management inspection program based on Ergon Energy's new Vegetation Strategy;
- Upgrade the existing access track maintenance program;
- Commence a new program for inspecting and testing automatic circuit recloser and sectionaliser protection systems every two year cycle from 2010-11;
- Introduce additional communication maintenance programs and a new maintenance program following the rollout of UbiNet Stage 1;
- Introduce new meter inspection programs; and
- Commence a new program for the SCADA Master Station and related equipment that was introduced through Program LINK.

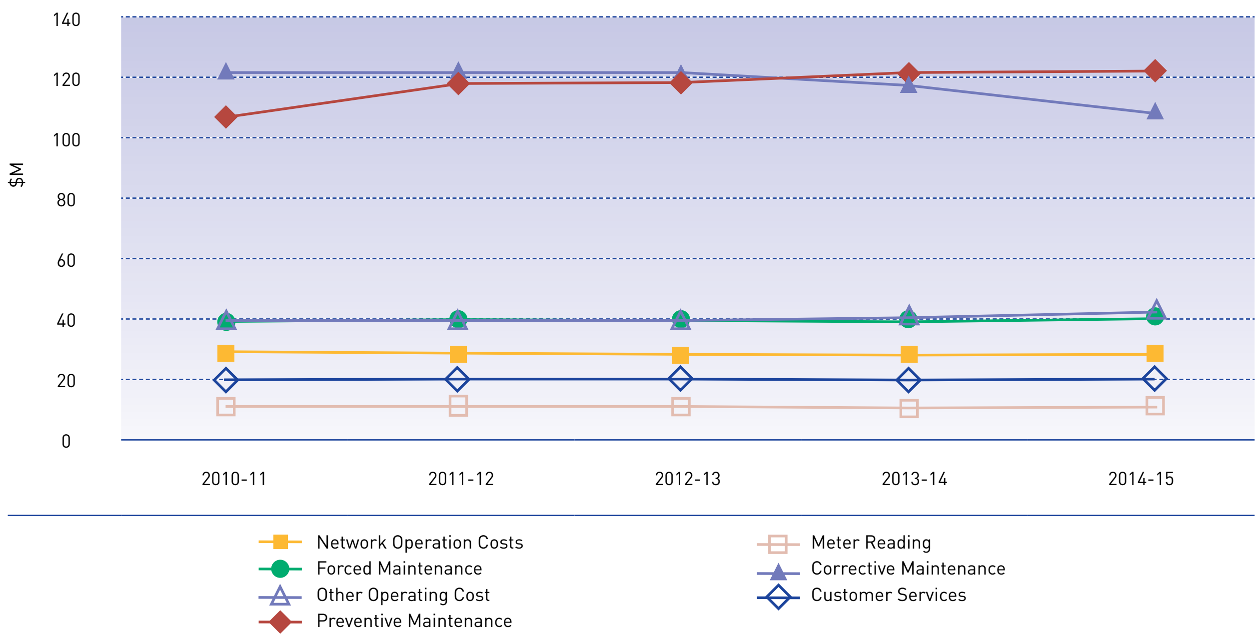
Corrective Maintenance

Increases in Preventive Maintenance will flow through to this area as Corrective Maintenance work is identified through the preventive inspections. In addition to this, a review of vegetation management programs has resulted in a new strategy that will deliver a more comprehensive and efficient approach to vegetation management. Additional work is required to clear a backlog of vegetation as the transition is made to the new strategy. Work will also continue on the access track program introduced in the current regulatory control period.

Corrective Maintenance expenditure will increase for:

- Poles, pole tops, conductors and connectors, and distribution services following upgrades to the line patrol and pole top inspection programs that are to be undertaken as part of the Preventive Maintenance programs;

Figure 10: *Forecast Operating Expenditure – by Category Driver – 2010-15 ($M Real $2009-10)*



Source: Tables for Proposal 26.1

- Access track remediation following upgrades to the inspection program that is to be undertaken as part of the Preventive Maintenance program; and
- The vegetation management cutting and clearing program following upgrades to the inspection program that is to be undertaken as part of the Preventive Maintenance program.

It is therefore expected that, in relation to each of these expenditure categories, the increased inspection program that is to be undertaken as part of the Preventive Maintenance program will identify the need for more Corrective Maintenance work to be undertaken.

Affordable Alternatives to Address Peak Demand

Almost $70 million will be invested in developing affordable alternatives to address growing peak demand. Under the AER's new Demand Management Incentive Scheme (DMIS), Ergon Energy will invest $5 million (Nominal dollars) over five years to develop demand management initiatives. $61 million (Real $2009-10) over five years will be invested in developing non-network alternatives, aimed at addressing the issue in ways other than traditional network expansion.

Training

During the current regulatory control period training costs were included as part of the shared costs pool. Due to a change in accounting treatment, training costs of approximately $20 million per annum will be treated as operating expenditure. Ergon Energy is legally obliged to conduct a large amount of training, particularly to ensure that safe work practices are used in the field. Training will also target skills for SCADA and communications systems.

(N) 7.6 Delivering the Program of Works

Ergon Energy has forecast that its proposed capital and operating expenditure programs for the 2010-15 regulatory control period will constitute an average 9.5 per cent annual increase in work to be delivered, compared to 2008-09 levels.

Allowing for annual productivity improvement (3 per cent is assumed), the successful delivery of this work requires an average annual growth in the system workforce of around 3 per cent, with a peak annual system workforce growth of around 11 per cent or 332 full time equivalent (FTE) employees and contractors in 2010-11.

Comparing this to the actual historical system FTE growth of 368 FTE in 2006-07 which was achieved during a period of strong economic activity and a tight labour market, Ergon Energy considers that the proposed program of system capital and operating work for the next regulatory control period is deliverable.

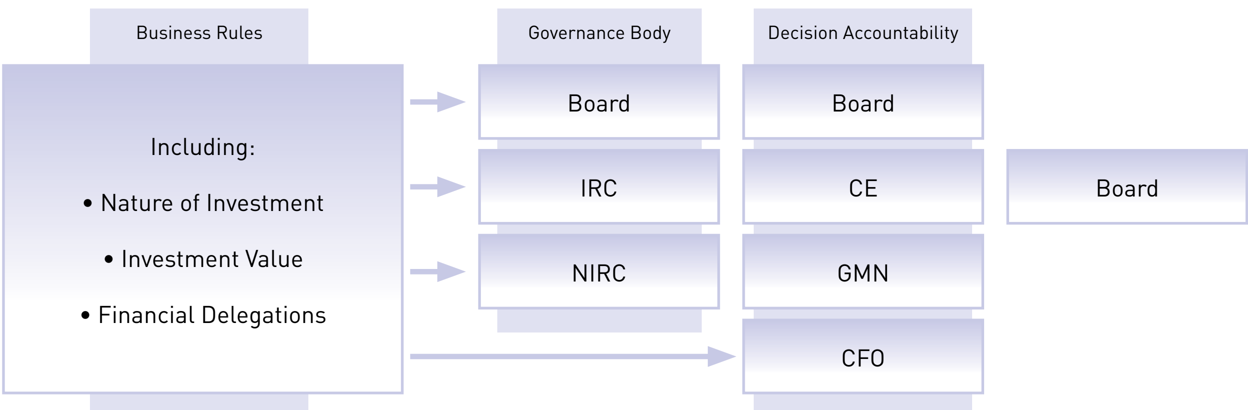
(N) 7.7 Investment Approvals

Ergon Energy uses a comprehensive framework for the development and prioritisation of investment programs. The framework is supported by a hierarchy of governance bodies and approval authorities to ensure investment is aligned with the organisation's strategic and operational priorities. This includes the Investment Review Committee (IRC), which operates at a business-wide, strategic level to ensure an appropriate balance between asset investments, customer service, product and asset research and development and business change within the investment portfolio. It also includes the Network Investment Review Committee (NIRC) which facilitates the efficient and effective management of all network asset-related capital and operating expenditure in accordance with the Asset Management Plan (AMP). The framework is shown in Figure 11.

(N) 7.8 Efficiency Benefit Sharing Scheme (EBSS)

In the current regulatory control period, Ergon Energy has implemented a number of initiatives to improve the efficiency and productivity of its operations. The effectiveness of these initiatives, and ongoing efficiency drives, will be tested in the next regulatory period with the introduction of the AER's EBSS. The EBSS will provide a financial incentive for Ergon Energy to improve the efficiency of its operating expenditure and to share any resulting efficiency gains (or losses) with customers.

Figure 11: *Investment Management – Governance and Decision Accountability*



(N) 8 REGULATORY PROPOSAL SNAPSHOT – STANDARD CONTROL SERVICES

Table 4 provides a snapshot of Ergon Energy's Regulatory Proposal for its Standard Control Services.

Table 4: *Regulatory Proposal Snapshot – Standard Control Services*

	Ergon Energy's Regulatory Proposal
ARR (5 years) Smoothed	6,761.15
X factor (Yr 1 / Yrs 2 to 5) - % [1]	- 27.05 / - 7.69
Opening RAB (1 July 2005)	4,146.17
Opening RAB (1 July 2010)	6,999.39
Closing RAB (30 June 2015)	13,097.89
Total Capital Expenditure (5 years)	6,032.94
Total Operating Expenditure (5 years)	1,898.46
Cost of Capital - %	9.49

Source: SCPTRM Submission Model and Tables for Proposal

[1] A negative P° and X factor mean an increase in prices

(N) 8.1 Demand Forecasts

Table 5 provides a high level summary of Ergon Energy's forecasts of coincident peak (maximum) demand, total energy consumption and customer numbers for the period 1 July 2010 to 30 June 2015. Ergon Energy has used these demand forecasts to develop its operating and capital expenditure forecasts.

Table 5: *Ergon Energy Demand Forecasts for 2010-15*

	2010-11	2011-12	2012-13	2013-14	2014-15	Average of 5 Year Total
EE Coincident peak (maximum) demand (MW) – September 2007	2,967	3,063	3,153	3,243	3,330	3,151
EE Total energy consumption (GWh)	15,870.51	16,450.40	16,874.17	17,432.66	17,887.16	16,902.98
EE Customer numbers	684,469	695,242	706,204	717,356	728,706	706,395

Source: Coincident peak (maximum (demand) – Ergon Energy's Network Planning 2007 forecasts (refer also NIEIR November 2007 report)
AR433c AER Data_v7_data room_28May09.xls

(N) 8.2 Capital Expenditure

Table 6 shows Ergon Energy's capital expenditure for the next regulatory control period is forecast to be $6.032 billion.

Table 6: *Forecast Capital Expenditure – by Category Driver – 2010-15 ($M Real $2009-10)*

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Asset Replacement	177.44	212.68	250.03	274.81	299.18	1,214.14	242.83
Corporation Initiated Augmentation	267.84	339.38	401.26	463.58	518.89	1,990.95	398.19
Customer Initiated Capital Works	336.11	354.99	315.56	328.70	359.63	1,694.99	339.00
Reliability and Quality Improvements	18.29	20.89	24.50	28.28	30.43	122.39	24.48
Other System	105.62	72.94	50.78	50.39	51.65	331.38	66.28
Non-System	180.90	199.03	135.19	82.27	81.70	679.10	135.82
Total	**1,086.20**	**1,199.90**	**1,177.32**	**1,228.03**	**1,341.49**	**6,032.94**	**1,206.59**

Source: Tables for Proposal 23.1

(N) 8.3 Operating Expenditure

Table 7 shows that Ergon Energy's operating expenditure for the next regulatory control period is forecast to be $1.898 billion.

Table 7: *Forecast Operating Expenditure – by Category Driver – 2010-15 ($M Real $2009-10)*

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Network Operating Costs	26.36	26.33	26.67	27.21	27.51	134.08	26.82
Network Maintenance Costs							
Preventive Maintenance	108.82	119.56	120.15	123.36	121.68	593.57	118.71
Corrective Maintenance	121.88	121.48	122.82	117.94	105.66	589.78	117.96
Forced Maintenance	41.00	40.85	41.34	41.42	41.08	205.69	41.14
Subtotal	271.70	281.89	284.31	282.72	268.42	1,389.04	277.81
Other Costs							
Meter Reading	11.75	11.81	12.03	12.31	12.48	60.38	12.08
Customer Services	19.82	19.86	20.19	20.60	20.81	101.28	20.26
Other Operating Costs	40.47	41.59	42.29	43.85	45.48	213.68	42.74
Subtotal	72.04	73.26	74.51	76.76	78.77	375.34	75.07
Total Operating Expenditure	**370.10**	**381.48**	**385.49**	**386.69**	**374.70**	**1,898.46**	**379.70**

Source: Tables for Proposal 26.1

(N) 8.4 Regulatory Asset Base

Ergon Energy's proposed opening Regulatory Asset Base for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15, is detailed in Table 8.

Table 8: *Ergon Energy's Regulatory Asset Base from at 1 July 2010 ($ M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15
Opening Regulatory Asset Base	6,999.39	8,041.17	9,220.93	10,410.39	11,672.77
Capital Expenditure (net of disposals)	1,145.14	1,296.53	1,303.17	1,392.84	1,559.42
Regulatory Depreciation	-103.36	-116.77	-113.71	-130.46	-134.30
Closing Regulatory Asset Base	8,041.17	9,220.93	10,410.39	11,672.77	13,097.89

Source: Tables for Proposal 40.2

(N) 8.5 Annual Revenue Requirement

Ergon Energy's proposed Annual Revenue Requirement for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15, is detailed in Table 9.

Table 9: *Annual Revenue Requirement for Standard Control Services for 2010-15 ($ M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Annual Revenue Requirement (smoothed)	1,100.22	1,213.87	1,339.25	1,477.59	1,630.21	6,761.15	1,352.23

Source: Tables for Proposal 49.2

(N) 8.6 Cost of Capital

Table 10 provides Ergon Energy's proposed parameters to calculate its rate of return on capital.

Table 10: *Parameters to calculate Nominal Post Tax Weighted Average Cost of Capital*

Parameter	Symbol	Value
Nominal Risk Free Rate	Rf	5.08%
Real Risk Free Rate	Rrf	2.57%
Inflation Rate	f	2.45%
Cost of Debt Margin	DRP	3.88%
Market Risk Premium	MRP	6.50%
Corporate Tax Rate	T	30.0%
Gamma	γ	0.20
Proportion of Equity Funding	E/V	40.0%
Proportion of Debt Funding	D/V	60.0%
Equity Beta	βe	0.80

Source: SCPTRM

(N) 8.7 P° and X Factors

Ergon Energy's proposed X factors for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15, are detailed in Table 11. Key drivers of the initial increase stem from higher than forecast growth in the current regulatory control period, especially in relation to the jump in new customer connections, and heightened costs of labour and materials.

Table 11: *X Factors for Standard Control Services for 2010-15 (per cent)*

	2010-11	2011-12	2012-13	2013-14	2014-15
X factors	-27.05	-7.69	-7.69	-7.69	-7.69

Source: Tables for Proposal 42.1

Note: A negative X factor represents a real increase in distribution prices.

(N) 8.8 Indicative Prices

Table 12 shows indicative prices for each Standard Control Service customer class in each year of the next regulatory control period. This is a simple expression of the prices forecast for Standard Control Services for the next regulatory control period. It is not the basis on which Ergon Energy intends to charge for these services.

Table 12: *Indicative Prices Standard Control Services by Customer Grouping 2010-15 (c/kWh Real $2009-10)*

Pricing Category	2010-11	2011-12	2012-13	2013-14	2014-15
ICC	0.857	0.889	0.949	0.992	1.057
CAC	4.057	4.230	4.490	4.741	5.060
SAC	10.416	10.821	11.241	11.676	12.126
EG	0.101	0.107	0.113	0.120	0.127

Source: RIN 2.2.5 Table 1 and AR433c AER Data_v7_data room_28May09.xls

1. REGULATORY PROPOSAL

Rules – Clauses 6.8.2, 6.9.3(a), 6.10.3, 6.12.3(a) and 11.26.2

Ergon Energy Corporation Limited (Ergon Energy) is pleased to submit this Regulatory Proposal to the Australian Energy Regulator (AER) for the five year regulatory control period, 1 July 2010 to 30 June 2015.

This Regulatory Proposal is made in accordance with the requirements of Chapter 6 and Chapter 11 of the National Electricity Rules (Rules). In particular, it:

- Is submitted to the AER by 1 July 2009, as required under clause 11.26.2 of the Rules;
- Includes the following elements required under clause 6.8.2(c) of the Rules:
  - → A Classification Proposal – this is set out in Chapter 14 of this Regulatory Proposal;
  - → A Building Block Proposal for Standard Control Services – this is set out in Chapters 17 to 51 of this Regulatory Proposal;
  - → A demonstration of the application of the control mechanism, and the necessary supporting information, for Alternative Control Services – this is set out in Chapters 53, 54 and 55 of this Regulatory Proposal;
  - → Indicative Prices for Direct Control Services for each year of the regulatory control period – this is set out in Chapter 52, 53, 54 and 55 of this Regulatory Proposal; and
  - → Details the parts of the Regulatory Proposal that Ergon Energy claims to be confidential – this is set out in Chapter 2 of this Regulatory Proposal.

  Ergon Energy notes that, because neither the AER's Framework and Approach Paper nor this Regulatory Proposal classifies any of Ergon Energy's Distribution Services as Negotiated Distribution Services, it has not included a Negotiating Framework in this Regulatory Proposal, as it would otherwise do under clause 6.8.2(c)(5) of the Rules.
- Complies with the requirements of, and contains, or is accompanied by, the information required by the Regulatory Information Notice (RIN) served on Ergon Energy by the AER under section 28F(1)(a) of the National Electricity Law (NEL) on 22 April 2009, in accordance with clause 6.8.2(b)(1) of the Rules.

Ergon Energy has prepared a 'Skeleton' document to accompany this Regulatory Proposal that provides a detailed breakdown of where in this Regulatory Proposal Ergon Energy has complied with the requirements of:

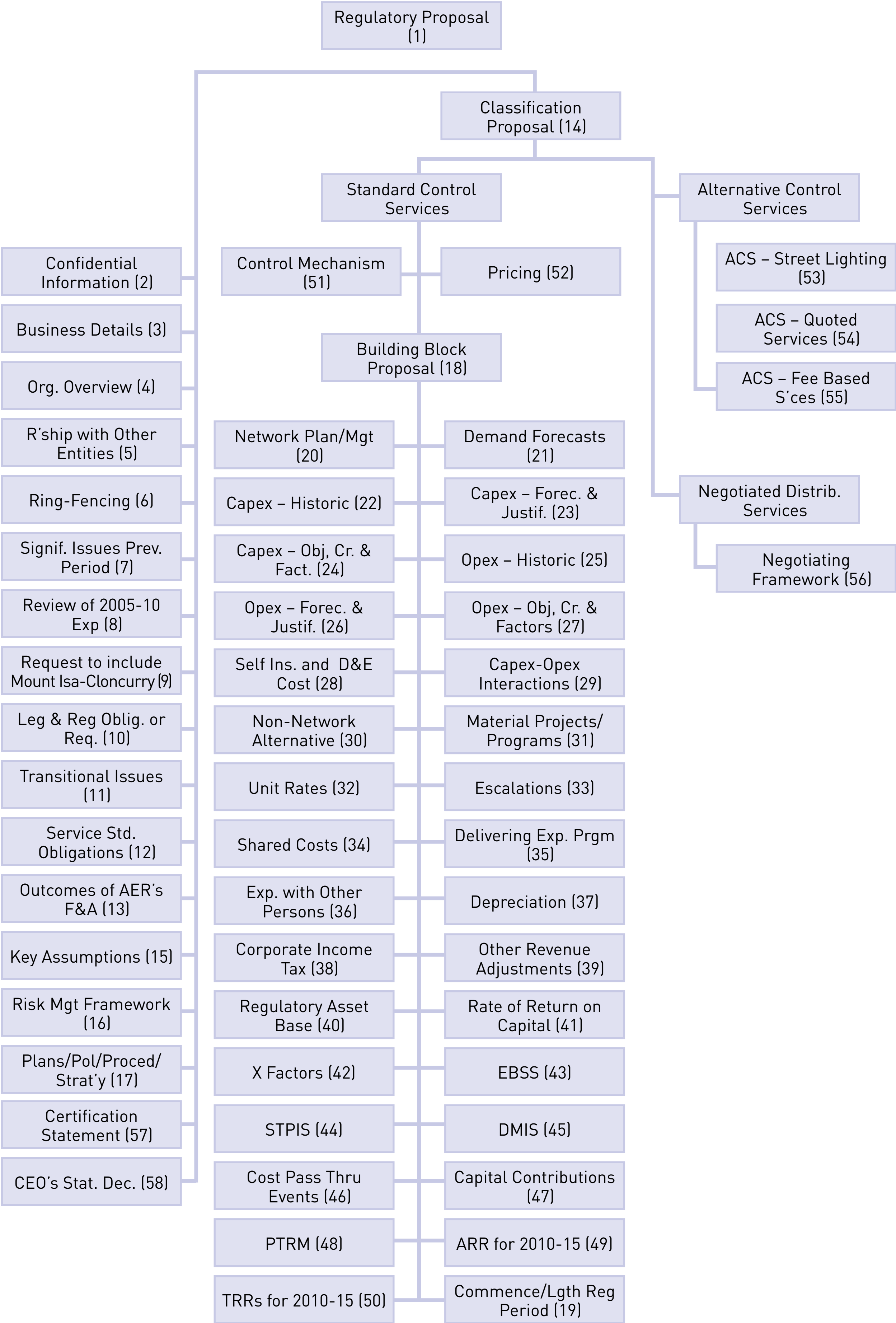
- Chapter 6 and Chapter 11 of the Rules;
- The AER's Framework and Approach Paper;
- The AER's RIN; and
- The AER's various Guidelines, Models and Schemes.[3]

Figure 12 illustrates the structure of this Regulatory Proposal. The bracketed numbers correspond with the chapters of this Regulatory Proposal. The attachments to this Regulatory Proposal are not referenced in Figure 12.

In this Regulatory Proposal numbers in tables may not add due to rounding differences.

[3] AER's various Guidelines, Models and Schemes are available from: http://www.aer.gov.au/content/index.phtml/itemId/709250

Figure 12: *Structure of Ergon Energy's Regulatory Proposal*



1. REGULATORY PROPOSAL – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR369	National Electricity Law, 28F(1)(a)

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR367c & 368c	AER Regulatory Information Notice

QCA Documents

Nil

Codes and Rules

AR364 National Electricity Rules

Ergon Energy Documents

AR467c	EE Regulatory Proposal Skeleton, June 2009

2. CONFIDENTIAL INFORMATION

Rules – Clauses 6.8.2(c)(6), 6.19.2 and 8.6
RIN – Attachment 3
AER's Information Policy – Section 1.3(b)

2.1 MEETING THE REGULATORY REQUIREMENTS

Ergon Energy claims that certain information provided in, and accompanying, this Regulatory Proposal should be treated by the Australian Energy Regulator as confidential and should not be published.

Ergon Energy has:

- Identified in section 2.3 of this Regulatory Proposal what information it claims to be confidential and wants not to be published on that ground, in accordance with the requirements of clause 6.8.2(c)(6) of the Rules and section 1.3(b)(i) of the AER's Information Policy.[4] This includes a claim that certain pricing information should be confidential on the basis of clause 6.19.2 of the Rules, which provides that:
  a. *Subject to the Law and the Rules, all information about a Service Applicant or Distribution Network User used by Distribution Network Service Providers for the purposes of distribution service pricing is confidential information and must be treated in accordance with rule 8.6.*[5]
  b. *No requirement in this Chapter 6 to publish information about a tariff class is to be construed as requiring publication of information about an individual customer.*
- Submitted a confidential version, and a non-confidential version, of this Regulatory Proposal in accordance with the requirements of Attachment 3 of the AER's Regulatory Information Notice (RIN) and section 1.3(b)(ii) of the AER's Information Policy;
- Clearly marked 'Confidential' on the relevant parts of this Regulatory Proposal and accompanying information for which it claims confidentiality, in accordance with the requirements of Attachment 3 of the AER's RIN section and section 1.3(b)(iii) of the AER's Information Policy; and
- Given reasons in section 2.2 of this Regulatory Proposal to support its confidentiality claims, in accordance with the requirements of Attachment 3 of the AER's RIN and section 1.3(b)(iv) of the AER's Information Policy.

2.2 TYPES OF CONFIDENTIAL INFORMATION

Attachment 3 of the AER's RIN requires Ergon Energy to provide reasons to support its confidentiality claims about information provided in, or accompanying, this Regulatory Proposal. Similarly, section 1.3(b)(iv) of the AER's Information Policy requires that Ergon Energy should "unless otherwise indicated, provide reasons in support of the confidentiality claim".

Ergon Energy has established 11 categories of information that it claims to be confidential. These 11 categories, and the reasons why Ergon Energy is claiming confidentiality in relation to each, are as follows:

2.2.1 Information that has been Compulsorily Acquired by the AER

The completed RIN pro formas contain commercially sensitive information about Ergon Energy's assets, employees, suppliers, finance strategies and work program. This information has been requested by the AER, and provided by Ergon Energy, on the basis of the AER's information gathering powers under the National Electricity Law (NEL). This information is not otherwise in the public domain and, if released publicly, could adversely affect the markets in which Ergon Energy provides its services and acquires materials and services from third parties.

2.2.2 Information about Ergon Energy's Employees

There is various commercially sensitive information about the profile, recruitment and retention of Ergon Energy's employees that is not otherwise in the public domain and which, if released publicly, could adversely affect Ergon Energy's operations and result in distortions in the labour and contractor market.

2.2.3 Information about Ergon Energy's Assets, Operations and Performance

There is various commercially and technically sensitive information about Ergon Energy's assets, system limitations and constraints, operational performance and risks, and asset and operational management. This information is not otherwise in the public domain and, if

[4] Australian Competition and Consumer Commission and Australian Energy Regulator, "Information Policy – The collection, use and disclosure of information", 2008.

[5] Clause 8.2 of the Rules details general confidentiality provisions that apply to registered participants in the National Electricity Market and to NEMMCO.

released publicly, could adversely affect the security of Ergon Energy's assets and operations. Furthermore, if released publicly, this information could adversely affect the markets in which Ergon Energy provides its services and acquires materials and services from third parties.

2.2.4 Information Previously Submitted to Regulators

There is various commercially sensitive information that Ergon Energy has previously submitted to Regulators, in particular the Queensland Competition Authority (QCA). This information should continue to be confidential by virtue of its previous treatment. Furthermore, this information is not otherwise in the public domain and, if released publicly, could adversely affect the markets in which Ergon Energy provides its services and acquires materials and services from third parties.

2.2.5 Information Previously Provided to Shareholders

There is various commercially sensitive information that has been prepared exclusively for Ergon Energy's shareholders that is not otherwise in the public domain. If publicly released, this information could adversely affect the markets in which Ergon Energy provides its services and acquires materials and services from third parties.

2.2.6 Ergon Energy Board Papers

There are various Board papers that provide the basis for internal policy decisions. These were prepared exclusively for consideration by Ergon Energy's Board and are not otherwise in the public domain. If publicly released, these documents could adversely affect the markets in which Ergon Energy provides its services and acquires materials and services from third parties.

2.2.7 Plans, Policies, Procedures and Strategies

There are various commercially sensitive plans, policies, procedures and strategies that are specific to Ergon Energy's internal operations. Ergon Energy uses these documents as the basis for its internal analysis and decision making, including, where necessary, to engage contractors to assist it to undertake certain work. These documents have been prepared exclusively for consideration by Ergon Energy and are not otherwise in the public domain. If publicly released, these documents could adversely affect the markets in which Ergon Energy provides its services and acquires materials and services from third parties.

2.2.8 Internal Models

There are various models that Ergon Energy has developed, which have been prepared exclusively for its internal use in order to provide a basis for analysis and decision making. These models were prepared exclusively for consideration by Ergon Energy and are not otherwise in the public domain. If publicly released, these models could adversely affect the markets in which Ergon Energy provides its services and acquires materials and services from third parties.

2.2.9 Specialist Consultancy Reports

There are various commercially sensitive consultancy reports that contain information and advice that has been used as the basis for Ergon Energy's internal analysis and decision making. These documents were prepared exclusively for consideration by Ergon Energy and are not otherwise in the public domain. If publicly released, these documents could adversely affect the markets in which Ergon Energy provides its services and acquires materials and services from third parties. Furthermore, the publication of this information could breach the terms and conditions under which the information was provided.

2.2.10 Unit Rates and Unit Costs

There is various commercially sensitive information about the unit rates and unit costs of Ergon Energy undertaking work itself, and acquiring certain materials and services from third parties. This information has been prepared exclusively for consideration by Ergon Energy and is not otherwise in the public domain. If publicly released, this information could adversely affect the market for certain materials and services that Ergon Energy acquires from its suppliers and contractors, including by contravening supply agreements. Furthermore, the publication of this information could breach service agreements between Ergon Energy and its suppliers.

2.2.11 Customer Prices and Charges

There is various commercially sensitive information about prices and charges that Ergon Energy levies on its customers. This information has been prepared exclusively for consideration by Ergon Energy and is not otherwise in the public domain. If publicly released, this information could adversely affect the markets in which Ergon Energy provides its services. Furthermore, the publication of this information could breach supply agreements between Ergon Energy and its customers.

2.3 INFORMATION THAT ERGON ENERGY CLAIMS TO BE CONFIDENTIAL

Clause 6.8.2(c)(6) of the Rules and section 1.3(b)(i) of the AER's Information Policy require Ergon Energy to identify what information it claims to be confidential and wants not to be published on that ground.

Table 13 details the information that Ergon Energy claims to be confidential in the 11 categories that are detailed in section 2.2 above. This information includes certain:

- Chapters and sections of this Regulatory Proposal; and
- Documents and other information that have been provided to the AER with this Regulatory Proposal.

Table 13: *Information Ergon Energy claims to be Confidential*

Information Category	Confidential Information	Other Confidential Category that also is applicable		
1. Information that has been Compulsorily Acquired by the AER	AR322c	3		
	AR367c			
	AR368c			
	Chapter 36	10		
	Section 41.5.1			
2. Information about Ergon Energy's Employees	AR059c	3		
	AR236c	3	7	8
	AR268c			
	AR272c	3	7	8
	AR435c	3	7	
	Section 4.11			
3. Information about Ergon Energy's Assets, Operation and Performance	AR024c	7		
	AR033c	9		
	AR034c	9		
	AR039c	5		
	AR065c	9		
	AR112c	8		
	AR128c	9		
	AR172c	7		
	AR248c	7		
	AR249c	7		
	AR250c	7		
	AR251c	7		
	AR252c	7		
	AR254c	7		
	AR283c	8		
	AR307c	7	8	10
	AR308c	7	8	10
	AR310c	9		
	AR319c	7		
	AR323c			
	AR374c	9		
	AR375c	8	11	
	AR376c	8	11	
	AR412c	8	9	
	AR413c			
	AR424c	8		
	AR447c	8		
	AR448c	7		
	AR463c	7		
	AR464c	8		
	AR467c			
4. Information previously submitted to Regulators	AR427c	5		
	AR428c	5		
	AR431c	5		
5. Information previously provided to Shareholders	AR040c	6		
	AR119c	6		
	AR120c	6		
	AR121c	6		
	AR122c	6		
	AR123c	6		
	AR124c	6		
	AR173c	6		
	AR174c	6		
	AR203c	6		
	AR370c	6		

Information Category	Confidential Information	Other Confidential Category that also is applicable	
	AR511c		
	AR512c		
	AR536c	6	
	AR537c	6	
6. Ergon Energy Board Papers	AR054c		
	AR074c		
	AR245c		
	AR246c		
	AR247c		
	AR313c	7	9
	AR317c	7	9
	AR347c	7	9
7. Plans, Policies, Procedures and Strategies	AR022c		
	AR038c	11	
	AR269c	8	10
	AR333c	8	10
	AR410c		
	AR462c	10	
	AR514c		
	AR515c		
	AR516c		
	AR517c		
	AR518c		
	AR535c		
8. Internal Models	AR322c		
	AR420c	3	10
	AR436c		
	AR469c		
	AR478c	11	
	AR479c	10	11
	AR480c	10	11
	AR481c	10	11
	AR482c	10	11
	AR493c	10	
9. Specialist Consultancy Reports	AR022c	3	10
	AR310c	10	
	AR311c	10	3
	AR510c	10	3
	AR534c		
	Section 23.8.3	2	3
	Section 4.18.2	3	
	Section 21.2.3	3	
	Section 28.1.3	6	
10. Unit Rates and Unit Costs	AR434c		
	Section 32.1		
	Section 34.3.6	3	
	Section 54.6.2	11	
	Section 54.7	11	
	Section 55.6.2	11	
	Section 55.7	11	
11. Customer Prices and Charges	AR354c		
	AR421c		
	AR433c	3	
	AR443c	3	
	AR478c	3	
	AR479c	3	
	AR480c	3	
	AR481c	3	
	AR482c	3	
	Section 52.4		

2. CONFIDENTIAL INFORMATION – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice
AR533	Australian Competition and Consumer Commission and Australian Energy Regulator, "Information Policy - The collection, use and disclosure of information" 2008

QCA Documents

Nil

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

Nil

C CONFIDENTIAL INFORMATION

3. BUSINESS DETAILS

RIN – Sections 2.1(a)(1)-(4)
RIN Pro forma - 2.1

Section 2.1(a)(1) to (4) of the Australian Energy Regulator's (AER) Regulatory Information Notice (RIN) requires Ergon Energy to provide the following information about its business:

Trading name:	Ergon Energy
Australian Business Number:	50 087 646 062
Registered office:	22 Walker Street, Townsville, 4810
Principal place of business:	34-36 Dalrymple Road, Garbutt, Townsville, QLD, 4814
Postal Address:	Level 4, 22 Walker Street Townsville Qld 4810
Contact person and contact details:	***Tony Pfeiffer*** General Manager Regulatory Affairs Ergon Energy Corporation Limited Email: tony.pfeiffer@ergon.com.au Ph: (07) 3228 7711 Mobile: 0417 734 664 Fax: (07) 3228 8130 or ***Carmel Price*** Manager Regulatory Affairs – Network Regulation Ergon Energy Corporation Limited Email: carmel.price@ergon.com.au Ph: (07) 4121 9545 Mobile: 0408 702 814

3. BUSINESS DETAILS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c AER Regulatory Information Notice

QCA Documents

Nil

Codes and Rules

Nil

Ergon Energy Documents

Nil

C CONFIDENTIAL INFORMATION

4. ORGANISATIONAL OVERVIEW

RIN - Sections 2.3.1(a)(1)-(9)

4.1 ERGON ENERGY'S ROLE IN THE ELECTRICITY SUPPLY CHAIN

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

Ergon Energy's responsibilities under its Distribution Authority and the Electricity Act 1994 (Qld), include to:

- Allow, as far as is technically and economically practicable, a person to connect to its supply network, or take electricity from its supply network, on fair and reasonable terms;[6] 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.[7]

Ergon Energy's role as a Distribution Network Service Provider (DNSP) in the electricity supply chain can be distinguished from:

- Generators – While Ergon Energy owns grid-connected generators at four sites in Queensland, these assets are not used for entering either the generation or retail markets and have no impact on the National Electricity Market (NEM). Rather, these grid-connected generators are used to provide network support to ensure the reliable performance of its long rural distribution feeders. The Queensland Competition Authority (QCA) has issued Ergon Energy with a ring fencing waiver in relation to its grid-connected generators.

  Ergon Energy also owns and operates generators as part of its isolated systems outside of the NEM that supply communities in Western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait Islands as well as Palm and Mornington Islands. None of these generation assets is covered by this Regulatory Proposal.

  In a limited number of instances, Ergon Energy has entry assets that are directly connected to embedded generators assets, rather than to transmission assets, for which site-specific charges are levied.
- Transmission Network Service Providers (TNSP) – Ergon Energy is not a TNSP, although it does own some high voltage assets that might otherwise be owned and operated by a TNSP. However, clause 9.32.1(b) of the Rules provides a permanent derogation in relation to the definition of "transmission network" in Queensland. This clause states that:

  > *Despite clause 6A.1.5(b) and the glossary of the Rules, in Queensland the transmission network assets are to be taken to include only those assets owned by Powerlink Queensland or any other Transmission Network Service Provider that holds a transmission authority irrespective of the voltage level and does not include any assets owned by a Distribution Network Service Provider whether or not such distribution assets are operated in parallel with the transmission system.*

  Ergon Energy receives electricity at high voltages from Powerlink's transmission system at 48 transmission network connection points. It converts this electricity to lower voltages throughout its distribution system in order to supply its customers.
- Retailers – Ergon Energy is not an electricity retailer, although it is the parent entity of Ergon Energy Qld Pty Ltd (EEQ). EEQ provides non-competing electricity retail services in regional Queensland to customers who have not taken up market contracts. These retail services are not regulated by the Australian Energy Regulator (AER).

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[6] Electricity Act 1994 (Qld), section 43(1).

[7] Ibid, section 42(a)(b).

4.2 CURRENT OWNERSHIP ARRANGEMENTS

Section 2.3.1(a)(1) of the AER's Regulatory Information Notice (RIN) requires Ergon Energy to provide details of its current ownership arrangements.

Section 7(3) of the Government Owned Corporations Act 1993 (Qld) states that "A company GOC is a GOC that is incorporated or registered under the Corporations Act".

Ergon Energy is incorporated under the Corporations Act 2001 (Cth)[8] and is a wholly Queensland Government-owned 'company GOC', for the purposes of the Government Owned Corporations Act 1993 (Qld).[9] This is because Ergon Energy is one of the entities listed in Schedule 2 of the Government Owned Corporations Regulation 2004 (Qld) and section 41 of this Regulation states that "Each government entity mentioned in schedule 2 continues as a company GOC".

4.3 NO PROPOSED CHANGES TO OWNERSHIP ARRANGEMENTS FOR 2010-15

Section 2.3.1(a)(1) of the AER's RIN requires Ergon Energy to provide details of any proposed changes to its current ownership arrangements over the next regulatory control period.

There are no changes proposed to Ergon Energy's current ownership arrangements as a Queensland Government-owned 'company GOC', including for the period 1 July 2010 to 30 June 2015.

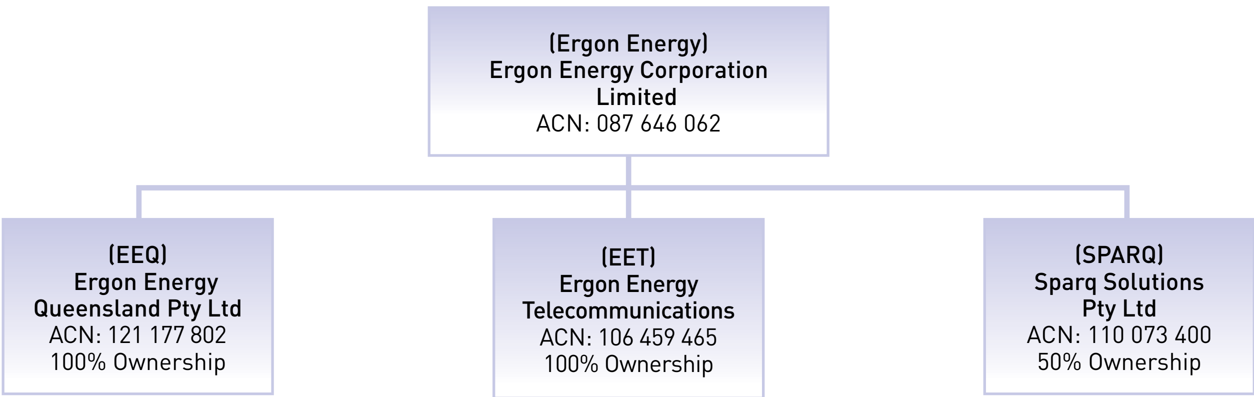
4.4 OTHER BUSINESSES OPERATED BY ERGON ENERGY

Section 2.3.1(a)(1) of the AER's RIN requires Ergon Energy to provide details of any other businesses that it operates.

The Ergon Energy Group comprises a series of companies involved in the purchase, distribution and sale of electricity in Queensland, both within and outside of the NEM.

Figure 13 illustrates the structure of the Ergon Energy Group.

Figure 13: *Ergon Energy Group Structure*



[8] The Commonwealth Corporations Law is available from: http://www.austlii.edu.au/au/legis/cth/consol_act/ca2001172/

[9] Government Owned Corporations Act 1993 (Qld), section 7(3).

4.4.1 Ergon Energy Corporation Limited (Ergon Energy)

Ergon Energy is the parent entity of the Ergon Energy Group. Ergon Energy is also the distribution network owner and DNSP. Ergon Energy is responsible for the provision of a range of regulated Distribution Services and unregulated activities:

- Distribution Services - Ergon Energy provides 'Distribution Services' within the meaning of the National Electricity Rules. These services are regulated under Section 6 of the Rules and are the subject of this Regulatory Proposal. These services are detailed in the Classification Proposal in Chapter 14 of this Regulatory Proposal; and
- Unregulated activities – Ergon Energy provides a range of distribution-related activities that do not involve its distribution system, as well as other unregulated activities, including isolated generation and distribution of electricity to remote communities not connected to the national grid. These activities are not regulated by the AER and are therefore not the subject of this Regulatory Proposal.

4.4.2 Ergon Energy Qld Pty Ltd (EEQ)

EEQ is a wholly owned subsidiary of Ergon Energy and is responsible for providing electricity retail services in regional Queensland to non-contestable customers.

Section 55G of Electricity Act has the effect of making EEQ a non-competing electricity retailer. It can only provide retail services at the uniform tariff (notified prices) to customers in Ergon Energy's distribution area, in accordance with a Retail Authority issued by the DME.

EEQ's services are not regulated by the AER and are not the subject of this Regulatory Proposal.

4.4.3 Ergon Energy Telecommunications Pty Ltd (EET)

EET is a wholly owned subsidiary of Ergon Energy and is a licensed telecommunications carrier providing wholesale high-speed data capacity to the Ergon Energy Group and to external customers.

EET's services are not regulated by the AER and are not the subject of this Regulatory Proposal.

4.4.4 SPARQ Solutions Pty Ltd (SPARQ)

SPARQ is a joint venture company between Ergon Energy and ENERGEX Limited – the two shareholders own 50 per cent shares.

SPARQ's constitution restricts it to providing Information Communication and Telecommunication (ICT) services to Ergon Energy's and ENERGEX's businesses. Some of these ICT services are related to the provision of Distribution Services by Ergon Energy and some are related to the provision of other services and activities by Ergon Energy and other parts of the Ergon Energy Group. The relationship between Ergon Energy and SPARQ is discussed in further detail in Chapter 5 of this Regulatory Proposal.

4.5 ERGON ENERGY'S OPERATING STRUCTURE

Section 2.3.1(a)(2) of the AER's RIN requires Ergon Energy to provide an overview of its structure.

Ergon Energy performs the functions of the DNSP. It is responsible for the provision of both regulated Distribution Services and unregulated activities.

However, from operational and cost allocation perspectives, the Ergon Energy Group is structured as follows:

- There are four companies within the Ergon Energy Group – Ergon Energy, EEQ, EET and SPARQ. These are referred to as "Districts" within the Group's Chart of Accounts;
- Ergon Energy and EEQ are ring-fenced in accordance with the QCA's Ring-Fencing Guidelines;
- SPARQ and EET provide support services and their costs are allocated between the four Districts, including Ergon Energy;
- There are six Business Units within Ergon Energy that also provide support services across the four Districts, including Ergon Energy:
  - → Office of the Chief Executive;
  - → Corporate Governance;
  - → Finance & Strategic Services;
  - → Employee & Shared Services;
  - → Customer & Stakeholder Engagement; and
  - → Corporate Sustainability & Innovation.
- There are two further Business Units within Ergon Energy - Energy Services and Customer Services. Wherever possible, their costs are directly attributed within Ergon Energy however, where they cannot be directly attributed, costs are allocated between Ergon Energy and the three other Districts.

The support costs that are allocated to Ergon Energy are further allocated between 'Lines of Business'. The following are the current Lines of Business for Ergon Energy:

- Regulated Operating Expenditure;
- Regulated Capital Expenditure;
- Customer Services;
- Isolated Generation Operating Expenditure;
- Isolated Generation Capital Expenditure;
- Non-Regulated Operating Expenditure;
- Non-Regulated Capital Expenditure;
- External Works (unregulated works performed at the request other parties) in the categories of:
  - → Powerlink; and
  - → Virginia Workshops.
- Solar Cities.

The Energy Services, Customer Services and Finance & Strategic Services business units perform the following critical roles in Ergon Energy's strategic asset management model:

- Asset Owner – this role is performed by the Finance and Strategic Services business unit. The Asset Owner acts on behalf of the Board and shareholder in dealings with the Asset Manager and Service Provider by defining Ergon Energy's risk appetite, governance, performance targets and investment criteria. The Asset Owner also provides asset policy, strategic direction and goals to accommodate the demands of growth, customer outcomes and financial return;
- Asset Manager – this role of managing system assets is performed by the Network group within the Energy Services business unit. The Asset Manager develops and manages asset-related strategy, objectives, plans and actions to achieve the strategic direction and goals to accommodate the demands of growth, customer outcomes and financial return; and
- Service Provider – this role is performed by the Operations, Operations Support and Transmission and Distribution Services groups within the Energy Services business unit, operating in conjunction with the Works and Contracts Management Group, and the Customer Service business unit. The Service Provider builds, operates and maintains assets for, and on behalf of, the Asset Manager, in order to ensure that the Asset Owner's needs are met.

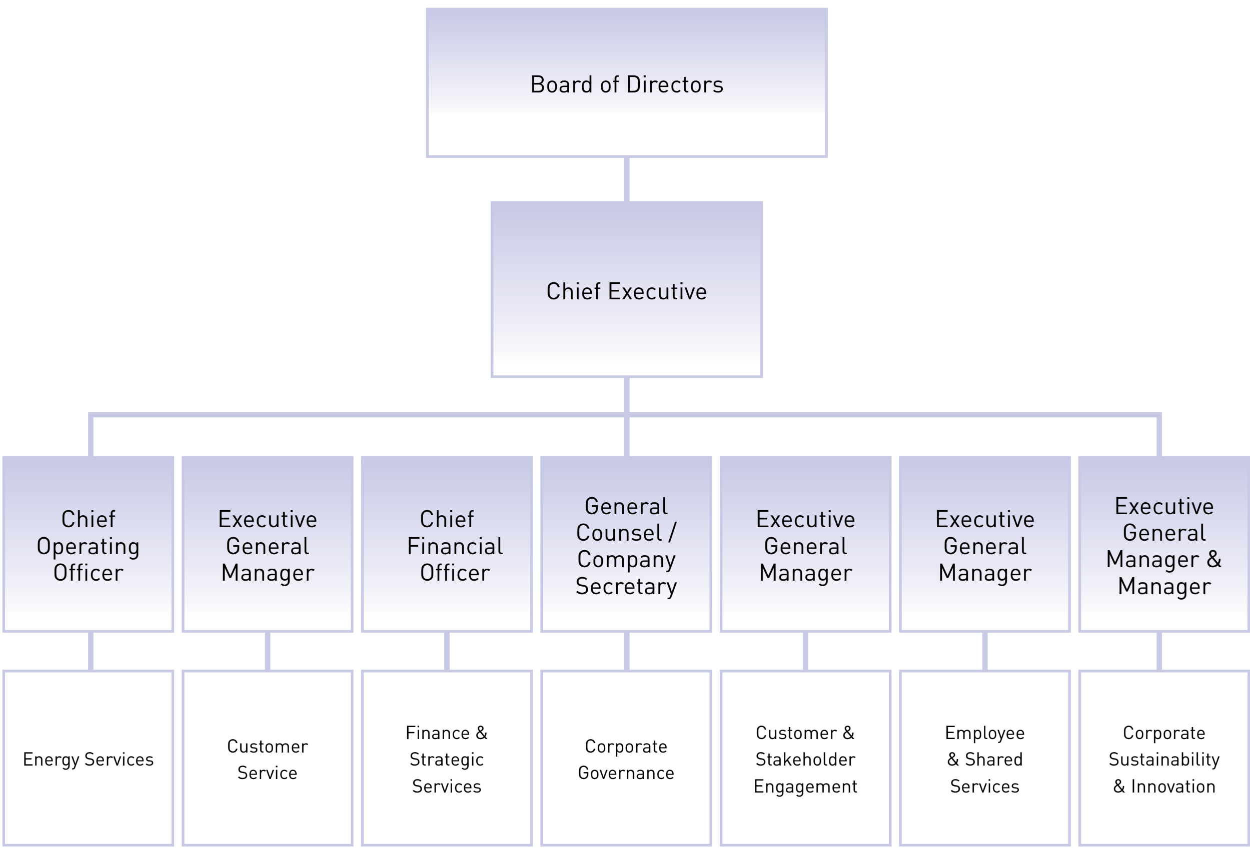
While Ergon Energy uses this strategic asset management model as a basis for planning and managing its internal operations, there is no external requirement to use this model, and this Regulatory Proposal reflects the coordinated response of the whole of Ergon Energy, in its capacity as a DNSP.

4.6 ORGANISATIONAL CHART

Section 2.3.1(a)(2) of the AER's RIN requires Ergon Energy to provide an organisational chart.

Figure 14 illustrates Ergon Energy's organisational structure. In particular, it shows the relationship between the Board of Directors, the Executive Management Team and the various Business Units within Ergon Energy.

***Figure 14:** Ergon Energy's Organisational Chart*



4.7 LINE OF BUSINESS CONTRIBUTION TO STANDARD CONTROL SERVICES

Section 2.3.1(a)(3) of the AER's RIN requires Ergon Energy to explain how each division and or business unit contributes to the provision of Standard Control Services.

The contribution of each Business Unit to each category of Distribution Services, including Standard Control Services, and unregulated activities is based on the Ergon Energy Group Chart of Accounts. This approach is explained in detail in Ergon Energy's Cost Allocation Method (CAM), which has been approved by the AER.

As costs are incurred, those costs that can be directly attributed are posted to an account code consisting of four Segments: Responsibility Centre, Activity, Product Code and Expense Element.

Activities define the nature of the work being undertaken and are classified according to the various Lines of Business. Each Activity category and sub-category has been mapped to a Distribution Service (i.e. a Standard or an Alternative Control Service) or an unregulated activity. This mapping is detailed at Appendix C of Ergon Energy's CAM.

A Shared Cost Percentage Rate for the relevant Line of Business is applied to the directly attributed costs within the Activities Segment as the costs are processed.

Ergon Energy is therefore able to map the contribution of each Line of Business to Standard Control Services by virtue of the direct relationship between Activities in the Chart of Accounts and the various categories of Distribution Services and unregulated activities.

4.8 LINE OF BUSINESS CONTRIBUTION TO ALTERNATIVE CONTROL SERVICES

Section 2.3.1(a)(3) of the AER's RIN requires Ergon Energy to explain how each division and /or business unit contributes to the provision of Alternative Control Services.

Ergon Energy is able to map the contribution of each Line of Business to Alternative Control Services by virtue of the direct relationship between Activities in the Chart of Accounts and the various categories of Distribution Services and unregulated activities. This approach is explained in detail in Ergon Energy's CAM.

4.9 LINE OF BUSINESS CONTRIBUTION TO NEGOTIATED DISTRIBUTION SERVICES

Ergon Energy does not have any Negotiated Distribution Services. There are therefore no Activities in the Chart of Accounts that are mapped to Negotiated Distribution Services.

4.10 LINE OF BUSINESS CONTRIBUTION TO UNREGULATED ACTIVITIES

Section 2.3.1(a)(3) of the AER's RIN requires Ergon Energy to explain how each division and / or business unit contributes to the provision of unregulated services.

Ergon Energy is able to map the contribution of each Line of Business to unregulated activities by virtue of the direct relationship between Activities in the Chart of Accounts and the various categories of Distribution Services and unregulated activities. This approach is explained in detail in Ergon Energy's CAM.

4.11 EMPLOYEES AND CONTRACTORS NUMBERS BY BUSINESS UNIT FOR 2007-08

Section 2.3.1(a)(4) of the AER's RIN requires Ergon Energy to provide details of current staffing numbers.

Table 14 details Ergon Energy's employees and contractors on the basis of headcount as at 30 June 2008:

- "Employees" comprise permanent and fixed term employees of Ergon Energy; and
- "Contractors" resources comprise labour hire, project resources, consultants and external trainees and apprentices, but do not include core tendered contractors (such as vegetation management contractors, pole inspection contractors etc).

Table 14: *Ergon Energy's Employees and Contractors as at 30 June 2008*

Business Unit	Employees	Contractors	Total
Office of the Chief Executive			
Energy Services			
Customer Services			
Finance and Strategic Services			
Corporate Governance			
Customer and Stakeholder Engagement			
Employee and Shared Services			
Corporate Sustainability and Innovation			
Total	**4,489**	**320**	**4,809**

Note – Data is presented on the basis of headcount not full time equivalent employees and does not include vacancies.

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4.12 CHANGES TO EMPLOYEE AND CONTRACTOR NUMBERS BY BUSINESS UNITS FOR 2010-15 AND THE REASONS FOR ANY CHANGES

Section 2.3.1(a)(4) of the AER's RIN requires Ergon Energy to provide details of any expected change in staffing numbers over the next regulatory control period.

Table 15 details forecasts of Ergon Energy's employees only on the basis of headcount and vacancies as at 31 December 2010 and 31 December 2015:

Table 15: *Forecast Ergon Energy's Employees*

Business Unit	2010 Forecast	2015 Forecast
Office of the Chief Executive		
Energy Services		
Customer Services		
Finance and Strategic Services		
Corporate Governance		
Customer and Stakeholder Engagement		
Employee and Shared Services		
Corporate Sustainability and Innovation		
Total	***4573- 4697**	***4439- 4725**

** Where 2 forecast numbers are shown, the variance is due to a forecast difference between the 2 growth scenarios – i.e. Sustained Growth and High Growth*

Note – Data is presented on the basis of headcount plus vacancies not full time equivalent employees.

Ergon Energy emphasises that care should be taken in comparing the data in Table 14 and Table 15. This is because:

- Table 14 includes both employees and contractors, whereas Table 15 only includes employees;
- Table 15 includes headcount plus vacancies, whereas Table 14 only includes headcount.

There are numerous internal strategies impacting Ergon Energy and its workforce. These are examined in a document entitled "Ergon Energy Strategic Workforce Plan 2008-2018", which has been provided on a confidential basis to the AER at the same time as this Regulatory Proposal. This document identifies three key technological advances that may reduce Ergon Energy's workforce:

- The implementation of Advanced Metering Infrastructure (AMI);
- The implementation of Field Force Automation (FFA); and
- Ongoing realisation of benefits from Project Jet, which is the project that introduced Ergon Energy's Ellipse Enterprise Resource Planning solution in 2006.

Ergon Energy has reflected workforce savings from these three technological advances into the employee forecasts in Table 14 and Table 15. It should be noted, however, that Ergon Energy has only incorporated capital or operating expenditure allowances in relation to FFA (and not AMI) into its SPARQ Information Communications Technology forecasts in this Regulatory Proposal. As a result:

- The employee forecasts in Table 14 and Table 15 represent the minimum number of employees that Ergon Energy expects it will have in 2010 and 2015. It is possible that these levels may need to be higher if the benefits expected from the implementation of Project Jet do not materialise and AMI does not proceed in the course of the 2010-15 regulatory control period; and
- As discussed in Chapter 46, Ergon Energy considers that expenditure associated with a regulatory requirement to introduce Advanced Metering Infrastructure should be treated as a cost pass through event in the next regulatory control period.

4.13 BASIS USED FOR CALCULATING STAFFING NUMBERS FOR 2010-15

Section 2.3.1(a)(4) of the AER's RIN requires Ergon Energy to provide details of the basis used for calculating staffing numbers for 2010-15.

Ergon Energy prepared the whole-of-business workforce demand forecasts for employees in Table 15 for 2010 and 2015 on a bottom-up basis by conducting scenario analysis with Managers across its business. The outcomes of this analysis were aggregated at a Business Unit level.

The document entitled "Ergon Energy Strategic Workforce Plan 2008-2018" details the methodology that was used, as well as the findings that were made, to prepare the forecasts.

4.14 KEY INFORMATION SYSTEMS TO PROVIDE REGULATED SERVICES

Section 2.3.1(a)(5) of the AER's RIN requires Ergon Energy to provide details of key information systems used to provide regulated Distribution Services.

Table 16 gives an alphabetical listing, and a brief description, of the key information systems that Ergon Energy uses to provide its Distribution Services. It is emphasised that this is not an exhaustive list of all of the information systems that Ergon Energy uses to provide these services.

Table 16: *Key Information Systems used by Ergon Energy*

System	Description
B2B Hub / Handler	This is operated by National Electricity Market Management Company (NEMMCO) for the delivery and acknowledgement of Business to Business (B2B) transactions between market participants.
Customer Management System (CMS)	This is used with FACOM within Ergon Energy's National Contact Centre (NCC) to manage customer service delivery.
COGNOS	The budget planning modules are used within Ergon Energy modules and provide a broad range of tools and reporting capability.
DINIS	This is load flow / fault calculation software. While not a full Distribution Management System, DINIS covers some of this capability for Ergon Energy.
Ellipse [Accounting System]	Ellipse is an Enterprise Resource Planning solution sourced from Mincom. It is used within Ergon Energy to manage assets, works, finance, logistics, HR and payroll.
ECORP	This is Ergon Energy's corporate data system that is linked with ESATS and contains a series of tables that hold data in relation to connection points and premises. Most of the data in ECORP is based on extracts from FACOM and FeederStat.
ESATS	This is Ergon Energy's standing data repository. It contains a series of tables that hold various extracted and stored data fields. The data contained in these tables provide all of the mandated NMI standing data fields required for NMI Discovery. Where a NMI is in MSATS, ESATS populates and updates the NMI data.
FACOM	This is Ergon Energy's Customer Information System (CIS) and contains all of its customer and premises data. Ergon Energy Queensland's (EEQ) retail customers and Ergon Energy Corporation Limited's distribution-only accounts for second tier customers are managed in FACOM. EEQ's retail customers are billed from FACOM.
Feedback and Claim Tracking System (FACTS)	This is the Ergon Energy database that captures all customer feedback (positive or negative) and enquiries regarding guaranteed service levels.
FeederStat	This is Ergon Energy's feeder management system. It pinpoints where a particular premises is located and what feeder or substation it is connected to. FeederStat is used when faults and outages are being analysed and facilitates the NCC logging fault related calls as they are received and providing information to customers on restoration times.

System	Description
Market Settlement and Transfer Solution (MSATS)	This is the centralised system managed and operated by NEMMCO that maintains roles, relationships and NMI Standing Data.
MSATS Browser	This is a web interface provided by NEMMCO for market participants to access the information to which they are entitled within the MSATS system.
MV-90	This is the Ergon Energy system used for the remote reading of Type 1 to 4 metering installations.
MVRS	This is the Ergon Energy system that contains the manual meter reads for all type 6 metering installations.
Network Billing Manager (NBM)	This system receives billing extracts from NetBill, wraps this data into a B2B compliant format and emails the data from Ergon Energy to second tier retailers.
NEMLink	NEMLink is the gateway that Ergon Energy uses to move data between ESATS and MSATS and to process B2B transactions. It consists of: • An interface that manages the workflow and history of each of the MSATS and B2B transactions received, or initiated, by Ergon Energy; and • A gateway which receives and sends transactions to NEMMCO and second tier retailers.
NetBill	NetBill generates Ergon Energy's Statements of Charges to retailers for all NUOS, event and interest charges attributable to second tier NMIs, at a NMI level. It exports this data to the NBM system for emailing to the relevant retailer.
Supervisory Control and Data Acquisition (SCADA)	While SCADA is a general term, it is used within Ergon Energy to refer specifically to the ABB system used for Network Operations.
Smallworld	This is a geographic information system used to manage the spatial location of assets.
TOHT	This system hosts Ergon Energy's second tier meter data and validates and publishes this meter data to the market (i.e. to MSATS).

4.15 UNREGULATED SERVICES

Section 2.3.1(a)(6) of the AER's RIN requires Ergon Energy to provide details of whether it provides any non-regulated services.

Clause 6.1.1 of the Rules provides that:

> *The AER is responsible, in accordance with this Section, for the economic regulation of Distribution Services provided by means of, or in connection with, distribution systems that form part of the national grid.*

The AER is therefore only responsible for the economic regulation, including the classification, of Distribution Services. These are services that are provided by means of, or in connection with, a Distribution System.

The note to clause 6.2.1 of the Rules further states that:

> *If the AER decides against classifying a distribution service, the service is not regulated under the Rules.*

Ergon Energy considers that this note is intended to clarify that an unregulated service can be either:

- A Distribution Service that the AER decides should not be classified as either a Direct Control Service or a Negotiated Distribution Service; or
- A service or activity that is not a Distribution Service, which therefore falls outside of the AER's jurisdiction under the Rules.

The major categories of unregulated activities undertaken by Ergon Energy are provided below. Also provided is a brief explanation and rationale supporting their classification:

Unregulated Services / Activities	Rationale
Watchman Lighting (e.g. unmetered flood lighting at car yards) *Provision, Operation & Maintenance, including lamp replacements*	Watchman lighting is not a Distribution Service as defined in the Rules. Any party can provide, operate and maintain watchman lighting and a market already exists for these activities.
High Load Escorts *Scoping the route* *Travelling with the load and lifting powerlines* *Approving/authorising contractors*	High load escorting is not a Distribution Service as defined in the Rules. Other parties can be authorised by Ergon Energy to perform work in close proximity to its powerlines, including lifting. There is already a market operating for the provision of high load escort services by parties other than Ergon Energy.
Meter Data Agent (MDA) *Data collection for metering types 1-4*	MDA services have always been 'contestable' and provided on a competitive basis in the NEM. These services have never been regulated under Section 6 of the Rules.
Non-Distribution Services at customers' request, e.g: *Erection of additional poles within customers' premises/land;* *Location of underground cables;* *Electrical inspection, voltage and load checks where problem/fault is on the customers' installation*	These services are not a Distribution Service as defined in the Rules. Other parties (such as electrical contractors, powerline construction contractors) can, and do, provide these services.

Unregulated Services / Activities	Rationale
The four companies within the Ergon Energy Group, Ergon Energy, EEQ, EET and SPARQ, perform various activities that are Unregulated Services including:	These services either do not relate to the national interconnected grid or are not Distribution Services because they are generation, retail or other non-electricity industry activities.
Ownership and operation of 33 Isolated Systems Generators; *Ownership and operation of 34 Isolated Systems Networks;* *Ownership and operation of a network in the North West Minerals Province (near Mount Isa);* *An undersea cable;* *Works for Powerlink;* *Certain electrical assets within customers' electrical installations;* *Sale of Remote Area Power Stations and Solar PV Systems;* *Non-competing Retail entity selling to retail customers on Qld gazetted Notified Prices only;* *Wholesale fibre telecommunications services;* *IT Services to support Ergon Energy and ENERGEX's business operations.*	Activities that might otherwise be Distribution Service activities, but should be Unregulated Services, include: • The Isolated Systems Networks – because they are not part of the interconnected grid, and the Rules therefore do not apply to them; • The North West Minerals Province network – because it is not part of the interconnected grid, and the Rules therefore do not apply to them. In the event that this network ever becomes interconnected, there would need to be regard for a separate pre-existing Australian Consumer and Competition Commission (ACCC) authorisation; and • The undersea cable is the subject of a commercial arrangement that pre-dated the initial National Electricity Code, and has been treated as an Unregulated Service by the QCA. Maintenance and technical activities are performed on an unregulated sub-contract basis for Powerlink, e.g. transformer maintenance. This is not a Distribution Service. Isolated Systems Generation activities are not Distribution Service activities and are not part of the interconnected grid. Electrical assets within customers' electrical installations are not part of a Distribution System, and are therefore not Distribution Services. Remote Area Power Stations and Solar Photovoltaic Systems sales are not Distribution Services because they involve commercial sale arrangements and do not relate to the distribution of electricity using a Distribution System. Retailing electricity is not a Distribution Service. Telecommunications services are not Distribution Services. SPARQ is a joint venture company wholly owned by Ergon Energy and ENERGEX Limited. SPARQ provides IT services to support both Ergon Energy's and ENERGEX's businesses. Some of these activities are, and others are not, related to the provision of Distribution Services. This is discussed further in Section 5 of this Regulatory Proposal.

4.16 UNREGULATED REVENUE AS PROPORTION OF TOTAL REVENUE

Section 2.3.1(a)(6) of the AER's RIN requires Ergon Energy to provide details of proportion of total revenue earned from unregulated services.

Ergon Energy's regulatory accounts for 2007-08 show that its unregulated revenue was $43.176 million and that its total revenue was $1,268.7 million. Unregulated revenue therefore comprised 3.4 per cent of Ergon Energy's total revenue for 2007-08.

4.17 CUSTOMERS

Section 2.3.1(a)(7) of the AER's RIN requires Ergon Energy to overview its customer base.

Ergon Energy provides its Distribution Services to:

- *Electricity Retailers* – Retailers purchase wholesale energy that is transported through Powerlink's transmission system and Ergon Energy's Distribution System to end-use customers. Ergon Energy currently provides Distribution Services to EEQ and a small number of competing electricity retailers. Although there are over 20 retailers licensed to provide customer retail services in Queensland, only a small number of these retailers are currently actively competing for customers in Ergon Energy's distribution area;
- *Community* – About 1.4 million[10] people currently rely on Ergon Energy every day for the safety, quality, reliability and availability of their electricity supply; and
- *End-Use Customers* – Ergon Energy provides services to end-use customers throughout its supply area. Table 17 below provides a breakdown, based on the pricing categories used in its Pricing Principles Statement, of the number of customers to whom Ergon Energy provides services in its eastern zone, western zone and the Mount Isa-Cloncury system. These numbers are based on the National Metering Identifiers (NMIs) in each pricing category. The table includes street lighting and other unmetered customers. It excludes Ergon Energy's isolated customers as they are not part of the NEM and are therefore not regulated by the AER and are not the subject of this Regulatory Proposal.

Table 17: *Ergon Energy's Customers (NMIs) as at 30 June 2008*

Customer Type	East	West	Mt Isa	Total
Individually Calculated Customer	56	12	-	68
Connection Asset Customers	178	8	-	186
Embedded Generators	31	1	-	32
Standard Asset Customers >100MWh p.a.	6,526	752	180	7,458
Standard Asset Customers <100MWh p.a.	582,747	52,418	10,312	645,477
Total	**589,538**	**53,191**	**10,492**	**653,221**

Source: SAC GWh & Cust Fcst 09-10 DCOS Amended.xls

[10] Derived from information contained at http://www.oesr.qld.gov.au/queensland-by-theme/demography/population/index.shtml

The "classes of network users" detailed in the above table are defined in Ergon Energy's Pricing Principles Statement as follows:

- Individually Calculated Customers (ICCs):
  - → Typically have energy consumption greater than 40 GWh per annum; or
  - → Are classed as ICCs with energy consumption lower than 40 GWh per annum but:
    - » They have a dedicated supply system which is quite different and separate from the remainder of the supply network; or
    - » There are only two or three customers in a supply system making average prices inappropriate; or
    - » They are connected at or close to a transmission connection point and the inclusion of the cost of average shared network would increase their network price above stand-alone; or
    - » Inequitable treatment of otherwise comparable customers would result from the 40 GWh threshold.

  Typically, these customers are:

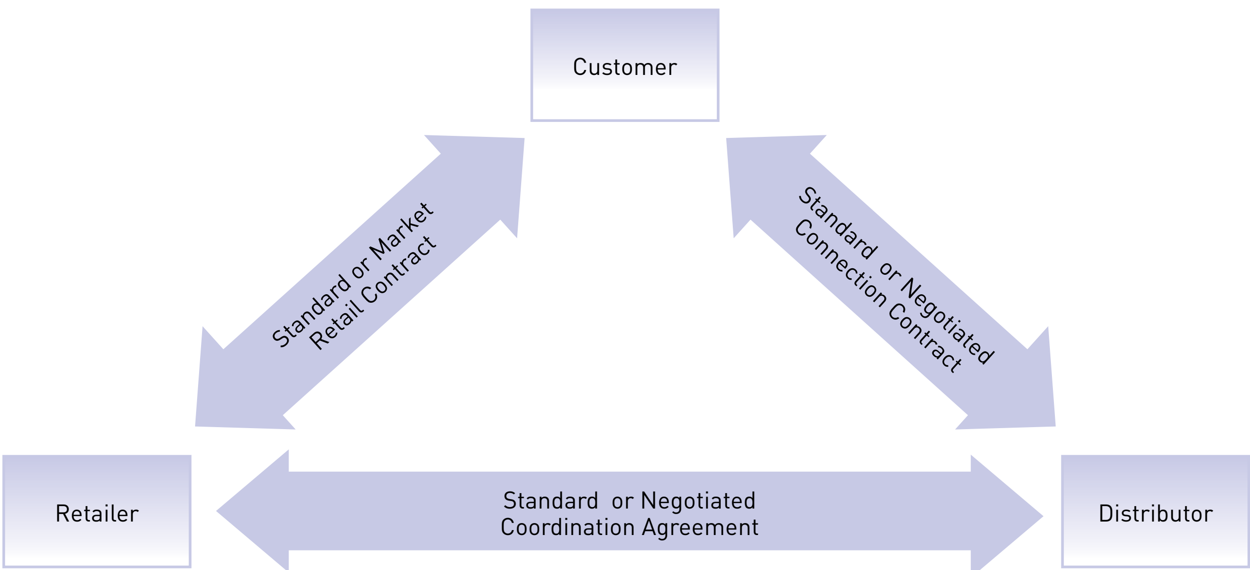
  - → Large industrial premises such as coal and metals mines, ports, chemical and metals processing plants; and
  - → Connected at a sub-transmission or high voltage network.
- Connection Asset Customers (CACs):
  - → Typically have energy consumption greater than 4 GWh per annum; or
  - → Are classed as a CAC with energy consumption lower than 4 GWh per annum where:
    - » They have a dedicated supply system which is quite different and separate from the remainder of the supply network; or
    - » Inequitable treatment of otherwise comparable customers would result from the 4 GWh threshold.

  Typically, these customers are:

  - → Medium to large industrial premises such as processing plants, manufacturing plants and abattoirs;
  - → Connected at high voltage (although some may be LV customers); and
  - → Have a maximum demand greater than 1.0 MW.
- Embedded Generators (EGs) – These comprise embedded generators that are:
  - → Connected to, and only generate into, the distribution system; and
  - → Connected to, generate for part of the year and take load from the distribution system for the other part of the year.

A tripartite contractual relationship was established between Ergon Energy, end-use customers and retailers upon the introduction of full retail competition (FRC) in Queensland on 1 July 2007. The nature of this relationship is illustrated in Figure 15.

Figure 15: *Tripartite Contractual Relationship*



Ergon Energy provides customer connection services to customers under either a Standard or a Negotiated Connection Contract. The interaction with retailers is managed through a Standard or Negotiated Co-ordination Agreement, which sets out how Ergon Energy and the electricity retailer agree to streamline their respective relationship with customers and to co-ordinate with each other in the performance of certain functions and obligations.

Ergon Energy also provides certain Distribution Services directly to the customer's connection point, with no involvement from a retailer as an intermediary.

Ergon Energy's Standard Connection Contract and Standard Co-ordination Agreement are detailed in Annexures A and C (respectively) of the Queensland Electricity Industry Code.[11]

4.18 KEY CUSTOMER CONSIDERATIONS IMPACTING ON EXPENDITURE FORECASTS REFERENCING DATA IN DEMAND FORECAST PRO FORMA

Clause 2.3.1(a)(7) of the Rules requires Ergon Energy to provide an overview of its customer base and to examine customer considerations that have impacted on the development of the DNSP's expenditure forecasts, with reference to the customer data provided in relation to its demand forecast.

4.18.1 Nature and Characteristics of Ergon Energy's Regions

Ergon Energy has three regions each with their own General Manager. Each of the three regions has two sub-regions:

- Northern:
  - → Far North; and
  - → North Queensland
- Central:
  - → Mackay; and
  - → Capricornia
- Southern:
  - → Wide Bay; and
  - → South West

These regions are used for managerial, planning and operational purposes and should be distinguished from the East, West and Mount Isa zones that are used by Ergon Energy for pricing purposes.

The six sub-regions have distinctly different characteristics, as discussed below.

4.18.1.1 Far North

The Far North Queensland area is a tropical environment with high annual rainfall and exposure to summer electrical storms and cyclones. A substantial part of the wet tropics of Far North Queensland is also World Heritage Listed, requiring special consideration with regard to the operation and maintenance of any electrical infrastructure.

The Far North region consists of three main geographic areas with regard to Ergon Energy's electrical infrastructure:

- The Far North Coastal strip covers the city of Cairns and environs as well as the townships and surrounding rural areas of Cardwell, Tully, Mission Beach, Innisfail, Gordonvale and Babinda.
- The Far North Tablelands area is centred around the major rural towns of Atherton and Mareeba and includes the smaller rural communities of Malanda, Millaa Millaa, Ravenshoe, Mt Molloy, Dimbulah and Chillagoe. In addition, the coastal communities of Mossman, Port Douglas and Cooktown are supplied from the Tablelands network; and
- The Far North Western system takes in the Georgetown, Normanton, Croydon and Karumba communities in the Gulf of Carpentaria.

4.18.1.2 North Queensland

The North Queensland region is a tropical environment with exposure to summer electrical storms and cyclones that extends from Bowen in the south to Ingham in the north and west to the Northern Territory border.

It consists of four main geographic areas with regard to Ergon Energy's electrical infrastructure:

- The Townsville area covers the city of Townsville and environs as well as the townships and surrounding rural areas north to and including Ingham;
- The Burdekin/Bowen area covers the coastal strip of the North Queensland region south of Townsville and is centred near the major rural towns of Ayr and Home Hill in the Burdekin, and the coastal community of Bowen. It also includes the town of Collinsville and its surrounding rural loads;
- The Mid-Western system extends from Charters Towers west to Julia Creek and takes in the towns of Hughenden, Winton and Richmond; and
- The Western system comprises the Mount Isa and Cloncurry regions; and also the non-regulated network supplying the Carpentaria Minerals Province mining loads.

[11] Queensland Government, Electricity Industry Code (Fourth Edition – made 31 July 2008, effective 4 August 2008), found at: http://www.dme.qld.gov.au/Energy/electricity_industry_code.cfm

4.18.1.3 Mackay

The Mackay area is a sub-tropical environment with exposure to summer electrical storms and cyclones.

The region consists of two main geographic areas with regard to Ergon Energy's electrical infrastructure:

- The Coastal Strip is centred on the provincial city of Mackay and extends from the small rural community of Carmila in the south, to the rural township of Proserpine and surrounding area in the north including the tourist destinations of Airlie Beach and Laguna Quays. The Coastal Strip also provides supply to the Hayman, Hamilton, Daydream, South Molle and Long Islands of the Whitsunday group; and
- The Bowen Basin area is centred about the mining towns of Moranbah, Glenden and Nebo and includes the coal mines of Moranbah North, North Goonyella, Coppabella, Burton Downs, South Walker, Goonyella/Riverside, Hail Creek, Peak Downs, Millenium, Carborough Downs and Moorvale.

4.18.1.4 Capricornia

The Capricornia area extends from Miriam Vale in the south to Clairview in the north and west to Longreach, including the major provincial centres of Rockhampton and Gladstone. Numerous coal mines are established in the western areas of the region. Major coal fired power stations, providing a significant portion of Queensland's power, are located at Stanwell, Callide and Gladstone.

The Capricornia region consists of three operational areas with regard to Ergon Energy's electrical infrastructure:

- The Northern Operational Area incorporates the provincial city of Rockhampton and the surrounding coastal area. The Northern area extends from the Capricornia / Mackay Regional boundary south to Raglan and west to the Great Dividing Range;
- The Southern Operational Area takes in the port city of Gladstone and the western communities of Biloela and Moura, extending south to the Capricornia / Wide Bay Regional boundary; and
- The Western Operational Area takes in the major rural and mining communities of Emerald, Blackwater, Barcaldine, Clermont and Dysart, along with their surrounding areas. The Western Operational Area extends north to the Capricornia / Mackay / North Queensland Regional boundaries, south to the Capricornia, Wide Bay and South West regional boundaries and west to the Queensland, Northern Territory and South Australian borders.

4.18.1.5 Wide Bay

The Wide Bay supply area extends from Nanango in the south-west to Bundaberg in the north, including the major provincial centre of Maryborough as well as the Hervey Bay coastal area. The region also includes the Burnett area involving the rural centres of Kingaroy, Gayndah and Mundubbera. The Tarong coal fired power station is also located in the Wide Bay supply area. The high voltage network in the Wide Bay region consists of both 132 kV and 66 kV sub-transmission networks covering five geographic areas:

- The Maryborough area covers the provincial city of Maryborough and rural communities of Howard to the north, Owanyilla, Gootchie and Woolooga to the south west, and the Hervey Bay coastal area centred on Pialba and Torquay;
- The Isis area covers the rural communities of Childers, Farnsfield, Gayndah, Mundubbera and Eidsvold west of Maryborough;
- The Bundaberg area is centred about the provincial city of Bundaberg and also takes in the smaller rural communities of Givelda, Bullyard, South Kolan, Wallaville, Gooburrum, Meadowvale as well as the coastal communities of Bargara and Burnett Heads;
- South west of Maryborough is the Kilkivan area, which takes in the rural communities of Kilkivan, Goomeri, Murgon, Wondai and Proston; and
- South west of Kilkivan is the Kingaroy network area centred about the rural town of Kingaroy and taking in the rural communities of Nanango, Yarraman and Melrose.

4.18.1.6 South West

The South West supply area commences at about Toowoomba in the east (just west of the ENERGEX boundary) and extends west to the South Australian border. The southern boundary of the region is predominantly the NSW border. The region consists of three main geographic areas with regard to Ergon Energy's electrical infrastructure:

- The Toowoomba/Warwick area covers the provincial city of Toowoomba and environs, and extends south to include Warwick and Stanthorpe;
- This Dalby/Chinchilla Area area is situated to the north west of Toowoomba and covers the towns and surrounds of Dalby and Chinchilla including south to Meandarra, north to Wandoan, and west to about half way between Miles and Roma; and
- The Roma and Western system extends from Roma west and takes in the towns of Charleville, Quilpie, Thargomindah and Cunnamulla. It also extends south of Roma to include the St George and Dirranbandi areas.

4.18.2 Key Drivers of Regional Demand Forecasts

Chapter 21 of this Regulatory Proposal examines Ergon Energy's demand forecasts for Standard Control Services for the regulatory control period 2010-15. It indicates that the key drivers of demand across Ergon Energy's supply area in the next regulatory control period are expected to be:

- Population growth;
- Major new industry or commercial developments;
- Economic growth; and
- Climatic effects and air conditioning penetration.

The nature and extent of these drivers vary by region and result in significant differences in demand forecasts between the regions.

Ergon Energy prepares annual demand forecasts of system demand (MW) and engages National Institute of Economic and Industrial Research (NIEIR) to prepare an independent top-down forecast of maximum demand to validate Ergon Energy's internally produced forecasts.

Due to the timing for the preparation of this Regulatory Proposal, Ergon Energy prepared its capital expenditure forecasts based on November 2007 demand forecast data validated against NIEIR's November 2007 'Maximum Demand Forecasts for Ergon Energy connection points to 2017' report.

Ergon Energy prepared further demand forecasts in 2008 and validated these against NIEIR's September 2008 'Maximum Demand Forecasts for Ergon Energy connection points to 2018' report. Ergon Energy's 2008 demand forecasts were higher than the 2007 forecasts. However, in late 2008, the global financial crisis emerged and Ergon Energy considered it prudent to ask NIEIR to update its September 2008 report.

NIEIR revised downwards its September 2008 demand forecasts for Ergon Energy in its April 2009 report 'Economic Outlook for Australia and Queensland to 2018-19 – December 2008'. However, the updated forecasts remain higher, on average, than the 2007 forecasts.

Table 18 compares the maximum demand forecasts that were prepared by Ergon Energy in 2007, 2008 and 2009.

Table 18: *Ergon Energy Coincident Peak (Maximum) Demand Forecasts for 2010-15 based on 2007 data and compared with 2008 data and 2009 data (MW)*

	2010-11	2011-12	2012-13	2013-14	2014-15	Average of 5 Year Total
EE Coincident peak (maximum) demand – September 2007 (MW)	2,967	3,063	3,153	3,243	3,330	3,151
EE Coincident peak (maximum) demand – September 2008 (MW)	3,033	3,198	3,297	3,415	3,496	3,288
EE Coincident peak (maximum) demand – April 2009 Forecast (MW)	2,845	3,100	3,223	3,378	3,467	3,203

Source: Coincident peak (maximum demand) - Ergon Energy's Network Planning 2007, 2008 and 2009 forecasts (refer also NIEIR November 2007, September 2008 and April 2009)

Ergon Energy considers it reasonable to base its capital expenditure forecasts for the next regulatory control period on its 2007 demand forecasts, supported by explanations referenced to NIEIR's September 2008 report, because Ergon Energy's 2007 forecasts are, on average, lower than both of the subsequent 2008 and 2009 forecasts.

As discussed in Chapter 21 of this Regulatory Proposal, NIEIR's forecasts involve three scenarios – base, high and low. NIEIR's 2008 report states that:

The key features of the base scenario projection for Queensland gross regional product are:

- → *Strongest growth in Far North Queensland with average growth of 5.5 per cent between 2008 and 2018;*
- → *Strong growth in North Queensland, with average regional product growth of 4.7 per cent;*
- → *Slower, but still solid, growth in the major coal producing regions of Mackay and Capricornia;*
- → *In South West Queensland, gross regional product growth averages 2.0 per cent between 2008 and 2018; and*
- → *Continued relatively strong growth in South East Queensland, which averages 4.3 per cent between 2008 and 2018, 0.1 percentage points above the projection for Queensland as a whole.*

Recognising that population growth, major new industry or commercial developments and economic growth are three of the key drivers of Ergon Energy's demand, Table 19 details the NIEIR's forecasts of growth in gross regional product, population and dwelling stock for the six regions for the period 2007 to 2017 and 2008 to 2018.

Table 19: *NIEIR's Forecasts – 2007 to 2017 and 2008 to 2018 (percentage)*

Region	Gross regional product	Population	Dwelling stock
Far North			
North			
Mackay			
Capricornia			
Wide Bay Burnett			
South West			
South East (ENERGEX)			
Average			

Sources:

- NIEIR, Maximum Demand Forecasts for Ergon Energy Connection Points to 2011, November 2007, pages 27-29
- NIEIR Maximum Demand Forecasts for Ergon Energy Connection Points to 2018, September 2008, pages 26-27

It can be seen from Table 19 that there are significant differences in the key drivers of demand growth across the six regions. These differences are reflected in Ergon Energy's demand forecasts in Chapter 21 of this Regulatory Proposal. They are also discussed in detail in Ergon Energy's:

- Annual Network Management Plan, Part B of which details the nature of the emerging network constraints, and Ergon Energy's responses to these constraints, that result from the forecast demand growth in each region; and
- Sub-transmission Network Augmentation Plans, which describe the capital works that are needed to meet the augmentation requirements of the sub-transmission network in order to accommodate the normal load forecasts for the next 10 years.

The way in which these documents relate to Ergon Energy's demand forecasts are discussed in detail in Chapter 23 of this Regulatory Proposal.

4.19 ENVIRONMENTAL FACTORS

Section 2.3.1(a)(8) of the AER's RIN requires Ergon Energy to detail the environmental factors that affect its operations.

The key environmental factors impacting on Ergon Energy's operations are:

- A service area of 1,698,100 square kilometres, which covers 97 per cent of the Queensland land mass – an area approximately six times the size of the State of Victoria. Vast distances and low customer density result in significant geographic isolation in large parts of Ergon Energy's service area;
- Significant summer-winter and day-night temperature variations, which translate into large variability in seasonal and daily electricity demand;
- High rainfall, which can adversely affect asset condition, for example by causing pole top rot, and restrict access for operational purposes, for example in the Channel Country, which is prone to prolonged flooding that initiates hundreds of kilometres away;
- Extreme winds, including cyclones, which can cause extensive damage to assets across vast areas. Cyclones are particularly prevalent along the northern coastal strip of Queensland;
- Lightning and summer storms, which require lightning arresters and additional earth protection to be installed. These events are particularly prevalent in the south west and south east of Ergon Energy's supply area;
- Vegetation whose types, density and growth rates adversely affect the operation of assets and limit access for operational purposes. This requires an extensive vegetation management program;
- Topography, which can affect the type of assets that need to be built as well as the approach to, and cost of, construction works;
- Soil conditions, including soil instability in areas such as the Darling Downs; and

- Wildlife, including termite infestations, which can adversely affect the condition and integrity of assets, such as wooden poles.

Ergon Energy's electricity distribution system is built to accommodate, as well as possible, these environmental challenges, and is characterised by:

- A large radial network, including approximately 65,000 km of SWER lines, operating at three voltage levels (11, 12.7 and 19.1 kV) and servicing around 26,000 customers. Over 68 per cent of Ergon Energy's feeder powerlines are classified as non-urban;
- Connection to Powerlink's high voltage transmission network at 48 transmission network connection points and direct connection to, and supply from, a small number of embedded generators;
- Low load density and a high geographic spread of customers. Ergon Energy has the lowest customer density of any network in the western world for the 100,000 km of line west of the Great Dividing Range;
- High numbers of new customer connections, due to strong population growth and high levels of investment in the industrial and mining sectors. This results in increased pressures to meet customer expectations regarding connection times and, for major customer loads, difficulties in predicting the timing and magnitude of the load to be serviced. Ergon Energy's forecast growth in customer numbers is discussed in Chapter 21 of this Regulatory Proposal;
- Shifts in end-usage patterns to include larger loads (e.g. air conditioning) and more sophisticated and complex electronic equipment. The standards and technologies upon which the network has been based may not be capable of meeting customer expectations as to the future reliability and quality of supply; and
- A sustained increase in maximum demand. Maximum demand for Ergon Energy's grid connected network is forecast to grow rapidly (at an average of 3.27 per cent) from the 2006-07 maximum demand level of 2,584 MW. Capital investment is required to ensure that network utilisation remains within appropriate bounds. Ergon Energy's forecast growth in maximum demand is discussed in Chapter 21 of this Regulatory Proposal.

4.20 EXPLANATION OF HOW ENVIRONMENTAL FACTORS IMPACT DNSP'S EFFICIENT COSTS AND EXPENDITURE FORECASTS

Section 2.3.1(a)(8) of the AER's RIN requires Ergon Energy to detail how environmental factors affect its efficient costs and how they have impacted its proposed expenditure forecasts.

The environmental factors discussed in section 4.19 affect all aspects of the planning, management and operation of Ergon Energy's distribution system, including:

- The security of supply standards that are applied to planning the construction of new assets. Larger industrial loads and higher density areas, typically in coastal locations, are typically served by more reliable systems whereas lower density rural areas are typically being served by technology such as Single Wire Earth Return (SWER), which is capable of spanning long distances at minimal cost. Ergon Energy service standards are discussed in Chapter 12 of this Regulatory Proposal;
- The standards at which assets are built, in order to ensure that they are fit for purpose given the environmental conditions in which they will be operating. For example, assets need to be built to higher standards in the northern coastal strip of Queensland, where cyclones are particularly prevalent;
- The types of assets that form part of the distribution system in order to protect against environmental factors. For example, additional lightning arresters and earth protection need to be installed in the south west and south east of Ergon Energy's supply area, where lighting strikes and summer storms are particularly prevalent;
- The nature and cycle times of the inspections that are undertaken of assets as part of the Preventive Maintenance program and the resultant Asset Replacement capital expenditure and Corrective and Forced Maintenance. It is noted that:
    - → Geographic isolation significantly impacts Ergon Energy's approach to asset maintenance, including the need to limit site visits through amalgamation of differing maintenance regimes; and
    - → Vegetation management is the largest component of the Corrective Maintenance program.

These environmental factors are reflected into Ergon Energy's plans, policies, procedures and strategies, which are discussed in Chapter 17 of this Regulatory Proposal, and in its capital and operating expenditure forecasts, which are discussed in Chapters 23 and 26 of this Regulatory Proposal.

4.21 OVERVIEW OF DNSP'S NETWORK

Section 2.3.1(a)(9) of the AER's RIN requires Ergon Energy to provide an overview of its distribution network.

Ergon Energy's electricity Distribution System is characterised by:

- A low load density and high geographic spread of customers. Ergon Energy has the lowest customer density of any network in the western world for the 100,000 km of line west of the Great Dividing Range[12];
- A large radial network, including approximately 65,000 km of SWER lines, operating at three voltage levels (11, 12.7 and 19.1 kV) and servicing around 26,000 customers[13]. Over 68 per cent of Ergon Energy's feeder powerlines are classified as non-urban[14]; and
- Connection to Powerlink's high voltage transmission network at 48 Transmission Network Connection Points and direct connection to and supply from a small number of embedded generators[15].

Table 20 provides a statistical summary of Ergon Energy's distribution system in 2007-08 and has been updated with the December 2008 and March 2009 quarterly service quality statistics.

***Table 20:** Features of Ergon Energy's Distribution System*

Item	Value / Unit
Network service area (square kilometres) [1]	1,698,100 sq kms
Total length of lines (kilometres) - distribution and sub- transmission [1]	146,339 kms
Customers per kilometre of line [2]	5.2
Total distribution customers: [3]	632,196
Urban feeder [3]	251,213
Short rural feeder [3]	307,124
Long rural feeder [3]	69,985
Number of poles [1]	939,227
Distribution losses [1]	6.50%
Number and capacity of transformers (MVA):	
Sub-transmission [1]	628 / 7,508 MVA
Distribution [1]	85,034 / 6,099 MVA

[1] Source: Ergon Energy, Annual Service Quality Report (July 2007 – June 2008), found at: http://www.qca.org.au/files/E-SerQual-Ergon-AnnRep0708-0409.pdf

[2] Source: QCA – Ergon Energy's Financial and Service Quality Performance 2007-08 (March 2009), found at http://www.qca.org.au/files/E-SerQual-QCA-ErgonAnnRep0708-0409.pdf

[3] Source: Ergon Energy, Quarterly Service Quality Report (October - December 2008), found at http://www.qca.org.au/electricity/service-quality/qtrservqualrep.php

[12] Ergon Energy, Network Management Plan 2007-2012 – Part A, page 7.

[13] Ibid, page 79.

[14] Ergon Energy, Annual Report 2006-07, at page 13.

[15] Ergon Energy, Network Management Plan 2007-2012 – Part A, page 8.

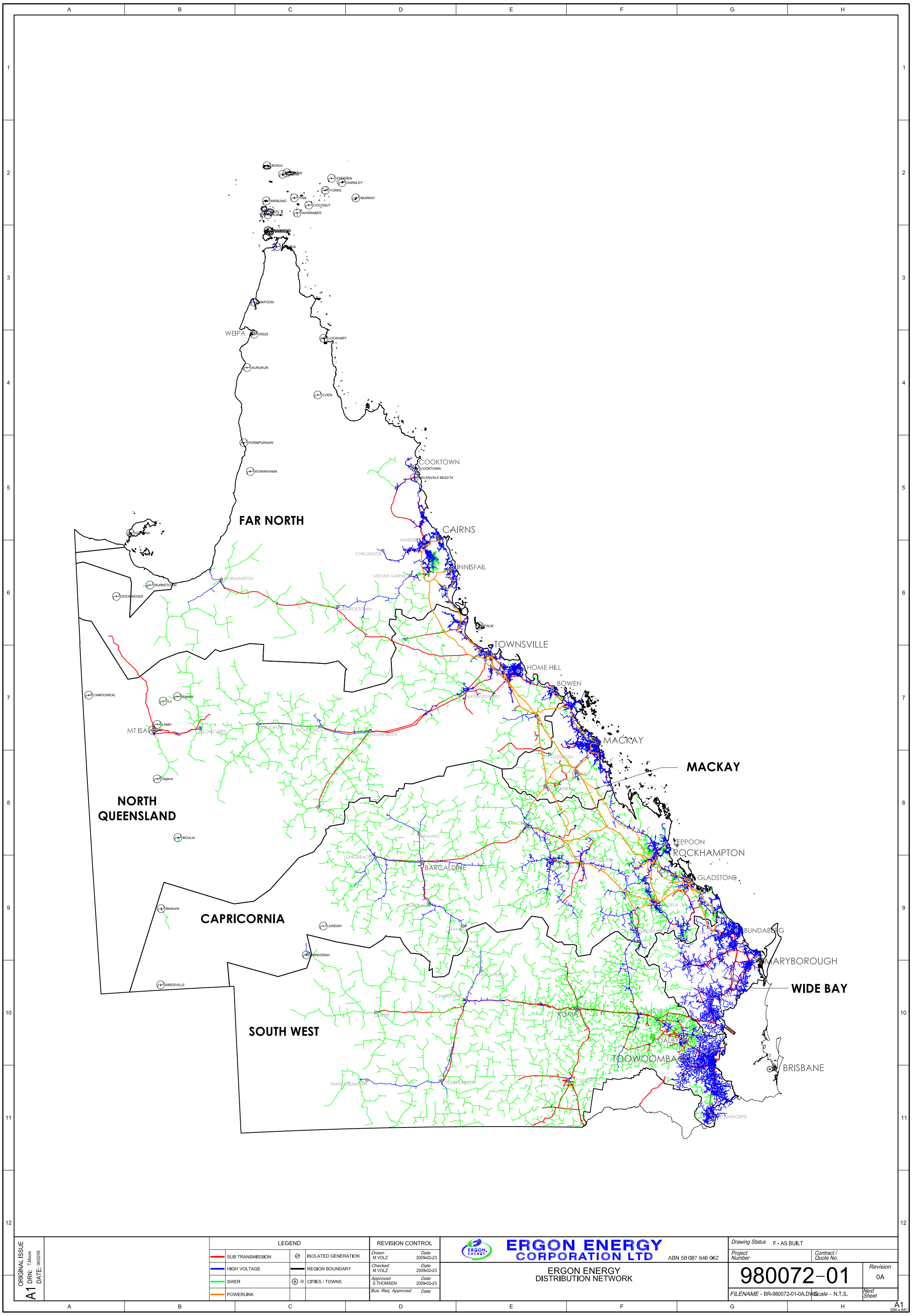
4.22 RECENT HIGH LEVEL MAP OF NETWORK SHOWING MAJOR NETWORK FEATURES INCLUDING KEY FORECAST AUGMENTATIONS

Section 2.3.1(a)(9) of the AER's RIN requires Ergon Energy to provide a recent high level map of the network showing major network features including key forecast augmentations.

Ergon Energy has prepared four maps of its distribution service area:

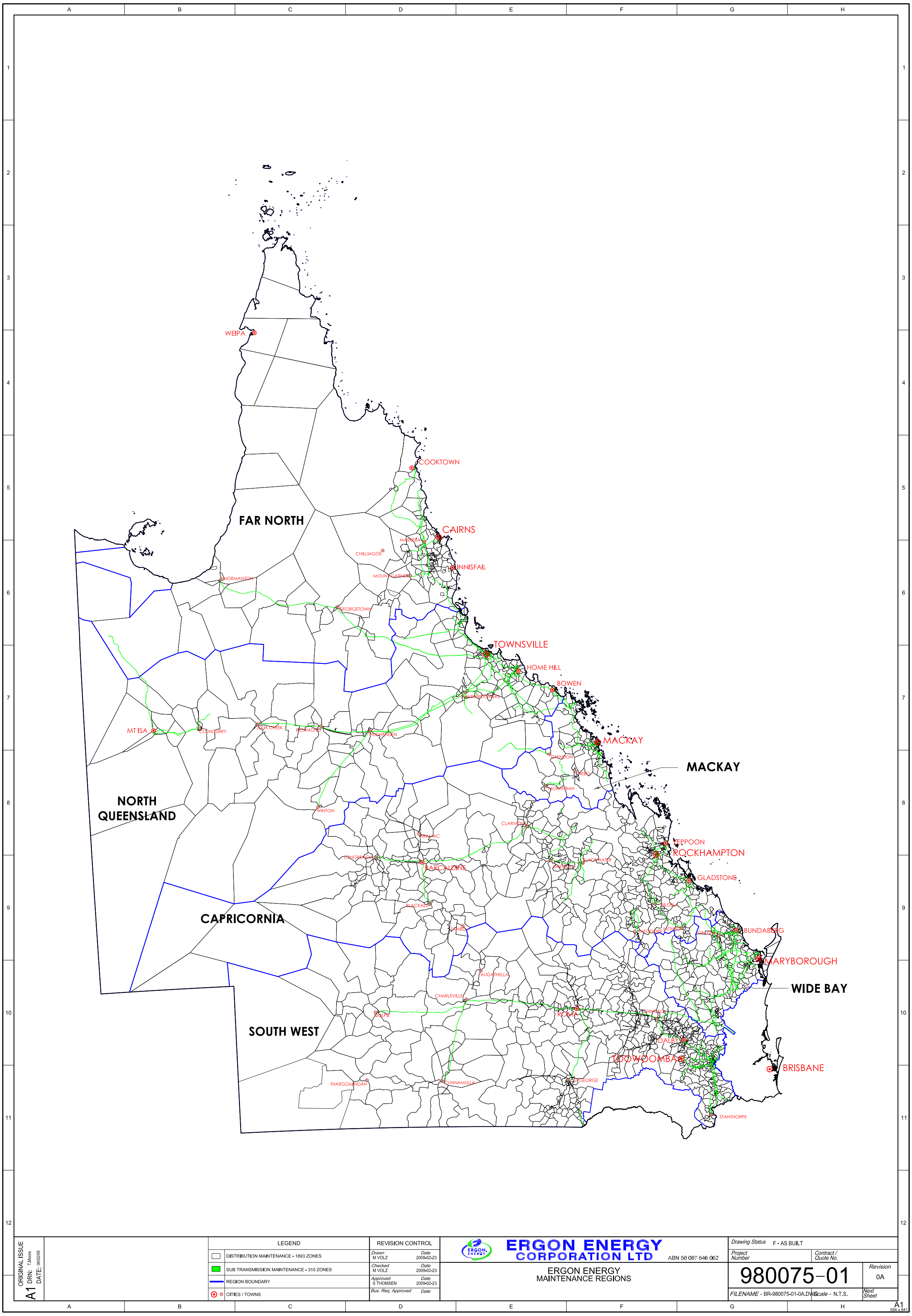
- *Map 1* shows the key features of the existing distribution network;
- *Map 2* shows the maintenance areas into which Ergon Energy packages its maintenance work;
- *Map 3* shows the depot zones and the number of customer and connections points serviced by each depot zone; and
- *Map 4* shows the key forecast augmentations to Ergon Energy's distribution network in the next regulatory control period based on the material projects from the Sub-transmission Network Augmentation Plans and Artemis 7.

***Map 1:** Key features of the existing distribution network*



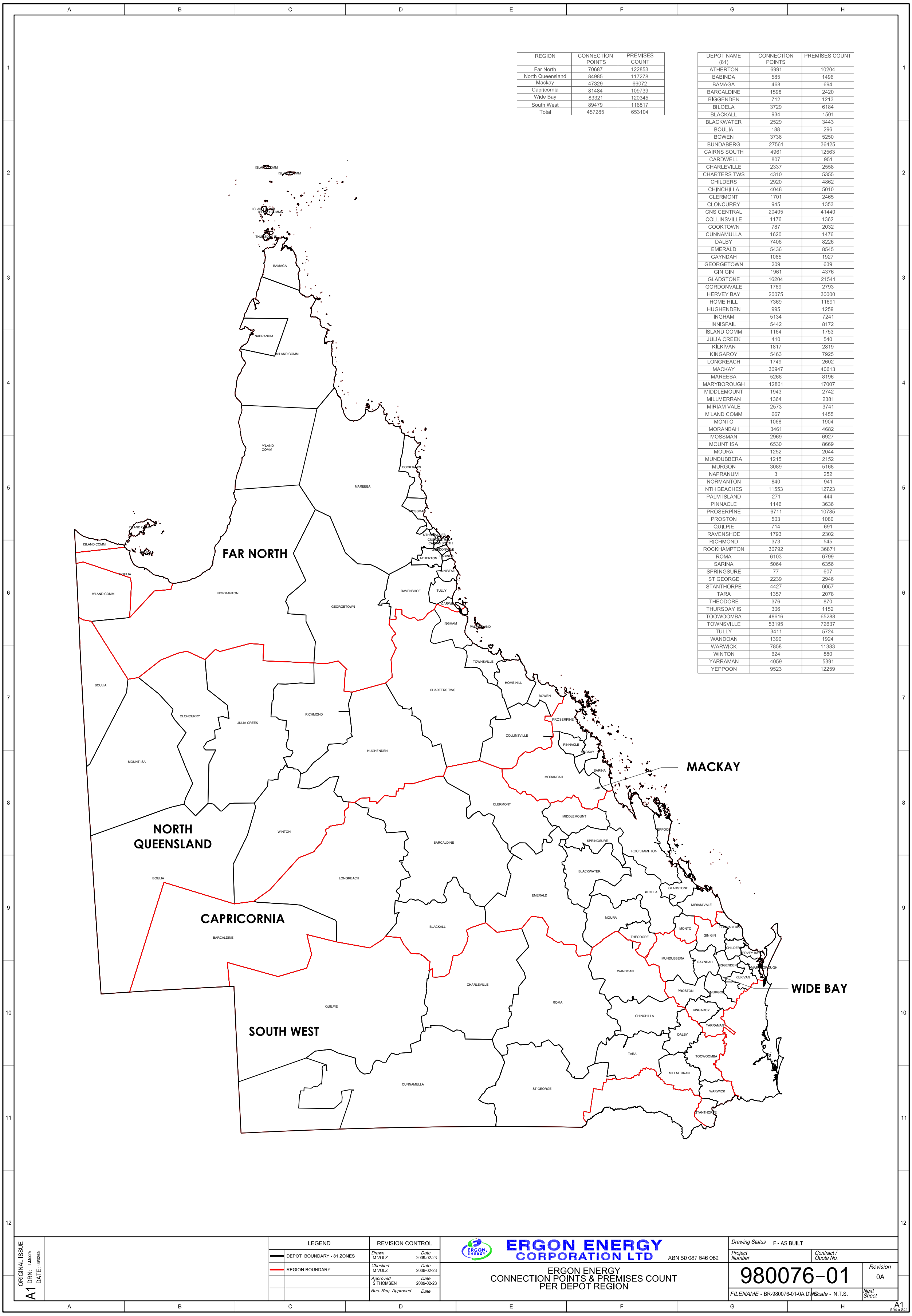
Map available electronically on request

***Map 2:** Maintenance areas into which Ergon Energy packages its maintenance work*



Map available electronically on request

Map 3: *Depot zones and the number of customer and connections points serviced by each depot zone*

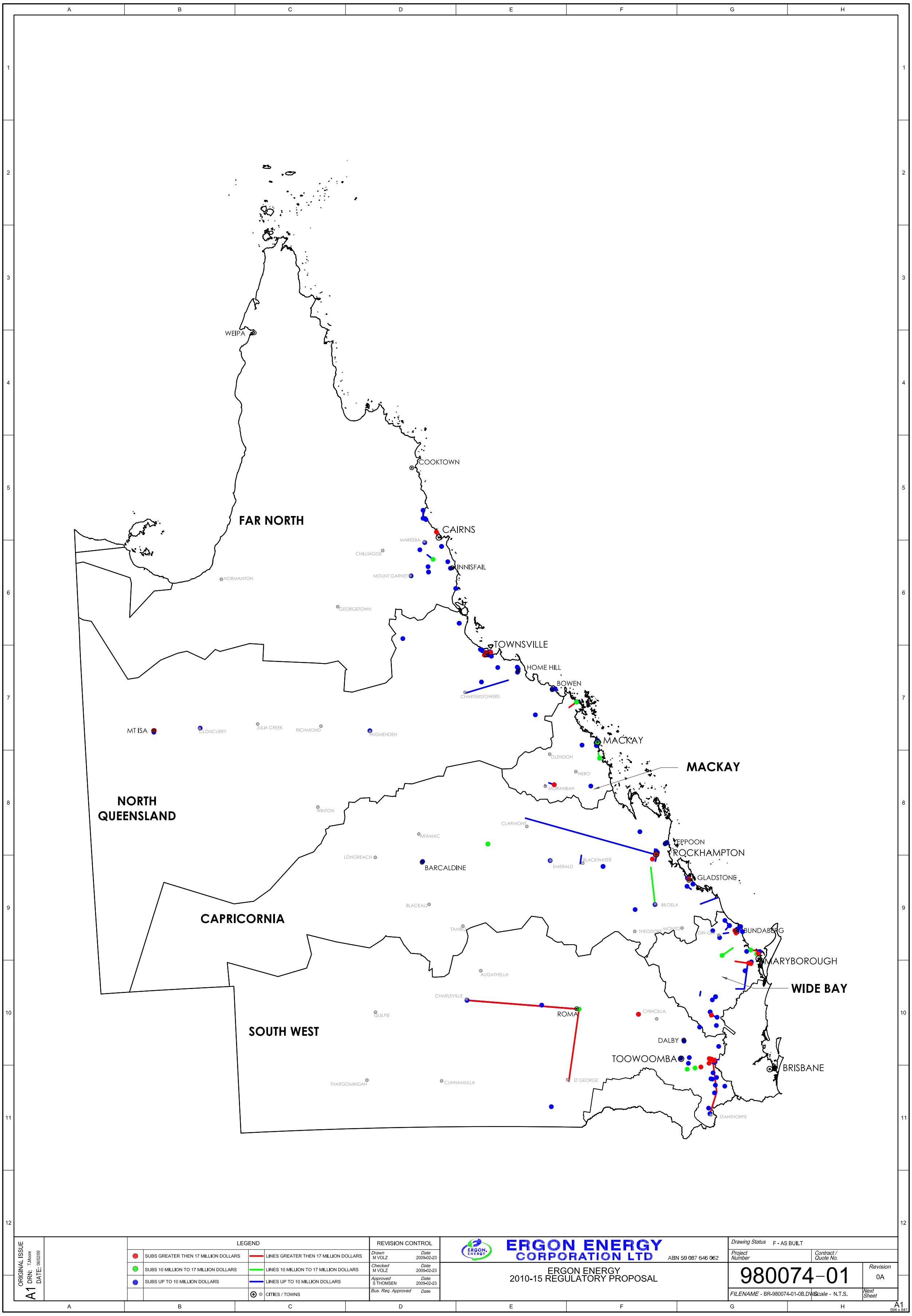


REGION	CONNECTION POINTS	PREMISES COUNT
Far North	70687	122853
North Queensland	84985	117278
Mackay	47329	66072
Capricornia	81484	109739
Wide Bay	83321	120345
South West	89479	116817
Total	457285	653104

DEPOT NAME (81)	CONNECTION POINTS	PREMISES COUNT
ATHERTON	6991	10204
BABINDA	585	1496
BAMAGA	468	694
BARCALDINE	1598	2420
BIGGENDEN	712	1213
BILOELA	3729	6184
BLACKALL	934	1501
BLACKWATER	2529	3443
BOULIA	188	296
BOWEN	3736	5250
BUNDABERG	27561	36425
CAIRNS SOUTH	4961	12563
CARDWELL	807	951
CHARLEVILLE	2337	2558
CHARTERS TWS	4310	5355
CHILDERS	2920	4862
CHINCHILLA	4048	5010
CLERMONT	1701	2465
CLONCURRY	945	1353
CNS CENTRAL	20405	41440
COLLINSVILLE	1176	1362
COOKTOWN	787	2032
CUNNAMULLA	1620	1476
DALBY	7406	8226
EMERALD	5436	8545
GAYNDAH	1085	1927
GEORGETOWN	209	639
GIN GIN	1961	4376
GLADSTONE	16204	21541
GORDONVALE	1789	2793
HERVEY BAY	20075	30000
HOME HILL	7369	11891
HUGHENDEN	995	1259
INGHAM	5134	7241
INNISFAIL	5442	8172
ISLAND COMM	1164	1753
JULIA CREEK	410	540
KILKIVAN	1817	2819
KINGAROY	5463	7925
LONGREACH	1749	2602
MACKAY	30947	40613
MAREEBA	5266	8196
MARYBOROUGH	12861	17007
MIDDLEMOUNT	1943	2742
MILLMERRAN	1364	2381
MIRIAM VALE	2573	3741
M'LAND COMM	667	1455
MONTO	1068	1904
MORANBAH	3461	4682
MOSSMAN	2969	6927
MOUNT ISA	6530	8669
MOURA	1252	2044
MUNDUBBERA	1215	2152
MURGON	3089	5168
NAPRANUM	3	252
NORMANTON	840	941
NTH BEACHES	11553	12723
PALM ISLAND	271	444
PINNACLE	1146	3636
PROSERPINE	6711	10785
PROSTON	503	1080
QUILPIE	714	691
RAVENSHOE	1793	2302
RICHMOND	373	545
ROCKHAMPTON	30792	36871
ROMA	6103	6799
SARINA	5064	6356
SPRINGSURE	77	607
ST GEORGE	2239	2946
STANTHORPE	4427	6057
TARA	1357	2078
THEODORE	376	870
THURSDAY IS	306	1152
TOOWOOMBA	48616	65288
TOWNSVILLE	53195	72637
TULLY	3411	5724
WANDOAN	1390	1924
WARWICK	7858	11383
WINTON	624	880
YARRAMAN	4059	5391
YEPPOON	9523	12259

Map available electronically on request

***Map 4:** Key forecast augmentations to Ergon Energy's distribution network in the next regulatory control period based on the material projects from the Sub-transmission Network Augmentation Plans and Artemis 7*



Map available electronically on request

4. ORGANISATIONAL OVERVIEW – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR371	Electricity Act 1994 (Qld)
AR372	Government Owned Corporations Act 1993 (Qld)
AR373	Government Owned Corporations Regulation 2002 (Qld)

AER Documents

AR367c & 368c	AER Regulatory Information Notice

QCA Documents

Nil.

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR364	National Electricity Rules
AR398	National Electricity Code, V9.4, April 2005

Ergon Energy Documents

AR065c	NIEIR November 2007 Maximum Demand Forecasts
AR128c	NIEIR September 2008 Maximum Demand Forecasts
AR268c	EE Ergon Energy Strategic Workforce Plan 2008-2018
AR314	EE Cost Allocation Method, AER Approved
AR329	EE Pricing Principles Statement Release 5, April 2009
AR374c	NIEIR April 2009 report "Economic Outlook for Australia and Queensland to 2018-19 – December 2008"
AR375c	EE Sub-transmission Network Augmentation Plans 2007
AR376c	EE Sub-transmission Network Augmentation Plans 2008
AR377	EE Map 2 Maintenance Areas, 23 February 2009
AR378	EE Map 4 Reg Proposal Material Projects from SNAPs, 23 February 2009
AR379	EE Map 3 Depots & Customer Nos & CPts, 23 February 2009
AR380	EE Map 1 Distribution Network, 23 February 2009
AR381	EE Annual Report 2006-07
AR401	EE Network Management Plan, Summary, 2008-13
AR402	EE Network Management Plan, Part A 2008-09 to 2012-13
AR445	EE Network Management Plan, Part B 2008-09 to 2012-13

5. RELATIONSHIPS WITH OTHER ENTITIES

Rules – Clauses 6.5.6(e)(9) and 6.5.7(e)(9)
NEL – Sections 28A-B
RIN – Sections 2.3.2(a)(1)-(6), and 2.3.2
RIN Pro forma - 2.3.2

5.1 ENTITIES THAT CONTROL DNSP

Section 2.3.2(a)(1) of the Australian Energy Regulator's (AER) Regulatory Information Notice (RIN) requires Ergon Energy to detail any other entities that controls it.

As discussed in Section 4.2 of this Regulatory Proposal, Ergon Energy is a wholly Queensland Government-owned 'company GOC', for the purposes of the Government Owned Corporations Act 1993 (Qld).

There are no entities that control Ergon Energy.

5.2 ENTITIES THAT ARE CONTROLLED BY DNSP

Section 2.3.2(a)(2) of the AER's RIN requires Ergon Energy to detail any other entities that it controls.

As discussed in Section 4.4 of this Regulatory Proposal, Ergon Energy:

- Wholly owns Ergon Energy Queensland (EEQ) Pty Ltd;
- Wholly owns Ergon Energy Telecommunications Pty Ltd; and
- Has a 50 per cent shareholding in SPARQ.

There are no other entities that are controlled by Ergon Energy.

5.3 ENTITIES THAT ARE CONTROLLED BY ENTITY THAT CONTROLS DNSP

Section 2.3.2(a)(3) of the AER's RIN requires Ergon Energy to detail any other entities that are controlled by an entity that controls Ergon Energy.

As there are no entities that control Ergon Energy, there are no entities that are controlled by an entity that controls Ergon Energy.

5.4 ENTITIES THAT ARE CONTROLLED BY ENTITY THAT IS CONTROLLED BY DNSP

Section 2.3.2(a)(4) of the AER's RIN requires Ergon Energy to detail any entities that are controlled by an entity that controls Ergon Energy.

There are no entities that are controlled by entities that are controlled by Ergon Energy.

5.5 DIRECTORS OF DNSP

Section 2.3.2(a)(5) of the AER's RIN requires Ergon Energy to provide information in relation to the directors of Ergon Energy.

The Directors of Ergon Energy are:

- Dr Ralph Craven (Chair);
- Mr John Bird;
- Ms Terri Hamilton (until 30 June 2009);
- Mr Anthony Mooney;
- Ms Susan Forrester;
- Ms Helen Stanton; and
- Mr Wayne Myers.

5.6 DIRECTORS OF ENTITIES THAT ARE CONTROLLED BY DNSP

Section 2.3.2(a)(6) of the AER's RIN requires Ergon Energy to provide information in relation to entities that are controlled by, or control, it.

The Directors of EEQ are:

- Mr Ian McLeod (Chair);
- Mr Jim Chisholm;
- Mr Greg Evans; and
- Mr Justin Fitzgerald.

The Directors of EET are:

- Mr John Bird (Chair);
- Mr Wayne Myers; and
- An application has been made to also appoint Dr Ralph Craven.

The Directors of SPARQ are:

- Mr Ian McLeod (Chairman);
- Mr Terry Effeney (ENERGEX personnel);
- Mr Peter Weaver (ENERGEX personnel);
- Mr Greg Evans;
- Mr Darren Busine (ENERGEX personnel); and
- Mr Mal Leech.

5. RELATIONSHIPS WITH OTHER ENTITIES – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR369	National Electricity Law
AR372	Government Owned Corporations Act 1993 (Qld)

AER Documents

AR367c & 368c	AER Regulatory Information Notice

QCA Documents

Nil

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR364	National Electricity Rules

Ergon Energy Documents

Nil

6. RING-FENCING

Rules – Clauses 6.17.1, 6.17.2 and 11.14.5

This chapter proposes the continuation of the existing ring-fencing arrangements that apply to Ergon Energy until new arrangements are developed by the Australian Energy Regulator.

6.1 RULES REQUIREMENTS

Clause 6.17.1 of the Rules requires Ergon Energy to comply with Ring-Fencing Guidelines prepared by the AER under clause 6.17.2 of the Rules.

Clause 11.14.5(b)(3) of the Rules provides that:

> *guidelines in force for a participating jurisdiction immediately before the AER's assumption of regulatory responsibility (transitional guidelines) continue in force for that jurisdiction subject to amendment, revocation or replacement by guidelines made under the new regulatory regime.*

Clause 11.14.5(c) of the Rules states that:

> *The transitional guidelines:*
>
> 1. *are taken to be guidelines made by the AER under the new regulatory regime; and*
> 2. *are to be construed as if references to a Jurisdictional Regulator were references to the AER.*

Clause 11.14.5(d) of the Rules goes on to provide that:

> *A waiver granted, or additional ring fencing requirement imposed, by a Jurisdictional Regulator under the transitional guidelines continues in force under the transitional guidelines subject to variation or revocation by the AER.*

6.2 PROPOSED RING-FENCING ARRANGEMENTS

The AER has not issued any new ring-fencing guidelines under clause 6.17.2 of the Rules.

As a consequence, Ergon Energy proposes that, in accordance with:

- Clause 11.14.5(b)(3) of the Rules, the Queensland Competition Authority's (QCA) current Ring-Fencing Guidelines continue in force until they are replaced by any new ring-fencing guidelines issued by the AER under clause 6.17.2 of the Rules;
- Clause 11.14(5)(c)(1) of the Rules, the QCA's current Ring-Fencing Guidelines be taken to be guidelines made by the AER under the new regulatory regime;
- Clause 11.14(5)(c)(2) of the Rules, the QCA's current Ring-Fencing Guidelines be construed as if references to the QCA were references to the AER; and
- Clause 11.14.5(d) of the Rules, the three Ring-Fencing Waivers issued to Ergon Energy by the QCA continue to apply.

The nature of the QCA's current Ring-Fencing Guidelines and the ring-fencing waivers that have been issued to Ergon Energy by the QCA are explained below.

6.3 CURRENT RING-FENCING GUIDELINES AND WAIVERS

In September 2000, the QCA issued its "Final Determination Electricity Distribution – Ring-Fencing Guidelines"[16]. These Guidelines set out the minimum ring-fencing obligations for Ergon Energy, as a Distribution Network Service Provider (DNSP) in Queensland.

The Guidelines provide that Ergon Energy may apply to the QCA to waive certain minimum ring-fencing obligations under section 1 of the Ring-Fencing Guidelines.

Following a public consultation process, the QCA granted Ergon Energy waivers from complying with the Ring-Fencing Guidelines in relation to:

- The interaction between Ergon Energy Corporation Limited (EECL) and Ergon Energy Queensland Pty Ltd (EEQ).
- Ergon Energy's isolated generation system; and
- Ergon Energy's grid-connected network support generators.

In addition, the QCA formally advised Ergon Energy that no waiver was required in relation to Ergon Energy's temporary grid-connected generators. As a result, the Ring-Fencing Guidelines do not apply to these activities.

[16] These Guidelines are available at http://www.qca.org.au/files/ACF187C.pdf

6.3.1 Interaction between EECL and EEQ

On 13 October 2006, Ergon Energy applied to the QCA for a waiver from its obligations under:

- Section 1(f) of the Ring-Fencing Guidelines relating to the disclosure to EEQ of confidential information provided by a customer or potential customer to EECL;
- Section 1(g) of the Ring-Fencing Guidelines relating to the disclosure to EEQ of confidential information obtained by EECL in the course of conducting its business and which might reasonably be expected to affect materially the commercial interests of a customer or prospective customer; and
- Section 1(i) of the Ring-Fencing Guidelines relating to ensuring that EECL's marketing staff are not also staff of EEQ.

Ergon Energy sought this waiver because there were significant reforms being made to the Queensland electricity market, including:

- Transferring certain customers, staff and management of the former Ergon Energy Pty Ltd (EEPL) to Powerdirect Australia (PDA);
- Introducing legislation which allowed the Queensland Government to dispose of its shares in PDA;
- Establishing EEQ as a new wholly owned subsidiary of EECL;
- Transferring certain customers of EEPL into EEQ; and
- Amending the *Electricity Act 1994* which places competition restrictions on EEQ.

Although these reforms did not change Ergon Energy's operational focus as a DNSP, they did establish new relationships between it and the newly created EEQ.

The QCA issued its Final Decision in February 2007 [17] granting Ergon Energy a waiver from complying with sections 1(f), 1(g) and 1(i) of the Ring-Fencing Guidelines on the basis that the costs of compliance would outweigh any benefits as EEQ was a non-competing retailer.

6.3.2 Ergon Energy's Grid Connected Network Support Generators

On 1 October 2003, Ergon Energy applied to the QCA for a waiver from its obligations under section 1(b) of the Ring-Fencing Guidelines in order to allow Ergon Energy to own and operate a related business within the same legal entity.

The waiver being sought related to the ownership and operation of Ergon Energy's four [18] existing grid-connected generators and any future grid-connected generation assets. These grid-connected generation assets do not impact on the National Electricity Market (NEM) and do not result in Ergon Energy entering the generation or retail markets. Rather these assets are used solely for the purpose of augmenting the existing distribution network to ensure reliable supply of its long rural distribution feeders and to meet obligations Ergon Energy has under its Distribution Authority. Ergon Energy emphasised to the QCA that all of its other ring-fencing obligations under the Ring-Fencing Guidelines would be met.

The QCA issued its Final Decision in February 2004 [19] . This decision granted Ergon Energy a waiver from complying with section 1(b) in respect of the four existing grid-connected generation sites, thus allowing them to be owned and operated within the legal entity of EECL, the DNSP. The decision did not extend to any future grid-connected generation sites.

6.3.3 Ergon Energy's Isolated Generation Systems

On 2 May 2001, Ergon Energy applied to the QCA for a waiver from its obligations under section 1(b) of the Ring-Fencing Guidelines in order to allow Ergon Energy to own and operate a related business within the same legal entity.

The waiver being sought related to Ergon Energy's ownership and operation of 33 isolated generation systems. The Isolated Generation Sites are at Aurukun, Badu, Bamaga, Bedourie, Birdsville, Boiga, Boulia, Burketown, Camooweal, Coconut, Coen, Darnley, Dauan, Doomadgee, Gununa, Hammond, Jundah, Kowanyama, Kubin, Lockhart River, Mabuiag, Mapoon, Murray, Palm Island, Pormpuraaw, Saibai, Stephen, Thursday Island, Warraber, Wasaga, Windorah, Yam and Yorke.

The QCA issued its Final Decision in September 2001. The decision granted Ergon Energy a waiver from complying with section 1(b) of the Ring-Fencing Guidelines in respect of these isolated generation sites, thus allowing them to be owned and operated within the legal entity of EECL, the DNSP.

[17] http://www.qca.org.au/files/ergonwaiver_finaldecision.pdf

[18] Location of Grid-Connected Generation Sites - Winton, Cooktown, Dajarra and Kajabbi

[19] http://www.qca.org.au/files/ACF63.pdf

6. RING-FENCING – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR371	Electricity Act 1994 (Qld)

AER Documents

Nil

QCA Documents

AR382	QCA Final Determination: Electricity Distribution Ring-Fencing Guidelines – September 2000
AR383	QCA Final Decision, Ring-Fencing Waiver, Grid Connected Generation – February 2004
AR384	QCA Final Decision, Ring-Fencing Waiver, EEQ – February 2007
AR385	QCA Final Decision, Ring-Fencing Waiver, Isolated Generation – September 2001

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

Nil

7. SIGNIFICANT ISSUES FROM PREVIOUS PERIODS

Rules – Clauses 11.16.4 and 11.16.5

This chapter identifies various issues that arose in the current or the previous regulatory control periods that have on going relevance to Ergon Energy and which it seeks to have addressed in the Australian enrgy Regulator's (AER) Distribution Determination for the next regulatory control period.

7.1 REGULATION OF MOUNT ISA – CLONCURRY NETWORK

Ergon Energy owns the Mount Isa–Cloncurry network that supplies approximately 10,500 customers in the North West of Queensland. The Mount Isa–Cloncurry network is isolated from the coastal network that connects the eastern Australian states and so operates outside of the National Electricity Market (NEM).

Section 89 of the Electricity Act provides that, with respect to the Mount Isa–Cloncurry network, the Minister may either:

- Decide, in the way that the Minister considers appropriate, the prices, or a methodology to fix the prices, that may be charged for the provision of customer connection services; or
- Direct the Queensland Competition Authority (QCA) to regulate the prices for the services under the Rules as if the supply network was part of the national grid.

The QCA was directed by the Queensland Treasurer in June 2001, under section 89B of the Electricity Act, to regulate pricing for the Mount Isa–Cloncurry network, other than the 220 kV network, as if it was part of the NEM. The 220 kV network is part of the North West Minerals Province, which is the subject of an Australian Competition and Consumer Commission (ACCC) Authorisation that makes it unregulated for network pricing purposes.

The QCA's 2005 Final Determination for the current regulatory control period therefore includes a determination in relation to the Mount Isa–Cloncurry network, other than the 220 kV network.

The Queensland Government recently amended the Electricity Act 1994 and the Electricity National Scheme (Queensland) Act 1997 to make the AER responsible for the economic regulation of the Mount Isa–Cloncurry network from 1 July 2010. This means that the AER's Distribution Determination for the next regulatory control period will need to include the Mount Isa–Cloncurry network as well as its distribution system that is part of the NEM.

As a consequence, this Regulatory Proposal includes Ergon Energy's Mount Isa–Cloncurry network as well as its distribution system that is part of the NEM.

7.2 REVENUE CAP'S INABILITY TO DEAL WITH GROWTH ABOVE FORECAST

A key limitation of the regulatory arrangements for the current regulatory control period is that the fixed revenue cap that covers all of Ergon Energy's prescribed Distribution Services does not deal satisfactorily with higher than forecast growth in customer demand. This is a particular issue for Ergon Energy because it results in its actual capital expenditure for Corporation Initiated Augmentation (CIA) and Customer Initiated Capital Works (CICW) being significantly higher than the forecasts that were used by the QCA in setting Ergon Energy's Aggregate Annual Revenue Requirement (AARR) and revenue caps. This problem manifests itself in different ways for CIA and CICW in relation to small and large customer connections.

For small customer connections, increased customer connections have resulted in:

- Ergon Energy needing to spend significantly more on CIA and CICW than was forecast by the QCA in setting Ergon Energy's AARR for the current regulatory control period; and
- Ergon Energy's capital contributions being significantly above the amounts forecast by the QCA for the current regulatory control period. This has translated into a reduction in Ergon Energy's annual revenue caps.

As a consequence, Ergon Energy has needed to significantly 'over-spend' on its capital expenditure building block in relation to small customer connections without being appropriately funded to do so in this regulatory control period.

For large customer connections, there are two pass through provisions in the QCA's Final Determination for the current regulatory control period, specifically for:

- "...large customer projects, with a cost in excess of $10 million, that occur during the next regulatory period but were totally unanticipated at the time of preparing this Determination"; and

- "...identified capital projects likely to proceed during the next regulatory period, but with a probability of less than 80 per cent certainty of proceeding. As this mechanism is only meant to protect Ergon from significant financial consequences (not remove all forecasting risk), each project will also have to have a potential (Capital Expenditure) cost of at least $5 million."

These cost pass through provisions recognised the considerable uncertainty in relation to Ergon Energy's capital expenditure requirements for large customer connections.

However, by their nature, these cost pass through provisions only allow Ergon Energy to apply to the QCA in limited circumstances to recover the costs of higher than expected capital expenditure requirements for large customer connections.

This Regulatory Proposal seeks to address these deficiencies of the current regulatory arrangements in the next regulatory control period.

7.3 ELECTRICITY DISTRIBUTION SERVICE DELIVERY (EDSD) REVIEW

In 2004, the Queensland Government established an Independent Panel to examine the operations of, and services provided by, Ergon Energy and ENERGEX.

The Panel issued its 'Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland' (the EDSD Review) to the Queensland Government in July 2004.

The Queensland Government accepted all of the EDSD Review's 44 recommendations and required Ergon Energy to address the recommendations that related to it.

As a consequence, Ergon Energy prepared a plan entitled 'The powerful new deal for regional Queensland customers – Ergon Energy's response to the Independent Review Panel Report: Electricity Distribution and Service Delivery for the 21st Century – August 2004'. This Plan was endorsed by the Queensland Government as an appropriate response to the EDSD Review's recommendations.

The QCA had regard for the EDSD Review when making its April 2005 Final Determination for the regulation of Ergon Energy's revenues for the current regulatory control period. The Final Determination includes a discussion about the EDSD Review necessitating Ergon Energy (and ENERGEX) to submit revised capital and operating forecasts to the QCA in order to address the EDSD Review's recommendations. The QCA engaged consultants to verify the reasonableness of the forecasts, and its Final Determination states that it is satisfied that they have been subjected to "vigorous review". Additional capital and operating expenditure was subsequently incorporated into the calculation of Ergon Energy's AARRs.

Chapter 11 of the Rules includes two transitional provisions that relate to the EDSD Review. Both clauses refer to Ergon Energy (and ENERGEX) having continuing obligations as a result of the EDSD Review:

- Clause 11.16.4 provides that "For the purposes of clause 6.5.8(c) the AER must also have regard to the continuing obligations on ENERGEX and Ergon Energy throughout the regulatory control period to implement the recommendations from the EDSD Review adopted by the Queensland Government"; and
- Clause 11.16.5 provides that "In formulating a service target performance incentive scheme... the AER... must also... take into account continuing obligations on ENERGEX and Ergon Energy throughout the regulatory control period to implement the recommendations from the EDSD Review adopted by the Queensland Government".

It is clear from both clauses of the Rules that the Queensland Government adopted the recommendations from the EDSD Review and that there is an on-going requirement that Ergon Energy (and ENERGEX) will continue to implement the actions arising from the Review in the next regulatory control period.

This Regulatory Proposal seeks to ensure that both Ergon Energy and the AER have due regard in the next regulatory control period for Ergon Energy's on going obligations arising from the EDSD Review.

7.4 FULL RETAIL COMPETITION

The Queensland Government introduced Full Retail Competition (FRC) in Queensland on 1 July 2007. Ergon Energy needed to acquire the following core capabilities in order to operate, and to discharge its new regulatory obligations, in an FRC environment:

- National Metering Identifier (NMI) standing data – Ergon Energy needs to be able to populate and maintain NMI and associated standing data in its own systems and in Market Settlement and Transfer Solution (MSATS);
- Customer transfers – Ergon Energy needs to be able to facilitate the transfer of customers between retailers;
- Service order management – Ergon Energy needs to be able to receive and process requests for defined Business to Business (B2B) services within prescribed timeframes and communicate the completion of these services to the requester;
- Energy data management – Ergon Energy needs to be able to fulfil its roles for the collection and processing of energy data;
- Network billing – Ergon Energy needs to be able to issue bills to multiple retailers and provide such information to retailers as may be required to substantiate and reconcile the charges billed; and

- Consumer protection – Ergon Energy needs to be able to fulfil its regulatory consumer protection obligations, including in relation to information and service provision.

As a result, Ergon Energy acquired some new, and modified some existing, systems and processes, and recruited and re-trained personnel, to meet its new regulatory obligations. Ergon Energy incurred costs of approximately $21 million ($18.5 million in operating expenditure, and $2.5 million in capital expenditure) during 2005-06 and 2006-07.

Prior to the introduction of FRC it was expected that the volume of retail customer transfers away from Ergon Energy Queensland would be low due to the effect of the safety-net Notified Prices being lower than what retailers were likely to offer on 'market' contracts. The Queensland Government therefore decided that Ergon Energy should operate on a 'Minimalist Transitioning Approach' (MTA) by establishing semi-manual systems (rather than fully automated systems) to respond to certain NMI discovery and creation requests. The MTA means Ergon Energy will only make investments in automated systems if and when the volume of customer transfers necessitates it. This is why Ergon Energy's capital expenditure to implement FRC was relatively low. The MTA is authorised by the Queensland Electricity Industry Code clause 6.8 and is supported by transitional arrangements in the Rules. The QCA is required to review the MTA annually to confirm whether it is appropriate for Ergon Energy to continue to operate under it. The QCA wrote to Ergon Energy in June 2008 advising that the arrangement should continue, and the 2009 review is nearing completion.

This Regulatory Proposal seeks to ensure that both Ergon Energy, and the AER, have due regard for Ergon Energy's on going obligations in the next regulatory control period arising from the introduction of FRC. In the event that the MTA is withdrawn, then Ergon Energy would be exposed to significant unplanned costs that have not been included in the forecasts in this Regulatory Proposal. Ergon Energy considers that this would be a regulatory change event as discussed in section 46.4.1 of this Regulatory Proposal.

7.5 ROLLOUT OF SMART METERS

In April 2007, the Council of Australian Governments (COAG) committed to a national mandated roll out of smart meters to areas where the benefits outweigh the costs.

In December 2007, the Ministerial Council on Energy (MCE) agreed that a consistent national minimum functionality for smart meters is necessary under any rollout plan in order to maximise the benefits.

The Ministerial Council on Energy (MCE) undertook a cost benefit analysis of smart meter functionality and costs and benefits of deployment.

On 13 June 2008, the MCE issued a 'Smart Meter Decision Paper' and a 'Statement of Policy Principles' in relation to smart meters.

The 'Smart Meter Decision Paper':

- Supported an accelerated smart meter rollout led by Distribution Network Service Providers (DNSP) based on a National Minimum Functionality that includes an interface to a Home Area Network;
- Noted that there were net benefits of a national rollout of smart meters but that:
  - → The net benefits varied between jurisdictions such that some jurisdictions have a risk of a negative net outcome; and
  - → "There remains some uncertainty around the level of costs, particularly business-specific costs which vary between individual businesses".
- Noted that "Queensland recognises potential benefits and possibility of a rollout. However Queensland has some jurisdiction-specific cost concerns and will consider rollout scope and timeline after further investigation via the pilots and further cost modelling. Queensland will also continue investigations into the benefits of direct load control";
- Supported a nationally consistent regulatory framework across the NEM in relation to any smart meter rollout;
- Noted that the "MCE agrees that in complying with any jurisdictional obligation to roll out smart meters distributors should receive regulatory cost recovery for direct costs consistent with the revenue and pricing principles in the NEL";
- Stated that the "MCE also notes that, consistent with the existing National Electricity Rules, distributors should not be penalised for stranding of related existing assets. The estimation of cost and benefits is consistent with this, having assumed no benefits of a reduced asset base"; and
- Supported the development of a consistent national legislative framework, including creating an obligation in the NEL for DNSPs to roll out smart meters where a jurisdictional implementation date has been set. The Paper states that "This will include any legislative support necessary to ensure appropriate cost recovery, as well as proposed supporting Rules as necessary".

The MCE's Statement of Policy Principles was issued in accordance with clause 4.4(a) of the Australian Energy Market Agreement (AEMA) and section 8 of the NEL. The Statement was intended to clarify the MCE's policy position, and to allow the Australian Energy Market Commission (AEMC) to consider any related Rule changes efficiently. It provided that:

- "There should be a national minimum functionality supported by a national regulatory framework for smart meters";

- "Distribution network service providers will be legislatively obliged to roll out smart meters to some or all residential and other small customers in those jurisdictions where a mandated roll out will take place";
- "A distribution network service provider who is obliged to roll out smart meters should have exclusivity over meter provision and responsibility for related metering data provision in respect of the customers covered by the mandate during the period in which the distribution network service provider must complete that mandate"; and
- "The regulatory framework for distribution network tariffs, consistent with the revenue and pricing principles, should ensure that distribution network service providers:
    a. are able to recover in a transparent manner the costs directly resulting from meeting the mandated service standards for smart meters and the costs of their existing investment which has been stranded by any mandatory roll out; and
    b. promptly pass on cost efficiencies resulting from the installation of smart meters to tariff classes affected by the costs of a smart meter rollout".

This Regulatory Proposal does not include any provision for capital or operating expenditure in relation to any smart meter rollout that Ergon Energy may be required to undertake. Rather, it proposes that, if Ergon Energy is required to rollout smart meters, then this should be the subject of a cost pass through application. This is dealt with in Chapter 46 of this Regulatory Proposal. This Regulatory Proposal does include an amount for the next regulatory control period's costs of a single smart meter trial that will commence in the current regulatory control period.

7.6 INCREASED CUSTOMER NUMBERS

Growth in new customer connections has been significantly higher than forecast for this period. Customer numbers were expected to grow at an average of 1.88 per cent from 2005 to 2010. Actual growth for the first three years of the current regulatory control period has been 2.31 per cent and is forecast to slow significantly to 1.57 per cent for the remaining two years. Table 21 compares the QCA's forecast of customer numbers with the actuals that Ergon Energy has experienced.

Table 21: *Growth in Customer Numbers*

	2004-05	2005-06	2006-07	2007-08	2008-09 (Estimate)	2009-10 (Estimate)
1. QCA Cust No. Forecast	609,777 [1]	620,753	633,168	644,565	656,812	669,291
2. QCA Forecast of New Customers		10,976	12,415	11,397	12,247	12,479
3. Percentage of New Customers against Existing Customers (QCA) [2]		1.80%	2.00%	1.80%	1.90%	1.90%
4. Ergon Energy Cust. No. Actual [1]	609,777	625,711	637,897	652,935	663,164	673,571
5. Ergon Energy Forecast of New Customers		15,934	12,186	15,038	10,229	10,407
6. Percentage of New Customers against Existing Customers (EE)		2.61%	1.95%	2.36%	1.57%	1.57%
% increase in new customers (i.e. increase of No 6 over No 3)		**45.17%**	**-1.85%**	**31.95%**	**-16.48%**	**-16.61%**

Source:

[1] Ergon Energy RIN 2.3.8 Table 1

[2] QCA Final Determination, April 2005, page 34

This translates to the five year average customer number increase above the 2004-05 forecast being 7 per cent. However, because the average customer number increases in the first three years of the current regulatory control period was 25 per cent, this has significantly impacted on Ergon Energy's need to invest capital expenditure in the categories of CICW and CIA.

The increased customer connections and requirements for shared network have occurred in the categories of:

- Strong growth in domestic and rural connections;
- Increased subdivision work; and
- Larger commercial and industrial connections linked to the resources boom.

7.7 COST ESCALATIONS

7.7.1 Contractor Prices

Ergon Energy's February 2005 submission[20] to the QCA (in response to the QCA's Draft Determination) included an additional $49 million in capital expenditure to accommodate the expected increase in contractor prices. The QCA's consultant, Burns and Roe Worley (BRW), and consequently the QCA, rejected this submission. Ergon Energy's actual capital expenditure in the current regulatory control period has borne out that contractor prices did indeed increase significantly. This is discussed in section 23.12 in this Regulatory Proposal.

In addition, the QCA adopted the same percentage for contactor price increases over two time periods:

- 2005-06 to 2007-08 – the known Union Collective Agreement rate of 4.0 per cent; and then
- 2008-09 to 2009-10 – continuation of 4.0 per cent.

However the Ergon Energy Union Collective Agreement 2008, which covers the period 2008-09 to 2010-11 has fixed wage increases (with contractor rates being tied to wages) at 4.5 per cent. This is discussed in section 26.8.2 of this Regulatory Proposal.

This means that Ergon Energy has been exposed to contractor prices that are higher than those the QCA made allowances for due to:

- Contractor prices increasing due to market forces; and
- Contractor prices that are tied to the Ergon Energy Union Collective Agreement 2008 wages increases being higher than the previous Union Collective Agreement increases.

7.7.2 Materials Prices

Ergon Energy's costs to purchase materials have increased significantly during the current regulatory control period, particularly for high volume essential items for electricity distribution.

Table 22 shows examples of materials cost percentage increases per annum which are based on the four year (2004-08) average prices that Ergon Energy has paid through its procurement contracts.

Table 22: *Increases in Materials Prices*

Items	Procurement Contracts Average per annum increases over four years 2004-08
Padmount Transformers	9.7%
Pole Mount Transformers	11.6%
Aluminium Underground Cables	5.6%
Copper Underground Cable	9.4%
Aluminium Conductor Steel Reinforced (ACSR) Aerial Cables	2.0%
Copper Aerial Cables	11.3%
Steel Cables	26.0%
Poles	5.4%

Source: Ergon Energy Procurement and Logistics (emails 5, 6, 7 May 2009)

[20] Pages 83, 84 and 85.

7.7.3 Escalation Indices

Ergon Energy has experienced significant capital expenditure input cost increases in the current regulatory control period. Ergon Energy engaged Sinclair Knight Mertz (SKM) to provide a report of cost indices for Ergon Energy's forecasts for the next regulatory control period by asset class. This report, 'Electricity Industry Labour, Commodity & Asset Price Cost Indices, St 2 (January 2009 Update of Escalators), 14 January 2009' is based on commodity price movements from 2005-06 through to 2014-15. The analysis of the 2005-10 period shows that the input costs have increased at a higher rate than QCA forecast when making its 2005 Determination.

Table 23 shows the average per annum increase for each of the five years 2005-06 to 2009-10.

Table 23: *Increases in Asset Prices*

Asset Class	Average p.a. increase based on five years 2005-2010
Overhead Sub-transmission Lines	8%
Underground Sub-transmission Cables	11%
Overhead Distribution Lines	9%
Underground Distribution Cables	11%
Distribution Equipment	7%
Substation Bays	8%
Substation Establishment	13%
Distribution Substation Switchgear	5%
Zone Transformers	5%
Distribution Transformers	8%
Low Voltage Services	6%
Metering	9%
Communications - Pilot Wires	10%
Generation Assets	6%
Street Lighting	10%
Other Equipment	10%
Control Centre - SCADA	10%

Source: Ergon Energy Procurement and Logistics (emails 5,6,7 May 2009)

7. SIGNIFICANT ISSUES FROM PREVIOUS PERIODS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR369	National Electricity Law, section 8
AR371	Electricity Act 1994 (Qld)
AR387	Electricity National Scheme (Qld) Act 1997

AER Documents

Nil

QCA Documents

AR386	QCA, Final Determination Regulation of Electricity Distribution, April 2005
AR415	QCA, Draft Determination, 23 December 2004

Codes and Rules

AR158	"Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland" (EDSD Review), July 2004
AR364	National Electricity Rules, chapter 11
AR388	MCE "Smart Meter Decision Paper", 13 June 2008
AR389	MCE "Statement of Policy Principles", June 2008
AR390	Australian Energy Market Agreement (AEMA), clause 4.4(a)

Ergon Energy Documents

AR160	EE "The powerful new deal for regional Queensland customers – Ergon Energy's response to the Independent Review Panel Report Electricity Distribution and Service Delivery for the 21st Century – August 2004"
AR416	EE Ergon Energy Response to QCA Draft Determination, 25 February 2005
AR461	SKM Electricity Industry Labour, Commodity & Asset Price Cost Indices, St 2 (Jan09 Update of Escalators), 14 January 2009

8. REVIEW OF 2001-10 EXPENDITURE

RIN – Section 2.4.4

This section provides information to address the requirements of the Australian Energy Regulatory's (AER) Regulatory Information Notice (RIN) in relation to the previous regulatory control period (2001-02 to 2004-05) and the current regulatory control period (2005-06 to 2009-10).

8.1 HISTORIC EXPENDITURE INFORMATION

Section 2.4.4(a) of the RIN identifies the need for Ergon Energy to provide historic expenditure information in relation to the period 2001-02 to 2007-08. This information is detailed in Chapters 22 and 25 of this Regulatory Proposal.

8.2 RELATIONSHIP TO AUDITED REGULATORY REPORTING INFORMATION

Section 2.4.4(b) of the RIN requires Ergon Energy to demonstrate the relationship between the expenditure information for the period 2001-02 to 2009-10 provided in Chapters 22 and 25 of this Regulatory Proposal and the audited regulatory reporting statements submitted to the Queensland Competition Authority (QCA).

The historical actual operating and capital expenditure values for 2001-02 to 2007-08 presented in Chapters 22 and 25 of this Regulatory Proposal are based on Ergon Energy's audited regulatory accounts as submitted to the QCA. These values:

- Are based on the same asset categories as are used in the regulatory accounts for capital expenditure;
- For operating expenditure have been backcast from the 2005-06 to 2007-08 regulatory accounts into the expenditure categories being used in this Regulatory Proposal. However, Ergon Energy has not been able to perform this backcasting for 2001-02 to 2004-05. Instead, it has only presented total operating expenditure values in Chapter 22, although a detailed breakdown of other expenditure categories that were used at the time is available to the AER in Ergon Energy's regulatory accounts;
- Exclude street lighting expenditure but include other expenditure relating to Excluded Distribution Services, which from 1 July 2010 will be classified as Alternative Control Services. It is not possible to remove other actual expenditure for services that are in the future to be classified as Alterative Control Services;
- Are in nominal dollars for each year in the previous and current regulatory control periods;
- Include Shared Costs (Overheads) for 2005-06 to 2007-08 that have been backcast using the AER's approved Cost Allocation Method, rather than the QCA's approved Cost Allocation Methods and Procedures; and
- Include shared costs as reported to the QCA in Ergon Energy's Annual Regulatory Accounts for 2001-02 to 2004-05 using the QCA approved Cost Allocation Methods and Procedures.

The forecast operating and capital expenditure values for 2008-09 and 2009-10 presented in this chapter are not based on audited regulatory accounts as they have not been prepared for these years. These values:

- Only relate to Standard Control Services;
- Are in nominal dollars for 2008-09 and 2009-10 and in real $2009-10 dollars for the period 2010-11 to 2014-15; and
- Include Shared Costs (Overheads) that have been allocated using the AER's approved Cost Allocation Method.

8.3 EXPLANATION OF DIFFERENCES WITH AUDITED REGULATORY REPORTING INFORMATION

Section 2.4.4(c) of the RIN requires Ergon Energy to explain any differences between the expenditure information for the period 2001-02 to 2009-10 provided in Chapters 22 and 25 of this Regulatory Proposal and the audited regulatory reporting information submitted to the QCA.

The only change between the expenditure information presented in Chapters 22 and 25 of this Regulatory Proposal and the audited regulatory accounts submitted to the QCA is that Shared Costs (Overheads) for 2005-06 to 2007-08 have been backcast using the AER's approved Cost Allocation Method, rather than the QCA-approved Cost Allocation Methods and Procedures. This has been done because the 2005-10 Cost Allocation Methods and Procedures allocates costs on a labour only basis, whereas in the future the AER's approved Cost Allocation Method provides for the allocation of costs on a total spend basis.

8. REVIEW OF 2001-10 EXPENDITURE – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

Nil

QCA Documents

Nil

Codes and Rules

Nil

Ergon Energy Documents

AR119c	EE Annual Regulatory Accounts for 2001-02
AR120c	EE Annual Regulatory Accounts for 2002-03
AR121c	EE Annual Regulatory Accounts for 2003-04
AR122c	EE Annual Regulatory Accounts for 2004-05
AR123c	EE Annual Regulatory Accounts for 2005-06
AR124c	EE Annual Regulatory Accounts for 2006-07
AR314	EE Cost Allocation Method, AER Approved
AR370c	EE Annual Regulatory Accounts for 2007-08
AR391	EE Cost Allocation Methods and Procedures approved by QCA, 2 May 2006

C CONFIDENTIAL INFORMATION

9. REQUEST TO INCLUDE MOUNT ISA-CLONCURRY NETWORK IN REGULATORY PROPOSAL

Rules – Clause 6.8.2(e)

The Australian Energy Regulator's (AER) F&A Stage 2 determined that its likely approach in its Distribution Determination for Ergon Energy for the next regulatory control period would be to assess whether to allow Ergon Energy to include the Mount Isa-Cloncurry network in its Regulatory Proposal based on the applicable law and rules as at the Regulatory Proposal due date (then 31 May 2009 but subsequently changed to 1 July 2009).

As discussed in section 7.1 of this Regulatory Proposal, the Queensland Government has amended the Electricity Act 1994 and the Electricity National Scheme (Qld) Act 1997 to confer the required powers on the AER to regulate the Mount Isa-Cloncurry network from 1 July 2010.

On this basis, Ergon Energy has included provision for the Mount Isa-Cloncurry network in this Regulatory Proposal.

Ergon Energy therefore requests that the AER assess this Regulatory Proposal on the basis that the AER will be responsible for the economic regulation of the Mount Isa-Cloncurry network from 1 July 2010. It is further requested that the AER have regard for clause 6.8.2(e) of the Rules and make a determination that Ergon Energy shall make one Regulatory Proposal that encompasses both the grid-connected network and the Mount Isa-Cloncurry network.

9. REQUEST TO INCLUDE MOUNT ISA-CLONCURRY NETWORK IN REGULATORY PROPOSAL – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR371	Electricity Act 1994 (Qld)
AR387	Electricity National Scheme (Qld) Act 1997

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)

QCA Documents

Nil

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

Nil

10. LEGISLATIVE AND REGULATORY OBLIGATIONS AND POLICY REQUIREMENTS

Rules – Clauses 6.3.1(c)(2) and 6.8.2(d)
RIN – Sections 2.3.4(a)-(c)
RIN Pro forma – 2.3.4
NEL – Section 2D

This chapter examines the key legislative and regulatory obligations, and the key Queensland Government policy requirements, that Ergon Energy must comply with in the current and next regulatory control periods.

Clauses 6.3.1(c)(2) and 6.8.2(d) of the Rules require Ergon Energy's Building Block Proposal and Regulatory Proposal to comply with the requirements of, and to contain or to be accompanied by the information required by, any relevant Regulatory Information Notice (RIN).

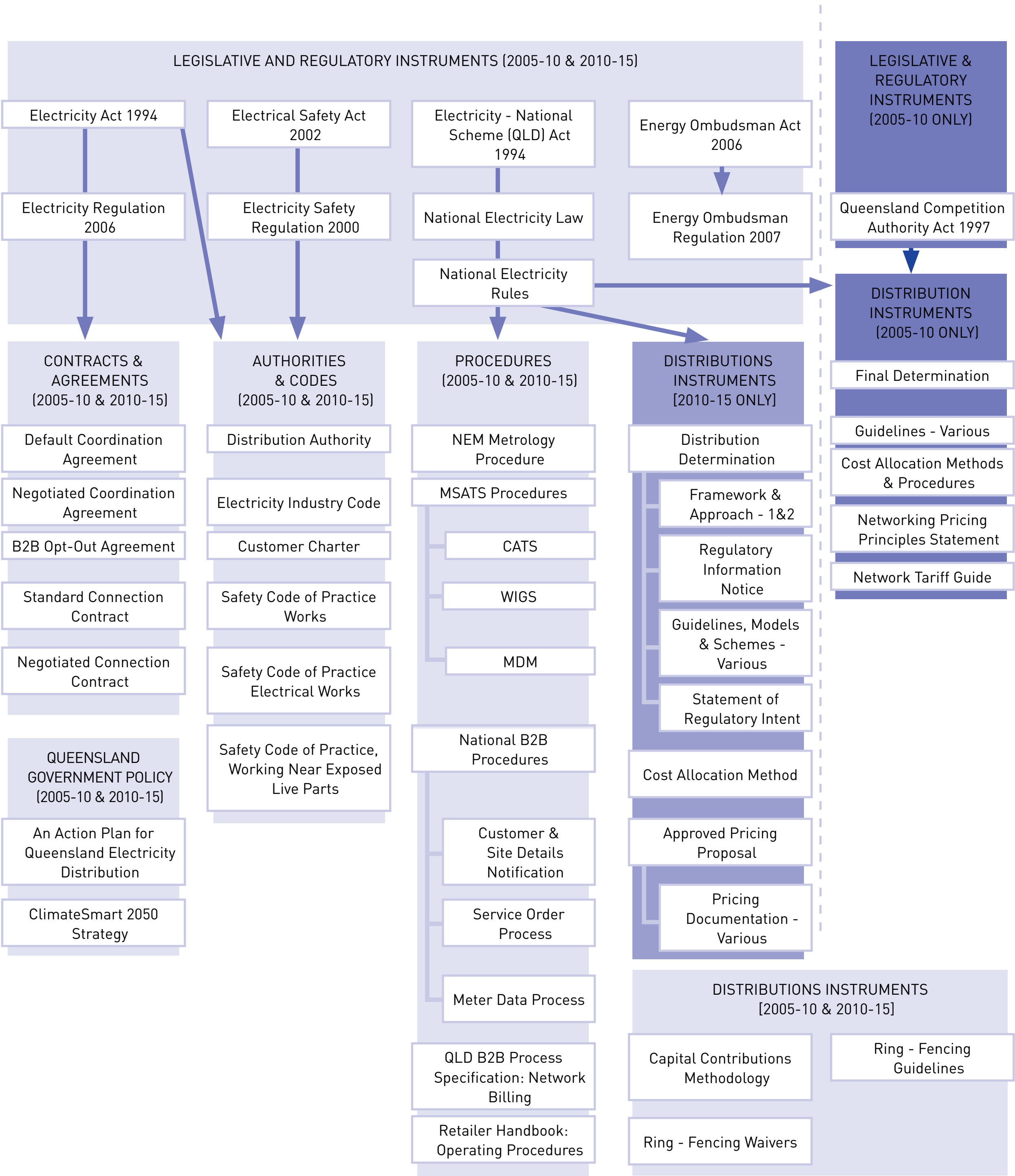
Sections 2.3.4(a) to (c) of the RIN require Ergon Energy to provide certain information about:

- Existing regulatory obligations or requirements relating to the provision of Direct Control Services that have a material impact on its expenditure forecasts; and
- Each new, anticipated or incremental regulatory obligation or requirement, or existing regulatory obligation or requirement that is expected to have a material impact on its expenditure forecasts.

The key industry specific legislative and regulatory instruments, and Queensland Government policies, that are relevant to Ergon Energy are represented in Figure 16:

- The light shaded instruments and policies apply in the current regulatory control period and will also apply in the next regulatory control period;
- The medium shaded instruments and policies apply in the next regulatory control period only; and
- The dark shaded instruments and policies will apply in the current regulatory control period only.

Figure 16: *Electricity Legislative and Regulatory Instruments*



10.1 2005-10 OBLIGATIONS AND REQUIREMENTS

Ergon Energy must comply with a variety of national and Queensland-specific legislative and regulatory instruments, and Queensland Government policies, in the current regulatory control period. The following is a summary of the key industry specific legislative and regulatory instruments. A table summarising key regulatory obligations and requirements under these instruments and other significant non-industry specific instruments is provided in the separate document entitled 'Legislative and Regulatory Obligations and Policy Requirements'.

Additional information explaining the compliance requirements, the enforcement authority/body, whether the obligations are reflected in the historical and current expenditures, together with anticipated and incremental regulatory obligations is provided in the RIN pro forma 2.3.4.

10.1.1 National Legislative and Regulatory Instruments

The key national legislative and regulatory instruments that apply to Ergon Energy in the current regulatory control period are as follows:

- Electricity – National Scheme (Qld) Act 1994 – this legislation provides that the National Electricity Law (NEL) and the National Electricity Rules (NER) apply as a law of Queensland. This Act incorporates the NEL as an attachment;
- NEL – This Law:
  - States a market objective to govern the National Electricity Market's (NEM's) development;
  - Establishes the governance arrangement for the NEM and Queensland's participation in the national market - including conferring policy oversight and review powers on the Ministerial Council on Energy (MCE), and functions and powers on the Australian Energy Market Commission (AEMC), the Australian Energy Regulator(AER) and Australian Energy Market Operator (AEMO);
  - Provides for the making of rules;
  - Confers powers and responsibilities with respect to the safety and security of the national system; and
  - Provides immunity for service providers in certain circumstances.
- National Electricity Rules – These Rules are made under the Law and set out the rights and obligations of participants in the NEM, National Electricity Market Management Company (NEMMCO) as market operator, and the market institutions. Of particular relevance to this Regulatory Proposal are:
  - Chapter 5, which deals with network connections;
  - Chapter 6, with the economic regulation of Distribution Services;
  - Chapter 7, which deals with metering; and
  - Chapter 11, which details transitional arrangements under Chapter 6.
- NEM Metrology Procedure – This document sets out Ergon Energy's obligations as a Responsible Person and Metering Provider in relation to the:
  - Provision, installation, routine testing and maintenance of metering installations. The Metrology Procedure also gives force to Queensland Government policy, which requires the installation of manually read interval meters (type 5) in new or replacement situations for all customers consuming below 100 MWh. The type 5 meter must be capable of being upgraded for use in a type 4 metering installation without the need to remove the meter [21]; and
  - Measurement of electrical energy and the provision of data to AEMO, so that it can convert consumption energy data into trading interval data to facilitate the efficient operation of the market.
- Market Settlement and Transfer Solution (MSATS) Procedures: Consumer Administration and Transfer Solution (CATS) Procedures Principles and Obligations – These procedures set out the principles governing consumer transfers, the registration of metering installations and the management of standing data in the NEM;
- MSATS Procedures: Wholesale, Interconnector, Generator and Sample NMI Procedure (WIGS) – These procedures set out the principles that govern consumer transfer, the registration of metering installation and management of standing data for National Metering Identifiers (NMIs) that are classified as wholesale, interconnector, generator or sample;
- MSATS Procedures: Meter Data Management Procedures (MDM) – These procedures define and document the management of metering data within MSATS;
- Business to Business (B2B) Procedures: Customer and Site Details Notification Process – These procedures define the business rules and transactions for regular updates of customer and premises between a retailer and a Distribution Network Service Provider (DNSP);
- B2B Procedures: Service Order Process – These procedures define the business rules and transactions for a retailer to request a DNSP to undertake a service order on behalf of the retailer or a customer and for the DNSP to provide advice regarding the outcome of the request; and

[21] NEM Metrology Procedure Part A, Schedule 3.

- B2B Procedures: Meter Data Process - These procedures define the business rules and transactions for MDPs to send data to retailers, DNSPs and other MDPs and for these parties to communicate about the data, for example by raising queries.

10.1.2 Queensland-Specific Legislative and Regulatory Instruments

The key Queensland legislative and regulatory instruments that apply to Ergon Energy in the current regulatory control period are as follows:

- Electricity Act 1994 and Electricity Regulation 2006 – these are the primary instruments governing Queensland's electricity supply industry. Amongst other things, they are the basis for establishing:
  - Ergon Energy's distribution authority;
  - Ergon Energy contractual relationships with retailers and customers;
  - Ergon Energy's rights and obligations for carrying out its operations; and
  - The industry regulatory framework, including giving regulators powers to make industry codes.
- Distribution Authority – the Regulator (the Department of Employment, Economic Development and Innovation - Mines and Energy) has issued Ergon Energy a distribution authority in accordance with the Electricity Act. It contains a broad range of obligations on Ergon Energy, including in relation to compliance with guaranteed service levels as notified from time to time;
- Electrical Safety Act 2002 and Electrical Safety Regulation 2000 - these instruments establish a safety framework by imposing obligations on persons who may affect the electrical safety of others. The Electrical Safety Act also supports Codes of Practice which provide practical advice regarding the discharge of obligations under the Act and Regulation.
- Energy Ombudsman Act 2006 and Energy Ombudsman Regulation 2007 – these instruments establish an independent dispute resolution mechanism for small customers who have a complaint about their energy supply;
- Default Coordination Agreement – this is a deemed agreement that applies between Ergon Energy and any retailer with whom it has a common customer. It is Annexure C of the Queensland Electricity Industry Code. The agreement defines the way in which the parties will discharge their respective obligations to customers and establishes common protocols for communicating customer information, in circumstances where a Negotiated Coordination Agreement has not been entered into;
- Negotiated Coordination Agreement – Ergon Energy can negotiate with any retailer with whom it has a common customer the terms and conditions under which the parties will discharge their respective obligations to customers and establish common protocols for communicating customer information. Any such agreement would replace the Default Coordination Agreement;
- B2B Opt-Out Agreement – this Agreement between Ergon Energy and EEQ allows the two businesses to communicate a B2B communication on a basis other than as set out in the B2B Procedures (as is permitted under clause 7.2A.4(k) of the Rules) and the Queensland B2B Process Specification: Network Billing (as is permitted under section 5.3(e) of the Electricity Industry Code);
- Standard Connection Contract – this is a deemed contract that details the rights and obligations of Ergon Energy and its customers regarding the provision of customer connection services, in circumstances where they have not entered into a Negotiated Connection Contract;
- Negotiated Connection Contract – this is a negotiated contract that details the rights and obligations of Ergon Energy and its customers regarding the provision of customer connection services. Any such agreement would replace the Standard Connection Contract;
- Electricity Industry Code – this Code has been made under the Electricity Act and contains a wide range of obligations that impact on Ergon Energy's operations, including establishing:
  - The need for Ergon Energy to prepare a Network Management Plan (NMP) and a Summer Preparedness Plan;
  - Minimum Service Standards (MSS) and Guaranteed Service Levels (GSL);
  - Reporting and monitoring arrangements;
  - Arrangements governing the provision of customer connection services, including under a Customer Charter and in accordance with a Standard Connection Contract;
  - Arrangements governing the provision of services between Ergon Energy and retailers, including under Standard Coordination Agreement;
  - Customer transfer and consent arrangements for the purposes of full retail competition; and
  - Various metering obligations.

The Electricity Industry Code currently provides for Ergon Energy to operate under the 'minimalist transitioning approach' [22] (MTA) until such time as the Queensland Competition Authority (QCA) issues a notice declaring it will no longer do so. The MTA details requirements in relation to NMI discovery and creation requests and the population of MSATS. Removal of the MTA would require Ergon Energy to make significant investments in systems and processes to enable

[22] Clause 6.8.

compliance with the Rules, the Electricity Industry Code and other NEMMCO requirements.

- Customer Charter – this Charter is required under the Electricity Industry Code and details customer's rights and obligations in relation to the provision of customer connection services by Ergon Energy;
- Queensland B2B Process Specification: Network Billing – this document describes the automation of the network billing process, its associated transactions and the associated business rules. It has been prepared in accordance with clause 5.3 of the Electricity Industry Code;
- Retailer Handbook: Operating Procedures – this document defines the standard protocols for communication and transactions between Ergon Energy and retailers operating within its distribution area, in order to facilitate the streamlined commencement and efficient ongoing operation of Full Retail Competition (FRC). In the Default Coordination Agreement, it is known as the 'Operational Procedures';
- Queensland Competition Authority Act 1997 – this gives the QCA powers and functions in relation to pricing practices for certain monopoly business activities, competitive neutrality and access to services. In addition to the powers and functions explicitly set out in the Act, it is noted that:
    - → Section 237 of the Electricity Regulation 1994 establishes the QCA as the Jurisdictional Regulator for Queensland, which makes it (amongst other things) responsible for regulating electricity Distribution Services under Chapter 6 of the Rules; and
    - → The Queensland Treasurer, as the relevant Minister under the Rules, appointed the QCA the Metrology Coordinator for Queensland as of 1 January 2003;
- Final Determination – this is the QCA's Final Determination issued in April 2005 for the regulation of revenues and prices from Distribution Services in the current regulatory control period;
- Guidelines – Various – there are various guidelines that the QCA has issued that apply to Ergon Energy in the current regulatory control period, including:
    - → Electricity Distribution Service Quality Guidelines – these Guidelines specify the information Ergon Energy is required to report to the QCA on a quarterly and annual basis;
    - → Guidelines for the Regulation of Excluded Distribution Services – these Guidelines detail how Ergon Energy's excluded Distribution Services are to be regulated under the Final Determination;
    - → Ring-Fencing Guidelines – these Guidelines detail Ergon Energy's ring-fencing obligations and related compliance reporting requirements; and
    - → Regulatory Reporting Guidelines – these Guidelines detail financial reporting requirements, including those related to cost allocation.
- Cost Allocation Methods and Procedures – this document is prepared by Ergon Energy in accordance with the Regulatory Reporting Guidelines to specify how it will allocate its shared costs;
- Network Pricing Principles Statement – this document is prepared by Ergon Energy in accordance with the QCA's Final Determination. It details the basis for developing network prices for all users of the Ergon Energy distribution network, including embedded generators, customers and retailers;
- Network Tariff Guide – this document is prepared by Ergon Energy to set out guidelines for network tariffs and rates for each network tariff code in order to give effect to the Network Pricing Principles Statement; and
- Capital Contributions Methodology – this document is prepared by Ergon Energy in accordance with its Network Pricing Principles Statement. It details the basis on which capital contributions will be determined and charged to customers.

10.1.3 Queensland Government Policy

The Queensland Government Policies that apply to Ergon Energy in the current regulatory control period are as follows:

- An Action Plan for Queensland Electricity Distribution – this document (arising from the EDSD Review discussed in Section 7.3 of this Regulatory Proposal) sets out the Queensland Government's high level requirements in relation to:
    - → 'Security of supply' standards;
    - → Customer communications; and
    - → Maintenance programs.
- A report on the Operational Review of Queensland Electricity Distributors (prepared by the Queensland Department of Mines and Energy) 23 June 2008 - this document is the report resulting from a direction by the Minister for Mines and Energy to the Department of Mines and Energy to establish a process to review the reliability and safety performance of the two distribution networks, and to determine whether there are unresolved systemic failures requiring further attention. Ergon Energy's response to this report and an accompanying action plan, which accompany this Regulatory Proposal, are effectively an obligation on Ergon Energy. Progress in line with the action plan is reported regularly.

- ClimateSmart 2050 Strategy – this is the Queensland Government's strategy containing initiatives to help meet the national emissions target agreed by the Council for the Australian Federation of a 60 per cent reduction by 2050 compared with 2000 levels which includes the Solar Bonus Scheme (feed-in tariff). The Queensland Government is currently reviewing, updating and consolidating its current ClimateSmart 2050: Queensland climate change strategy 2007.

10.2 2010-15 ANTICIPATED OR INCREMENTAL REGULATORY OBLIGATIONS

Section 2.3.4(b) of the RIN requires Ergon Energy to provide information about anticipated or incremental regulatory obligations that are expected to have a material impact on expenditures in the next regulatory control period. The section below describes the nature of these obligations in accordance with section 2.3.4(b)(1) of the RIN.

Additional information explaining the compliance requirements, the enforcement authority/body, the estimated cost of complying and the cost estimation methodology is provided in the RIN pro forma 2.3.4 to satisfy sections 2.3.4(b)(2)-(5) of the RIN.

10.2.1 National Legislative and Regulatory Instruments

All of the national legislative and regulatory instruments will continue to apply in the next regulatory control period, although various changes will have been made to each instrument between the two periods.

The most significant change for the purposes of this Regulatory Proposal will be that made as a result of introducing version 18 of Chapter 6, and the Queensland transitional arrangements in Chapter 11, of the Rules.

The application of Chapters 6 and 11 will result in Ergon Energy needing to comply with the following new national regulatory instruments in the next regulatory control period that do not apply in the current regulatory control period:

- Distribution Determination – the AER will issue a Distribution Determination for Ergon Energy in accordance with clause 6.2.4(a) of the Rules;
- Framework and Approach – the AER issued its Framework and Approach (F&A) for Ergon Energy in accordance with clause 6.8.1 of the Rules:
  - → The F&A Stage 1 was released on 28 August 2008 in relation to Ergon Energy's service classification and control mechanisms; and
  - → The F&A Stage 2 was released on 30 November 2008 in relation to the Service Target Performance Incentive Scheme (STPIS), Efficiency Benefit Sharing Scheme (EBSS), Demand Management Incentive Scheme (DMIS) and various other matters;
- Regulatory Information Notice – the AER issued a RIN for Ergon Energy on 22 April 2009 in accordance with section 28F(1)(a) of the NEL. Ergon Energy has addressed the requirements of this RIN in this Regulatory Proposal;
- Regulatory Information Order (RIO) – the AER is consulting on a draft RIO for all DNSPs, including Ergon Energy, in accordance with section 28F of the NEL. The RIO is intended to set out the manner and form in which Ergon Energy must annually submit to the AER information in relation to its direct control and negotiated Distribution Services;
- Guidelines – the AER has issued a guideline that applies to Ergon Energy in the next regulatory control period:
  - → Cost Allocation Guidelines – these guidelines outline the required content of Ergon Energy's cost allocation method and the basis on which the AER will assess that method for approval;
- Models – The AER has issued two models that Ergon Energy has used in submitting this Regulatory Proposal to the AER:
  - → Post Tax Revenue Model – the AER has issued a PTRM and an associated PTRM Handbook; and
  - → Roll Forward Model – the AER has issued a RFM and an associated RFM Handbook;
- Schemes – the AER has issued three schemes that Ergon Energy has addressed in submitting this Regulatory Proposal to the AER:
  - → STPIS;
  - → EBSS; and
  - → DMIS;
- Statement of Regulatory Intent – the AER has issued a Statement of Regulatory Intent in relation to the rate of return in accordance with clause 6.5.4 of the Rules; and
- Cost Allocation Method – the AER has approved the Cost Allocation Method that Ergon Energy submitted to it in accordance with the Cost Allocation Guidelines and clause 6.15 of the Rules. This document will be used by Ergon Energy for the purposes of attributing costs to, or allocating costs between, its Distribution Services, and other unregulated activities within the Ergon Energy Group.

10.2.2 Queensland-Specific Legislative and Regulatory Instruments

All of the Queensland-specific legislative and regulatory instruments detailed above in Section 10.1.2 will continue to apply to Ergon Energy in the next regulatory control period, on the same basis that they currently apply, except for:

- Queensland Competition Authority Act 1997 – this Act will continue to apply to Ergon Energy however, as the QCA will not be the Jurisdictional Regulator in Queensland under section 237 of the Electricity Regulation 1994, it will not be responsible for regulating electricity Distribution Services under Chapter 6 of the Rules. Ergon Energy understands that the QCA will continue to have certain responsibilities under the Queensland Electricity Industry Code and will be the Metrology Coordinator for Queensland;
- Final Determination – this document will cease to apply from 1 July 2010, although the transitional cost pass through provisions will apply under clause 11.16.9 of the Rules;
- Guidelines – Various – the Electricity Distribution Service Quality Guidelines and the Guidelines for the Regulation of Excluded Distribution Services will both cease to apply from 1 July 2010;
- Network Pricing Principles Statement – this document will cease to apply from 1 July 2010;
- Network Tariff Guide – this document will cease to apply from 1 July 2010.

There are three instruments in the current regulatory control period that will apply in the next regulatory control period, by virtue of transitional arrangements under Chapter 11 of the Rules:

- Capital Contributions Methodology - in accordance with clause 11.16.10(b) of the Rules, Ergon Energy has published on our website a Capital Contributions Methodology based upon its Network Pricing Principles Statement approved by the QCA. Ergon Energy proposes that this Policy apply in the next regulatory control period, unless it otherwise applies to the AER to amend it in accordance with clause 11.16.10(d) of the Rules;
- Ring-Fencing Guidelines – in accordance with clause 11.14.5(b)(3) of the Rules, the current Ring-fencing Guidelines will continue to apply to Ergon Energy until they are amended, revoked or replaced by guidelines made by the AER under clause 6.17 of the Rules; and
- Cost Allocation Guidelines – in accordance with clause 11.14.6 of the Rules, Ergon Energy is subject to the QCA's Guidelines (with respect to the current regulatory control period) and the AER's Guidelines (with respect to the next regulatory control period).

Minimalist Transitioning Approach (MTA)

As noted in sections 7.4 and 10.1.2, the Electricity Industry Code currently provides for Ergon Energy to operate under the MTA. Removal of the MTA during the 2010-15 regulatory control period would necessitate significant expenditure on systems and processes to ensure Ergon Energy is capable of complying with the Electricity Industry Code.

Demand Management Plan

In May 2009, the Queensland Government prepared an amendment to the Queensland Electricity Regulation 2006 to make it a condition of the Queensland distribution entities' Distribution Authorities that they must annually prepare a Demand Management Plan for approval by the regulator. The Demand Management Plan must include strategies, plans, cost estimates and performance targets for undertaking demand management initiatives. This new obligation will commence from 1 July 2009.

10.2.3 Queensland Government Policy

It is likely that the Queensland Government Policies detailed in Section 10.1.3 will change either in the current regulatory control period or in the next regulatory control period. Ergon Energy cannot anticipate the nature or timing of any such changes given that they would ultimately be a matter for the Queensland Government to decide. However, Ergon Energy notes that:

- Security of Supply - Ergon Energy is engaged in discussions with the Department of Employment, Economic Development and Innovation - Mines and Energy to revise the current security of supply standards; and
- Climate Smart 2050 Strategy – as noted in Section 10.1.3, the Queensland Government is currently reviewing, updating and consolidating its current 'ClimateSmart 2050: Queensland climate change strategy 2007'.

10. LEGISLATIVE AND REGULATORY OBLIGATIONS AND POLICY REQUIREMENTS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

Nil

QCA Documents

Nil

Codes and Rules

AR439	Qld Govt Report on the Operational Review of Queensland Electricity Distributors, 23 June 2008

Ergon Energy Documents

AR392	"Regulatory Proposal Chapter 10 Legislative and Regulatory Obligations and Policy Requirements"

11. TRANSITIONAL ISSUES

Rules – Clause 11.16
RIN – Section 2.4.1
RIN Pro forma – 2.4.1

Division 3 of Chapter 11 of the Rules details the transitional rules that apply to Ergon Energy for the first Distribution Determination to be made by the Australian Energy Regulator (AER) under Chapter 6 of the Rules.

Section 2.4.1(a) of the AER's Regulatory Information Notice (RIN) requires Ergon Energy to provide certain information on transitional issues, expressly identified in the Rules or otherwise, that it expects will have a material impact on, and should be considered by the AER in making its Distribution Determination.

This chapter provides information about material transitional rules, and how Ergon Energy believes they should be applied by the AER in making its Distribution Determination.

11.1 REGULATORY ASSET BASE

Clause 11.16.3 of the Rules provides that:

a. Ergon Energy can apply the same approach in the next regulatory control period to the treatment of services in the Regulatory Asset Base (RAB) as the Queensland Competition Authority (QCA) applied in its 2005 Final Determination for the current regulatory control period;
b. The AER must accept Ergon Energy's proposed approach if it is consistent with the approach the QCA applied for the current regulatory control period; and
c. The AER's Distribution Determination must prevent any cross-subsidisation between services arising from the treatment of the regulatory asset base.

Relevantly, Ergon Energy notes that the AER's Framework and Approach Stage 2 (F&A Stage 2) states that:

> *The NER do not permit the AER to undertake a prudency review of Ergon's capex for the current regulatory period. Ergon is permitted to roll forward the actual capex incurred by it consistent with the RFM as provided for in the NER.* [23]

11.1.1 Cause of Transitional Rule

In its 2005 Final Determination, the QCA distinguished between two types of services – regulated services and unregulated services. All of the regulated services were deemed to be prescribed distribution services. No excluded distribution services were identified in the 2005 Final Determination.

Prescribed distribution services were defined under the then National Electricity Code as Distribution Services provided by distribution network assets or associated connection assets. These are services that are determined by the jurisdictional regulator as those which should be subject to economic regulation (e.g. a revenue cap or price cap form of regulation). These services are effectively equivalent to Standard Control Services under the current services classification.

The QCA included all assets used in the provision of prescribed distribution services in Ergon Energy's RAB and made these prescribed distribution services subject to a fixed revenue cap form of regulation.

As part of its 2005 Final Determination, the QCA acknowledged that there would be some 'shared assets' that would be used by Ergon Energy for both prescribed distribution services and unregulated services. Accordingly, Ergon Energy identified the following 'shared asset' categories:

- Buildings;
- Motor vehicles;
- Computer software; and
- Office machines / furniture and equipment.

The QCA permitted Ergon Energy to include these shared assets in the regulated asset base but to then charge non-regulated parts of the Ergon Energy business the full costs of their use of those assets.

Specifically, the QCA required Ergon Energy to implement an internal service charge for the use of regulated assets by non-regulated services to ensure that the full cost of the asset used are borne by the beneficiary. This charge was required to reflect:

[23] AER, "Final framework and approach paper - Application of schemes - Energex and Ergon Energy 2010–15", page 54

- Direct and indirect costs of usage;
- Depreciation; and
- Return on assets.

The revenue associated with the use of these shared assets by unregulated businesses would then be deducted from Ergon Energy's annual regulated revenue.

In recognition of this treatment, the QCA made an ex-ante adjustment to Ergon Energy's annual regulated revenue in its 2005 Final Determination. This adjustment was based on forecasts of revenue Ergon Energy was expected to receive over the current regulatory control period from charging non-regulated parts of the business for the use of assets belonging to the regulated business.

The actual revenue received from the use of regulated assets by unregulated businesses is identified by Ergon Energy in its annual Regulatory Reporting Statements. Ergon Energy's annual regulated revenue is adjusted for the difference between the actual and forecast revenue as part of an annual unders and overs adjustment to the revenue cap. This adjustment is reflected in Ergon Energy's future Distribution Use of System (DUOS) tariffs.

In 2007, the QCA reclassified non-DUOS services, which until then had been treated as prescribed distribution services and regulated under a revenue cap as excluded distribution services. This resulted in the QCA reducing Ergon Energy's revenue cap for the remaining prescribed distribution services based on the QCA's cost allowance for non-DUOS services included in Ergon Energy's revenue cap at the time of the 2005 Final Determination. The allowance incorporated the operating costs as well as the return on assets and depreciation associated with the assets used in the provision of these services. As a result of the QCA's treatment, the assets associated with the provision of excluded Distribution Services have effectively been removed from Ergon Energy's RAB for the remainder of the current regulatory period.

11.1.2 How Transitional Rule Impacts on Distribution Network Service Provider (DNSP)

Ergon Energy's opening RAB as at the start of the current regulatory control period (i.e. 1 July 2005) is specified in clause S6.2.1(c)(1) of the Rules, and subsequently modified by correspondence between the QCA and the AER. This amount includes the value of 'shared assets' identified by the QCA in the 2005 Final Determination.

Ergon Energy's 1 July 2005 RAB will be rolled forward each year within the current regulatory control period for the purposes of determining the opening RAB at the start of the next regulated control period based on the actual capital expenditure and depreciation, plus other factors such as asset disposals as set out in clause S6.2 of the Rules.

Clause 11.16.3 of the Rules was necessary to clarify in the next regulatory control period the treatment of 'shared assets' that are used for providing Standard Control Services and other services or activities.

The clause makes it clear that Ergon Energy can choose to apply the same approach to the treatment of these assets as the QCA applied in its 2005 Final Determination.

Ergon Energy therefore proposes that the same approach should be applied to the treatment of 'shared assets' that are to be used for providing Standard Control Services and other services or activities as was applied to the treatment of regulated and unregulated services in the 2005 Final Determination.

11.1.3 How DNSP Considers Transitional Rule could be Addressed

Ergon Energy proposes to apply clause 11.16.3 of the Rules so that:

- Street lighting is removed from the RAB for Standard Control Services and included in a separate street lighting RAB;
- Contributed assets for large customer connection assets will be treated as Alternative Control Services in the next regulatory control period. They will not form part of the RAB for Standard Control Services;
- Any 'shared assets' that service other Alternative Control Services (i.e. not street lighting or new large customer connection assets), Standard Control Services and unregulated services will be included in the RAB for Standard Control Services;
- The other Alternative Control Services and unregulated services will be permitted to utilise shared regulatory assets in the RAB for Standard Control Services;
- Standard Control Services will apply an internal charge in relation to the other Alternative Control Services and unregulated services for the use of assets in the RAB, in the same manner as the QCA provided in its 2005 Final Determination for regulated and unregulated services. An estimate of the charge will be made in preparing the Regulatory Proposal and adjustments for the actual calculated charge will be made during the regulatory control period. The charge will incorporate:
  - → Direct and indirect costs of asset usage;
  - → Depreciation; and
  - → Return on assets.
- Standard Control Services will record the revenue received from the use of regulated assets by Alternative Control Services and unregulated services as an additional source of regulated revenue;
- The additional revenue would then be deducted from the Annual Revenue Requirement for Standard Control Services to determine the annual revenue caps; and

- Accordingly, Ergon Energy's Standard Control Services' tariffs would be reduced as part of the annual price setting process in order to avoid double recovery of costs associated with this asset usage.

11.1.4 Reference to Chapter of Regulatory Proposal

This transitional rule is applied in Chapter 40 of this Regulatory Proposal, which deals with the regulatory asset base.

11.2 EFFICIENCY BENEFIT SHARING SCHEME

Clause 11.16.4 of the Rules provides that:

a. The Efficiency Benefit Sharing Scheme (EBSS) to apply to Ergon Energy in the next regulatory control period must not apply to capital expenditure; and

b. In developing and implementing the EBSS to apply to Ergon Energy in the next regulatory control period the AER must have regard for the continuing obligations on Ergon Energy to implement the recommendations of the Electricity Distribution and Service Delivery Review (EDSD Review).

11.2.1 Cause of Transitional Rule

Clause 6.5.8(b) of the Rules provides that "An efficiency benefit sharing scheme may (but is not required to) be developed to cover efficiency gains and losses related to capital expenditure or distribution losses".

The transitional rule in clause 11.16.4 of the Rules was introduced following the 2004 EDSD Review's emphasis that the capital and operating expenditure 'building blocks' approved by the regulator should not constrain Ergon Energy's actual expenditure during a regulatory control period.

In initiating the transitional rule, the Queensland Government:

- Recognised that it would be inappropriate for over-spending on capital expenditure to be penalised above that involved in the actual expenditure amounts. Put differently, if Ergon Energy spends more than its forecast on capital expenditure, penalties over and above this amount would in fact further punish Ergon Energy for seeking to provide an improvement in service quality to customers; and
- Wanted to ensure that the AER had appropriate regard for the 2004 EDSD Review's views on over-spending an operating expenditure building block allowance in developing any EBSS.

11.2.2 How Transitional Rule Impacts on DNSP

The transitional rule in clause 11.16.4(a) of the Rules in relation to capital expenditure became redundant when the AER issued its EBSS Guideline. Section 3 of this Guideline states that "The EBSS does not apply to efficiency gains and efficiency losses that relate to capex or distribution losses". This means that the EBSS only applies to operating expenditure.

11.2.3 How DNSP Considers Transitional Rule could be Addressed

Ergon Energy generally accepts the AER's position on the application of an EBSS to the Queensland DNSPs, as detailed in the AER's EBSS Guideline and F&A Stage 2. These documents require Ergon Energy to propose in this Regulatory Proposal its:

- Capitalisation policy as at 1 July 2010;
- Growth adjustment method;
- Controllable cost categories; and
- Uncontrollable cost categories to be excluded from the EBSS, including cost pass throughs.

Ergon Energy believes that, in assessing its proposals in relation to these matters, the AER should have regard for the EDSD Review's intention that:

- Ergon Energy's actual expenditure during a regulatory control period should not be artificially constrained by the 'building blocks' approved by the regulator;
- Ergon Energy should be free to spend what is necessary to meet its service obligations to its customers; and
- Ergon Energy should not be unreasonably penalised for exceeding the 'building block' allowances.

11.2.4 Reference to Chapter of Regulatory Proposal

This transitional rule is applied in Chapter 43, which deals with the EBSS.

11.3 SERVICE TARGET PERFORMANCE INCENTIVE SCHEME (STPIS)

Clause 11.16.5 of the Rules provides that in formulating the Service Target Performance Incentive Scheme (STPIS) to apply to Ergon Energy in the next regulatory control period the AER must:

a. Take into account Ergon Energy's obligations to implement the recommendations of the EDSD Review;

b. Take into account the impact of severe weather events on service performance; and

c. Consider whether the scheme should be applied by way of a paper trail or whether a lower powered incentive is appropriate.

11.3.1 Cause of Transitional Rule

This transitional rule was introduced because:

- Ergon Energy has ongoing obligations to implement the recommendations of the 2004 EDSD Review. Many of these recommendations require Ergon Energy either to take specific action to improve the reliability of its distribution system or to comply with new regulatory obligations, in particular under the Queensland Electricity Industry Code, which came into effect on 1 January 2005. The transitional rule therefore sought to ensure that, in considering the future introduction of a STPIS, the AER would have regard for Ergon Energy's current obligations in relation to reliability improvement. These obligations exist despite Ergon Energy not having a STPIS in the current regulatory control period and will continue to apply even if a STPIS is introduced in the next regulatory control period;

- Ergon Energy's distribution system is regularly affected by severe weather events that adversely impact on its service performance. These events are beyond Ergon Energy's control. For this reason, in applying the minimum service standards under the Electricity Industry Code, the Queensland Government established an exclusions regime, whereby certain supply interruptions would not be taken into account in prescribed circumstances. The transitional rule therefore sought to ensure that the AER would incorporate similar exclusion provisions if a STPIS was introduced that included reliability based parameters; and
- Ergon Energy does not have a STPIS in the current regulatory control period. The transitional rule sought to ensure that the AER would have regard for this fact in developing any future STPIS. Importantly, Ergon Energy considers that its service standard reporting to the QCA in the current regulatory period could not be considered to have been a paper trial for any future STPIS. This is because there have not been any penalty and reward parameters set and tested and thus there has not been any 'practice run' of a scheme. As a result, Ergon Energy has not been able to learn what business modifications are necessary in order to operate effectively under a STPIS, as would otherwise be evident under a paper trial. The transitional rule sought to ensure that the AER would have regard for Ergon Energy's inexperience in operating under a STPIS and that, if the AER was to introduce a STPIS for Ergon Energy, it would consider applying a paper trial or having a relatively small amount of revenue at risk in the next regulatory control period.

11.3.2 How Transitional Rule Impacts on DNSP

In clause 2.5.4 of its F&A Stage 2, the AER had regard for the transitional requirement in clause 11.16.5 of the Rules and reached a preliminary position that Ergon Energy's maximum revenue at risk for the STPIS components in aggregate for each year of the next regulatory control period should be +/-2 per cent.

11.3.3 How DNSP Considers Transitional Rule could be Addressed

As discussed in Chapter 44 of this Regulatory Proposal, Ergon Energy agrees with the AER's preliminary position in its F&A Stage 2 and proposes that the maximum revenue at risk for the STPIS components in aggregate for each year of the next regulatory control period should be +/-2 per cent.

11.3.4 Reference to Chapter of Regulatory Proposal

This transitional rule is applied in Chapter 44 that deals with the STPIS.

11.4 FRAMEWORK AND APPROACH

Clause 11.16.6 of the Rules allowed Ergon Energy to submit a proposal to the AER by 31 March 2008 in relation to the classification of services and control mechanism to apply to the next regulatory control period. It also required the AER to publish its Framework and Approach Paper in relation to these matters within five months of receiving Ergon Energy's proposal.

11.4.1 Cause of Transitional Rule

This transitional rule was introduced in order to enable Ergon Energy to understand the AER's proposed approach to the classification of services, and the AER's definitive approach to control mechanisms, well before it submits its Regulatory Proposal.

11.4.2 How Transitional Rule Impacts on DNSP

Ergon Energy has accepted the classification of services, and has applied the control mechanisms, set out in the AER's F&A Stage 1.

11.4.3 How DNSP Considers Transitional Rule could be Addressed

This transitional rule has been fully addressed with the submission of Ergon Energy's proposal to the AER on 28 March 2008 and the AER's publication of its F&A Stage 1 on 28 August 2008.

11.4.4 Reference to Chapter of Regulatory Proposal

Ergon Energy has applied:

- The classification of services in the AER's F&A Stage 1 in Chapter 14 of this Regulatory Proposal; and
- The AER's control mechanisms in the AER's F&A Stage 1 in Chapters 51, 53, 54 and 55 of this Regulatory Proposal.

11.5 REGULATORY PROPOSAL (X FACTORS)

Clause 11.16.7 of the Rules deals with a situation where Ergon Energy needs to submit its Regulatory Proposal to the AER within two months of the AER completing its review of the rate of return and publishing its statement of regulatory intent.

The clause allows Ergon Energy to:

a. Treat a proposed statement of regulatory intent published under clause 6.16(b)(1) of the Rules as if it were the applicable statement of regulatory intent for the purposes of calculating its indicative prices under clause 6.8.2(c)(4) and proposed X factors under clause 6.5.9 of the Rules; and

b. Revise its calculation of indicative prices and proposed X factors in its Regulatory Proposal on or before 1 July 2009.

11.5.1 Cause of Transitional Rule

This transitional rule was introduced because, at the time of drafting the transitional rules, it was expected that the AER would not finalise its statement of regulatory intent until 31 March 2009. Given that Ergon Energy needs to submit its Regulatory Proposal to the AER by 31 May 2009, there was not considered to be sufficient time between the finalisation of the statement of regulatory intent and Ergon Energy's submission date for it to reflect the Weighted Average Cost of Capital (WACC) values into its Post Tax Revenue Model (PTRM) and pricing forecasts and to obtain internal approvals for its Regulatory Proposal.

Therefore, the transitional rule permits Ergon Energy to use the AER's proposed Statement of Regulatory Intent in its Regulatory Proposal and to allow an additional one month after the submission of the Regulatory Proposal to enable Ergon Energy to reflect the final statement of regulatory intent into its PTRM and pricing forecasts.

11.5.2 How Transitional Rule Impacts on DNSP

This transitional rule will not be applied because the AER applied to the Australian Energy Market Commission (AEMC) for a Rule change to extend the date for publication of its Statement of Regulatory Intent until 1 June 2009. The AEMC, in making this Rule change also extended the date for Ergon Energy to submit its Regulatory Proposal until 1 July 2009. The effect of these Rule changes is that the transitional rule has been made redundant.

11.5.3 How DNSP Considers Transitional Rule could be Addressed

The Rule changes described in section 11.5.2 makes the transitional rule redundant.

11.5.4 Reference to Chapter of Regulatory Proposal

The Rule changes described in section 11.5.2 makes the transitional rule redundant.

11.6 SIDE CONSTRAINTS

Clause 11.16.8 of the Rules provides that nothing in clause 6.18.6 of the Rules precludes Ergon Energy implementing any of the price paths approved by the QCA in the next regulatory control period, including any necessary adjustments to those price paths in light of the revenues expected for the first year of the next regulatory control period.

11.6.1 Cause of Transitional Rule

The QCA's Final Determination sets out the following requirements in relation to side constraints and related pricing for franchise (non-market) and contestable (market) customers:

- "The Authority has decided to remove all side constraints from prices for franchise customers (including potentially contestable customers who have not elected to enter the market) and requires the distributors to bring prices for these customers to a cost reflective basis immediately";
- "The Authority has applied side constraints of… CPI+5% to the annual movement in prices for Ergon's contestable customers"; and
- "There is a small group of contestable customers who currently continue to pay prices above or below the cost of providing their supply. For those paying above cost, the Authority requires that their prices be reduced in the next year. For those paying less than cost, the Authority has required that the distributors propose a price path that would move these customers to cost reflective pricing desirably by the end of this regulatory period".

Ergon Energy reflected these arrangements in its pricing principles statements, which have been approved by the QCA.

The continued application of these QCA-approved arrangements means a number of customers will continue to have annual price increases in the next regulatory control period that are outside those that would otherwise be permitted under clause 6.18.6 of the Rules.

11.6.2 Justification

This transitional rule is required in order to ensure a number of specified customers' prices are able to increase in a manner that moves them to a cost reflective price over time.

11.6.3 How Transitional Rule Impacts on DNSP

This transitional rule will enable Ergon Energy to increase a number of specified customers' prices in a manner that moves them to a cost reflective price over time.

11.6.4 How DNSP Considers Transitional Rule could be Addressed

This transitional rule will be applied in Ergon Energy's Pricing Proposal, which will be submitted to the AER in accordance with clause 6.18.2 of the Rules.

11.6.5 Reference to Chapter of Regulatory Proposal

This transitional rule has not been directly applied in this Regulatory Proposal but it will be applied in Ergon Energy's Pricing Proposal to the AER.

11.7 COST PASS THROUGHS APPLIED FOR IN NEXT REGULATORY CONTROL PERIOD

Clause 11.16.9 of the Rules provides that Ergon Energy may make a cost pass through application to the AER during the next regulatory control period within a year of an event or circumstance occurring during the current regulatory control period if Ergon Energy has not otherwise made an application in relation to that event or circumstance.

11.7.1 Cause of Transitional Rule

This transitional rule is necessary in order to manage the transition from the current regulatory control period to the next regulatory control period without prejudicing Ergon Energy's rights under the QCA's Final Determination and clause 6.6.1 of the Draft Rules.

11.7.2 How Transitional Rule Impacts on DNSP

This transitional rule will only apply if an event or circumstance arises during the current regulatory control period and Ergon Energy has not otherwise made an application in relation to that event or circumstance.

11.7.3 How DNSP Considers Transitional Rule could be Addressed

This transitional rule does not directly impact on Ergon Energy's Regulatory Proposal.

Ergon Energy will only make a cost pass through application during the next regulatory control period under this transitional rule within one year of a relevant event or circumstance arising during the current regulatory control period, as defined under the QCA's Final Determination.

11.7.4 Reference to Chapter of Regulatory Proposal

This transitional rule has not been applied in this Regulatory Proposal (because an event has not yet occurred which would be eligible for making application to the AER).

11.8 CAPITAL CONTRIBUTION METHODOLOGY

Clause 11.16.10 of the Rules:

- Requires Ergon Energy to publish on its website by 1 July 2009 a capital contribution policy based on the requirements relating to capital contribution in the Pricing Principles Statement approved by the QCA immediately prior to 1 July 2009; and
- Allows Ergon Energy to apply to the AER after 1 January 2010 to revise its published capital contribution policy.

11.8.1 Cause of Transitional Rule

This transitional rule was introduced because:

- Currently there is no national capital contribution guideline, and it was considered at the time of drafting the transitional rule that it would take considerable time to settle any such guideline due to the significant differences in the nature of the existing regimes across the National Electricity Market (NEM);
- Ergon Energy has well established mechanisms for capital contributions. The current policies were approved by the QCA in 2005 and have now been deployed; and
- There would be significant customer and implementation issues if a new (non-national) policy was to apply at the start of the next regulatory period and a further change was later required in order to implement national arrangements.

11.8.2 How Transitional Rule Impacts on DNSP

The transitional rule means that Ergon Energy's capital contribution policy will be based upon the requirements relating to capital contributions in the Pricing Principles Statement approved by the QCA immediately prior to 1 July 2009, unless it applies to the AER for an amendment and that amendment is approved.

11.8.3 How DNSP Considers Transitional Issue could be Addressed

Ergon Energy will publish on its website by 1 July 2009 a capital contribution policy based upon the requirements relating to capital contributions in the Pricing Principles Statement approved by the QCA immediately prior to 1 July 2009.

11.8.4 Reference to Chapter of Regulatory Proposal

Ergon Energy's capital contribution policy to apply in the next regulatory control period is discussed in Chapter 47 of this Regulatory Proposal.

11.9 ADJUSTMENT FOR QCA APPROVED COST PASS THROUGH AMOUNTS

There is currently no clause in the Rules that allows Ergon Energy to recover in the next regulatory control period cost pass through amounts that have been approved by the QCA in the current regulatory control period but not recovered through regulated revenue during the current regulatory control period by Ergon Energy.

11.9.1 Need for Transitional Provision

Due to the timeframe for the occurrence of a potential pass through event, the gathering of necessary supporting information, the submission of a cost pass through application by Ergon Energy and the assessment and approval by QCA, the earliest that any revenue approved for year t of the current regulatory control period can be incorporated in the Aggregate Annual Revenue Requirement (AARR) is in year *t+2*.

As such, it is possible that Ergon Energy may successfully apply to the QCA for the approval of a cost pass through event in 2008-09 or 2009-10 and not be able to recover the approved costs during the current regulatory control period.

Ergon Energy proposes that, in these circumstances, it should be able to recover its QCA-approved revenue in its Annual Revenue Requirements (ARRs) for the next regulatory control period.

11.9.2 How Transitional Provision Impacts on DNSP

It is proposed that the AER approve a transitional provision that will enable Ergon Energy to recover in the next regulatory control period cost pass through amounts that have been approved by the QCA in the current regulatory control period but not recovered by Ergon Energy through regulated revenue during the current regulatory control period.

11.9.3 How DNSP Considers Transitional Provision could Apply

The proposed transitional provision would only apply if the QCA approves a cost pass through amount in the current regulatory control period but, for timing reasons, Ergon Energy is not able to recover the amount through its regulated revenues during the current regulatory control period.

It is proposed that Ergon Energy would be able to increase its ARRs in the next regulatory control period to recover the shortfall of the QCA approved amounts.

11.9.4 Reference to Chapter of Regulatory Proposal

Ergon Energy's proposed revenue adjustments for the next regulatory control period are discussed in section 39.3 of this Regulatory Proposal.

11. TRANSITIONAL ISSUES – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Document

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR394 & 395	AER Final Decision EBSS, June 2008 & AER Appendix E EBSS, June 2008
AR 396 & 397	AER Final Decision STPIS, June 2008 & AER Appendix C STPIS, June 2008
AR399	AER Proposed Statement of Regulatory Intent, 11Dec08
AR520	AER Statement of Regulatory Intent

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005

Codes and Rules

AR364	National Electricity Rules
AR398	National Electricity Code, V9.4, April 2005

Ergon Energy Documents

Nil

12. SERVICE STANDARD OBLIGATIONS

Rules – Clauses 6.5.6(a)(3) and (4), 6.5.7(a)(3) and (4) and 6.6.2(b)(2)
RIN – Section 2.3.5
RIN Proforma - 2.3.5

Clauses 6.5.6(a)(3) and 6.5.7(a)(3) of the Rules require that Ergon Energy's operating and capital expenditure forecasts to "maintain the quality, reliability and security of supply of standard control services". Clauses 6.5.6(a)(4) and 6.5.7(a)(4) require Ergon Energy's operating and capital expenditure forecasts to "maintain the reliability, safety and security of the distribution system through the supply of standard control services".

Clause 6.6.2(b)(2) of the Rules require the service standards and service targets set under the Service Target Performance Incentive Scheme (STPIS) must not put at risk Ergon Energy's ability to comply with its service standards and service targets set under Queensland electricity legislation.

Section 2.3.5 of the Australian Energy Regulator's (AER's) Regulatory Information Notice (RIN) requires Ergon Energy to provide certain information in relation to internally and externally imposed service obligations.

The AER's F&A Stage 2 determined that its likely approach in its Distribution Determination for Ergon Energy for the next regulatory control period was that it will be guided by the Department of Employment, Economic Development and Innovation - Mines and Energy's position on the security of supply standards applicable to Ergon Energy for the next regulatory control period.

This chapter examines Ergon Energy's external and internal service standards.

12.1 EXTERNAL

Ergon Energy has externally imposed service standard obligations in relation to the following matters:

- Security of supply – this relates to how failures of components within the distribution system impact on the continuity of supply to customers – in particular, at what point would adverse events or failure of elements of the distribution system cause an outage. Typically, this is described in terms of supply scenarios 'N' and 'N-1' where an 'N' level of security could result in an outage following a single point of failure, whereas an 'N-1' level of security would require at least two elements to fail prior to an outage;
- Reliability of supply – this relates to the availability of the distribution system and the duration and frequency of outages that customers connected to the distribution system might expect to experience. Reliability is measured in terms of the duration and frequency of interruptions;
- Quality of supply – this relates to power quality of the distribution system. Power quality is described and measured in terms of frequency, voltage range, voltage fluctuation, voltage surges, voltage sags, harmonics and phase balance and how these relate to agreed standards for supply;
- Safety – this relates to the physical, mechanical and electrical safety of distribution system assets, such as whether poles are physically able to support wires or whether there is proper electrical earthing; and
- Customer service – this relates to the standards of service that individual customers are entitled to receive and the payments they may be entitled to receive from a Distribution Network Service Provider (DNSP) if the service they receive falls below these standards.

12.1.1 External obligations including performance measures and targets

12.1.1.1 Security of supply

The 2004 Electricity Distribution and Service Delivery Review (EDSD Review) included a recommendation that:

> *Ergon Energy be required (unless otherwise agreed with major customers) to maintain 'N-1' on all bulk supply sub stations and large zone supply substations (5MVA and above) and sub-transmission feeders. Critical high voltage feeders should also meet 'N-1' with the exception of those where Ergon Energy can provide satisfactory evidence that this does not put significant numbers of customers at risk. (Page 113)*

The Queensland Government issued 'An Action Plan for Queensland Electricity Distribution' that adopted the EDSD Review's recommendations and, amongst other things, required that:

> *More conservative planning criteria – ENERGEX and Ergon Energy will adopt more conservative planning assumptions, so that if assets fail across their systems they will have sufficient backup capacity to ensure customers don't lose supply. ENERGEX and Ergon Energy will aim to achieve best practice*

security of supply for their systems by 2009-10. (Section 3)

Following the EDSD Review and the release of the Queensland Government's Action Plan, the Review Panel's consultant, Evans and Peck, worked with Ergon Energy (and ENERGEX) to develop and agree on the appropriate security of supply standards that were necessary to give effect to the EDSD Report's recommendations. This resulted in the Ergon Energy document entitled 'Security Criteria NPD05' dated 12 April 2005.

These 'Security Criteria NPD05' have served as a cornerstone of Ergon Energy's subsequent network planning and are reflected into its annual Network Management Plans (NMP), which are annually submitted to the QCA. The NMPs therefore describe the way in which Ergon Energy is outworking the EDSD Report's security of supply standard recommendations.

Ergon Energy has used 'Security Criteria NPD05' as a basis for its capital and operating expenditure forecasts for the next regulatory control period.

12.1.1.2 Reliability of supply

Following the 2004 EDSD Review's recommendations, the Queensland Government introduced minimum reliability standards in the Queensland Electricity Industry Code. These standards came into effect on 1 January 2005.

The minimum service standards relate to the following measures:

- System Average Interruption Duration Index (SAIDI) – this is the total number of minutes, on average, that a customer is without electricity in a year and is calculated as the sum of the duration of each sustained customer interruption (measured in minutes), divided by the total number of customers for the year. A sustained customer interruption is one that lasts for at least one minute;
- System Average Interruption Frequency Index (SAIFI) – this is a measure of the average number of times a customer's supply is interrupted in a year and is calculated as the total number of sustained customer interruptions divided by the total number of customers for the year;
- Customer Average Interruption Duration Index (CAIDI) – this is a measure of the average duration of each sustained customer interruption and is calculated as the sum of the duration of each sustained customer interruption (in minutes) divided by the total number of sustained customer interruptions. It is therefore SAIDI divided by SAIFI.

The fourth edition of the Queensland Electricity Industry Code came into effect on 4 August 2008. It detailed the minimum service standards for 2005-06 to 2009-10 and indicative minimum service standards for 2010-11 to 2014-15. The indicative standards were not binding on Ergon Energy and were subject to change following future reviews of the minimum service standards.

In accordance with clause 2.4.4 of the Queensland Electricity Industry Code, the QCA began a review in 2008 of the minimum service standards for 2010-11 to 2014-15. In January 2009, the QCA issued its 'Draft Decision – Review of Electricity Distribution Network Minimum Service Standards and Guaranteed Service Levels to apply in Queensland from 1 July 2010'.

In April 2009, the QCA issued its 'Final Decision - Electricity Distribution Network Minimum Service Standards and Guaranteed Service Levels to apply in Queensland from 1 July 2010' in relation to the modified minimum service standards. The outcome of the Final Decision will be reflected into the fifth edition of the Queensland Electricity Industry Code.

Table 3 of pro forma 2.3.5 of the completed RIN details the network reliability performance parameters provided for in the amended Queensland Electricity Industry Code.

12.1.1.3 Quality of supply

Ergon Energy must comply with the requirements of:

- Sections 10 to 13 of the Electricity Regulation 2006 in relation to earthing, frequency and voltage; and
- Schedule 5 of the Rules in relation to the planning, design and operating criteria that must be applied to the distribution system.

Ergon Energy has prepared its capital and operating expenditure forecasts for the next regulatory control period to meet these regulatory requirements.

12.1.1.4 Safety

Ergon Energy must comply with the electrical safety matters set out in the Electricity Safety Act 2002 and the Electrical Safety Regulation 2002. This Act establishes the legislative framework for electricity safety regulation in Queensland and provides for a consultative framework for industry, works and the community.

Ergon Energy has prepared its capital and operating expenditure forecasts for the next regulatory control period to meet these legislative requirements.

12.1.1.5 Customer service

Following the 2004 EDSD Review's recommendations, the Queensland Government introduced a Guaranteed Service Level (GSL) scheme under the Queensland Electricity Industry Code.

The GSL Scheme came into effect on 1 January 2005 and made provision for Ergon Energy to make payments to customers when the level of service that they receive in relation to defined measures falls below specified levels. The GSL measures related to:

- Wrongful disconnections;
- Late connections;
- Late reconnections;
- Late attendance for hot water supply failure;

- Late attendance for appointment;
- Insufficient notice of planned interruption;
- Long interruption; or
- Frequent interruptions.

In accordance with clause 2.5.19 of the Queensland Electricity Industry Code, the QCA began a review in 2008 of the guaranteed service standards to apply for the next regulatory control period, commencing on 1 July 2010. In January 2009, the QCA issued its 'Draft Decision – Review of Electricity Distribution Network Minimum Service Standards and Guaranteed Service Levels to apply in Queensland from 1 July 2010'.

The QCA's Draft Decision proposed retaining the existing GSL measures and revising the value of GSL limits and payments.

In April 2009, the QCA issued its 'Final Decision - Electricity Distribution Network Minimum Service Standards and Guaranteed Service Levels to apply in Queensland from 1 July 2010' in relation to the modified minimum service standards. The outcome of the Final Decision will be reflected in the fifth edition of the Queensland Electricity Industry Code.

12.1.2 Programs, Projects or Initiatives for Maintaining or Improving Network Reliability and Customer Service Performance for 2010-15 to Satisfy External Obligation

Section 2.3.5(a)(2) of the RIN requires Ergon Energy to provide details of any internal programs, projects or initiatives aimed at maintaining or improving network reliability and customer service performance during the next regulatory control period, in order to satisfy the particular externally imposed obligation.

Ergon Energy has a variety of capital and operating expenditure programs that are designed to ensure that it achieves its externally imposed reliability and customer service performance obligations for the 2010-15 regulatory control period.

The Capital Expenditure – Reliability and Quality Improvements program relates to works that are directly targeted at addressing reliability or quality of supply issues across the distribution system. A key focus of this program will be to improve the performance of Ergon Energy's 50 worst performing feeders over the course of the next regulatory control period. The nature of this program is discussed in detail in section 23.5 of this Regulatory Proposal.

The Capital Expenditure – Asset Replacement program contains two parts, both of which will help Ergon Energy to meet externally and internally imposed service standards. As discussed in section 23.2 of this Regulatory Proposal:

- Defect-related capital expenditure concerns assets that have failed or are imminently about to fail. It therefore seeks to avoid Corrective and Forced Maintenance expenditure associated with assets in poor condition or beyond their economic or useful lives by providing for equipment to be replaced and refurbished in an orderly manner, based on Ergon Energy's Network Defect Classification Manual; and
- Condition based capital expenditure seeks to avoid the escalation of Corrective and Forced Maintenance expenditure by providing for equipment to be replaced and refurbished based on condition assessments.

Ergon Energy's Capital Expenditure – Corporation Initiated Augmentation (CIA) relates to capital expenditure that is needed to meet the augmentation requirements of Ergon Energy's sub-transmission and distribution networks. As discussed in section 23.3 of this Regulatory Proposal, Ergon Energy will invest in the capacity of its distribution system in order to meet its demand forecast and Network Planning Criteria NP02 and Security Criteria NPD05. This, in turn, will strongly contribute to Ergon Energy meeting its externally imposed service standard requirements.

Ergon Energy also has a Capital Expenditure – Other System forecast for the next regulatory control period, which relates to communications, protection, the Single Wire Earth Return (SWER) system, undergrounding and various other programs, including low voltage fuse retrofits, substation security, bunding and substation AC supplies. As discussed in section 23.6 of this Regulatory Proposal, these will also contribute to Ergon Energy meeting its reliability, quality of supply and other regulatory obligations.

Ergon Energy's operating and maintenance program will also play a significant role in contributing to it meeting its externally imposed reliability and customer service performance obligations for the 2010-15 regulatory control period. As discussed in detail in Chapter 26 of this Regulatory Proposal:

- Network operations expenditure relates to operating support services and some activity associated with the reconfiguration of the distribution network;
- Preventive Maintenance comprises scheduled inspection and maintenance activity. Work that is identified from this program can be undertaken as either asset renewal (defect manual) capital expenditure or Corrective Maintenance;

- Corrective Maintenance involves repair, replacement or restoration work that is carried out after the occurrence of an event or failure in order to eliminate the source of the failure or to reduce the frequency of its future occurrence; and
- Forced Maintenance involves unplanned repair, replacement or restoration work that is carried out as quickly as possible after the occurrence of an unexpected event or failure in order to bring the distribution network to at least its minimum acceptable and safe operating condition.

12.1.3 Impact of External Obligations on Capital Expenditure and Operating Expenditure Forecasts for 2010-15

Section 2.3.5(a)(3) of the RIN requires Ergon Energy to estimate the impact of satisfying its new, proposed or incremental externally imposed service standard obligations on its capital and operating expenditure forecasts for the next regulatory control period.

As discussed in section 12.1.2, Ergon Energy has a variety of capital and operating expenditure programs that are designed to ensure that it achieves its externally imposed service standards for the 2010-15 regulatory control period.

Ergon Energy has not been able to separate out from its expenditure forecasts the incremental costs of changes to its service standard obligations between the current and next regulatory control period. This is because:

- Each of the programs provides broader benefits to Ergon Energy than just service standard compliance. They also, for example, meet the dynamic needs of a continually growing customer base; and
- Ergon Energy has not prepared its expenditure forecasts for each of the programs on a baseline/ scope change basis.

However, Chapters 22, 23, 25 and 26 of this Regulatory Proposal provide a detailed breakdown of each of Ergon Energy's capital and operating expenditure programs, for the current and next regulatory control periods.

12.2 INTERNAL

12.2.1 Internal Obligations Including Performance Measures and Targets

In order to achieve its external performance targets, Ergon Energy sets internal targets, however these are only set to achieve the external obligations and are not used to prepare capital and operating expenditure forecasts.

12.2.2 Programs, Projects or Initiatives for Maintaining or Improving Network Reliability and Customer Service Performance for 2010-15 to Satisfy Internal Obligation

Ergon Energy does not have any specific programs, projects or initiatives for maintaining or improving network reliability and customer service performance that are specifically targeted to meet internal performance targets.

12.2.3 Impact of Internal Obligations on Capital Expenditure and Operating Expenditure Forecasts for 2010-15

There is no specific impact of internal obligations on Ergon Energy's capital and operating expenditure forecasts for the next regulatory control period because forecasts are set on the basis of meeting the external targets.

12.2.4 Explain How Internal Performance Standards Assist in Satisfying External Obligations

Ergon Energy has set internal performance standards to assist it in satisfying its external obligations. However Ergon Energy's capital and operating expenditure forecasts are based on satisfying the external obligations.

12. SERVICE STANDARD OBLIGATIONS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR042	Electricity Regulation 2006 (Qld)
AR371	Electricity Act 1994 (Qld)
AR405	Electrical Safety Act 2002 (Qld)
AR406	Electrical Safety Regulation 2002 (Qld)

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR367c & 368c	AER Regulatory Information Notice
AR396 & 397	AER Final Decision STPIS, June 2008 & AER Appendix C STPIS, June 2008

QCA Documents

AR400	QCA "Draft Decision – Review of Electricity Network Minimum Service Standards and Guaranteed Service Levels to apply in Queensland from 1 July 2010"
AR521	QCA "Final Decision – Electricity Distribution Network Minimum Service Standards and Guaranteed Service Levels to apply in Queensland from 1 July 2010"

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR158	"Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland" (EDSD Review), July 2004
AR364	National Electricity Rules
AR404	Qld Govt "An Action Plan for Queensland Electricity Distribution" (EDSD Action Plan), 23 August 2004

Ergon Energy Documents

AR078	EE Network Maintenance Defect Classification Manual
AR160	EE "The powerful new deal for regional Queensland customers – Ergon Energy's response to the Independent Review Panel Report Electricity Distribution and Service Delivery for the 21st Century – August 2004"
AR175	EE Security Criteria Network Planning - NPD05, 12 April 2005
AR401	EE Network Management Plan, Summary, 2008-13
AR402	EE Network Management Plan, Part A 2008-09 to 2012-13
AR445	EE Network Management Plan, Part B 2008-09 to 2012-13

13. OUTCOMES OF AER'S FRAMEWORK AND APPROACH

Rules – Clauses 6.8.1(b) and (c), 11.16.3, 11.16.4, 11.16.5, 11.16.6, 11.16.8, 11.16.9, and 11.16.10
RIN – Section 2.4.1

The Australian Energy Regulator (AER) issued its Framework and Approach (F&A) for Ergon Energy in accordance with clause 6.8.1 of the Rules, having regard for the requirements of clause 11.16 of the Rules, in two stages:

- The F&A Stage 1 that was released on 27 August 2008 dealt with service classification and control mechanisms; and
- The F&A Stage 2 that was released on 30 November 2008 dealt with the Service Target Performance Incentive Scheme (STPIS), Efficiency Benefit Sharing Scheme (EBSS), Demand Management Incentive Scheme (DMIS) and various other matters.

13.1 CLASSIFICATION OF SERVICES

The AER's F&A Stage 1 determined that its likely approach for the classification of Distribution Services in its Distribution Determination for Ergon Energy will be as detailed in Table 24.

Table 24: *AER's likely classification of Distribution Services*

Distribution Service Group	AER Service Classification
Network services	Standard Control Services
Connection services	
Metering services	
Street Lighting Services	Alternative Control Services
Quoted Services	
Fee Based Services	
Unregulated	Unclassified

Appendix B of the AER's F&A Stage 1 includes details of the services that fall within each group of services.

13.2 CONTROL MECHANISMS

The AER's F&A Stage 1 determined that its Distribution Determination for Ergon Energy will apply the control mechanisms detailed in Table 25.

Table 25: *Control Mechanisms to be applied to Distribution Services*

Distribution Service Group	AER Control Mechanism
Network services	Fixed revenue cap of the CPI – X form made in accordance with Part C of the Rules using a building block approach.
Connection services	
Metering services	
Street Lighting Services	Price cap, with a supporting price path, using a limited building block approach under which Ergon Energy: • Will not be required to provide a separate proposal on the weighted average cost of capital; • May propose reasonable simplifying assumptions in the building block proposal; and • May base its opening asset valuation for Street Lighting Services on the existing street lighting valuation, adjusted for capital expenditure and depreciation incurred in the current regulatory control period.
Quoted Services	Formula based price cap, with a supporting price path, that does not rely on a building block approach.
Fee Based Services	
Unregulated	No control mechanism.

In accordance with the requirements of clause 6.8.1(c) of the Rules, Ergon Energy has applied these control mechanisms in this Regulatory Proposal.

13.3 SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

The AER's F&A Stage 2 determined that its likely approach in its Distribution Determination for Ergon Energy for the next regulatory control period is to apply the national STPIS with +/- 2 per cent of revenue at risk. The national STPIS is detailed in the AER's guideline for the Scheme that was issued in June 2008.

The scheme will operate concurrently with the jurisdictional minimum service standards and guaranteed service levels that are contained in the Queensland Electricity Industry Code.

13.4 EFFICIENCY BENEFIT SHARING SCHEME

The AER's F&A Stage 2 determined that its likely approach in its Distribution Determination for Ergon Energy for the next regulatory control period is to apply the national EBSS. The national EBSS is detailed in the AER's guideline for the Scheme that was issued in June 2008.

13.5 DEMAND MANAGEMENT INCENTIVE SCHEME

The AER's F&A Stage 2 determined that its likely approach in its Distribution Determination for Ergon Energy for the next regulatory control period is to apply part A of the DMIS. The DMIS is detailed in the AER's guideline for the Scheme that was issued for Ergon Energy, ENERGEX and ETSA Utilities in June 2008.

Part A of the DMIS involves a Demand Management Incentive Allowance (DMIA) of a total of $5 million (Nominal), which has been allocated in five equal annual instalments of $1 million (Nominal).

13.6 OTHER MATTERS

The AER's F&A Stage 2 determined its likely approach in its Distribution Determination for Ergon Energy for the next regulatory control period in relation to a number of other matters. Specifically, the AER determined that:

- Ergon Energy is not required to include a negotiating framework in the absence of any service being proposed as a negotiated distribution service;

- It will assess whether to allow Ergon Energy to include the Mount Isa–Cloncurry network in its Regulatory Proposal based on the applicable law and rules as at 31 May 2009 (however consequent to the AER's F&A Stage 2 decision, the deadline in the Rules for Ergon Energy to lodge its Regulatory Proposal has been extended to 1 July 2009);
- It will liaise with Ergon Energy on establishing a methodology for changing asset categories and calculating remaining asset lives;
- It would not indicate its likely approach to a methodology for calculating the tax asset base and remaining tax lives in its framework and approach paper;
- It was unnecessary to indicate its likely approach on the treatment of street lighting assets in its framework and approach paper;
- It will adopt the 1 July 2005 opening regulatory asset base (RAB) value of $4,232.4 million (July 2005 dollars) nominated by the Queensland Competition Authority (QCA). The AER indicated that it will review and consult on Ergon Energy's proposal to reduce its opening RAB as at 1 July 2005 by $39 million (as a result of the removal of the inventory asset category) as part of its review of Ergon Energy's Regulatory Proposal;
- The Rules do not permit the AER to undertake a prudency review of Ergon Energy's capital expenditure for the current regulatory control period. Ergon Energy is permitted to roll forward the actual capital expenditure incurred by it consistent with the roll forward model as provided for in the Rules;
- It was inappropriate to indicate its likely approach in its framework and approach paper to the treatment of cost pass throughs for input cost increases;
- It was unnecessary to indicate its likely approach on a cost pass through materiality threshold in its framework and approach paper;
- The Rules permit nominated pass through events in relation to Alternative Control Services;
- It was unnecessary to indicate its likely approach to an eligible pass through amount, cost pass through information requirements and processes in its framework and approach paper; and
- It will be guided by the Department of Employment, Economic Development and Innovation - Mines and Energy's position on the security of supply standards applicable to Ergon Energy for the next regulatory control period.

13. OUTCOMES OF AER'S FRAMEWORK AND APPROACH – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR394 & 395	AER Final Decision EBSS, June 2008 & AER Appendix E EBSS, June 2008
AR 396 & 397	AER Final Decision STPIS, June 2008 & AER Appendix C STPIS, June 2008
AR407 & 408	AER Final Decision DMIS, October 2008 & AER DMIS (Scheme), October 2008

QCA Documents

Nil

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR364	National Electricity Rules

Ergon Energy Documents

Nil

14. CLASSIFICATION PROPOSAL

Rules – Clauses 6.2.1-6.2.3, 6.2.7, 6.7, 6.8.1(b)(1), 6.8.2(c)(1), 6.12.1(1), 6.12.3(b) and 11.16.6
RIN – Sections 2.2.5(a)(1), 2.4.6 and 2.4.7
RIN Pro forma – 2.2.5
F&A Stage 1 - Section 2.5

Ergon Energy proposed a classification of services to the Australian Energy Regulator (AER) on 31 March 2008 in accordance with clause 11.16.6 of the Rules. As discussed in Chapter 13 of this Regulatory Proposal, the AER issued its F&A Stage 1 on 27 August 2008. This included the AER's likely approach to the classification of Ergon Energy's services, as required by clause 6.8.2(c)(1) of the Rules.

Ergon Energy accepts the AER's likely classification of Ergon Energy's Distribution Services as detailed in the F&A Stage 1.

Section 2.2.5 of the AER's Regulatory Information Notice (RIN) requires Ergon Energy to provide certain information in relation to its Standard Control Services and Alternative Control Services. Sections 2.4.6 and 2.4.7 of the AER's RIN require Ergon Energy to provide certain other information in relation to Alternative Control Services only.

This chapter provides the name and description of each of Ergon Energy's Distribution Services and maps each service to the service listing at Appendix B of the AER's F&A Stage 1.

14.1 STANDARD CONTROL SERVICES

This Classification Proposal has three groups of Standard Control Services – Network Services, Connection Services and Metering Services. These are the same groups of services as the AER suggested in its F&A Stage 1.

Table 26 maps the list of Network Services that the AER included in Appendix B of its F&A Stage 1 to a list of services that Ergon Energy considers that it provides.

Table 26: *Ergon Energy's Network Services*

Service Listed in F&A Stage 1 Appendix B	Services that Ergon Energy Provides
Constructing the network	Distribution Network Service Provider (DNSP) funded construction of distribution network assets
Maintaining the network	Network maintenance
Operating the network for DNSP purposes	Network operations
Planning the network	Network planning (e.g. load on system, future requirements for system)
Designing the network	Design standards and designing the network
Emergency Response	Emergency services (e.g. reinstatement of network after natural disaster)
Administrative Support	Call centres
	Network claim processing
	Network billing
	Supply of electricity to a customer's electrical installation or premises
	Network switching and testing for DNSP purposes
	Populate and maintain National Metering Identifier (NMI) standing data in Market Settlement and Transfer Solution (MSATS)
	NMI discovery request
	Cold water reports
	Loss of supply (DNSP fault)
	Creation and allocation of NMI

Table 27 maps the list of Connection Services that the AER included in Appendix B of its F&A Stage 1 to a list of services that Ergon Energy considers that it provides.

Table 27: *Ergon Energy's Connection Services*

Service Listed in F&A Stage 1 Appendix B	Services that Ergon Energy Provides
Commissioning of connection assets	Provision of connection services (e.g. connection asset such as padmount transformer, service line for metered and unmetered connections)
Service connections for small customers	
Installation inspection	Inspection and testing of electrical work
Operating and maintaining connection assets	Operating and maintaining connection assets

Table 28 maps the list of Metering Services that the AER included in Appendix B of its F&A Stage 1 to a list of services that Ergon Energy considers that it provides.

Table 28: *Ergon Energy's Metering Services*

Service Listed in F&A Stage 1 Appendix B	Services that Ergon Energy Provides
Commissioning of metering and load control equipment	Provision and installation of hot water meter and load control equipment
Type 5–7 metering	Provision and installation of Type 5 to 7 meter
	Provision of minimum requirement of historical (2 years) Type 5 to 7 metering data
Scheduled meter reading	Scheduled meter read
Unscheduled meter reading — non-chargeable	Final Meter Read
Metering investigation	Meter tampering (where an onsite inspection is required to determine if equipment tampering has occurred)
	Meter inspection (where onsite inspection is required to determine if fault has occurred)

14.2 ALTERNATIVE CONTROL SERVICES

This Classification Proposal has three groups of Alternative Control Services – Street Lighting Services, Quoted Services and Fee Based Services. These are the same groups of services as the AER suggested in its F&A Stage 1.

Table 29 maps the Street Lighting Services that the AER included in Appendix B of its F&A Stage 1 to the services that Ergon Energy considers that it provides.

Table 29: *Ergon Energy's Street Lighting Services*

Service Listed in F&A Stage 1 Appendix B	Services that Ergon Energy Provides
Provision, construction and maintenance of street lighting	Street Lighting - Provision and Operating and Maintenance (O&M)

Table 30 maps the list of Quoted Services that the AER included in Appendix B of its F&A Stage 1 to a list of services that Ergon Energy considers that it provides.

Table 30: *Ergon Energy's Quoted Services*

Service Listed in F&A Stage 1 Appendix B	Services that Ergon Energy Provides
Rearrangement of network assets	Removal/relocation of Ergon Energy's assets at customer request
	Move point of attachment at customer request
Covering of low voltage mains	Tiger tails
Non standard data services (type 5–7 metering)	Metering Data Provider services
	Metering Data Provider services above minimum requirements (reading & data)
Ancillary metering services (type 5-7 metering)	Type 5 to 7 meter test
	Change tariff
	Change time switch
	Removal of meter Type 5 to 7
	Removal of load control device
	Special meter read (off-cycle meter read during business hours)
	Reprogram card meters
	Exchange meter
	Move meter
Supply enhancement	Provision of connection services above minimum requirements
	Overhead service upgrade
	Underground service upgrade
Metering enhancement	Provision, installation and maintenance of meters above minimum requirements
	Prepayment meters at customer request
Temporary disconnect/reconnect services	Temporary disconnection and reconnection (including de-energisations and re-energisations involving a line drop)
After hours services	De-energisation after hours
	Re-energisation after hours
	Attend loss of supply after hours
Emergency recoverable works	Emergency recoverable works
Large customer connections	Provision of connection services (e.g. connection asset such as padmount transformer, service line for metered and unmetered connections)
Auditing of design and construction	Subdivision fees
	Project fees
Miscellaneous	High load escorts - lifting of lines
	Rectification of illegal connections
	Conversion of aerial bundled cables
	Provision of service crew / additional crew

Table 31 maps the list of Fee Based Services that the AER included in Appendix B of its F&A Stage 1 to a list of services that Ergon Energy considers that it provides.

Table 31: *Ergon Energy's Fee Based Services*

Service Listed in F&A Stage 1 Appendix B	Services that Ergon Energy Provides
Specification and design enquiry fees	Subdivision Fees
	Project Fees
De-energisation and Re-energisation	De-energisation during business hours
	Re-energisation during business hours
Re-test	Re-Test Fee (e.g. if premises fails test the first time)
Supply Abolishment	Supply Abolishment
Temporary supply services	Metered Temporary Builders Supplies
Fault response—not DNSP fault	Attend loss of supply
Wasted attendance	Wasted truck visit

For completeness, Table 32 maps the list of Unregulated Services that the AER included in Appendix B of its F&A Stage 1 to a list of services that Ergon Energy considers that it provides. None of these services is regulated by the AER or covered by this Regulatory Proposal.

Table 32: *Ergon Energy's Unregulated Services*

Service Listed in F&A Stage 1 Appendix B	Services that Ergon Energy Provides
Non-Distribution Services	Non-Distribution Services at customers' request
	Ownership and operation of 33 Isolated Systems Generators;
	Ownership and operation of 34 Isolated Systems Networks;
	Ownership and operation of a network in the North West Minerals Province (near Mount Isa);
	An undersea cable;
	Works for Powerlink;
	Certain electrical assets within customers' electrical installations;
	Sale of Remote Area Power Stations and Solar PV Systems;
	Non-competing Retail entity selling to retail customers on Qld gazetted Notified Prices only;
	Wholesale fibre telecommunications services;
	IT Services to support Ergon Energy and ENERGEX's business operations.
Distribution Services provided in a competitive market: • High load escorts • Type 1-4 metering • Watchman lights	High load escorts – scoping and contractor approvals
	Watchman Lights - Provision and O&M
	MDA Types 1-4
	Erection of extra poles (on customer's installation)
	Location of underground cables
	Voltage & Load Check - Fault Found on Customer's Installation

Chapters 53, 54 and 55 of this Regulatory Proposal address the requirements of the RIN:

- Section 2.4.6(a)(1)(ii) to provide a demonstration of the application of the proposed control mechanism; and
- Section 2.4.6(a)(2)-(5) to provide expenditure information, asset value information, demand information and service level information for each category of Alternative Control Service.

14.3 NEGOTIATED DISTRIBUTION SERVICES

This Classification Proposal proposes that none of Ergon Energy's Distribution Services be classified as Negotiated Distribution Services. This is consistent with the AER's F&A Stage 1, in which it did not suggest that any of Ergon Energy's services be classified as Negotiated Distribution Services.

14. CLASSIFICATION PROPOSAL – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR367c & 368c	AER Regulatory Information Notice

QCA Documents

Nil

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

Nil

15. KEY ASSUMPTIONS

Rules – Clauses S6.1.1(4), S6.1.1(5), S6.1.2(5) and S6.1.2(6)
RIN - Section 2.3.3(a)
RIN Pro forma - 2.3.3

Clauses S6.1.1(4) and S6.1.2(5) of the Rules require this Regulatory Proposal to detail the key assumptions that underlie Ergon Energy's capital and operating expenditure forecasts.

Clauses S6.1.1(5) and S6.1.2(6) of the Rules require this Regulatory Proposal to include a certification by Ergon Energy's directors of the reasonableness of the key assumptions that underline the capital and operating expenditure forecasts. This certification, as described in Chapter 57 of this Regulatory Proposal in the form of Attachment 4 of the Regulatory Information Notice (RIN), is provided as a separate document lodged with this Regulatory Proposal.

Sub section 2.3.3(a) of the RIN requires Ergon Energy to provide the following information regarding the key assumptions that have been used to develop its capital and operating expenditure forecasts:

- A description of the assumption;
- What information the assumption has been used to forecast;
- The method used to develop the assumption; and
- How the assumption has been applied to develop the relevant expenditure forecast.

Table 33 provides this information, broken down by assumptions that apply to:

- Both capital and operating expenditure forecasts; and
- Capital expenditure forecasts only.

Ergon Energy interprets key assumptions to be substitutes for facts or inputs necessary to prepare forecasts, where those facts or inputs are not known with certainty or cannot reasonably be derived from other data. Ergon Energy has therefore developed a key assumption where it does not otherwise have an objectively verifiable factual basis on which to prepare its capital and operating expenditure forecasts.

Table 33: *Key Assumptions underlying Capital and Operating Expenditure Forecasts*

Description	Forecast information	Method	Application
Capital and Operating Expenditure Forecasts			
1. Ergon Energy's company structure (i.e. EECL, EEQ, EET and SPARQ) will continue and any restructure of business units within Ergon Energy will not affect the capital and operating expenditure forecasts. The company structure is detailed in Chapter 4 of this Regulatory Proposal.	This assumption applies across all of Ergon Energy's capital and operating expenditure forecasts.	There is no specific method that has been used to develop this assumption.	The application of this assumption means that the capital and operating expenditure forecasts are based on the continuation of the current company structure. Any restructure would require changes to Ergon Energy's cost allocation method.
2. The forecast capital and operating expenditure programs for 2008-09 and 2009-10 will be delivered.	This assumption applies across all of Ergon Energy's capital and operating expenditure forecasts.	There is no specific method that has been used to develop this assumption.	The application of this assumption means that there will not be a carry forward of uncompleted projects and programs from the current regulatory control period into the next regulatory control period (whilst noting that some programs are cyclical).
3. There will be no major changes to the current legislative and regulatory framework in the next regulatory control period. If any such changes occur they will be treated as a cost pass through event.	This assumption applies across all of Ergon Energy's capital and operating expenditure forecasts.	There is no specific method that has been used to develop this assumption.	The application of this assumption means that the expenditure forecasts have been designed to achieve compliance with the current legislative and regulatory obligations.
4. The Network Planning Criteria reflected in 'NPD05' give effect to the EDSD Review's recommendations and provide an appropriate basis for Ergon Energy's capital and operating expenditure forecasts for the next regulatory control period. In the event that there is a different externally mandated standard introduced, then this would be treated as a cost pass through event.	This assumption applies across all of Ergon Energy's capital and operating expenditure forecasts, in particular for Corporation Initiated Sub-transmission and Distribution Augmentation capital expenditure.	The basis for the development and application of the Network Planning Criteria is explained in Chapter 20 of this Regulatory Proposal.	The application of this assumption means that the capital and operating expenditure forecasts have been designed to achieve compliance with the Network Planning Criteria, and therefore the EDSD Review's recommendations.

Description	Forecast information	Method	Application
5. The current ring-fencing waivers will continue.	This assumption applies across all of Ergon Energy's capital and operating expenditure forecasts.	This assumption reflects the current ring-fencing arrangements and is consistent with clause 11.14.5 of the Rules, as discussed in Chapter 11 of this Regulatory Proposal.	The application of this assumption means that the capital and operating expenditure forecasts are based on the continuation of the current ring-fencing arrangements. There is no requirement to change the way in which Ergon Energy undertakes its generation (including network support generation) activities in the next regulatory control period.
6. The AER will be responsible for the economic regulation of the Mount Isa-Cloncurry network from 1 July 2010.	This assumption applies across all of Ergon Energy's capital and operating expenditure forecasts.	The nature, and basis for the application of this assumption are explained in Chapter 9 of this Regulatory Proposal.	The application of this assumption means that the capital and operating expenditure forecasts incorporate allowances for the Mount Isa-Cloncurry network.
7. Ergon Energy will be able to acquire the necessary labour and materials to deliver its capital and operating expenditure programs in accordance with its unit rate forecasts.	This assumption applies across all of Ergon Energy's capital and operating expenditure forecasts.	The nature, and basis for the application of, this assumption are explained in Chapter 35 of this Regulatory Proposal.	The application of this assumption means that Ergon Energy has not built any contingencies into its unit rates, in the event that labour and material costs are higher than forecast.
8. There will be no significant changes in Ergon Energy's plans, policies, procedures and strategies during the next regulatory control period that will materially impact on its system and non-system capital and operating expenditure forecasts for that period.	This assumption applies across all of Ergon Energy's capital and operating expenditure forecasts.	There is no specific method that has been used to develop this assumption.	The application of this assumption means the capital and operating expenditure forecasts will not need to be adjusted in the next regulatory control period, except to the extent that plans, policies, procedures and strategies (and therefore expenditure forecasts) need to change for externally driven matters, such as legislative changes.

Description	Forecast information	Method	Application
Capital Expenditure Forecasts Only			
9. Actual demand in the next regulatory control period will not materially deviate from the demand forecast detailed in Chapter 21 of this Regulatory Proposal.	This assumption applies to the forecasts of Corporation Initiated Sub-transmission and Distribution Augmentation capital expenditure and small Customer Initiated Capital Works (CICW).	The method by which demand has been forecast has been explained in Chapter 21 of this Regulatory Proposal.	The application of this assumption means that the capital expenditure forecast is structured to meet reasonable forecasts of maximum demand, energy consumption and customer numbers.
10. The current Capital Contributions Methodology (covering both cash contributions and gifted assets), and the current accounting for revenues derived from capital contributions, will continue to apply.	This assumption applies to the capital contribution component of the small CICW forecast in Standard Control Services.	This assumption reflects the current capital contribution arrangements and is consistent with clause 11.16.10 of the Rules.	The application of this assumption means that all capital contributions will continue to be treated, and accounted for, on their current basis.
11. Contestability will result in approximately 50 per cent of: a. Standard Control Service new medium size customer connections; and b. Alternative Control Service new large connection assets being undertaken by third parties.	This assumption applies to the forecasts of small CICW and subdivisions (which are 'shared' network) and to the resourcing forecast.	Approximately 50 per cent has been determined on the basis of the volume of works being undertaken by third parties for subdivisions in the current regulatory control period.	The application of this assumption means that Ergon Energy's delivery program has been formulated on the basis of the share of these works between itself and third parties. This does not impact on the expenditure forecasts given the treatment of gifted assets.

15. KEY ASSUMPTIONS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice

QCA Documents

Nil

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR158	"Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland" (EDSD Review), July 2004
AR364	National Electricity Rules
AR388	MCE "Smart Meter Decision Paper", 13 June 2008
AR389	MCE "Statement of Policy Principles", June 2008

Ergon Energy Documents

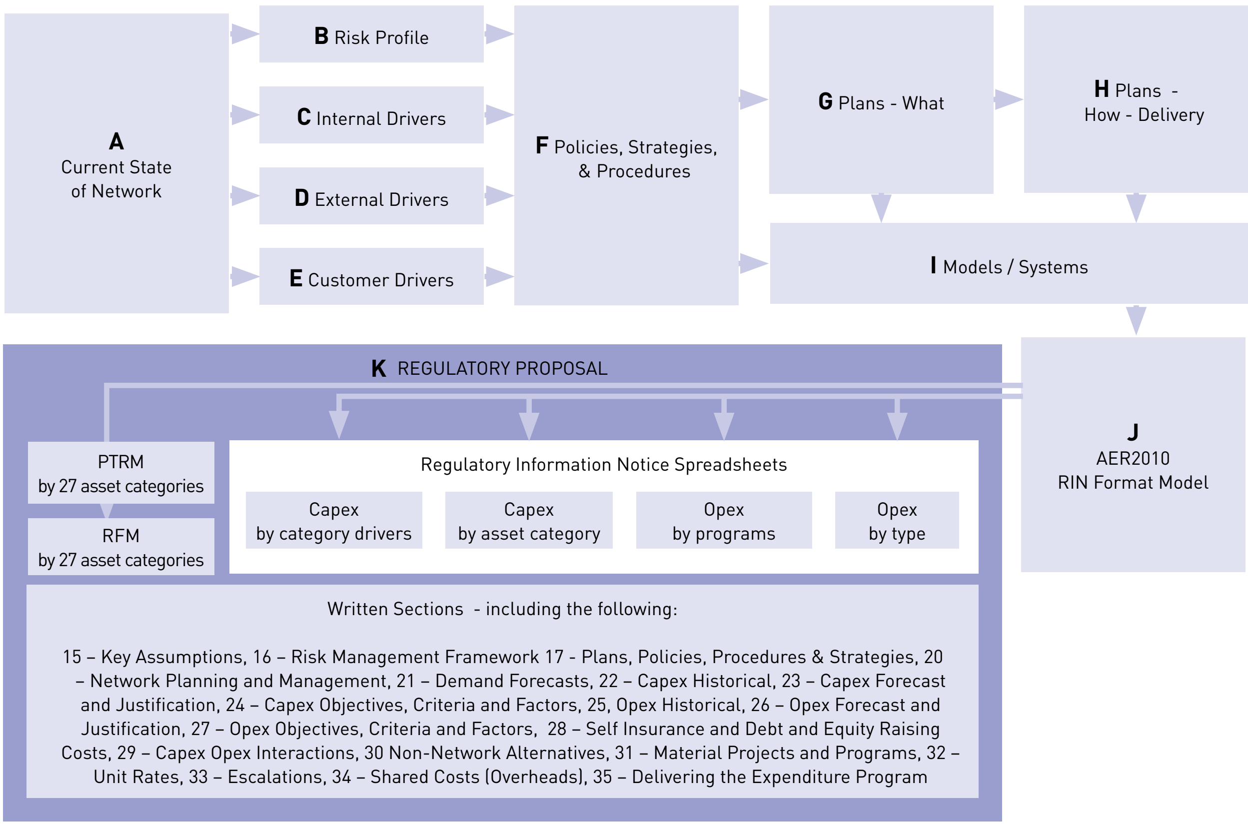
AR047	EE Capital Contributions Methodology (QCA Approved), 20 April 2005
AR064	EE Network Planning Criteria – NP02 V2.03, 30 May 2000
AR314	EE Cost Allocation Method, AER Approved
AR470	EE RIN Attachment 4: Directors' Certification Statement

16. RISK MANAGEMENT FRAMEWORK

Ergon Energy's network is planned, constructed and maintained within the framework of its business-wide Risk Management Policy. This is achieved through the application of Ergon Energy's risk approach in the development of its policies, strategies and procedures and the implementation of plans. This means there is a strong nexus between Ergon Energy's expenditure forecasts and its Risk Management Framework.

This approach is illustrated in Figure 17 in the context of Ergon Energy's Regulatory Proposal Method. Ergon Energy's Risk Profile (Box B) is applied in the development of its policies, strategies and procedures (Box F) and its plans translate this risk approach into the planning, construction and maintenance of its assets, which are delivered through into capital and operating expenditure (Box K).

Figure 17: *Key Assumptions underlying Capital and Operating Expenditure Forecasts*



16.1 CORPORATE RISK MANAGEMENT POLICY

Ergon Energy's business-wide Risk Management Policy integrates risk management into its corporate governance, business planning and strategic planning processes. Ergon Energy's Risk Management Framework is consistent with AS/NZS.4360:2004.

The primary objectives of Ergon Energy's Risk Management Policy are to implement a risk management framework that:

- Ensures the overall strategic direction of the business is appropriate in view of the external market, including the regulatory environment, in which it operates;
- Provides a means of identifying priorities (in terms of relative levels of risk) and allocating scarce resources effectively and efficiently;
- Provides a means of demonstrating due diligence in discharging legal and regulatory requirements and meeting the expectations of, and standards required by, key external stakeholders; and
- Provides a means of identifying and maximising opportunities for business growth and diversification where such opportunities involve some degree of risk.

Ergon Energy meets these objectives by applying the following strategies:

- Establishing common guidelines and methods for assessing and quantifying risk;
- Identifying key areas of risk exposure and reporting these to Ergon Energy's Board. It is the role of the following committees of the Board to monitor risk:
    - → Audit and Financial Risk Committee – it is responsible for reviewing and reporting on financial risk and compliance; and
    - → Operational Risk Committee – it is responsible for reviewing and reporting on business and operational risks, other than financial risks.
- Ensuring that risk management-related plans and strategies are integrated into the budgetary, strategic and business planning process and are reflected in operational plans and processes;
- Defining acceptable levels or ranges of risk tolerance and risk appetite for different areas of the business for both hazard and opportunity-type risks;
- Ensuring that business continuity planning is implemented to address major business continuity risks, such as cyclones or critical supply network failures; and
- Ensuring that levels and areas of risk retention are appropriate and that, where necessary, insurance or other forms of risk financing and risk transfer are in place.

16.2 CORPORATE RISK MANAGEMENT METHODOLOGY

Ergon Energy's Risk Management Methodology involves:

- Establishing the context – this involves establishing the strategies and organisational context in which the risk management process takes place. This involves establishing the target level of risk for the activity being assessed to;
- Identify risks – this involves identifying what, when, why and how events could prevent, degrade or delay the achievement of Ergon Energy's objectives;
- Analyse risks – this involves determining the existing business processes and analysing risks in terms of likelihood of occurrence and business impact. The analysis should consider:
    - → The likelihood of an event occurring; and
    - → The potential consequences and their magnitude.
- Assess and prioritise risks – this involves comparing estimated levels of risk against target risk levels and prioritising major risks that require action from minor acceptable risks;
- Treatment of risks – this involves developing and implementing a specific management plan that includes the options of avoidance, transfer, reduction or acceptance of the risks;
- Monitor and review – this involve monitoring and reviewing the performance of the risk management process and changes that might affect it.

The steps following the establishment of the context (i.e. Step 1) are discussed in detail below:

16.2.1 Risk Identification

Ergon Energy's Risk Management Methodology sets out a systematic approach to risk identification which involves:

- Developing a sound understanding of the strategic and operational objectives of the business, including critical success factors, and the threats to the achievement of these objectives. These threats represent risks; and
- Analysing the significant functions undertaken within the business to identify the significant risks that flow from these activities including the use of audits and strengths-weaknesses-opportunities-threats (SWOT) analysis.

Once identified, these risks are incorporated into Ergon Energy's Corporate and Business Unit Risk Profiles. These profiles are updated annually and are endorsed by the Executive Management Team and Operational Risk Committee of the Board. In addition, a monthly risk and compliance issues register is maintained, which is reviewed and updated monthly and is provided to the Extended Executive Management Team.

16.2.2 Risk Analysis

Ergon Energy analyses risks by combining estimates of their consequences and likelihood in the context of no control measures (inherent risk), existing control measures and after treatment (residual risk).

Controls act to reduce risks (preventive controls) and mitigate consequences (corrective controls). Examples of controls include:

- Physical measures, such as modification to the physical hazard, routine inspections, Preventive Maintenance, supervision and testing to compliance;
- Training and administrative measures, such as policies, standard operating procedures, compliance management (within codes, standards or specification) and quality assurance; and
- Responsive measures, which are intended to defend against risks and consequences in particular areas, such as contingency plans and disaster recovery plans.

Ergon Energy's Risk Management Methodology outlines three steps for undertaking risk analysis.

Step 1 – Establish inherent risk

It is assumed that for each risk or event there are no controls in place. The worst consequences and rate is determined according to the definitions in Table 34.

Table 34: *Nature and Consequence of Risks*

Description	Safety	Environmental	Service Delivery
Catastrophic	Circumstances that lead to a single fatality.	Long term impact to sensitive environments. Negative widespread national and international media coverage. Emergency response involving external emergency services.	Outage duration greater than 40,000,000 customer minutes. Business terminating interruption to major customer (greater than 10 MW).
Major	Circumstances that lead to serious injury, hospitalisation, lost time injury.	Medium term impact to sensitive or non-sensitive environments. Negative state media coverage.	Outage duration 5,000,000 to 40,000,000 customer minutes. Major financial loss (greater than $5 million) to major customer.
Moderate	Circumstances that lead to first aid being required.	Moderate impacts to non-sensitive environments or minor impact to sensitive environments. Many complaints received from community and customers.	Outage duration 1,000,000 to 5,000,000 customer minutes. Significant financial loss ($1 million to $5 million) to major customer.
Minor	Circumstances that lead to a near miss.	Minor impacts to non-sensitive environments. Isolated community and customer complaints.	Outage duration 200,000 to 1,000,000 customer minutes. Financial loss (up to $1 million) to major customer.
Insignificant	Not Applicable.	Incident contained on-site. Impact tolerated without complaints.	Outage duration less than 200,000 customer minutes.

Financial Impact	Legal / Regulatory Exposure	Corporate Reputation
Greater than $20 million.	Prosecution of Directors and or Managers. Loss of operating licence.	Parliamentary inquiry. Shareholder intervention.
$5 million to $20 million.	Prosecution of Company / Regulatory Penalty.	Formal ministerial direction. Highly critical and sustained publicity. Statewide media coverage.
$1 million to $5 million.	Major adverse audit report leading to significant works required. Regulatory improvement notice or fine.	Negative questions on notice in Parliament. Negative questions at local council. Critical but not sustained publicity and media coverage.
$200,000 to $1 million.	Minor adverse audit report leading to minor works required.	Single local issue that has potential to spread if not managed quickly. Community outrage results in reprioritising work program.
Less than $200,000.	Minor adverse audit report with no material ongoing impact.	Low level Parliamentary question. Regional Operations Manager involvement and adverse media reports.

Assuming that there are no controls in place, the potential likelihood of such an event is calculated by reference to Table 35.

Table 35: *Likelihood of Occurrence of Risk*

Description	Likelihood of Occurrence
Almost Certain	1. Will occur in most circumstances 2. Reasonably expected to occur (less than 12 months)
Likely	1. Likely to occur within next 3 years 2. Probably occur in near future
Possible	1. Likely to occur within next 10 years 2. Might occur at some time
Unlikely	1. Not specifically expected to occur but may occur some time in future (less than 10 years) 2. May occur in exceptional circumstances
Rare	1. Foreseeable but not normally expected to occur (more than 10 years) 2. Requires a chain of related unlikely events to occur

The inherent risk is then established by combining the consequences and likelihood of risk event with reference to Table 36. This establishes the inherent risk of the event or activity.

Table 36: *Risk Rating Matrix*

		Likelihood				
		Rare	Unlikely	Possible	Likely	Almost Certain
Consequence	Catastrophic	Medium	High	High	Extreme	Extreme
	Major	Medium	Medium	High	High	Extreme
	Moderate	Low	Medium	Medium	High	High
	Minor	Very Low	Low	Medium	Medium	Medium
	Insignificant	Very Low	Very Low	Low	Medium	Medium

Step 2 – Residual risk

The next step involves considering the actual controls that are in place that reduce the likelihood or consequence of the identified risk. Ergon Energy re-evaluates the consequence and likelihood of the risk on the basis of the current controls in place.

This process results in a 'residual' risk rating.

If the 'residual' risk rating is considered not to be acceptable, Ergon Energy then determines the appropriate risk treatment options to manage the risk.

Step 3 – Target risk

After the application of additional risk treatment options or controls, the risk or event is again analysed and its consequence and likelihood is assessed, assuming that the risk treatment option is implemented. This calculates the target risk rating and determines whether the controls put in place address the risk exposure.

16.2.3 Assessing and Prioritising Risk

Ergon Energy's Risk Management Methodology establishes a framework for assessing risks and prioritising them for treatment. This involves an assessment of the effectiveness of existing controls.

Ergon Energy has in place a control practices matrix which guides the assessment of whether the controls in place are effective. The control matrix requires the following questions to be answered:

- Does the control address the risk effectively?
- Is the control officially documented and communicated?
- Is the control in operation and applied consistently?

The Control Practices Matrix is detailed in Figure 18.

Figure 18: *Control Practices Matrix*

	Does the control address the risk effectively?		Is the control officially documented?		Is the control in operation and applied consistently?		
Yes	1		1		1		
Partly	3		2		2		
No	6		3		3		Total Control Rating
Add scores		+		+		=	

The scores from the Control Practices Matrix are used to give a control rating and to describe the control effectiveness, as illustrated in Table 37.

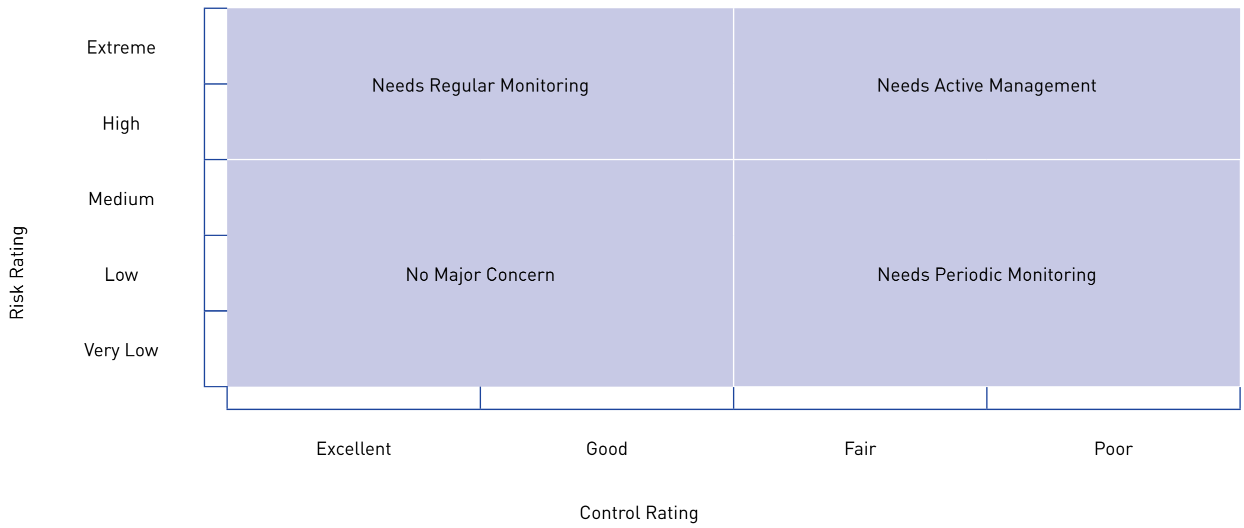
Table 37: *Control Evaluation Table*

Score	Rating	Description
7 - 12	Poor	At best, control addresses risk, but is not documented or in operation; at worst control does not address risk and is neither documented nor in operation.
5 - 6	Fair	Control addresses risk, at least partly, but documentation and/or operation of control could be improved.
4	Good	Control addresses risk, but documentation and/or operation of control could be improved.
3	Excellent	Control addresses risk, is officially documented and in operation.

The ranking of risks allows a risk profile to be compiled as a basis for determining priorities and actions. Ergon Energy's Risk Management Ranking Map is used to combine the selected risk rating from Table 36 and Table 37 for each of the risks identified.

The map, which is illustrated in Figure 19, sets out the actions required to manage each risk efficiently and effectively. It ensures that priorities are established which will allow resources to be directed to the relevant areas.

Figure 19: *Risk Management Ranking Map*



16.2.4 Treatment of Risks

Ergon Energy's Risk Management Methodology provides that risks that fall into the low priority or acceptable risk categories may be accepted with minimal further treatment. Low priority and accepted risks are to be monitored and periodically reviewed to ensure they remain acceptable.

High level or unacceptable risk categories require specific planning for improvements and funding. Risk Management Plans are developed for identified major risks.

16.2.5 Monitor and Review

Ergon Energy's Risk Management Methodology provides for a monitoring and review process to manage high priority risks.

Ergon Energy has developed and put in place a Business Unit Risk Profile which includes identified risks from across its business with a residual risk rating of medium and above. The Business Unit Risk Profile is reviewed annually and endorsed by the Operational Risk Committee of the Board. The Business Unit Risk Profile includes:

- A description of the risk;
- Risk owner;
- Residual risk rating;
- Key control measures;
- Risk monitoring activities; and
- Risk reporting forums.

Ergon Energy has also developed a Corporate Risk Profile, endorsed by the Operational Risk Committee of the Board, identifying 15 key risks which summarise the most significant risks for each business unit.

The Corporate Risk Profile provides a description of each key risk and shows the inherent and residual risk ratings. The Corporate Risk Profile also includes target risk ratings, which show the level of risk with control measures that have already been implemented and those that are planned to be implemented.

16.3 ASSET RELATED RISKS

Ergon Energy's Risk Management Framework is applied to the identification and management of asset related risks. The application of the risk management framework in the development of its key asset management plans means that Ergon Energy's risk approach is a significant driver of asset related expenditure.

16.3.1 Asset Management Plan

Ergon Energy's Asset Management Plan (AMP) provides the framework for managing electricity infrastructure assets taking into account service obligations, stakeholder expectations and risk.

As part of the development of the AMP, a suite of Asset Equipment Plans (AEPs) were developed to document the maintenance and replacement strategies for Ergon Energy's 26 asset classes. Ergon Energy identified the following asset-related risks for its business from the development of its AMP and AEPs:

- Physical failure risks, such as functional failure, incidental damage, malicious damage or terrorist action;
- Operational risks, including the control of the asset, human factors and all other activities which affect its performance, condition or safety;
- Natural environmental events such as lightning, storms and floods;
- Factors outside Ergon Energy's control, such as failures in externally supplied materials and services and obsolescence of equipment;
- Stakeholder risks such as failure to meet regulatory performance requirements or reputation damage; and
- Asset-related design, specification, procurement, construction, installation, commissioning, inspection, monitoring, maintenance, refurbishment, replacement, decommissioning and disposal risks.

Ergon Energy has prepared an asset-specific Risk Assessment consistent with the Corporate Risk Management Methodology, that:

- Defines the risk appetite and associated risk profiles for its assets;
- Provides a qualitative identification and assessment of high priority and medium priority asset and asset management related risks; and
- Identifies actions and initiatives to manage risk.

16.3.2 Implementation of Risk Management Actions

Ergon Energy is implementing the risk management actions identified in the Risk Assessment, starting with high priority risks and then medium priority risks.

This is being undertaken through a combination of:

- Integrating the asset/equipment register with the risk management system, which includes addressing certain risks identified in the Asset Equipment Plans in the Business Unit Risk Profiles;
- Developing Risk Management Plans for each major risk, including:
  - → Proposed actions;
  - → Resource requirements;
  - → Responsibilities;
  - → Timing;
  - → Performance measures; and
  - → Reporting and monitoring requirements;
- Including the risks and risk management measures in the Asset Equipment Plans (AEP) for each asset class together with an indication as to whether remedial action is currently budgeted;
- Including in the risk management system a view of the consolidated risk exposure of Ergon Energy from the aggregated network element risks;
- Using the residual risk and the cost of controls to bring the residual risk to a tolerable level will be key determinants in the prioritisation of the capital investment program; and
- Updating asset management planning documentation as required.

This process of implementation is targeted for completion by June 2010. The Risk Assessment and Risk Register will be subject to periodic review.

16.3.3 Other Plans for Management of Asset-Related Risks

Ergon Energy has a suite of planning documents focussed on the management of asset-related risks, which are linked to, and guided by, the AMP. The key planning documents include:

- Network Management Plan;
- Summer Preparedness Plan;
- Disaster Management Plan / Emergency Management Plans; and
- Contingency Plans.

These plans identify key risks to Ergon Energy's network infrastructure and put in place strategies for managing these risks consistent with Ergon Energy's Risk Management Policy. These include:

- Identification of network limitations and options for network (Capital Expenditure based) and non-network (Operating Expenditure based) solutions;
- Augmentations to and/or maintenance of parts of the network to minimise outages during storm season; and
- Ensuring access to systems spares to reduce the risk of extensive load-shedding in the event of critical primary plant failure.

Commitment to these plans impact on Ergon Energy's capital and operating expenditure and highlights the linkages between Ergon Energy's Risk Management Framework and expenditure forecasts. These plans are discussed further below.

16.3.3.1 Network Management Plan

The Network Management Plan 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 its customers.

The Network Management Plan is developed within the framework of Ergon Energy's Strategic Plan and Network Vision and builds upon the progress made against the prior year's Network Management Plan. The Asset Management Plan guides development of the asset-related components of the Network Management Plan, particularly with respect to:

- The policies and strategies underpinning asset management;
- Assessments of compliance with policies;
- Contingency planning and asset security levels;
- Network capacity and load forecasts;
- Identification of network limitations;
- Augmentation works scheduled to undergo the Regulatory Test/public consultation;
- Analysis, options and potential projects; and
- Opportunities for non-network solutions.

The Network Management Plan facilitates public consultation and stakeholder feedback on specific network constraints, supply issues and proposed solutions. This transparency helps to promote awareness of potential investment opportunities which may be cost effective in avoiding or postponing network expansion (e.g. via the Regulatory Test), while still satisfying customers' electrical requirements.

16.3.3.2 Summer Preparedness Plan

The Summer Preparedness Plan details how Ergon Energy plans to:

- Prepare its network for the upcoming summer to minimise outages of customers' electricity supply;
- Manage and minimise the impact of extreme weather events on customers' electricity supply;
- Identify and respond to emergencies that have the potential to impact on customers' electricity supply; and
- Keep customers informed of electricity supply issues over the summer.

The Summer Preparedness Plan has been developed within the framework of Ergon Energy's Network Management Plan and Asset Management Plan to the extent that:

- Many of the initiatives in the Summer Preparedness Plan will improve the network's performance over the medium to longer-term; and
- Much of the annual program of works outlined in the Network Management Plan – developing, maintaining and operating the network - is aimed at preparing the network for summer, as it is the summer period when the network experiences its highest load and exposure to significant weather events.

16.3.3.3 Disaster Management Plan / Emergency Management Plans

Ergon Energy has a documented response and restoration philosophy as part of its whole-of-business Disaster Management Plan and six regional Emergency Management Plans.

The Disaster Management Plan is authorised by the Chief Executive and establishes Ergon Energy's operational priorities in situations of disasters or emergencies. These are:

- Ensuring personal safety - both public and Ergon Energy staff;
- Protecting equipment and infrastructure from damage; and
- Efficient supply restoration - including meeting the communication requirements of customers and other emergency services.

The Disaster Management Plan documents a process for the rapid response to all large scale disasters, including the co-ordination of resources to areas affected by a major event. Supply restoration priorities, as detailed in the Disaster Management Plan, have been determined in accordance with statutory disaster management groups and draw upon broad experience in minimising community disruption. The Disaster Management Plan is supported by subsidiary plans from other business units indicating how they will support the restoration process.

An Emergency Management Plan exists for each region. The Emergency Management Plans are authorised by the relevant General Manager Operations and document the actions that are required by the key business units in the lead up to, and during, significant network events. Each Emergency Management Plan also has supporting plans based on both business unit and geographic responses.

16.3.3.4 Contingency plans

Contingency planning is an important part of Ergon Energy's establishment of general contingency capability as well as its annual summer preparedness planning and emergency management planning for specific events.

In particular, contingency planning is an integral part of Ergon Energy's management of unplanned outages that may result from failure of major plants, such as power transformers in single transformer zone substations or where N -1 transformer capacity is not available. In this context, contingency planning may mean having adequate access to:

- *Systems spares* - These spares provide replacements in the event of failure of primary plant and thereby reduce the risk of extensive load-shedding in the event of critical primary plant failure;
- *Temporary generating capacity* - The provision of stand-alone generating units to reduce the impact of taking network items out of service for maintenance or network expansion and reduce the impact of unplanned outages associated with critical primary plant; and
- *Mobile and skid mounted substations* – Increasing the ability to respond quickly and effectively to outages associated with major plant failure through the use of mobile and skid mounted substations at critical sites across the network

Ergon Energy's confidential suite of P53E documents and contingency plans on its intranet site [24] specifically relate to the management of load on the distribution system during a contingency or disaster event and are applicable to all of Ergon Energy's area.

The system risks remaining from asset failures are assessed and targeted Contingency Plans are put in place until such time as replacement works can be completed.

Ergon Energy has a large pool of skilled personnel to support its contingency plans. In addition, Ergon Energy has relationships across the industry, as well as contractors to call on to respond effectively to events as they arise.

16.3.4 Key Asset Risks

Ergon Energy's Corporate Risk Profile identifies those risks which have the potential to significantly affect the achievement of Ergon Energy's corporate and business objectives. The Corporate Risk Profile identifies the following key asset related risks:

- Network capacity – network fails to keep pace with population and economic growth increases;
- Network reliability – asset maintenance practices are insufficient to meet reliability targets and minimum service standards;
- Community safety – members of the community are injured or killed as a result of the failure of Ergon Energy assets or the acts of its employees or contractors;
- Response to disruption events – Ergon Energy's response to disruption events (e.g. storms, cyclones, floods, hot weather, bushfires) do not meet community needs or expectations.

The Corporate Risk Profile includes actions and initiatives to address these risks and to achieve target risk ratings which consequently impacts on expenditure. These actions and initiatives include the following:

- Complete and operationalise works delivery improvement plan;
- Develop and implement five year (rolling) works program;
- Annual testing exercise of Disaster/Emergency Management Plans; and
- Implement field switching authorisation project.

[24] http://intranet/Business_Units/Energy_Services/S_08_Network/_Production_Online_Help.asp?url=/_Resources/Business_Units/Distribution Business/Operations/Strategic_%20Asset_%20Management/PRODUCTION%20ONLINE%20HELP/Contingency%20Plans)

16. RISK MANAGEMENT FRAMEWORK – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

Nil

QCA Documents

Nil

Codes and Rules

Nil

Ergon Energy Documents

AR024c	EE Asset Management Plan for 2009-10 to 2014-15
AR077	EE EP26 Risk Management Policy, V2, 8 May 2007
AR099	EE Strategic Plan - 3 Horizons
AR135	EE Summer Preparedness Plan 2008-09
AR172c	EE ED000401R100 Disaster Management Plan, 20 October 2008
AR226	EE Asset Equipment Plans 2009
AR248c	EE_Emergency Management Plan - Wide Bay
AR249c	EE_Emergency Management Plan - Far North
AR250c	EE_Emergency Management Plan – Central, Capricornia
AR251c	EE_Emergency Management Plan - South West
AR252c	EE_Emergency Management Plan – Central, Mackay
AR254c	EE_Emergency Management Plan - Northern
AR401	EE Network Management Plan, Summary, 2008-13
AR402	EE Network Management Plan, Part A 2008-09 to 2012-13
AR409	EE P89T01R01 V2 Risk Management Methodology Reference Guide
AR410c	EE P53E Loss of Load Plans
AR445	EE Network Management Plan, Part B 2008-09 to 2012-13
AR476	EE Network Vision 2030

17. PLANS, POLICIES, PROCEDURES AND STRATEGIES

RIN – Section 2.3.6
RIN Pro forma - 2.3.6

This chapter provides a brief description of Ergon Energy's key plans, policies, procedures and strategies. These documents have been developed and used to guide the businesses' day to day operations and have been relied upon in the development of Ergon Energy's Regulatory Proposal for the 2010-15 regulatory control period.

Ergon Energy's Asset Management Plan provides more detailed information about its Plans, Policies, Procedures and Strategies.

Section 2.3.6(a) of the Regulatory Information Notice (RIN) specifies a listing of documents that should be described and provided. This chapter describes documents that have been relied upon by Ergon Energy in preparing this Regulatory Proposal, with the exception of specific demand management documentation which is incorporated into other asset management documentation.

17.1 CORPORATE PLANS, POLICIES, PROCEDURES AND STRATEGIES

17.1.1 Strategic Plan – Three Horizons

The Strategic Plan defines the scope of the Ergon Energy Group's operations as a regional electricity distributor and a non-competitive electricity retailer. Ergon Energy's vision is to be 'a world-class, customer-driven energy business'.

The Strategic Plan identifies Ergon Energy's key performance drivers and outlines the business' response to these drivers and identifies the priorities for the coming year as well as setting the direction for future years extending out to 2020.

The strategic planning framework is based on 'Three Horizons' which are aligned with the regulatory control periods: Horizon One is the current regulatory control period (1 July 2005 to 30 June 2010), Horizon Two is the next regulatory control period (1 July 2010 to 30 June 2015), and Horizon Three is the regulatory control period after that (1 July 2015 to 30 June 2020).

The Strategic Plan sets performance targets and establishes a framework against which performance is measured.

17.1.2 Network Vision: 2030

Ergon Energy's 'Network Vision: 2030' (Network Vision) provides a long-term strategic view of the way in which the network will be configured and existing, enhanced and new asset technologies will be deployed, by the conclusion of Horizon Three and beyond.

The Network Vision has been prepared to assist Ergon Energy in ensuring that the network related asset and asset technology decisions and investments that are made today, support Ergon Energy's long-term asset planning needs.

The Network Vision is supported by a series of high-level principles intended to guide Ergon Energy's investment in, and deployment of, asset technology.

These are [25]:

1. Advanced components and evolving asset technologies will be integrated into the network with existing assets. For example, advanced components will produce high power densities, greater reliability and power quality, enhanced electrical efficiency producing sustainable gains and improved diagnostics.

2. Communications infrastructure will be effective, fully-integrated, secure and reliable. For example, infrastructure such as CoreNet and UbiNet will facilitate an open communications architecture and a high-speed, resilient two-way communication technology for the transfer of real-time information.

3. Power system sensing and measurement will facilitate the transformation of data into operational information. For example, advanced sensing and measurement devices and techniques will assess the state and condition of network elements, establish their capacity and failure probability in real-time, or near real-time, and provide the basis for advanced system protection and optimised asset management.

[25] These principles are broadly based on the asset technology categories applied in the National Energy Technology Laboratory for the US Department of Energy, Compendium of Modern Grid Technologies, June 2007. Found at http://www.netl.doe.gov/moderngrid/docs/Compendium%20of%20Modern%20Grid%20Technologies%20V1%200%20Final.pdf

4. Essential components will be monitored to enable rapid diagnosis and timely, appropriate response to any event. For example, the Supervisory Control and Data Acquisition (SCADA) system will provide fault location information in response to operational data and alarms and respond and forward asset condition management messages.

5. Interfaces and decision support will transform power system data into information that can be understood and used for operational and asset management decision-making. For example, improved interfaces and decision support will be used to transform complex power system data into information that can be understood and used for operational and asset management decision-making.

6. Distributed energy resources will be accommodated within the network architecture. For example, a range of technologies will be employed, servicing both the network and customers, which over time trend towards being more highly distributed.

7. Customer solutions and interfaces will be facilitated through digital technology advances and information exchange. For example, the provision of services and information via technologies such as Advanced Metering Infrastructure (i.e. 'smart meters'), to promote energy conservation and provide a greater understanding of the quality and cost of supply.

The Network Vision does not replace Ergon Energy's short to medium-term network planning, investment or management strategies or pre-empt the specific projects or investment decisions that will be required to deliver the Network Vision identified.

Economically sustainable investment and appropriate risk management practices will guide the asset implementation strategies and delivery programs derived from the Network Vision, as detailed in Ergon Energy's:

- Asset Management Plan;
- Asset policies;
- Asset plans and programs; and
- Programs of work.

17.1.3 Corporate Plan 2008-09 to 2012-13

The confidential Corporate Plan is prepared annually and expands on the framework established by the Strategic Plan for the following five year period, providing further detail with respect to Ergon Energy's:

- Environmental situation (i.e. the current state);
- Strategy;
- Strategic Initiatives;
- Performance Measures and Targets; and
- Financial affairs.

17.1.4 Statement of Corporate Intent 2008-09 to 2012-13

The confidential annual Statement of Corporate Intent (SCI) is a confidential document that is essentially the financial and performance contract between Ergon Energy and its Shareholders (i.e. the Queensland Government's Treasurer and Minister for Employment, Economic Development and Innovation - Mines and Energy). A public version of the SCI is available on Ergon Energy's website: http://www.ergon.com.au/about_us/corporate_intent.asp

The SCI outlines the strategies that will be implemented in 2008-09, forming part of the five year Corporate Plan and the 20 year Strategic Plan to achieve Ergon Energy's vision to be a 'customer-driven, world-class energy business'.

The SCI is developed and provided to the shareholder in accordance with the requirements of the Queensland Government Owned Corporations Act 1993 in particular in sections 102-113 which require that the SCI include Ergon Energy's capital structure and dividend policies, and outline of proposed major infrastructure investments, an outline of borrowings, policies and procedures relating to the acquisition and disposal of major assets, accounting policies etc.

17.1.5 Risk Management Policy EP26

Ergon Energy's EP26 Risk Management Policy commits the business to implementing an effective and integrated Risk Management framework through:

- Establishing common guidelines and methods for risk quantification;
- Identifying and reporting on key areas of risk exposure;
- Integration of risk plans and strategies through the business; and
- Defining acceptable levels or ranges of risk tolerance.

Refer to Chapter 16 of this Regulatory Proposal for a detailed discussion of Ergon Energy's risk management framework.

17.2 ASSET MANAGEMENT

17.2.1 Asset Management Policies

Ergon Energy's policies are concise, broad, formal statements that establish guiding principles or rules by which it will make its decisions and take action. They are therefore direct inputs into the development of its asset management plans, but are not themselves plans for action.

Some policies also take the form of criteria, such as Ergon Energy's Network Planning Criteria – NP02, that specify the security of supply standards that it will apply in planning its system and in developing its capital expenditure forecasts.

Ergon Energy's key asset related policies currently include:

- EP51 Asset Management Defect Policy:
  Ergon Energy will repair and remediate defects identified on electrical network assets in order to ensure electrical network assets are maintained in a safe condition, in order to avoid an asset failing prior to its next inspection and to mitigate the need for forced operating expenditure. This policy details a framework for defect prioritisation, defect remediation and compliance reporting.
- Capital Contributions Methodology (QCA Approved):
  This document details the circumstances in which capital contributions will be required of customers. Ergon Energy's approach to capital contributions is aimed at limiting the incidence of uneconomic connections, and thus minimising the potential for network charge increases resulting directly from the introduction of new customers.
- Network Planning Criteria – NP02:
  The Network Planning Criteria sets out the criteria to be used by Ergon Energy for network planning studies including in respect to:
  - → Plant ratings;
  - → Forecasting;
  - → Line routes;
  - → Transformer rating and firm capacity of zone substations; and
  - → Condition assessments of ageing plant.

Note that some sections of NP02 relating to security criteria have been superseded by the Security Criteria NPD05.

- Security Criteria – NPD05:
  The Security Criteria provide target security levels within which network development can be planned and against which overall security levels can be assessed and reported. The targets outlined in Ergon Energy's Security Criteria provide guidelines for the planning of the general supply network and are not applicable to individual customers whose connection contracts provide for alternative supply security levels. The Security Criteria were developed and agreed with the Shareholder following the Electricity Distribution and Service Delivery (EDSD) Review (which can be found at http://www.dme.qld.gov.au/Energy/independent_report.cfm) and the release of the Queensland Government's 'An Action Plan for Queensland Electricity Distribution – August 2004', to give effect to the EDSD Report's recommendations.
- Workplace Security and Access Policy EP28:
  The Workplace Security and Access Policy commits Ergon Energy to providing a secure and safe work environment and to conducting its activities to protect the health and safety of its employees, contractors and the public. This policy details the security and access processes and controls that are to be applied based on a risk assessment, including consideration of the premises, the likelihood of an incident and any past security breaches.

17.2.2 Asset Management Strategies

Ergon Energy's strategies reflect approaches to issues that are designed to deliver particular outcomes or goals. A strategy typically details where Ergon Energy starts from, where it is aiming to be in a given period of time, how it plans to get there, and how it will know that it has achieved its goals.

Strategies assist in the identification of risks which may result in a shift in priorities and work sequences in plans and practices.

Ergon Energy's key asset-related strategies currently include:

- Asset Maintenance Strategy:
  Provides an overall outline of Ergon Energy's strategy on asset maintenance, including the drivers for asset maintenance and the high-level regime that will be applied.
- Strategic Plan for Asset Renewal:
  Describes Ergon Energy's strategy for asset renewal on an asset class basis and maps a path from the current state of assets to the intended future state. The strategy includes justification for the planned strategy initiatives.
- Operational Communications Strategy Overview Logical Design, Operational Communications Strategy Overview Infrastructure Design (UbiNet), Operational Communications Security Standard, Operational Communications Development Strategy:
  Describes Ergon Energy's intention to provide voice communication coverage for operational activities together with secure operational data communications to facilitate safe, effective and efficient day-to-day operations of the electricity network.

- SCADA Acceleration Strategy:
  Describes the intention to enhance network functionality by the extension of remote control capability. Extended coverage of SCADA is one of the integral parts of the overall remote control strategy.
- Underground Cabling Strategy:
  Provides guidance about the way in which undergrounding of the distribution network will be undertaken, how costs will be apportioned between Ergon Energy and customers and provides cost benefit analysis.
- Feeder Improvement Program:
  The Feeder Improvement Program is a composite set of proactive and reactive feeder improvement programs to improve the performance of feeders that are 'substantial outliers' (i.e. are poorly performing).
- Power Quality Strategic Program:
  The Power Quality Strategic Program is a program to enhance the monitoring of power quality. The program includes a number of pilots to test and validate use of technologies.
- Weed Management Strategy:
  Describes the approach Ergon Energy will adopt to the management of weeds amongst its distribution network.
- Vegetation Strategy 2010-15 :
  The confidential Vegetation Strategy 2010-15 describes Ergon Energy's approach to Vegetation Management, at a summary and concept level.
- Network Performance Strategy 2010-15:
  Describes the long-term strategy for network performance improvement for Ergon Energy at a summary and concept level.
- Corporate Property Strategic Plan V23:
  The confidential Corporate Property Strategic Plan describes the approach and development strategies for the continuing provision of non-system related properties, in particular the development of depot and office facilities to support the continued operations of Ergon Energy.

17.2.3 Asset Management Plan

The AMP provides a framework for the efficient management of Ergon Energy's electricity infrastructure assets over their life cycle. It balances costs against service obligations and stakeholder expectations, including expectations of customers, regulators and the Shareholding Ministers. The AMP describes, for the period 2009-10 to 2014-15:

- Volume 1 – Asset Management Framework
  Volume 1 focuses on the role of the 'Asset Owner'. This volume outlines the role of Ergon Energy's corporate visions, strategies and key management practices in guiding its asset management. In particular:
  - → Ergon Energy's strategic business model for asset management, separating the roles of Asset Owner, Asset Manager and Service Provider;
  - → The internal and external factors influencing Ergon Energy's approach to asset management, including regulatory requirements, customer and stakeholder expectations, and climate change; and
  - → The philosophies guiding Ergon Energy's asset management practices.
- Volume 2 – Asset Management in Practice
  Volume 2 focuses on the role of the 'Asset Manager'. This volume details the plans and programs established by Ergon Energy to deliver its asset augmentation, replacement and maintenance requirements for the period 2009-10 to 2014-15. In particular:
  - → The way in which Ergon Energy will apply its asset management philosophies in practice;
  - → Ergon Energy's major asset programs;
  - → The nature of its expenditure forecasts; and
  - → The systems, models and governance arrangements supporting asset management.
- Volume 3 – Asset Management Operations and Service Delivery
  Volume 3 focuses on the role of the 'Service Provider'. This volume details how Ergon Energy will deliver its approved program of works. In particular it identifies the practices and processes supporting Ergon Energy's operations in a service delivery context.

Ergon Energy's AMP is still under development (in the past there had not been documentation in this format). Volumes 1 and 2 are complete. It is planned to complete Volume 3 before the commencement of Horizon Two. As the AMP is being developed, so too are some of the accompanying policies, strategies and plans. Therefore some documents referenced are in 'draft' at the time of preparing this Regulatory Proposal.

17.2.3.1 AMP – Plans 'What'

Ergon Energy's Asset Management Plan Chapter 3 describes the plans which are about 'what' needs to be done. These plans are:

- Asset Equipment Plans 2009:
  Plans that document the maintenance and replacement strategies for 26 asset classes.
- Sub-transmission Network Augmentation Plans (SNAPs) 2007:
  Annual plans developed for each of Ergon Energy's six regions which describe the capital works for the sub-transmission network that are required in order to accommodate normal load forecasts and emerging constraints for a 10 year horizon. The SNAPs form the basis of the budget planning

process with respect to the sub-transmission network, including development of the Five and Ten Year Capital Works Plans. SNAPs have particular regard for the Network Planning Criteria (discussed in section 17.2.1) and Security Criteria (discussed in section 17.2.1).

- Distribution Network Augmentation Plans (DNAPs) 2007:
  Annual plans (Excel spreadsheets) developed for each of Ergon Energy's six planning regions which provide a detailed listing and description of the capital works that are needed to meet the augmentation requirements of the distribution network that are required in order to accommodate normal load forecasts and emerging constraints for a 10 year horizon. The DNAPs form the basis of the budget planning process with respect to the distribution network including development of the Five and Ten Year Capital Works Plans.
- Network Preventive Maintenance Programs for 2010-11 to 2014-15:
  Description of the Preventive Maintenance work plan for a five year horizon for major asset categories. The Preventive Maintenance Plan is used as the basis for the maintenance budget, including preparation of the Five Year Budget and Workplan for Preventive Maintenance, which identifies the estimated quantity, budget and resource hours per annum, by region and for Ergon Energy as a whole. The goal of the Preventive Maintenance Plan is to achieve the overall lowest life cycle cost for the category of assets while adhering to statutory obligations.
- Meter Asset Management Plan NA0009000R102 V3:
  Describes the asset management methodology applied to Ergon Energy's electricity metering asset class in order to maximise the technical and operational performance and value of Ergon Energy's meter equipment over the asset life cycle and ensure compliance with regulatory requirements.
- 20 Year Strategic Plan for Single Wire Earth Return (SWER) network:
  Ergon Energy has a combination of documents that describe the strategic framework for the management of Ergon Energy's 63,827 km of SWER network distributing single-phase power to more than 26,000, or 4 per cent, of Ergon Energy's customers. SWER makes up approximately 73 per cent of Ergon Energy's total line lengths associated with long rural feeders, and approximately 15 per cent of its total line lengths associated with short rural feeders. This plan has been prepared to support future program of works to ensure that the SWER network is operated as intended for the present loading peak, as well as meeting incremental load growth, performance targets, customer needs and safety requirements.

17.2.3.2 AMP – Plans 'How'

Ergon Energy's Asset Management Plan Chapter 4 describes the plans which are about 'how' work needs to be undertaken. These plans include:

- Network Defect Classification Manual:
  A set of 17 documents which comprise a manual that describes Ergon Energy's defect classification and prioritisation requirements for recording defects during an asset inspection. The defect classification and priorities in the manual are consistent with Ergon Energy's corporate risk profile.
- Climate Change Response Plan 2008-10 Horizon One:
  Forms a key outworking of Ergon Energy's Strategic Plan and Environment Policy and has been aligned to the Strategic Plan's strategic directions for Horizon One. This plan provides for a Climate Change Response Framework which identifies the intended business outcomes for the areas of understanding climate change, building business resilience, proactively influencing and capitalising on opportunities and the Climate Change Response Action Plan which identifies a range of climate change strategies and actions, at business unit level, for each of the key areas of response outlined in the Climate Change Response Framework.
- P55C06R01 Code of Practice Powerline Clearance (Vegetation) 2006:
  The Code of Practice Powerline Clearance (Vegetation) 2006 sets out the minimum safety clearances that must be maintained between vegetation and powerlines (these distances are determined by Ergon Energy), the practices that will be used to ensure safe clearances are maintained, and vegetation management and planting practices that customers and the community should adopt to minimise the risk of vegetation contacting powerlines.
- Strategic Workforce Plan 2008-18:
  The confidential Strategic Workforce Plan 2008-18 ensures that Ergon Energy will have sufficient labour resources to deliver its capital and operating expenditure projects and programs.
- Joint ICT Plan and Finances (two documents):
  The confidential Joint ICT Plan and Finances identifies the likely system direction for a planning horizon of notionally 15 years. This plan documents a roadmap for investment in ICT which progressively delivers business capability while also maximising joint efficiency and interoperability. Ergon Energy's and ENERGEX's ICT services are provided by their subsidiary company SPARQ Solutions. Hence, the 'joint' nature of the ICT plan. The plan is reviewed quarterly (with respect to external technology trends and evolving business plans), annually (for broader business relevance as part of the annual consolidated program of works review) and five yearly (for a major review as part of the regulatory

reset process to ensure consistency between the Joint ICT Plan, business strategies and external technology trends).

- Security Standards and Guidelines P89Y09R02 V2: This document supports the Workplace Security and Access Policy and covers all Ergon Energy land and buildings and relates to the security of all staff, corporate property and inventory. It covers both physical security risks and risks associated with inadequate processes and work practices.
- Easement / Wayleave Reference PW000806R100 V1: This document describes the easement and wayleave reqirements across Ergon Energy's distribution system and details the process for entering into an easement or wayleave agreement. In particular, it details the criteria for determining whether an easement or wayleave is required.

17.2.3.3 AMP – Key Focus Plans

Ergon Energy's Asset Management Plan (AMP) Chapter 5 describes plans which have a key and/or specific focus. These plans include:

- Network Management Plan:
  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. This plan is a rolling five year plan that is prepared in accordance with the Queensland Electricity Industry Code section 2.3. It is a public document[26] published annually following approval by the Queensland Competition Authority.
- Summer Preparedness Plan 2008-09:
  Details how Ergon Energy plans to prepare its network for the upcoming summer to minimise outages; manage and minimise the impact of extreme weather events; identify and respond to emergencies; and keep customers informed of electricity supply issues over summer. This plan is an annual plan that is prepared in accordance with the Queensland Electricity Industry Code section 2.2. It is a public document[27] published annually following approval by the Queensland Competition Authority (QCA).
- Disaster Management Plan ED000401R100 and Emergency Management Plans [AR248, 249, 250, 251, 252, 254]:
  Management plans that document Ergon Energy's response and restoration philosophy as part of its whole-of-business Disaster Management Plan and six regional Emergency Management Plans. The Disaster Management Plan documents a process for the rapid response to all large-scale disasters, including the co-ordination of resources to areas affected by a major event. Supply restoration priorities have been determined in accordance with statutory disaster management groups and draw upon broad experience in minimising community disruption. Emergency Management Plans are regionally focussed and document the actions that are required by the key business units in the lead up to, and during, significant network events.
- Contingency Plans:
  The confidential Contingency Plans are posted on Ergon Energy's internal intranet site http://intranet/Business_Units/Energy_Services/S_08_Network/_Production_Online_Help.asp?url=/_Resources/Business_Units/Distribution_Business/Operations/Strategic_%20Asset_%20Management/PRODUCTION%20ONLINE%20HELP/Contingency%20Plans] together with the P53E suite of plans:

  The contingency plans describe Ergon Energy's management of unplanned outages that may result from failure of major plants, such as power transformers in single transformer zone substations or where N-1 transformer capacity is not available. These plans include having adequate access to system spares, temporary generating capacity and mobile and skid-mounted substations. Contingency Plans are prepared for individual zone substations in each of Ergon Energy's regions.

17.3 ACCOUNTING POLICIES

17.3.1 Capitalisation Accounting Policies

Ergon Energy's capitalisation policy is incorporated in its two accounting policies 'Property Plant and Equipment' and 'Intangible Assets' which provide guidance in respect of:

- Key criteria for recognition of an asset; and
- Clarification of accounting treatment in respect of initial recognition as an asset and subsequent expenditure, including refurbishment costs.

The policy applies to all of Ergon Energy's business units and legal entities.

17.3.2 Cost Allocation Method

Ergon Energy's AER-approved Cost Allocation Method (CAM) outlines the principles to be used by Ergon Energy to directlyattribute and allocate its shared costs across the various business units and subsidiaries within the Ergon Energy group of companies.

Ergon Energy's CAM was approved by the AER on 27 February 2009. Ergon Energy's CAM is published on Ergon Energy's [28] and the AER's websites [29].

[26] Ergon Energy's website: http://www.ergon.com.au/about_us/network_management_plan.asp

[27] Ergon Energy's website: http://www.ergon.com.au/about_us/summer_preparedness.asp

[28] Ergon Energy's website: http://www.ergon.com.au/network_info/CostAllocationMethod.asp

[29] AER's website: http://www.aer.gov.au/content/index.phtml/itemId/727381

17.3.3 Corporate Plan Guidelines for Financial Year ending 30 June 2009 and 30 June 2010

Ergon Energy's confidential Corporate Plan Guidelines detail the Corporate Plan process for Ergon Energy and provide the basis for preparation of the annual budget and the next regulatory control period forecasts. The Guidelines include directions in respect of:

- Escalations to be applied to work plans;
- Labour cost and escalations; and
- Applicable business rules including cost allocation methodology.

17.4 SELF INSURANCE

17.4.1 Self Insurance Board Resolution

Ergon Energy's Board decided at its meeting on 27 March 2009 that Ergon Energy would carry self insurance. This Board resolution is confidential.

17.4.2 Self Insurance Arrangements for 2010-15, Synergies Report

This confidential Synergies self insurance report provides advice to Ergon Energy on its current Self Insurance practices and provides support for recognition by the AER of a self insurance program for the 2010-15 regulatory control period. The report includes a review of self insurance arrangements across Australian electricity distribution and transmission businesses which informed the identification of the necessary features of a self insurance proposal for regulatory purposes. The report also draws upon the analysis and results of the actuarial report prepared by Finity Consulting Pty Ltd (Finity) for Ergon Energy.

17.4.3 Self Insurance Arrangements for 2010-15, Finity Report

This confidential Finity report provides independent advice to Ergon Energy in respect to self insurance including:

- Identification of self insured risks;
- Actuarial advice on the estimated cost of annual losses arising from those risks; and
- A basis to develop a self insurance program.

17.5 EXPENDITURE APPROVAL PROCESS

17.5.1 Investment Review Committee Charter A0000603R100

Ergon Energy's AMP Chapter 9 provides a detailed description of Ergon Energy's investment approval process.

The Investment Review Committee (IRC) Charter identifies the functions, activities and purpose of the IRC. The key objectives of the IRC are:

- Ensuring an appropriate balance between asset investments, customer service, product and asset research and development and business change within the investment portfolio;
- Ensuring the investment portfolio and the individual components of the portfolio adequately address risk management, purpose and performance outcomes, sustainability, efficacy and availability for business planning timeframes;
- Within the investment portfolio, reviewing individual components beyond the investment thresholds of the managers reporting to the Chief Executive;
- Reviewing variations outside the investment portfolio agreed funding and outcome expectations; and
- Providing a strategic oversight and scrutiny of the elements of the portfolio for continued alignment with the purpose and performance outcomes and delivery of projected outcomes.

17.5.2 Network Investment Review Committee Guidelines

Ergon Energy's AMP Chapter 9 provides a detailed description of Ergon Energy's investment approval process.

The Network Investment Review Committee (NIRC) Guidelines charge the NIRC with facilitating the efficient and effective management of all network asset related capital and operating expenditure in accordance with the AMP. The NIRC Guidelines detail the functions and activities of the NIRC, including to:

- Oversee the investment management process within the asset management function;
- Provide and maintain a framework for project submissions;
- Review and endorse network development and maintenance strategies in line with the AMP;
- Review and endorse network capital and operating budgets and quarterly expenditure forecasts;
- Prioritise investment proposals, programs and projects;
- Evaluate, endorse and review specific programs and projects in accordance with the AMP and budget;
- Review post completion audits of specific programs and projects;
- Review current major projects against estimates for the projects; and
- Review total investment program against budget.

17.5.3 Overview of Changes in Ergon Energy's Plans, Policies, Procedures and Strategies

Table 38 explains the changes in Ergon Energy's plans, policies, procedures and strategies between the current regulatory control period and the next regulatory control period. It also examines the impacts of these changes.

It should be noted that the RIN pro forma 2.3.6 contains similar, but different information. The difference is that the RIN pro forma only requires a description of the changes in Plans, Policies, Procedures and Strategies where those changes have a 'material' impact on the forecast expenditures.

Table 38: *Explanations of Changes in Plans, Policies, Procedures and Strategies*

Plan, Policy, Procedure or Strategy	Changes in 2005-10 that will impact 2010-15	Nature and reason for change in 2005-10	Nature of impact of change on 2010-15 expenditure forecasts
Corporate Plans, Policies, Procedures and Strategies			
1. Strategic Plan [AR099]	Yes – the Strategic Plan was developed in its current format in March 2008.	Board and Executive Management Team decision to sharpen focus by amending the Strategic Plan.	Nil – however Strategic Plan is now aligned with regulatory control periods.
2. Network Vision [AR476]	Yes – the Network Vision was developed in its current format in December 2008, however there were earlier versions in 2004 and 2005.	Board and Executive Management Team decision to sharpen focus by amending the Network Vision.	Nil – however Network Vision is now aligned with regulatory control periods.
3. Corporate Plan [AR174c]	Corporate Plan is prepared annually and has a rolling five year outlook.	Annual review.	Nil.
4. Statement of Corporate Intent [AR 173c]	Statement of Corporate Intent is prepared annually and has a rolling five year outlook.	Annual review.	Nil.
5. Risk Management Policy [AR077]	Yes - Risk Management Policy updated on 8 May 2007.	Changes were to reflect the sale of Ergon Energy's contestable retail business (ex EEPL / Powerdirect Australia).	Nil.
Asset Management			
6. Asset Management Defect Policy [AR318]	Yes Asset Management Policy EP51 Ver 2 updated on 1 May 2008. P1 Defects Reference Standard NA000403R218 updated 15 January 2008 P2 Defects Reference Standard NA000403R219 updated 21 June 2008.	Changes were to reflect updated information.	Nil.
7. Capital Contributions Methodology [AR047]	Nil.	Nil.	Nil.
8. Network Planning Criteria [AR064]	Nil.	Nil.	Nil.
9. Security Criteria [AR175]	Nil.	Nil.	Nil.
10. Workplace Security and Access Policy [AR459]:	Nil.	Nil.	Nil.

Plan, Policy, Procedure or Strategy	Changes in 2005-10 that will impact 2010-15	Nature and reason for change in 2005-10	Nature of impact of change on 2010-15 expenditure forecasts
11. Asset Maintenance Strategy [AR355]	Yes	Initial documentation.	Material impact as additional Preventive Maintenance costs are forecast as a result. Strategy for preparation of Operating Expenditure forecasts.
12. Strategic Plan for Asset Renewal [AR451]	Yes	Initial documentation.	Material impact on asset replacement program.
13. Operational Communications Strategy Overview Logical Design [AR452], Operational Communications Strategy Overview Infrastructure Design (UbiNet) [AR453], Operational Communications Security Standard [AR454], Operational Communications Development Strategy [AR455]	Yes	Initial documentation.	Material impact on Operating Expenditure Preventive Maintenance and Capital Expenditure Other Communications (through the UbiNet project).
14. SCADA Acceleration Strategy [AR342]	Yes	Initial documentation.	Material impact.
15. Underground Cabling Strategy [AR450]	Yes	Initial documentation.	Immaterial impact.
16. Feeder Improvement Program [AR341]	Yes – part of Network Performance Strategy.	Initial documentation.	Material impact.
17. Power Quality Strategic Program [AR340]	Yes – part of Network Performance Strategy.	Initial documentation.	Material impact.
18. Weed Management Strategy [AR449]	Yes	Initial documentation.	Immaterial impact.
19. Vegetation Strategy [AR448c]	Yes – Vegetation Strategy documented for the first time.	Initial documentation.	Material increase in vegetation management expenditure. Strategy for preparation of Operating Expenditure forecasts.

Plan, Policy, Procedure or Strategy	Changes in 2005-10 that will impact 2010-15	Nature and reason for change in 2005-10	Nature of impact of change on 2010-15 expenditure forecasts
20. Network Performance Strategy [AR336]	Yes – Network Performance documented for the first time in October 2008.	Initial documentation.	Material impact. Strategy for preparation of Capital and Operating Expenditure forecasts.
21. Corporate Property Strategic Plan [AR319c]	Yes – Corporate Property Strategic Plan documented for the first time on 28 August 2006.	Initial documentation.	Material impact. Strategy for preparation of Capital and Operating Expenditure forecasts.
22. Asset Management Plan [AR024]	Yes – Asset Management Plan documented for the first time in March 2009.	Initial documentation.	Immaterial impact in that there is no change to approach in current regulatory control period. Strategy for preparation of Capital and Operating Expenditure forecasts.
23. Asset Equipment Plans [AR226]	Yes – update to include more information and update asset populations.	Periodic update.	Material impact on Operating Expenditure Preventive Maintenance and Capital Expenditure Asset Replacement. Basis for preparation of Capital and Operating Expenditure forecasts for 2010-15.
24. Sub-transmission Network Augmentation Plans [AR375c & AR376c]	Yes – update to Sub-transmission Network Augmentation Plans.	Annual Update.	Immaterial impact in that these are routine updates. Basis for preparation of Capital Expenditure forecasts for 2010-15.
25. Distribution Network Augmentation Plans [AR424c]	Yes – update to Distribution Network Augmentation Plans.	Annual Update.	Immaterial impact in that these are routine updates. Basis for preparation of Capital Expenditure Forecasts for 2010-15.
26. Network Preventive Maintenance Programs for 2010-11 to 2014-15 [AR446]	New Preventive Maintenance Programs and cycle times.	Annual review to improve public safety and optimise investment.	Material impact. Changes are to the Preventive Maintenance programs.
27. Meter Asset Management Plan [AR075]	Yes – Meter Asset Management Plan updated on 1 February 2008.	Updated to reflect comments from NEMMCO.	Nil.
28. Strategic Plan for SWER [AR444]	Yes – Strategic Plan for SWER documented for the first time on 30 November 2007.	Initial documentation.	Immaterial impact. Strategy for preparation of Capital and Operating Expenditure forecasts.

Plan, Policy, Procedure or Strategy	Changes in 2005-10 that will impact 2010-15	Nature and reason for change in 2005-10	Nature of impact of change on 2010-15 expenditure forecasts
29. Network Defect Classification Manual [AR078]	Changes are progressively incorporated when changes to defect classification is required. Changes will be made to give effect to changes in maintenance programs detailed in the AEPs e.g. lightning arrester defect classifications.	Nil.	Material impact. Changes in defect classification impacting asset replacement are made in this document.
30. Climate Change Response Plan [AR332]	Nil.	Nil.	Nil.
31. Code of Practice Powerline Clearance (Vegetation) 2006 [AR076]	Nil.	Nil.	Nil.
32. Strategic Workforce Plan 2008-18 [AR268c]	Yes – Strategic Workforce Plan 2008-2018.	Cyclical update.	Immaterial impact in that these are routine updates. Strategy for preparation of resource forecasts for regulatory control period 2010-15.
33. Joint ICT Plan Sep08 Baseline [AR307c]	Yes – quarterly review.	General update.	Immaterial impact in that these are routine updates.
34. Joint ICT Finances Sep08 Baseline [AR308c]			Strategy for ICT forecasts.
35. Security Standards and Guidelines [AR458]	Nil.	Nil.	Nil.
36. Easement / Wayleave Reference [AR457]	Nil.	Nil.	Nil.
37. Network Management Plan [AR401, AR402 & AR445]	Yes – annual update.	General update.	Immaterial impact in that these are routine updates. Strategy for preparation of Capital and Operating Expenditure forecasts.
38. Summer Preparedness Plan [AR135]	Yes – annual update.	General update.	Immaterial impact in that these are routine updates. Strategy for preparation of Capital and Operating Expenditure forecasts.
39. Disaster Management [AR172c]	Yes – Updated 20 October 2008.	Amended to include collaboration with Powerlink, new definitions and load shedding requirements.	Nil.
40. Emergency Management Plans [AR248, 249, 250,251, 252, 254]	Nil.	Nil.	Nil.
41. Contingency Plans [on Ergon Energy's intranet site]	Nil.	Nil.	Nil.

Plan, Policy, Procedure or Strategy	Changes in 2005-10 that will impact 2010-15	Nature and reason for change in 2005-10	Nature of impact of change on 2010-15 expenditure forecasts
Accounting Policies			
42. Capitalisation Accounting Policies [AR284 & AR285]	Yes – updated to reflect accounting standards changes.	Updated to reflect the current International Accounting Standard.	Immaterial impact on 2010-15 expenditure forecasts.
43. Cost Allocation Methodology [AR314]	Yes – New Cost Allocation Method approved by the AER on 27 February 2009.	Shared Costs (Overheads) were allocated on the basis of Labour only in 2005-10. However from 2010-15 Shared Costs (Overheads) will be allocated on the basis of Total Costs.	Changed cost allocation method has been reflected in the forecasts for the 2010-15 regulatory control period. Regulatory Information Notice historical data has been backcast (to the extent possible) to be consistent with the AER-approved CAM.
44. Corporate Plan Guidelines for Financial Year ending 30 June 2010 [AR269c] 45. Corporate Plan Guidelines 2008-09 [AR333c]	Yes – Instructions for preparation of budgets and Corporate Plan.	Annual update.	Forms the basis for some of the forecasts for 2010-15 regulatory control period.
Self Insurance			
46. Ergon Energy Board Resolution [AR347c]	Yes – Ergon Energy Board resolution 27 March 2009.	Ergon Energy will commence self-insuring certain events from 1 July 2010.	Self insurance amounts included in 2010-15 regulatory control period forecasts.
47. Self Insurance Arrangements for 2010-15 – Synergies Report [AR317c]	As above.	As above.	As above.
48. Self Insurance Arrangements for 2010-15 – Finity Report [AR313c]	As above.	As above.	As above.
Expenditure Approval Process			
49. Investment Review Committee Charter [AR213]	Yes – Investment Review Committee Charter documented for the first time in October 2008. Governance arrangements for approval of Capital and Operating Expenditure forecasts.	Initial documentation.	Nil.
50. Network Investment Review Committee Guidelines [AR321]	Yes – Network Investment Review Committee Charter updated in September 2008 following some changes to governance arrangements for approval of Network's Capital and Operating Expenditure forecasts.	Initial documentation.	Nil.

17. PLANS, POLICIES, PROCEDURES AND STRATEGIES – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR372	Government Owned Corporations Act 1993 (Qld)

AER Documents

AR367c & 368c	AER Regulatory Information Notice

QCA Documents

Nil

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR158	"Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland" (EDSD Review), July 2004
AR404	Qld Govt "An Action Plan for Queensland Electricity Distribution" (EDSD Action Plan), 23 August 2004

Ergon Energy Documents

AR024c	EE Asset Management Plan for 2009-10 to 2014-15
AR047	EE Capital Contributions Methodology (QCA Approved) 20 April 2005
AR064	EE Network Planning Criteria – NP02, V2.03, 30 May 2000
AR075	EE NA000900R102 Meter Asset Management Plan, V3, 1 February 2008
AR076	EE P55C06R01 Code of Practice Powerline Clearance (Vegetation) 2006, V2
AR077	EE EP26 Risk Management Policy, V2, 8 May 2007
AR078	EE Network Maintenance Defect Classification Manual
AR099	EE Strategic Plan - 3 Horizons
AR135	EE Summer Preparedness Plan 2008-09
AR172c	EE ED000401R100 Disaster Management Plan, 20 October 2008
AR173c	EE Statement of Corporate Intent 2008-09, 29 May 2008
AR174c	EE Corporate Plan 2008-09 to 2012-13, 28 May 2008
AR175	EE Security Criteria - NPD05, 12 April 2005
AR213	EE A0000603R100 Investment Review Committee Charter, V1, October 2008
AR226	EE Asset Equipment Plans 2009
AR248c	EE _Emergency Management Plan - Wide Bay
AR249c	EE _Emergency Management Plan - Far North
AR250c	EE _Emergency Management Plan – Central, Capricornia
AR251c	EE _Emergency Management Plan - South West
AR252c	EE _Emergency Management Plan – Central, Mackay
AR254c	EE _Emergency Management Plan - Northern
AR268c	EE Strategic Workforce Plan 2008-18, May 2008
AR269c	EE Corporate Plan Guidelines 2009-10, 4 November 2008
AR283c	EE Distribution Network Augmentation Plans 2008
AR284	EE Capitalisation Accounting Policy Property Plant and Equipment, March 2009
AR285	EE Capitalisation Accounting Policy Intangible Assets, March 2009
AR307c	EE Joint ICT Plan Sep08 Baseline, V1.2, 19 January 2009
AR308c	EE Joint ICT Finances Sep08 Baseline, V1.4, 2 February 2009
AR313c	Finity EE Self Insurance Arrangements for 2010-15, V2, March 2009
AR314	EE Cost Allocation Method, AER Approved
AR317c	Synergies EE Self Insurance Arrangements for 2010-15, 19 March 2009
AR318	EE EP51 Asset Management Defect Policy, 1 May 2008
AR319c	EE Corporate Property Strategic Plan, V23, 28 August 2006
AR321	EE Network Investment Review Committee Guidelines, V1, September 2008

C CONFIDENTIAL INFORMATION

AR332	EE Climate Change Response Plan 2008-10, Horizon One, July 2008
AR333c	EE Corporate Plan Guidelines 2008-09, 5 November 2007
AR336	EE Network Performance Strategy 2010-15, V4, 24 March 2009
AR340	EE Power Quality Strategic Program, 1 April 2009
AR341	EE Feeder Improvement Program, 1 April 2009
AR342	EE SCADA Acceleration Strategy, 1 April 2009
AR347c	EE Self Insurance 27 March 2009 Board Resolution, signed 30 March 2009
AR355	EE Asset Maintenance Strategy, V8, April 2009
AR375c	EE Sub-transmission Network Augmentation Plans 2007
AR376c	EE Sub-transmission Network Augmentation Plans 2008
AR401	EE Network Management Plan, Summary, 2008-13
AR402	EE Network Management Plan, Part A 2008-09 to 2012-13
AR424c	EE Distribution Network Augmentation Plans 2007
AR444	EE Strategic Plan for Single Wire Earth Return, V1.0.7, 30 November 2007
AR445	EE Network Management Plan, Part B 2008-09 to 2012-13
AR446	EE Network Preventative Maintenance Programs for 2010-11 to 2014-15, V7, May 2009
AR448c	EE Vegetation Strategy, 31 March 2009
AR449	EE Weed Management Strategy 2010-15, 2 April 2009
AR450	EE Underground Cabling Strategy, 31 March 2009
AR451	EE Strategic Plan for Asset Renewal, 3 April 2009
AR452	EE Operational Communications Strategy Overview Logical Design, 28 November 2008
AR453	EE Operational Communications Strategy Overview Infrastructure Design (UbiNet), 28 November 2008
AR454	Operational Communications Security Standard, 28 November 2008
AR455	EE Operational Communications Development Strategy, V1.1, 28 November 2008
AR457	EE Easement / Wayleave Reference, PW000806R100, V1, 11 July 2008
AR458	EE P89Y09R02 Security Standards & Guidelines, V2, 3 September 2006
AR459	EE EP28 Workplace Security and Access Policy, 26 April 2002
AR476	EE Network Vision 2030
AR536c	EE Corporate Plan 2009-10 to 2013-14, May 2009
AR537c	EE Statement of Corporate Intent 2009-10, May 2009

18. BUILDING BLOCK PROPOSAL

Rules – Clauses 6.3.1(b)(c), 6.4.3, 6.5.6, 6.5.7, 6.5.9, 6.8.2(c)(2), 6.12.1 and S6.1

This Regulatory Proposal is made in accordance with the requirements of Chapter 6 and Chapter 11 of the National Electricity Rules (Rules). In particular, it:

- Is prepared in accordance with the Post Tax Revenue Model, other relevant requirements of Part C of Chapter 6 and clause S6.1 of the Rules, as required by clause 6.3.1(c)(1) of the Rules;
- Complies with the requirements of, and contains or is accompanied by information required by, any relevant regulatory information instrument, as is required by clause 6.3.1(c)(2) of the Rules;
- Is prepared in accordance with the building block approach detailed in clause 6.4.3 of the Rules;
- Addresses the requirements of clause 6.5.6 of the Rules in relation to forecast operating expenditure;
- Addresses the requirements of clause 6.5.7 of the Rules in relation to forecast capital expenditure;
- Includes an X factor that conforms with the requirements of clause 6.5.9 of the Rules;
- Relates only to Standard Control Services, as required by clause 6.8.2(c)(2) of the Rules;
- Contains the information and matters relating to capital expenditure detailed in clause S6.1.1 of the Rules;
- Contains the information and matters relating to operating expenditure detailed in clause S6.1.2 of the Rules; and
- Contains the additional information and matters detailed in clause S6.1.3 of the Rules.

Ergon Energy's Skeleton document which, accompanies this Regulatory Proposal, provides a detailed breakdown of where in this Building Block Proposal Ergon Energy has complied with the requirements of:

- Chapter 6 and Chapter 11 of the Rules;
- The AER's Framework and Approach Paper;
- The AER's RIN; and
- The AER's various Guidelines, Models and Schemes.

Figure 20 illustrates the structure of this Building Block Proposal. The bracketed numbers correspond with the Chapters of this Regulatory Proposal. The attachments to this Regulatory Proposal are not referenced in this figure.

Figure 20: *Structure of Ergon Energy's Building Block Proposal*

18. BUILDING BLOCK PROPOSAL – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR367c & 368c	AER Regulatory Information Notice

QCA Documents

Nil

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR467c	EE Regulatory Proposal Skeleton, June 2009

19. COMMENCEMENT AND LENGTH OF REGULATORY CONTROL PERIOD

Rules – Clauses 6.3.2(a)(4), 6.3.2(b), 6.12.1(2)(ii), 6.12.3(e) and S6.1.3(13)

Clause S6.1.3(13) of the Rules requires Ergon Energy's Building Block Proposal to contain the proposed commencement and length of the regulatory control period.

Ergon Energy proposes that its next regulatory control period:

- Commence on 1 July 2010. This is the day after Ergon Energy's current regulatory control period ends; and
- Be for a period of five years, so that the period would end on 30 June 2015. This is the minimum duration for a regulatory control period permitted under clause 6.3.2(b) of the Rules and is the same length as Ergon Energy's current regulatory control period.

Clause 6.12.3(e) of the Rules requires that the Australian Energy Regulator approve a proposed regulatory control period if it consists of five years.

19. COMMENCEMENT AND LENGTH OF REGULATORY CONTROL PERIOD – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

Nil

QCA Documents

Nil

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

Nil

20. NETWORK PLANNING AND MANAGEMENT

Rules – Clauses S6.1.1(2), and S6.1.2(2)
RIN – Sections 2.3.7 and 2.3.10(b)(5)

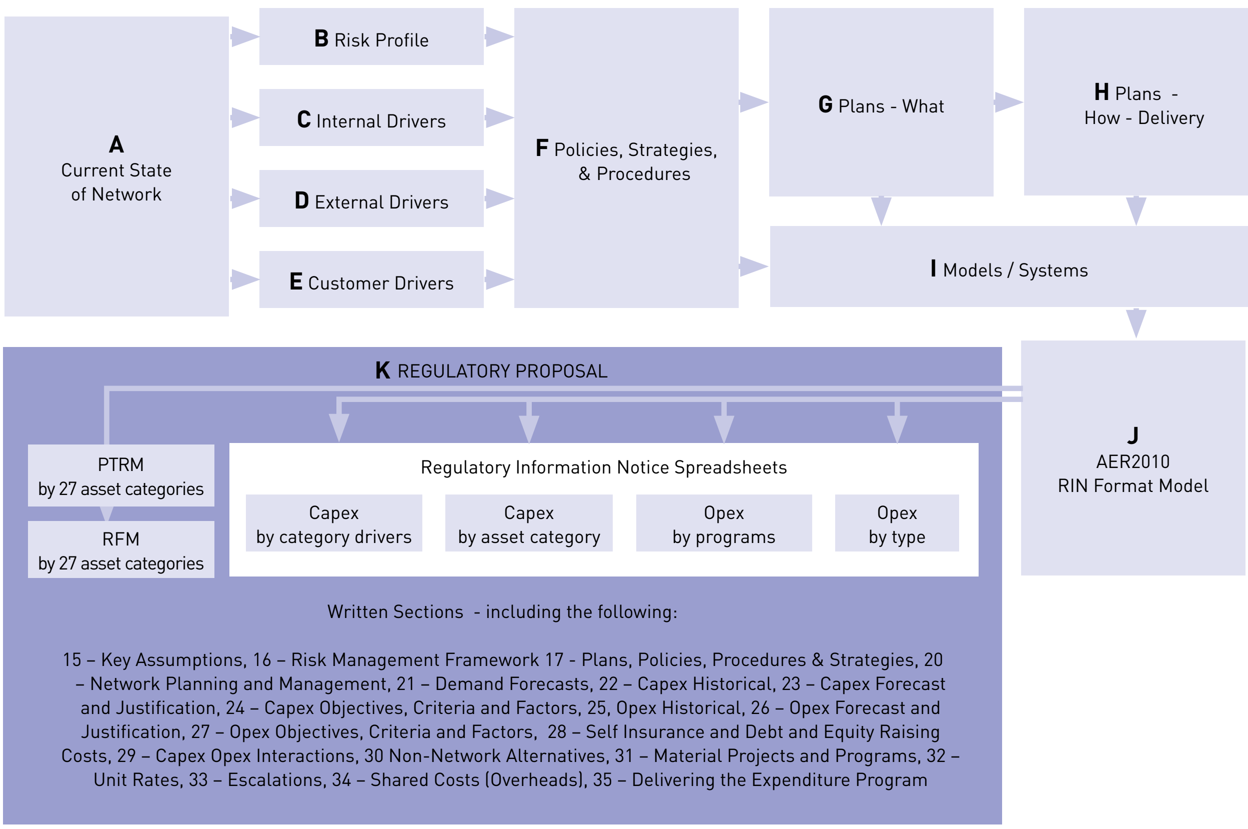
Clauses S6.1.1(2) and S6.1.2(2) of the Rules require Ergon Energy's Building Block Proposal to contain information in relation to the method it has used for developing its capital and operating expenditure forecasts.

Section 2.3.7 of the Australian Energy Regulator's (AER) Regulatory Information Notice (RIN) requires Ergon Energy to provide certain information in relation to its approach to network planning and management. Section 2.3.10(b)(5) of the AER's RIN requires Ergon Energy to provide information about how the profile of expenditure for different types of projects and programs has been developed.

20.1 REGULATORY PROPOSAL METHOD

Ergon Energy's method for developing the capital and operating expenditure forecasts that are detailed in this Regulatory Proposal is illustrated in Figure 21 and is described below.

Figure 21: *Method for Developing Capital and Operating Expenditure Forecasts*



Ergon Energy has applied the following method for developing the capital and operating expenditure forecasts detailed in this Regulatory Proposal:

- Step A involved Ergon Energy examining the current physical nature and condition of its distribution system and assessing its historic and current performance in providing Distribution Services to its customers;
- Steps B to E involved Ergon Energy assessing its:
  - → Risk profile having regard for the risk management framework detailed in Chapter 16 of this Regulatory Proposal;
  - → Internal drivers, including in relation to its existing capability and operational practices for the management of the distribution system;
  - → The impact of external drivers, in particular the legislative and regulatory obligations or requirements detailed in Chapter 10 of this Regulatory Proposal; and
  - → Customer drivers, in particular having regard for the demand forecasts and service standards detailed in Chapters 21 and 12 respectively of this Regulatory Proposal.
- Step F involved Ergon Energy refining and confirming its policies, strategies and procedures for managing and operating its distribution system. Key documents are described in section 20.3.2 of this Regulatory Proposal and are discussed further in Chapters 23 and 26 in the context of justifying Ergon Energy's capital and operating expenditure forecasts for the next regulatory control period;
- Step G involved Ergon Energy developing its plans for what capital and operating expenditure programs it needs to undertake in the next regulatory control period, having regard for Steps A to F. These include such plans as the Sub-transmission Network Augmentation Plans (SNAPs), the Distribution Network Augmentation Plans (DNAPs), the Asset Equipment Plans (AEP), as well as individual plans for assets such as property and fleet;
- Step H involved Ergon Energy developing plans for how it would deliver the capital and operating expenditure programs identified in Step G, in terms of labour resources, physical resources and information technology, as well as how it would respond to matters such as climate change and the global financial crisis;
- Step I involved Ergon Energy reflecting its capital and operating expenditure programs into a series of internal models and systems;
- Step J involved Ergon Energy consolidating its capital and operating expenditure forecasts into a model (with a series of work books) that was structured in accordance with the requirements of the AER's RIN (i.e. Ergon Energy's RIN Submission Model). At this stage, unit rates, escalations and overheads were then applied to the forecasts, as discussed in Chapters 32, 33 and 34 of this Regulatory Proposal; and
- Step K involved Ergon Energy populating the AER's Post Tax Revenue Model, Roll Forward Model and RIN spreadsheets based on outputs from its RIN Submission Model.

These elements of Ergon Energy's method for developing its capital and operating expenditure forecasts are explained further in the remainder of this Regulatory Proposal.

20.2 NETWORK CAPACITY, PERFORMANCE AND UTILISATION

Section 2.3.7(a)(1) of the AER's RIN requires Ergon Energy to provide details about network performance and/or utilisation and comparison with target levels.

Section 2.3.7(a)(5) of the AER's RIN requires Ergon Energy to explain the historic network capacity or performance levels and their impact on service levels at key points in the distribution system.

Part B of Ergon Energy's Network Management Plan (NMP) provides detailed information regarding the capability, performance, asset management and development planning of Ergon Energy's distribution system. In particular, it details:

- Network capacity information and load forecasts;
- Identification of network limitations;
- Augmentation works scheduled to undergo regulatory test/public consultation;
- Analysis, options and potential projects; and
- Opportunities for non-network solutions.

Part B of Ergon Energy's 2008-09 NMP contains:

- A Bulk Supply Substation Capacity Report that provides detailed information for all of Ergon Energy's bulk supply substations;
- A Zone Substation Capacity Report that provides detailed information for all of Ergon Energy's zone substations;
- A Transmission and Sub-transmission Line Capacity Report that provides detailed information for all transmission and sub-transmission lines which are at risk of exceeding their rating under system intact or contingency conditions;
- Details of emerging network constraints and responses;
- Details of significant issues with regard to the capacity and security of Ergon Energy's transmission and sub-transmission network. These issues are presented on a regional, bulk supply area and/or substation basis; and
- Details of constraints on the distribution network (i.e. 11 kV, 22 kV and Single Wire Earth Return (SWER) feeders) that result in a non compliance with Ergon Energy's design planning criteria.

Because this information is presented in detail in Part B of the 2008-09 NMP, Ergon Energy has not replicated this information in this Regulatory Proposal. Ergon Energy therefore refers the AER to its NMP for information about its historic network capacity or performance levels and their impact on service levels at key points in the distribution system.

20.3 EXPLAIN APPROACH TO NETWORK PLANNING, INVESTMENT EVALUATION AND OPERATING EXPENDITURE DECISION MAKING

Section 2.3.7(a)(2) of the AER's RIN requires Ergon Energy to explain its approach to network planning, investment evaluation and operating and maintenance expenditure decision making.

20.3.1 Network Planning

Ergon Energy's approach to network planning is reflected in two key sets of documents:

- SNAPs; and
- DNAPs.

Ergon Energy prepares 10 year SNAPs for each of its six regions. These plans describe the capital works that are needed to meet the augmentation requirements of the sub-transmission network in order to accommodate the normal load forecasts for the next 10 years. The Plans are prepared having regard for:

- The Network Load Forecasting Procedure and associated Work Instructions;
- The Network Planning Criteria NP02 and Security Criteria NPD05;
- The Demand / Load Forecast Spreadsheets;
- The load flow analysis performed in DINIS;
- Major Customer Initiated Capital Works (CICW) forecasts;
- Strategic network development studies;
- Demographic Spatial Load Forecast Reports;
- Joint Planning Studies between Ergon Energy and Powerlink;
- Distribution augmentation forecasts;
- Demand management initiatives; and
- The current works plan.

The SNAPs are prepared annually and form the basis of the annual budget planning process, including the development of a Ten and Five Year Capital Works Plan. Once the work arising from the SNAPs has been quantified, forecasts are prepared using the Growth Plan Unit Rates which have been built up from the Unit Rates Master List Spreadsheet. The five year forecasts for the next regulatory control period are included in this Regulatory Proposal.

The role of the SNAPS in the development of the corporation initiated capital expenditure program for the sub-transmission system is described in further detail in section 23.3.3.1 of this Regulatory Proposal.

Ergon Energy prepares separate 10 year regional DNAPs for its six regions. These are Excel spreadsheets that provide a detailed listing and description of the capital works that are needed to meet the augmentation requirements of the distribution network, in order to accommodate the normal load forecasts for the next 10 years. These DNAPs are prepared drawing on:

- Distribution Network Current State Assessments;
- The Network Planning Criteria NP02 and Security Criteria NPD05;
- The Demand / Load Forecast Spreadsheets;
- The load flow analysis performed in DINIS;
- Strategic network development studies;
- The identification of potential demand management initiatives; and
- Regional Distribution Capability Reviews and 10 year DNAP for Ergon Energy's six regions.

The DNAPs are prepared annually and form the basis of the annual budget planning process, including the development of a Ten and Five Year Capital Works Plan. Once the work arising from the DNAPs has been quantified, forecasts are prepared using the Growth Plan Unit Rates which have been built up from the Unit Rates Master List Spreadsheet. The five year forecasts for the next regulatory control period are included in this Regulatory Proposal and are 'loaded' into the Regulatory Proposal models via the Growth Forecast Spreadsheet.

The role of the DNAPs in the development of the Corporation Initiated Augmentation (CIA) capital expenditure program for the distribution system is described in further detail in section 23.3.3.2 of this Regulatory Proposal.

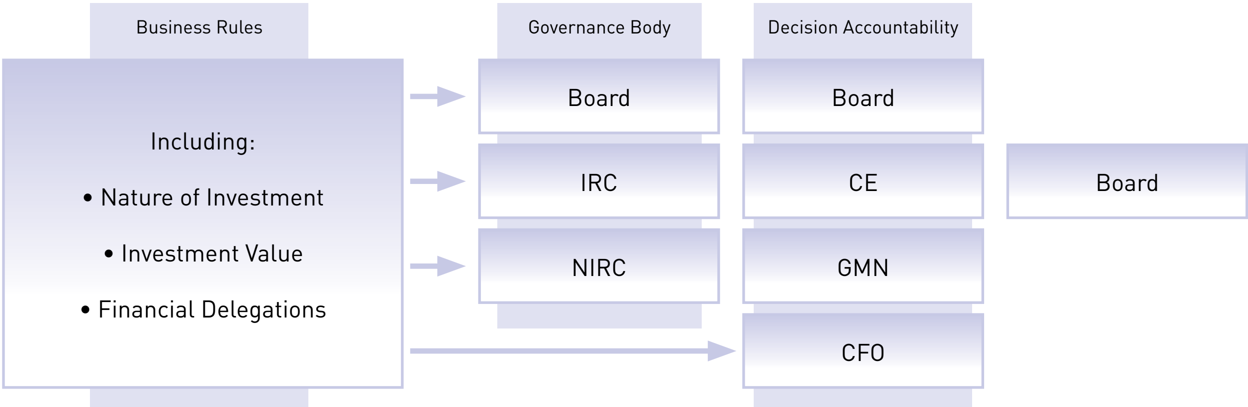
20.3.2 Investment Approval Process

Ergon Energy has a comprehensive framework for the development and prioritisation of its asset investment program, supported by a hierarchy of governance bodies and approval authorities. The role of the governance bodies is to determine whether an investment should be endorsed or recommended to the decision-making body as well as providing advice to the decision-making body of any issues identified through its oversight and scrutiny functions.

The decision-making body is ultimately accountable for approval of the investment.

The endorsement and approval roles are illustrated in Figure 22.

***Figure 22:** Investment Management - Governance and Decision Accountability*



Within this framework:

- The Board has decision accountability for the enterprise investment portfolio and in doing so maintains overarching alignment of investments direction with Ergon Energy's strategic direction and performance outcomes.
- The Investment Review Committee (IRC) supports the Board and Chief Executive (CE) by developing a balanced capital and operating fund investment portfolio and by providing strategic oversight and scrutiny across the portfolio to sustain the business on both a five year and annual basis.

  Further to this, the Executive Management Team annually set specific portfolio performance metrics and milestones representing the portfolios' expected contribution to Ergon Energy's strategic development and key result area targets. Individual staff members may also have annual key performance indicators (KPIs) associated with their role on, and the outcomes of the IRC.

  The IRC's functions and activities are governed by the Investment Review Committee Charter, with the key objectives of:

→ Ensuring an appropriate balance between asset investments, customer service, product and asset research and development and business change within the investment portfolio;

→ Ensuring the investment portfolio and the individual components of the portfolio adequately address risk management, purpose and performance outcomes, sustainability, efficacy and availability for business planning timeframes;

→ Within the investment portfolio, reviewing individual components beyond the investment thresholds of the managers reporting to the Chief Executive;

→ Reviewing variations outside the investment portfolio agreed funding and outcome expectations; and

→ Providing strategic oversight and scrutiny of the elements of the portfolio for continued alignment of the purpose and performance outcomes with the delivery of projected outcomes.

In order to achieve these objectives, the IRC:

- Establishes strategic portfolio objectives aligned to meeting key result area targets and capability for the future;
- Prioritises and establishes the program of works, as an output of business planning and strategy cycles and the allocation of program funding;
- Reviews the high level budget provisions which form the basis for Statement of Corporate Intent;
- Reviews each investment business case considering risk appetite, value for money, likelihood of the achievement of the outcomes and level of investment that the project presents (i.e. financial and resource requirements) for endorsement to the Chief Executive;
- Manages financial exception approval beyond delegation thresholds; and
- Reviews delivery results, outcomes and benefit realisation in accordance with the original business case and/or realignment to emerging strategic priorities.

There are two mechanisms that support the IRC in the realisation of its objectives:

- The Network Investment Review Committee (NIRC) is a sub-committee of the IRC and provides similar support for the General Manager Network (GMN) as the IRC provides for the Chief Executive. The purpose of the NIRC is to ensure that the network investment portfolio and the individual components of the portfolio adequately address risk management, purpose and performance outcomes, sustainability, efficacy and availability for business planning timeframes.

  The NIRC's functions and activities are governed by the Network Investment Review Committee Guidelines, which charges it with facilitating the efficient and effective management of all network asset related capital and operating expenditure in accordance with the Asset Management Plans (AMP). Such expenditure includes all network and customer initiated capital projects; Asset Replacement and Refurbishment programs for network and generation assets, Preventive and Corrective Maintenance programs and operational projects.

  To fulfil its charter, the NIRC is required to perform a number of specific functions, namely:

  - Oversee the investment management process within the asset management function;
  - Provide and maintain a framework for project submissions;
  - Review and endorse network development and maintenance strategies in line with the AMP;
  - Review and endorse network capital and operating budgets and quarterly expenditure forecasts;
  - Prioritise investment proposals, programs and projects;
  - Evaluate, endorse and review specific programs and projects in accordance with the AMP and budget;
  - Review post completion audits of specific programs and projects;
  - Review current major projects against estimate; and
  - Review total investment program against budget.
- The Chief Financial Officer (CFO) is delegated on behalf of the IRC to review the individual components of the investment portfolio in the non-network asset classes, customer service, change, growth and research and development areas beyond the investment thresholds of the managers reporting to the Chief Executive.

  The CFO's role in investment management and prioritisation is documented in the IRC Charter.

20.3.3 Operating Expenditure Decision Making

There are five components to Ergon Energy's operating and maintenance expenditure: Network Operations, Preventive Maintenance, Corrective Maintenance, Forced Maintenance and Other Operating Expenditure.

Expenditure in relation to Network Operations is driven by a commitment to:

- Deliver services to customers on time and in full to communicate unplanned outages to customers and to monitor and manage load to prevent unnecessary outages;
- Provide effective and efficient switching and outage co-ordination practices in order to minimise outages and operational risk, promote industry, safety and environmental standards, and manage and maintain load shedding sequences; and
- Provide high quality network monitoring and response in order to respond to faults and alarms, enact disaster recovery and investigate incidents.

Ergon Energy's Network Operations forecast is explained in further detail in section 26.2 of this Regulatory Proposal.

Expenditure in relation to Preventive Maintenance is based on the AEP that set out the asset management methodology for each of Ergon Energy's 26 equipment types for system assets. These plans identify the drivers of condition-based asset renewal activity for each asset equipment type. The AEP address the current situation, the maintenance policy, issues and challenges, and strategies for change and improvement. Each AEP drives a long-term annual expenditure plan extending out until at least 2017.

Ergon Energy's Preventive Maintenance forecast is explained in further detail in section 26.3 of this Regulatory Proposal.

Expenditure in relation to Corrective Maintenance is forecast at the aggregate level using a top-down/baseline-and-scope-change approach. The aggregate forecast is then disaggregated and 'allocated' across each of Ergon Energy's 26 equipment types for system assets.

Ergon Energy's Corrective Maintenance forecast is explained in further detail in section 26.4 of this Regulatory Proposal.

Expenditure in relation to Forced Maintenance is forecast at the aggregate level using a top-down/baseline-and-scope-change approach. The aggregate forecast is then disaggregated and 'allocated' across each of Ergon Energy's 26 equipment types for system assets.

Ergon Energy's Forced Maintenance forecast is explained in further detail in section 26.5 of this Regulatory Proposal.

Expenditure in relation to the various sub-categories of Other Operating Expenditure is determined as follows:

- The meter reading and customer services expenditure forecasts have both been developed based on historic baseline expenditure, with adjustments made for identified scope changes and workload growth;
- The self insurance forecast is based on a review conducted by Synergies Economic Consulting in partnership with Finity Consulting;
- The DMIA allowance of $1 million per annum (Nominal) is based on the notional amount provided for in the AER's F&A Stage 2;
- GSL costs in line with historical costs and adjusted for increases in the GSL amounts across the various categories; and
- Training costs in line with historical costs and in accordance with detailed bottom-up estimates collated as part of the 2008-09 budget preparation process.

The Other Operating Expenditure forecast is explained in further detail in section 26.6 of this Regulatory Proposal.

20.4 COPIES OF KEY DOCUMENTS USED TO PLAN DNSP'S SYSTEM AND TO DEVELOP CAPITAL EXPENDITURE AND OPERATING EXPENDITURE FORECASTS

Section 2.3.7(a)(3) of the AER's RIN requires Ergon Energy to provide copies of the key documents used to plan its distribution system and to develop its capital and operating expenditure forecasts.

Ergon Energy will make available to the AER a data room with this Regulatory Proposal that contains copies of all of the key documents that it has used to plan its distribution system and to develop the capital and operating expenditure forecasts that are detailed in Chapters 23 and 26 of this Regulatory Proposal. Amongst an extensive range of other documents, the data room contains Ergon Energy's:

- AMP;
- SNAPs;
- DNAPs; and
- AEPs.

20.5 EXPLAIN HOW KEY DOCUMENTS SUPPORT CAPITAL EXPENDITURE AND OPERATING EXPENDITURE FORECASTS FOR 2010-15

Section 2.3.7(a)(4) of the AER's RIN requires Ergon Energy to explain how the key documents support the capital and operating expenditure forecasts.

Chapters 23 and 26 of this Regulatory Proposal provide a detailed explanation of the estimation process for each sub category of Ergon Energy's capital and operating expenditure forecasts. In particular, these sections explain the nature of the key documents and models that are used to prepare the forecasts and how they relate to each other.

20.6 EXPLAIN HOW KEY DOCUMENTS RELATE TO EACH OTHER

Section 2.3.7(a)(4) of the AER's RIN requires Ergon Energy to explain how the key documents supporting the capital and operating expenditure forecasts relate to each other.

Chapters of this Regulatory Proposal provide a detailed explanation of the estimation process for each sub-category of Ergon Energy's capital and operating expenditure forecasts. In particular, these sections explain how the documents supporting the capital and operating expenditure forecasts relate to each other.

20.7 EXPLAIN NETWORK CAPACITY OR PERFORMANCE LEVELS FOR 2010-15 AND HOW MEET EXTERNAL AND INTERNAL PERFORMANCE STANDARDS

Section 2.3.7(a)(6) of the AER's RIN requires Ergon Energy to provide an explanation of the target capacity or performance levels and how these meet external and internal performance standards.

Ergon Energy's network planning processes described in this chapter are designed to meet the:

- National Electricity Rules Chapter 5 – Chapter 5 of the Rules defines the technical parameters within which the distribution network must be operated in order to [30]:
  - → Ensure the safe and reliable operation of customers' equipment;
  - → Ensure the safe and reliable operation of Ergon Energy's equipment;
  - → Comply with good electricity industry practice; and
  - → Avoid the imposition of undue costs on the industry or customers.
- Ergon Energy Corporation Limited Security Criteria Network Planning Targets NPD05 – The Network Security Criteria defines the amount of redundancy, if any, that should be available in the distribution network to continue to supply customers after failure of an item of plant. This criteria was developed by the Queensland Department of Employment Economic Development and Innovation - Mines and Energy in conjunction with the Queensland distributors following the EDSD Review;
- Network Planning Criteria NP02 – This defines how the Ergon Energy network should be planned to ensure customers are provided with a safe, reliable and economic source of electricity.

The network planning process involves assessing the capacity of the network to comply with these performance standards against the forecast load increases at each point in the network. Recommendations for augmentation of the network are made when the performance standard cannot be maintained with the existing network. Further explanation about target capacity and performance levels are assessed as described in Chapter 23 of this Regulatory Proposal.

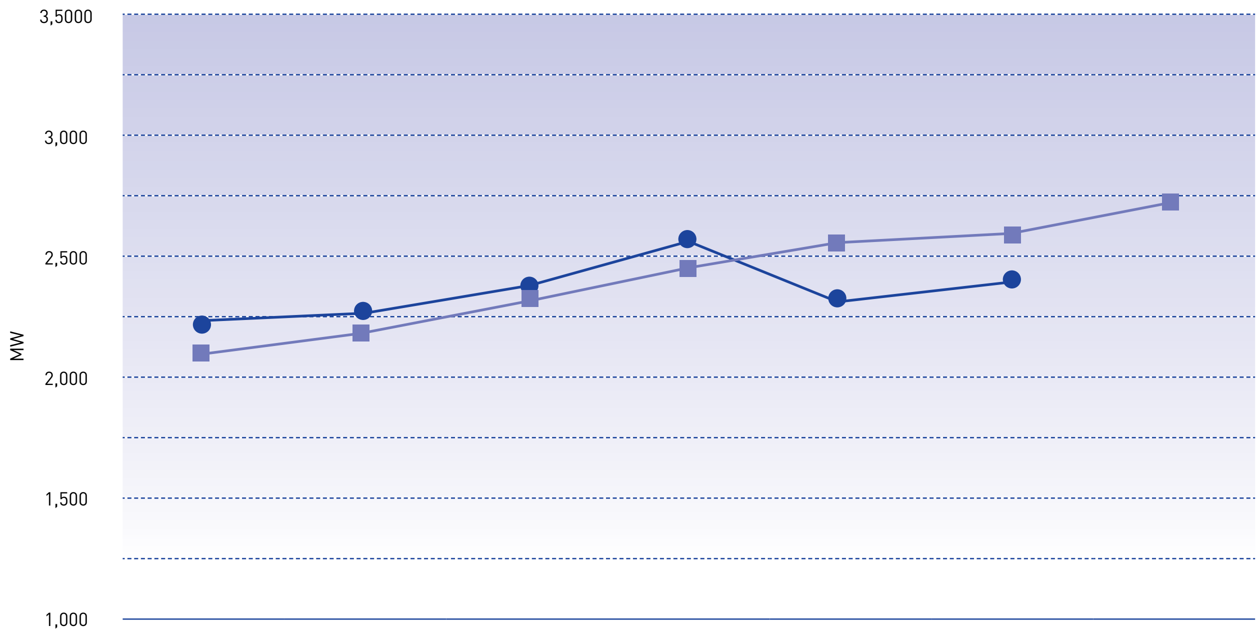
20.8 EXPLAIN HOW NETWORK CAPACITY IN 2005-10 MET ACTUAL DEMAND RELATIVE TO DEMAND FORECAST

Section 2.3.7(a)(7) of the AER's RIN requires Ergon Energy to provide an explanation of how network capacity in the current regulatory control period met actual demand relative to the demand forecast for each year.

When making its 2005 Final Determination, the Queensland Competition Authority (QCA) accepted Ergon Energy's maximum demand forecasts prepared for the current regulatory control periods [31].

Figure 23 details the maximum demand forecast approved by the QCA and the actual maximum demand for the current regulatory control period.

Figure 23: *Ergon Energy System Maximum Demand – Actual and Forecast*



	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10
Actual	2,213	2,268	2,380	2,584	2,332	2,406	
Forecast	2,118	2,201	2,331	2,464	2,554	2,638	2,724

Source: EE (TL) Spreadsheet (CP Amends) 22Apr09

[30] Paraphrased from Rules S5.1a – Purpose (of system standards).

[31] QCA, Final Determination – Regulation of Electricity Distribution, April 2005, Table 2.4, page 34

It should be noted that the forecasts are 50 per cent Probability of Exceedance (POE) forecasts. POE means the likelihood that a forecast value will be exceeded by the actual value. For example, for an annual forecast a 50 per cent POE is likely to be exceeded once every second year, whereas a 10 per cent POE is likely to be exceeded once every 10 years.

Ergon Energy's actual load tracked higher than forecast for the first two years of the current regulatory control period. However, the summers of 2007-08 and 2008-09 were mild compared to the long-term trend. This has resulted in actual load, and in particular air conditioning load, being lower than was expected at the time of preparing the forecasts in these years.

Throughout the 2005-10 regulatory control period, Ergon Energy annually assessed its network constraints and prepared forecasts of where new constraints were likely to emerge. This analysis is documented in the annual NMPs. Further explanation about this process is described in section 21.3.1 of this Regulatory Proposal.

During the 2005-10 regulatory control period, the Corporation Initiated Augmentation (CIA) capital expenditure program was undertaken and network capacity was increased to meet the target capacity and performance standards discussed in section 20.7 of this Regulatory Proposal. The capital expenditure on Corporation Initiated Augmentation has been in excess of that forecast by Ergon Energy prior to the QCA's 2005 Determination but has not been sufficient to fully meet Network Security Criteria. Any system security risks that emerged in the current regulatory control period have been managed by contingency plans. When constraints emerged, they were approved for augmentation after preparing a report which described the constraint that existed or was imminent, and demonstrated that the recommended works delivered the overall least cost solution to resolve the constraint.

20.9 EXPLAIN HOW FORECAST CAPACITY WILL MEET PERFORMANCE STANDARDS AND FORECAST DEMAND BASED ON FORECAST CAPITAL EXPENDITURE AND OPERATING EXPENDITURE FOR 2010-15

Section 2.3.7(a)(8) of the AER's RIN requires Ergon Energy to provide an explanation of how forecast capacity will meet performance standards and forecast demand based on the capital and operating expenditure proposed for the next regulatory control period.

Section 21.1 of this Regulatory Proposal describes Ergon Energy's forecast demand. Having regard for this forecast, Ergon Energy has prepared its CIA capital expenditure program forecast to ensure that target capacity and performance standards will be met. Projects are recommended to proceed when a constraint emerges as a result of load increasing, or load changing in nature, at various points in the distribution network. These projects are then risk assessed and ranked in the program of works. Further explanation about the plans to alleviate constraints is described in Chapter 23 of this Regulatory Proposal.

Ergon Energy has developed an augmentation program that targets meeting security criteria as constraints emerge during the 2010-15 regulatory control period and is intended to ensure that performance improves and does not deteriorate from its current level. This work has been in progress since the completion of the EDSD Review. This work is a matter of priority and has been spread over an extended period to:

- Ensure that sufficient resources are available to also deliver the CICW program;
- Ensure that sufficient resources are available to deliver the maintenance programs; and
- Allow other programs of work in the areas of capital expenditure (i.e. the Asset Replacement and Reliability and Quality Improvement) to proceed.

20.10 EXPLAIN HOW PROFILE OF EXPENDITURE PROJECTS/PROGRAMS HAS BEEN DEVELOPED

Section 2.3.10(b)(5) of the AER's RIN requires Ergon Energy to explain how the profile of the expenditure for different types of projects and programs have been developed.

The profile of capital expenditure has been smoothed over the entire regulatory control period. This has been done to align with expected resource availability and to ensure that peaks and troughs in both expenditure and resource requirements are minimised. For these reasons CIA capital expenditure does not match exactly the timing of network constraints.

Ergon Energy accepts that there will be some variation in risk profile during the regulatory control period in order to ensure optimum use of the resources available to implement the entire program of works.

Further explanation of the way in which capital expenditure and operating expenditure projects and programs have been developed, including their profile, is included in Chapters 23 and 26 respectively.

20. NETWORK PLANNING AND MANAGEMENT – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR367c & 368c	AER Regulatory Information Notice

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005

Codes and Rules

AR158	"Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland" (EDSD Review), July 2004
AR364	National Electricity Rules

Ergon Energy Documents

AR024c	EE Asset Management Plan for 2009-10 to 2014-15
AR064	EE Network Planning Criteria – NP02, V2.03, 30 May 2000
AR175	EE Security Criteria - NPD05, 12 April 2005
AR226	EE Asset Equipment Plans 2009
AR283c	EE Distribution Network Augmentation Plans 2008
AR289	EE Regional Distribution Capability Reviews 2008
AR291	EE P51F01 Network Load Forecasting Procedure
AR292	EE P51F01B01 Manage Network Forecasting Statistical Metering Database Work Instruction, 1 August 2002
AR293	EE P51F01B02 Prepare Draft Forecast Work Instruction, 1 August 2002
AR294	EE P51F01B03 Generate Weather Corrected Base Values Work Instruction, 1 August 2002
AR321	EE Network Investment Review Committee Guidelines, V1, September 2008
AR375c	EE Sub-transmission Network Augmentation Plans 2007
AR376c	EE Sub-transmission Network Augmentation Plans 2008
AR401	EE Network Management Plan, Summary, 2008-13
AR402	EE Network Management Plan, Part A 2008-09 to 2012-13
AR412c	EE Demand/Load Forecast Spreadsheets 2007-08
AR424c	EE Distribution Network Augmentation Plans 2006-07
AR434c	EE Unit Rates Master List Spreadsheet, 5 May 2009
AR436c	EE Demand/Load Forecast Spreadsheets 2007
AR445	EE Network Management Plan, Part B 2008-09 to 2012-13
AR464c	EE Demographic Spatial Load Forecast Reports 2008

21. DEMAND FORECASTS (SYSTEM ONLY)

Rules – Clauses 6.5.6(a)(1), 6.5.6(c)(3), 6.5.7(a)(1), 6.5.7(c)(3) and S6.1.1(3)
RIN – Sections 2.3.8(a)(1)-(7)
RIN Pro forma – 2.3.8

Clauses 6.5.6(a)(1) and 6.5.7(a)(1) of the Rules require Ergon Energy's operating and capital expenditure forecasts to "meet or manage the expected demand for standard control services". Clauses 6.5.6(c)(3) and 6.5.7(c)(3) require the Australian Energy Regulator (AER) to accept Ergon Energy's operating and capital expenditure forecasts if they reasonably reflect a realistic expectation of the demand forecast required to achieve the operating and capital expenditure objectives.

Clause S6.1.1(3) of the Rules requires Ergon Energy's Building Block Proposal to detail "the forecasts of load growth relied upon to derive the capital expenditure forecasts and the method used for developing those forecasts of load growth".

Section 2.3.8 of the Regulatory Information Notice (RIN) requires Ergon Energy to provide certain information in relation to its demand forecasts.

This section examines Ergon Energy's demand forecasts for Standard Control Services for the regulatory control period 2010-15.

21.1 DEMAND FORECASTS FOR 2010-15

Clause S6.1.1(3) of the Rules requires Ergon Energy to detail the demand forecasts used to derive its capital expenditure forecasts. Section 2.3.8(a)(1) of the AER's RIN requires Ergon Energy to detail the demand forecasts that Ergon Energy has used to develop its operating and capital expenditure forecasts.

Table 39 provides a high level summary of Ergon Energy's forecasts of coincident peak (maximum) demand, total energy consumption and customer numbers for the period 1 July 2010 to 30 June 2015. Ergon Energy has used these demand forecasts to develop its operating and capital expenditure forecasts.

Table 39: *Ergon Energy Demand Forecasts for 2010-15*

	2010-11	2011-12	2012-13	2013-14	2014-15	Average of 5 Year Total
EE Coincident peak (maximum) demand (MW) – September 2007	2,967	3,063	3,153	3,243	3,330	3,151
EE Total energy consumption (GWh)	15,870.51	16,450.40	16,874.17	17,432.66	17,887.16	16,902.98
EE Customer numbers	684,469	695,242	706,204	717,356	728,706	706,395

Source: Coincident peak (maximum demand) - Ergon Energy's Network Planning 2007 forecasts (refer also NIEIR November 2007) and AR433c AER Data_v7_data room_28May09.xls

Pro forma 2.3.8 of the AER's RIN provides a detailed breakdown of Ergon Energy's historic and forecast demand based on the September 2007 (i.e. 2006-07) forecasts.

Ergon Energy prepares annual demand forecasts of system demand (MW) and engages the National Institute of Economic and Industrial Research (NIEIR) to prepare an econometric forecast of maximum demand to validate Ergon Energy's internally produced forecasts.

Due to the timing for the preparation of this Regulatory Proposal, Ergon Energy prepared its capital expenditure forecasts based on November 2007 demand forecast data validated against NIEIR's November 2007 report.

Ergon Energy prepared further demand forecasts in 2008 and validated these against NIEIR's September 2008 report. Ergon Energy's 2008 demand forecasts were higher than the 2007 forecasts. However, in late 2008, the global financial crisis emerged and Ergon Energy considered it prudent to ask NIEIR to update its September 2008 report.

In February/March 2009, NIEIR revised downwards its September 2008 demand forecasts for Ergon Energy however the updated forecasts remain higher, on average, than the 2007 forecasts. These are presented in NIEIR's April 2009 report.

Ergon Energy considers it conservative to base its capital expenditure forecasts for the next regulatory control period on its 2007 demand forecasts.

Table 40 compares the maximum demand forecasts that were prepared in 2007, 2008 and 2009. It is evident that the 2007 average demand of the five year forecast period is lower (and therefore more conservative) than the average demand of both the 2008 and 2009 Ergon Energy forecasts.

Table 40: *Ergon Energy Coincident Peak (Maximum) Demand Forecasts for 2010-15 based on 2007 data and compared with 2008 data and 2009 data*

	2010-11	2011-12	2012-13	2013-14	2014-15	Average of 5 Year Total
EE Coincident peak (maximum) demand – September 2007 (MW)	2,967	3,063	3,153	3,243	3,330	3,151
EE Coincident peak (maximum) demand – September 2008 (MW)	3,033	3,198	3,297	3,415	3,496	3,288
EE Coincident peak (maximum) demand – February 2009 Forecast (MW)	2,845	3,100	3,223	3,378	3,467	3,203

Source: Coincident peak (maximum demand) - Ergon Energy's Network Planning 2007, 2008 and 2009 forecasts (refer also NIEIR November 2007, September 2008 and April 2009).

Ergon Energy's detailed analysis of the 2008 and updated 2009 forecasts compared with the 2007 forecasts used for this Regulatory Proposal indicates that:

- A number of large customer projects, in particular connection of new coal mines, are likely to be deferred as a result of the global financial crisis;
- Any downturn as a result of the global financial crisis is likely to recover in 2012-13, after which the proposed projects have a high probability of proceeding;
- The revised forecasts show:
  - → Reduced loads compared to the 2007 forecast for the period up to and including 2010-11; then
  - → Similar loads for 2011-12 and 2012-13; followed by
  - → Some acceleration of development during 2013-14 and 2014-15 as deferred projects are commissioned;
- The average peak demand during the 2010-11 to 2014-15 regulatory period remains reasonably similar in all three forecasts;
- Although the timing of projects has changed and been reflected in the capital expenditure forecasts, the overall amount of augmentation that needs to be completed during the entire regulatory period remains consistent with that developed from the 2007 forecasts.

Ergon Energy believes that, despite a slowing of load growth at the beginning of the next regulatory control period, the projects that are deferred during that time will be connected during the latter stages of the same regulatory control period. This will result in the recommended augmentation program not being materially changed from that developed from the 2007 load forecast. This means that it is reasonable for Ergon Energy to use its 2007 demand forecasts to prepare this Regulatory Proposal.

21.2 EXPLAIN KEY DRIVERS IMPACTING DEMAND FOR 2010-15

Sections 2.3.8(a)(1) and (2) of the RIN requires Ergon Energy to explain the key drivers that are likely to impact on Ergon Energy's maximum demand, energy consumption and customer numbers for the regulatory control period 2010-15.

The key drivers of demand in Ergon Energy's supply area in the next regulatory control period are expected to be:

- Population growth;
- Major new industry or commercial developments;
- Economic growth; and
- Climatic effects and air conditioning penetration.

21.2.1 Population Growth

Ergon Energy's overall customer numbers have grown by around 2 per cent per annum over the five year period 2003-08, with actual growth in 2007-08 of 2.6 per cent. This sustained growth has been driven mainly by development in the coastal regional centres of Hervey Bay (Fraser Coast), Mackay, Townsville and Cairns, as well as the Toowoomba region.

Population statistics from the 2006 census also show population growth of 2 per cent or greater per annum in the five years to 2006 for these centres. The Hervey Bay area in particular has experienced high growth with an average population growth of 5.1 per cent per annum over the five years to 2006 with Fraser Coast local government area having a combined 3.3 per cent growth. Growth in the Townsville Regional Council has also been strong at 2.7 per cent over the five years to 2006.

This population growth is projected to slow slightly in the next regulatory control period to an average 2.5 per cent per annum.

The long-term projected average population growth across these areas is up to 3 per cent per annum, reflecting the national demographic trend to seaside residential development.

Despite these population growth trends, certain rural shires within Ergon Energy's supply area are experiencing falling populations. However, due to changing lifestyle trends and the increased penetration of refrigerative air-conditioning, the population decline does not necessarily translate into falling electricity demand or expectations of network performance.

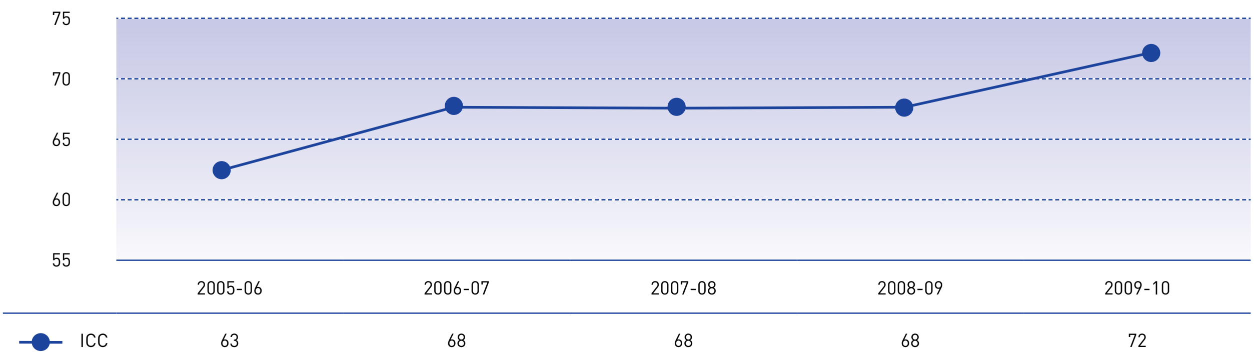
Ergon Energy's Network Pricing customer number forecasts (based on connected National Metering Identifiers (NMIs)) for the next regulatory control period is consistent with population forecasts, and is on average around 1.5 per cent per annum.

Customers are categorised into four classes for network pricing purposes:

- Large - Individually Calculated Customers (ICCs);
- Large - Connection Asset Customers (CACs);
- Large - Embedded Generators (EGs); and
- Small - Standard Asset Customers (SACs).

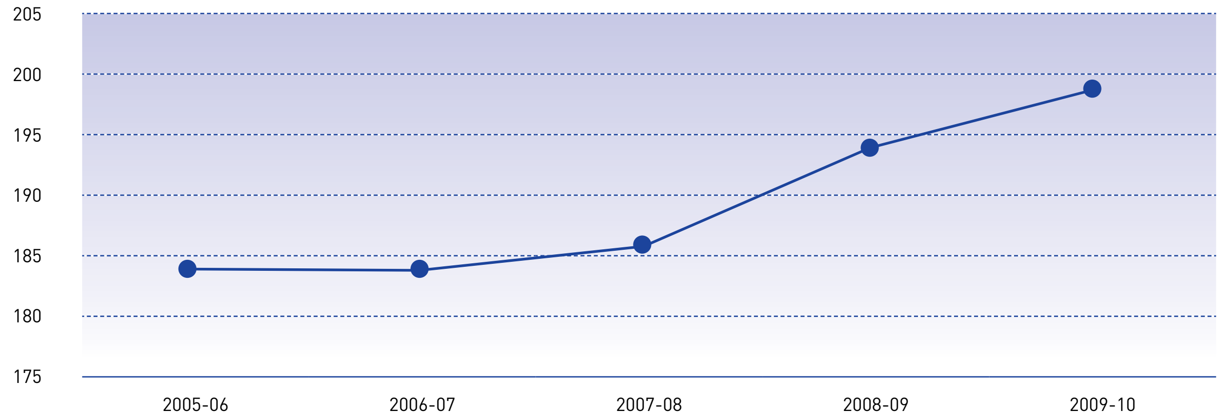
Customer numbers for each class in the current regulatory control period are depicted in Figure 24, Figure 25, Figure 26 and Figure 27. Network Pricing's customer numbers growth in the current regulatory control period has averaged 2 per cent.

Figure 24: *2005-10 Individually Connected Customers Numbers*



Source: AR433c AER Data_v7_data room_28May09.xls

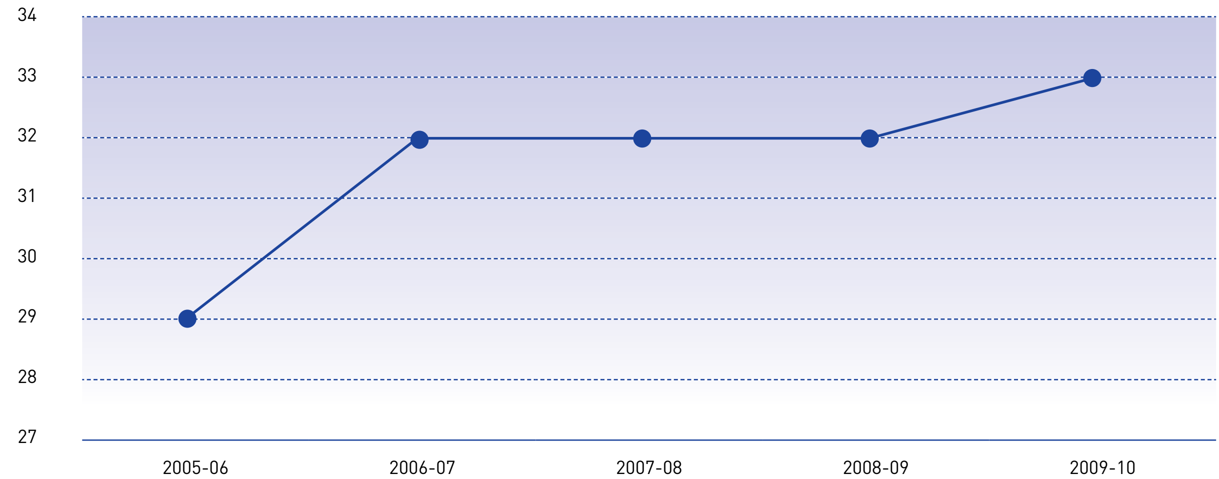
Figure 25: *2005-10 Connection Asset Customers Numbers*



	2005-06	2006-07	2007-08	2008-09	2009-10
CAC	184	184	186	194	199

Source: AR433c AER Data_v7_data room_28May09.xls

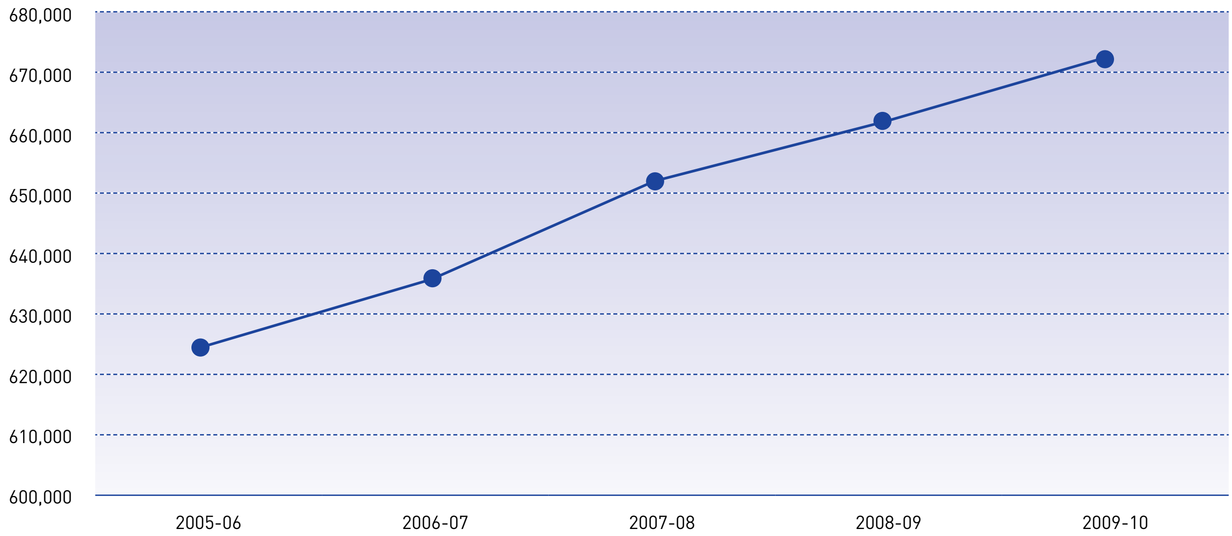
Figure 26: *2005-10 Embedded Generator Numbers*



	2005-06	2006-07	2007-08	2008-09	2009-10
EG	29	32	32	32	33

Source: AR433c AER Data_v7_data room_28May09.xls

Figure 27: *2005-10 Standard Asset Customers Numbers*



625,711	637,897	652,935	663,164	673,571

SAC (Includes customer numbers for Street Lighting Unmetered, not connections)

Source: AR433c AER Data_v7_data room_28May09.xls

21.2.2 Major New Industry or Commercial Developments

Queensland is a major source of steaming and coking coal to world markets. Queensland is also a major source of metals (gold, copper, zinc, lead and aluminium) in terms of mining and processing. These key resources represent major opportunities for the State which, if developed, would require significant additional energy supplies. There are also significant opportunities for renewable generation projects.

The connection of major industrial and mining loads is a key issue for Ergon Energy, although the financial risks of these new large connections can be somewhat alleviated if the design and construction of these connections is classified as an Alternative Control Service, as is proposed in Chapter 54 of this Regulatory Proposal, and therefore excluded from the revenue cap. New large customer connections almost always also result in Ergon Energy needing to expand its shared network, and the forecast costs of these works are included in the Standard Control Service forecasts in the category of Customer Initiated Capital Works (CICW).

High levels of investment in the mining sector in particular are expected to continue, albeit potentially later in the next regulatory control period as discussed in section 21.1. The quantum and timing of such new connections are difficult to predict, because they are influenced by world commodity prices and other economic and public policy factors.

This poses a number of risks for Ergon Energy in terms of future planning and resourcing, and requires continual monitoring for growth and new investment.

Providing these new 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 a major extension of network assets.

At the end of June 2008, Ergon Energy had:

- An aggregated demand of 1.2 GW in major customer connection projects under development, as well as 69 potential projects with a value estimated at over $900 million on the development horizon. These customer projects include new coal mines, upgrades to existing coal mines and coal terminals, new hard rock mining loads, Liquified Natural Gas (LNG) plants, coal seam methane installations and other commercial and industrial development projects; and
- 16 potential generator projects (i.e. directly connected to the distribution network) with an estimated value of $200 million and an increase generation demand of 500 MW.

The difficulty in accurately forecasting the level and timing of growth in the major customer segment results from:

- The combination of volatile market environments with the long lead time of some major customer connections, making it difficult to predict the timing and magnitude of the load that will be required to be supplied from the transmission and distribution systems;
- Timing of project starts. A number of projects, particularly in the mining sector, have been scheduled for a considerable time but many new projects in the coal sector have crystalised relatively quickly, prompted by the growing economy of China and its demand for energy. Similarly, buoyant conditions in the metals industry are bringing projects on line;
- The economic decline reducing demand for products. A down-turn in the economy of the purchasing country will see new projects deferred or existing projects closed down;
- Life of project versus asset life. Many of the projects have a life considerably shorter than the life of the assets required to provide the supply. For example, typically gold mines have a life of about 10 years and coal mines around 20 years. Yet both place significant demand on the distribution system in terms of the infrastructure required to supply their operational needs; and
- Renewable energy production opportunities or sources tending to be remote from major network infrastructure. For example, wind generation projects such as those proposed in the Toowoomba area and in Far North Queensland will, if progressed, require significant investment in infrastructure to deliver the energy produced.

21.2.3 Economic Growth

Queensland's gross state product (GSP) grew by 4.9 per cent in 2006-07 and 5.3 per cent in 2007-08, which has been underpinned by heavy investment in the resources sector as a result of high commodity prices and strong growth in private business investment and household consumption.

In September 2008, NIEIR forecast that Queensland's GSP growth would slow to 4.3 per cent in 2008-09, 3.5 per cent in 2009-10, 2.9 per cent in 2010-11 and 4.9 per cent in 2011-12. It projected average GSP growth in Queensland over the 2007-08 to 2011-12 period to be nearly 4.0 per cent per annum.

Queensland's employment growth in recent years has benefited from strong growth in construction, business services and public sector employment. Employment in Queensland grew by 3.6 per cent in 2005-06 and 4.6 per cent in 2006-07.

In September 2008, NIEIR forecast that Queensland's employment growth will slow in 2008-09 and 2009-10 before recovering in the post-2011 period and rising by nearly 3 per cent in 2011-12.

Private consumption expenditure growth in Queensland was 3.5 per cent in 2006-07, following growth of 4.3 per cent in 2005-06 and 6 per cent in 2004-05. This growth has been underpinned by high population growth rates, rapid employment growth and high levels of consumer confidence. A strong housing construction sector has also supported growth in household durables and appliance and equipment expenditures.

In September 2008, NIEIR forecast private consumption growth would decrease slightly from 5.6 per cent in 2007-08 and 4.9 per cent in 2008-09. It projected that, over the 2007-08 to 2011-12 period, private consumption expenditure growth in Queensland would average 4.4 per cent per annum.

Private business investment in Queensland rose by 10 per cent in 2006-07, following growth of over 26 per cent over the previous two years, with particularly strong growth in the mining, manufacturing and tertiary industry.

In September 2008, NIEIR forecast that private business investment in Queensland would grow at around 3.2 per cent growth per annum between 2007-08 and 2011-12 period.

Private dwellings investment in Queensland grew by 8.2 per cent in 2006-07, following growth of 4.5 per cent in 2004-05 and 0.8 per cent in 2005-06, which reflects strong underlying demand for new dwelling units as a result of Queensland's population growth.

In September 2008, NIEIR forecast that private dwelling expenditure in Queensland would continue to grow strongly over the coming years, with a sharp increase projected in 2010-11 and 2011-12. Overall housing construction expenditure is projected to rise by around 20 per cent over these two years.

Queensland Government consumption expenditure growth was 5.2 per cent in 2006-07, following growth of 3.6 per cent in 2005-06. It is understood that the Queensland Government has set aside funds to meet future liabilities.

In September 2008, NIEIR forecast that Queensland's public investment expenditure will rise at an average rate of 3 per cent per annum between 2007-08 and 2011-12.

As discussed in section 21.1, Ergon Energy has used its 2007 demand forecasts which are on average below NIEIR's 2008 forecast, and updated 2009 forecast which takes into account the global financial crises. Ergon Energy considers this approach as reasonable to compensate for the economic down-turn as a result of the global financial crisis.

A comparison of NIEIR's 2007 and 2008 forecasts for average market growth in gross regional product, population and dwelling stock for the period 2007 to 2017 and 2008 to 2018 is shown in Table 41.

Table 41: *NIEIR's Forecasts – 2007 to 2017 and 2008 to 2018 (percentage)*

Region	Gross regional product	Population	Dwelling stock
Far North			
North			
Mackay			
Capricornia			
Wide Bay Burnett			
South West			
South East (ENERGEX)			
Average			

Sources:

- NIEIR, Maximum Demand Forecasts for Ergon Energy Connection Points to 2011, November 2007, pages 27-29
- NIEIR, Maximum Demand Forecasts for Ergon Energy Connection Points to 2018, September 2008, pages 26-27

21.2.4 Climatic Effects and Air Conditioning Penetration

It has become generally accepted that climate change effects, including increased average temperatures, decreased average rainfall and increasingly volatile weather, are likely to impact on Queensland in the coming years. Higher summer temperatures and decreased average rainfall will tend to increase network peak demands or even extend the duration of peak demand periods due to air conditioning load and increased irrigation load.

Peak demand and high ambient temperatures have a significant impact on individual asset performance and life. Increasingly volatile weather is also likely to impact on network reliability, particularly in those parts of Ergon Energy's supply area that are considered to be especially sensitive to the effects of the El Nino weather pattern.

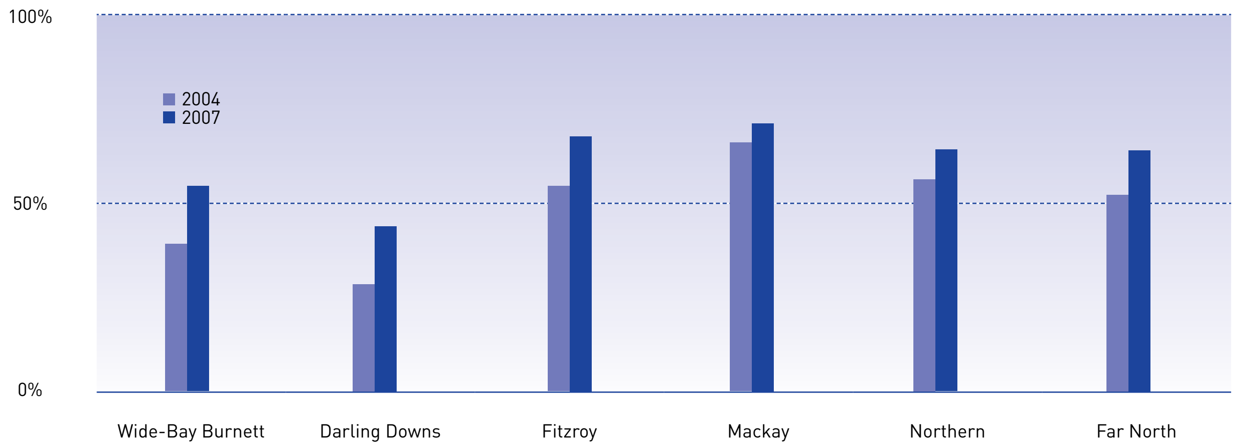
It has been Ergon Energy's practice to prepare demand forecasts for a 50 per cent Probability of Exceedance (POE) temperature condition (i.e. the temperature that can be expected to be exceeded once every two years). Temperature probabilities are of necessity based on historical recordings and do not include any allowance for forecast increases in average (and maximum) temperatures.

The use of 10 per cent 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 recommending consideration of this for critical areas, Ergon Energy commissioned independent consultants to review its forecasting practices and security criteria including the applicability of 10 per cent POE forecasts. This review endorsed the appropriateness of 10 per cent POE forecasts where the network is at higher risk and this is reflected in Ergon Energy's current practices as described in Chapter 20.

Ergon Energy's network serves tropical and sub-tropical areas with long established summer peaking loads, as well as the temperate South Western region, comprising Toowoomba and the Darling Downs, where the load is in the process of transitioning to summer peaking.

Figure 28 shows the break down by region of air conditioning penetration for the years 2004 and 2007 (data has been drawn from Queensland Household Surveys).

Figure 28: *Household Air Conditioning Penetration 2004-2007* [32]



Source: NMP 2008-09 p17 graph 3

The 2008 Queensland Household Surveys air conditioning penetration data is also provided with this Regulatory Proposal.

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 all areas have experienced an increased penetration of air conditioners, with significant increases in Wide Bay Burnett and Darling Downs.

Ergon Energy's load profiles, which are shown in Figure 29 and Figure 30, are typically quite flat, including on peak summer days, with the maximum demand occurring around 2.30pm. Figure 29 shows the load profiles for a peak day in 2007 (the most extreme recent peak) and a day in spring. The spring day curve (the lower line on the graph) demonstrates the essentially flat fundamental load profile, which is increased on hot days by thermally affected loads (the higher curve). This illustrates the large component of thermal load, which is composed mainly of commercial and domestic refrigeration and air conditioning.

Analysis of summer demands indicates a general and continuing positive trend in the temperature coefficients, or 'temperature-related variability' of maximum summer demands at non-industrial Bulk Supply Points, notwithstanding the results for 2007-08 which does not fit the trend of recent years.

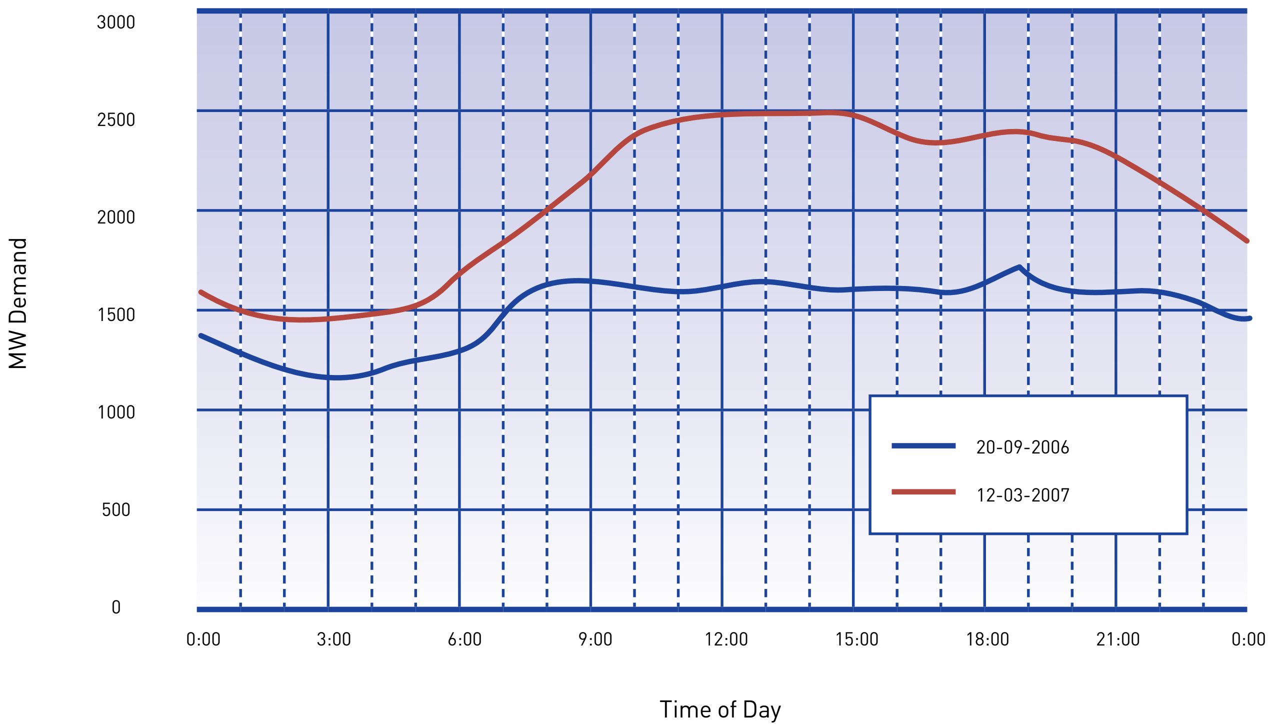
Total network coincident demand profiles for each peak day from six recent years are shown in Figure 30, while Figure 31 shows the average rate of demand growth over that period at each half hour of the peak days. Figure 30 shows demand growing fastest at around 4pm and 7pm. The time of peak therefore is expected to move to later in the day, driven by increasing penetration of domestic air conditioning.

Maximum demand occurring in the hottest part of summer, with a relatively flat load profile, results in severe stress on electrical infrastructure that effectively becomes de-rated, resulting in the need for augmentation and reinforcement to be implemented earlier to prevent escalation of the risk of failure.

The potential effects of climate change, including the likelihood of severe 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 at higher ambient temperatures with flat load profiles.

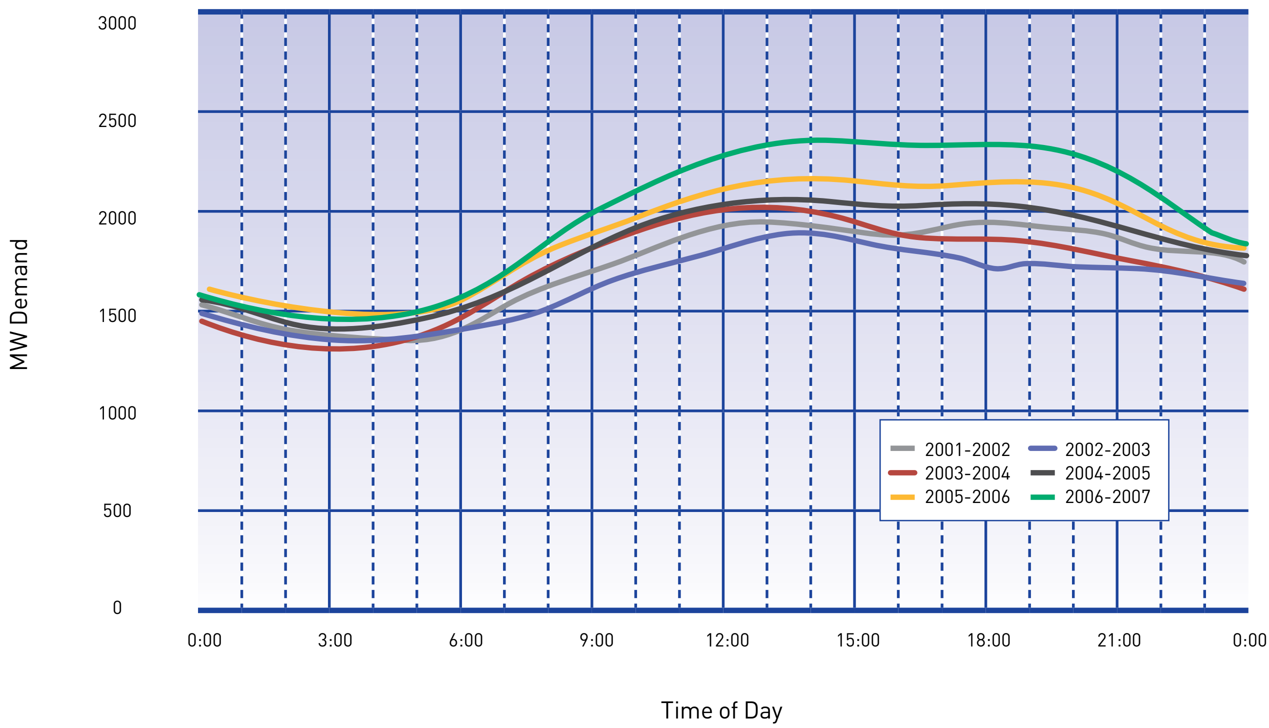
[32] Sourced from Ergon Energy's 2008-09 Network Management Plan

Figure 29: *Ergon Energy Load Profiles - Peak & Shoulder Days*



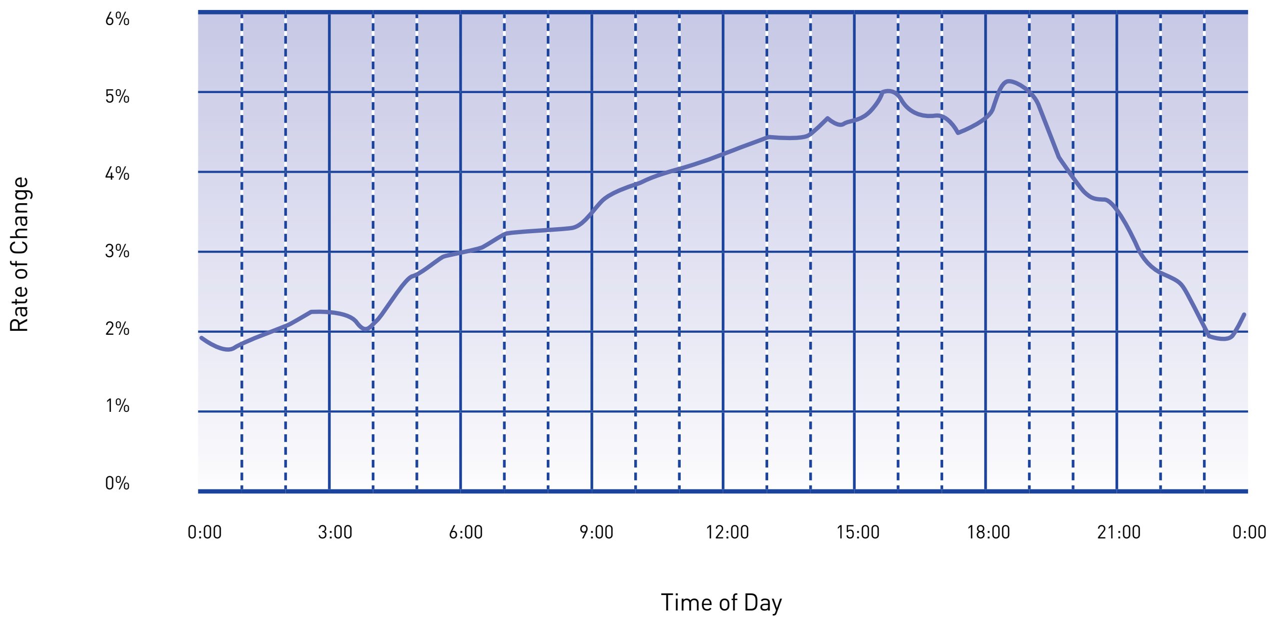
Source: NMP 2008-09 p18 graph 4

Figure 30: *Ergon Energy Peak Day Demand Profiles 2001-02 – 2006-07*



Source: NMP 2008-09 p19 graph 5

Figure 31: *Rate of Demand Growth (Five Year Average 2001-02 – 2006-07) Vs Time of Day*



Source: NMP 2008-09 p19 graph 6

21.3 METHODOLOGY (INCLUDING INPUTS AND ASSUMPTIONS) LIKELY TO IMPACT DEMAND FORECASTS FOR 2010-15

Clause S6.1.1(3) of the Rules requires Ergon Energy to detail "the forecasts of load growth relied upon to derive the capital expenditure forecasts and the method used for developing those forecasts of load growth".

Section 2.3.8(a)(3) of the RIN requires Ergon Energy to describe "the methodology that has been used to prepare the demand forecasts, including the key assumptions and inputs which have been used".

Although pro forma 2.3.8 of the RIN requires Ergon Energy to provide information in relation to maximum demand, energy consumption and customer numbers, Ergon Energy only uses forecasts of maximum demand and customer numbers (based on dwelling stock) to prepare its capital expenditure forecasts – it does not use energy consumption forecasts for this purpose. Furthermore, Ergon Energy does not use any of these demand forecasts to prepare its operating expenditure forecasts – they are only used to forecast capital expenditure forecasts.

The following subsections explain how Ergon Energy develops and applies its forecasts of maximum demand, energy consumption and customer numbers.

21.3.1 Maximum Demand

There are three maximum demand forecasts prepared by, or for, Ergon Energy, in order to identify where it needs to augment individual components of its distribution system. Two of the three forecasts are prepared by Ergon Energy's Network Forecasting & Development Group and the econometric forecast is prepared by the NIEIR and Ergon Energy's Network Strategic Planning Group.

21.3.1.1 Network Forecasting & Development Group's 10 Year Demand Forecasts

Ergon Energy's Network Forecasting & Development Group prepares a maximum demand forecast using a bottom up methodology in accordance with its internal procedure "P51F01 Network Load Forecasting Procedure".[33] This bottom-up methodology involves the following 13 stages.

In Stage 1, Network Forecasting & Development derives actual historic any time maximum demand by seasonal and annual periods from half-hour metered data in MW, together with the associated MVAR and MVA, for each of the bulk supply points and zone substations across Ergon Energy's six regions. The six regions are:

- Far North;
- North Queensland;
- Mackay;
- Capricornia;
- Wide Bay; and
- South West.

[33] Work Instructions P51F01B01 'Manage Network Forecasting Statistical Metering Database', P51F01B02 'Prepare Draft Forecast Work Instruction', and P51F01B03 'Generate Weather Corrected Base Values' are also relevant.

This data is generally sourced from metering data, however for the zone substations that do not have statistical metering (including National Electricity Market (NEM) data) or Supervisory Control and Data Acquisition (SCADA), estimates are used from Maximum Demand Indicator readings taken in the late 1990s. There are 30 of these zone substations and they are all very small in size, half being less than 1 MVA in capacity.

Stage 2 involves Network Forecasting & Development cleansing the historic any time seasonal maximum demand data in order to normalise them and remove anomalous events or circumstances, which would otherwise render the historic data useless for forecasting maximum demand. For example, this could involve:

- Removing events where loads have been switched between bulk supply points; or
- Identifying when a part of the network was augmented or reconfigured and making an associated adjustment; or
- Correcting for erroneous SCADA recordings.

Stage 3 involves undertaking straight line regression analysis for each of summer, winter and annual maximum demands recorded in order to forecast MW maximum demand 10 years into the future. As much of the available historic metering data is used in the regression as is relevant, depending on prominent step changes, rolling off (or increasing of) the growth or any other discontinuities in history which would produce unrealistic trends. There are some 1,500 such regressions (500 network elements multiplied by three seasons). The forecasts produced are intended to reflect the 'most likely' or 'base' case for 'average' weather conditions, consistent with a 50 per cent POE.

All of these regressions are checked for credibility, with Ergon Energy's staff applying judgement where needed. An instance where judgement is exercised is the winter regression giving a negative growth, whilst the summer is positive. Another situation is where a substation with predominantly irrigation load has had low loads in the past two years due to good rainfall in the area. All decisions to adjust, or in some cases to not adjust, the data are documented together with the forecast in the forecasting spreadsheets. The asset's forecast annual MW peak is the maximum of the summer, winter and annual values for each of the 10 years being predicted.

In Stage 4, Network Forecasting & Development identifies any step changes or spot load increases or decreases that it expects are likely to add to, or subtract from, Ergon Energy's maximum demand in the forecast period. This spot load forecast is done on a probabilistic basis to manage risks relating to the size, timing and likelihood of proceeding. The assessment is undertaken with input from Ergon Energy's Connection Managers, who have an in-depth understanding of the probability and timing of new connection activity proceeding in the field and liaise closely with all existing and potential major customers. This could involve, for example, a new mine opening or an existing large mining facility closing at a particular time.

Typically, routine subdivision works are not identified for this purpose as these are incorporated into the extrapolation of the maximum demand between years. Network Forecasting & Development extrapolates up to 10 years of recorded data and makes adjustments to accommodate confirmed and anticipated developments and other known local factors. Approved capital works projects that result in load transfers are incorporated into the forecasts, however, unapproved projects are not incorporated.

In Stage 5, Network Forecasting & Development applies the average power factor recorded (uncompensated) over the previous 10 years to each of the predicted seasonal MW in order to derive the future seasonal uncompensated MVAR. Installed and proposed power factor correction devices are applied to derive seasonal compensated MVAR. MVA is then calculated as the vector sum of MW and compensated MVAR.

In Stage 6, Network Forecasting & Development determines the summer and winter coincidence factors that are to be applied to the individual seasonal maximum demands for each bulk supply point and zone substation in order to derive the seasonal maximum demand forecasts for Ergon Energy's six regions. An individual coincidence factor is the average of the past 10 years, which reflects a 50 per cent POE. Under this assumption, there is a probability of exceeding the maximum demand forecast one in every two years. The 90th percentile of the same 10 historic values is used to determine the 10 per cent POE regional coincident demand forecast. Under this assumption, there is a probability of Ergon Energy exceeding the maximum demand forecast one in every 10 years. In this context:

- Coincident demand refers to the sum of the contributing demands for the same time period (or the any time maximum demand of the aggregate load);
- Maximum coincident demand for a time interval refers to the maximum of the sum of demands imposed by a group of loads over that time interval; whereas
- Maximum non-coincident demand refers to the sum of maximum demands of a group of loads over a time interval, where the maximum demands need not occur simultaneously.

In Stage 7, Network Forecasting & Development applies the coincidence factors to the predicted normalised maximum demand for each bulk supply point and zone substation in order to determine the coincident maximum demand (MW and MVAR) for each of Ergon Energy's six regions.

This analysis is undertaken based on a 50 per cent POE, which means that there is a probability of exceeding the maximum demand forecast one in every two years.

Stage 8 involves Network Forecasting & Development undertaking further analysis of the coincident maximum demand for each bulk supply point across each of Ergon Energy's six regions based on a 10 per cent POE, which means that there is a probability of exceeding the maximum demand forecast one in every 10 years.

Stage 9 involves Network Forecasting & Development aggregating the coincident maximum demand for all of the bulk supply points and zone substations within each of Ergon Energy's six regions. The coincident maximum demand is aggregated across the six regions in order to determine a forecast of aggregate demand (in MW, only) for the whole of Ergon Energy's network. Different forecasts are prepared for different purposes:

- For transmission and sub-transmission network capacity planning and operational purposes (as required by the National Electricity Rules (NER) and as agreed with Powerlink), Network Forecasting & Development prepares:
  - → 10 year connection point non-coincident annual, summer and winter maximum demand forecasts of MW, MVAR & MVA;
  - → 10 year connection point regional coincident annual, summer and winter maximum demand MW, MVAR & MVA;
  - → 10 year connection point state coincident annual, summer and winter maximum demand forecasts of MW, MVAR & MVA; and
  - → 10 year connection point energy (NPD Energy Forecasts have to date been based on extrapolating the NCP five year energy forecast and adding future major projects on a probabilistic basis.
- For distribution network capacity and operational purposes, Network Forecasting & Development prepares 10 year, non-coincident annual, summer and winter maximum demand forecasts of MW, MVAr and MVA for each zone substation.

It should be noted that:

- This forecasting process is undertaken annually by Network Forecasting & Development;
- None of Ergon Energy's maximum demand forecasts involve correcting any of the historic data for weather normalisation – rather, all calculations are based on actual historic data as recorded for metering purposes. Temperature correction techniques began to be developed and applied within Ergon Energy following the severe summer of 2001-02 and are used as a technique for reviewing forecast accuracy;
- Ergon Energy's aggregate coincident maximum demand is only prepared for inclusion in the Regulatory Proposal. It is not used in preparing expenditure forecasts because all the analysis for this purpose is undertaken at an asset level in order to identify where Ergon Energy needs to augment individual components of its distribution system;
- Only approved projects are reflected in the forecasts. This means that an approved new bulk supply point will be included but a planned (but not yet approved) bulk supply point will not be included; and
- Ergon Energy has a summer peak across all of its six regions, although summer, winter and annual maximum demand forecasts are prepared. The forecast annual maximum demand is the maximum of these three forecasts. It is noted that the South West region turned summer peaking four years ago, but with the last two mild summers, the winter peaks were higher than corresponding year's summer peaks for these last two years.

In Stage 10, Network Forecasting and Development prepares forecasts of the annual coincident maximum demand (in MVA) for the next 10 years by producing two workbooks for each of the six regions (plus an additional zone substation forecast for the Mount Isa-Cloncurry network). The workbooks provide forecasts by bulk supply points and zone substations. This can be considered Draft 1 of Ergon Energy's annual coincident maximum demand forecasts.

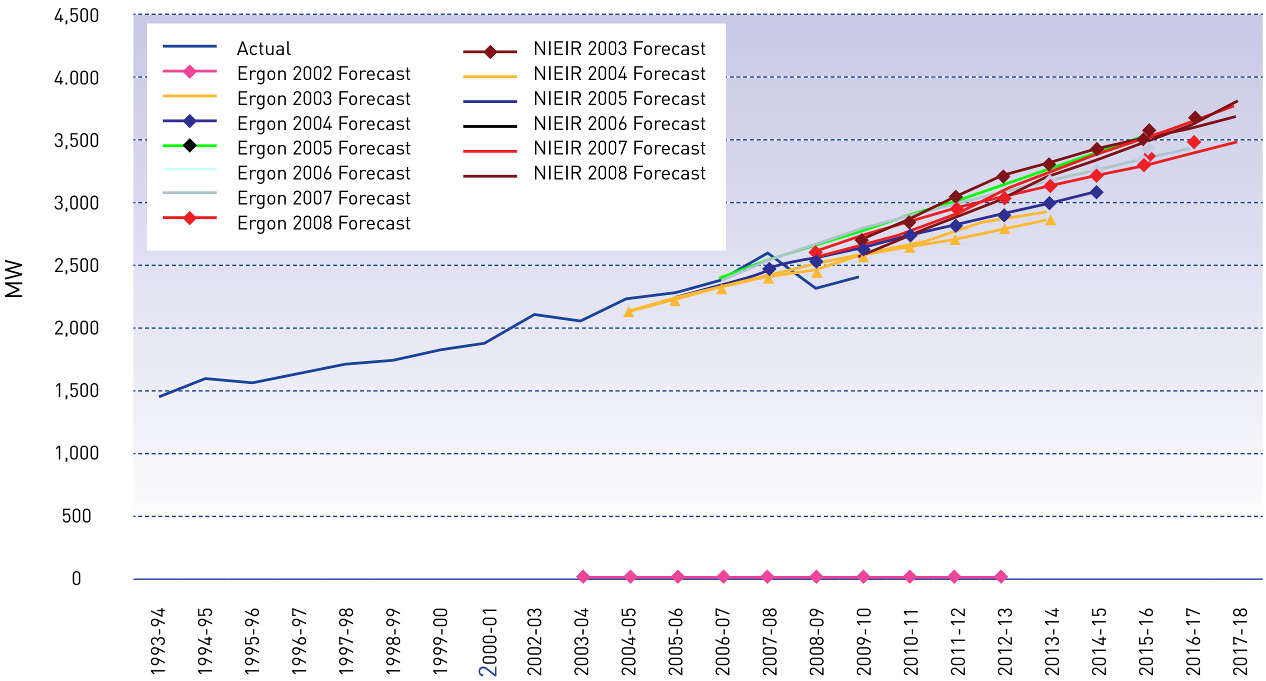
Stage 11 involves distributing the demand forecasts within Ergon Energy for peer review. This includes the Network Development Engineers and their support staff (who prepare the System Network Augmentation Plans), Distribution Planning Engineers and their support staff (who prepare the Distribution Network Augmentation Plans), Strategic Planning Engineers; Ergon Energy's Connection Managers and Regional Asset Management Development Officers. Feedback is incorporated into the forecasts resulting in the second version of the demand forecast. At this stage the zone substation forecasts are considered near final, with only the bulk supply point forecasts needing to be reconciled with NIEIR's econometric-derived forecasts. The bulk supply point forecasts also utilise the energy forecasts as prepared by Ergon Energy's Network Pricing group.

Stage 12 involves Ergon Energy annually engaging NIEIR to prepare econometric forecasts, which are used to test and validate Network Forecasting & Development's internally developed forecasts. This involves NIEIR producing independent forecasts using regionally based econometric models, which reference specific economic and demographic indicators as well as historical electricity usage. The nature of NIEIR's forecasts, and the methodology that it uses to prepare them, are discussed in the following sub section of this Regulatory Proposal.

In Stage 13, Network Forecasting & Development compares Draft 1 of Ergon Energy's annual coincident maximum demand forecasts with the forecasts produced by NIEIR in order to understand and reconcile any significant differences in outputs that have been produced between the two modelling approaches. The reconciliation is made against NIEIR's MW forecast under a base economic scenario at 50 per cent POE. Appendix G of NIEIR's September 2008 "Maximum demand forecasts for Ergon Energy connection points to 2018" compares NIEIR's and Network Forecasting & Development's approach to preparing their maximum demand forecasts.

Figure 32 is an example of how the Ergon Energy's forecasts and NIEIR's forecasts are reconciled. This type of analysis is performed for 111 network elements. The plots with the markers are Ergon Energy's derived forecasts, without markers is NIEIR's. Previous years' forecasts are included in order to judge the progress of the two separate forecasting processes. Where Ergon Energy's forecasts and NIEIR's forecasts track closely with each other, Ergon Energy considers the forecast to be adequately reconciled.

Figure 32: *Example of Comparison of Forecasts and Actual Total Maximum Demand at a Transmission Connection Point*



Source: NP&D

Stage 14 involves Network Forecasting & Development revising its MW forecasts and NIEIR revising its MW forecasts based on that they receive from each other about their initial forecasts. This results in Ergon Energy updating the second draft of its annual bulk supply point maximum demand forecasts.

The second draft of the demand forecast is provided to the Transmission Network Service Provider (Powerlink) for its review and feedback on any issues that are of concern.

Stage 14 also involves Network Forecasting & Development incorporating the energy forecasts of Network Pricing and with the use of load factors checking the two forecasts for consistency into the future. This results in the final version (version 3) of the annual maximum demand forecasts (in MW and MVA) for the next 10 years having produced two workbooks for each of the six regions and a further workbook for the Mount Isa-Cloncurry network. The workbooks provide forecasts by bulk supply points and zone substations. These final forecasts are:

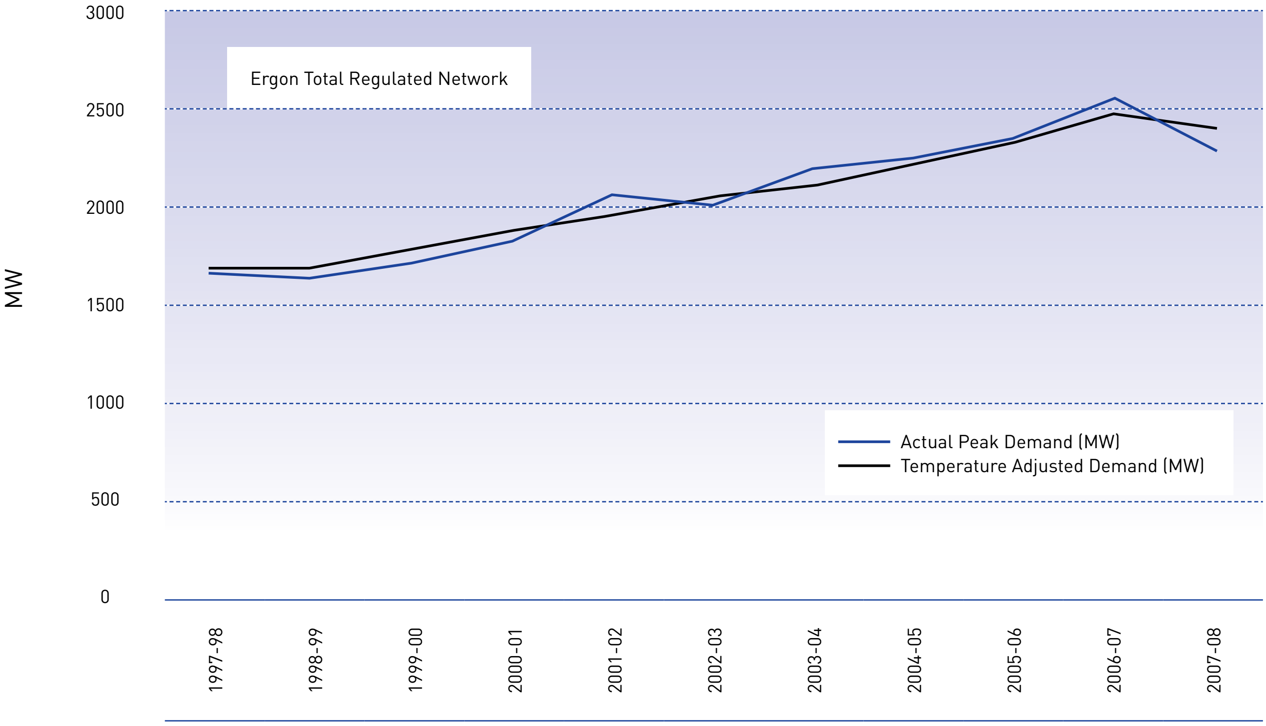
- Saved to a central database for future reference (for example variance analysis);
- Reported in the System Network Augmentation Plans (SNAPs) and are used as inputs in determining and reviewing these plans;
- Forwarded to Powerlink as a regulatory requirement (Bulk Supply Point forecasts only);
- Reflected in Part B of Ergon Energy's annual Network Management Plans;
- Used (zone substation forecasts only) as an input to the Distribution Loss Factor (DLF) determination process. The two year ahead values are used as input to the DINIS load flow models when determining the next financial year's margin loss factors; and
- Applied in Ergon Energy's DINIS load flow model. This model is used to identify constraints in the existing distribution system based on the maximum demand forecasts. By identifying where augmentation works are required, DINIS provides the basis preparing Ergon Energy's CICW forecasts for its sub-transmission and distribution parts of its network. The relationship between the maximum demand forecasts and augmentation works is explained in Ergon Energy's SNAPs, DNAPs and Distribution Capability Reports.

The key inputs used in the Network Forecasting & Development Group's model (which are broken down by bulk supply point, connection point or zone substation and then, as appropriate, by region, summer and winter peak and major customers) are:

- Actual annual historic MW, MVA, MVAr, load factors, power factors, diversity and coincident factors and installed transformer capacities;
- Installed and proposed VAR compensation units;
- Existing embedded generation recoded readings at time of substation peak and proposed generation ratings into the future;
- The time of recorded state winter and summer peak demand;
- Forecast annual Transmission Connection Point (TCP) energy requirements as prepared by Ergon Energy's Network Pricing group;
- Forecast network augmentation projects (permanent load transfers); and
- Prospective major customer load increases with probabilities of proceeding and completed major customer load increases since the last forecast was compiled.

Routinely each year, the one year ahead MW forecast is compared to actual recorded readings. Only the bulk supply points' recorded demand is weather corrected, and aggregated to the Ergon Energy network total demand. This involves applying MW/°C coefficients to bulk supply points exhibiting temperature correlations (regional centre bulk supply points, not those supply mining loads) and long term average diversity factors applied. Figure 33 is an illustration of the result of Ergon Energy network total weather corrected maximum demands. These weather corrected values are not used in the trend analysis as outlined in Stage 3.

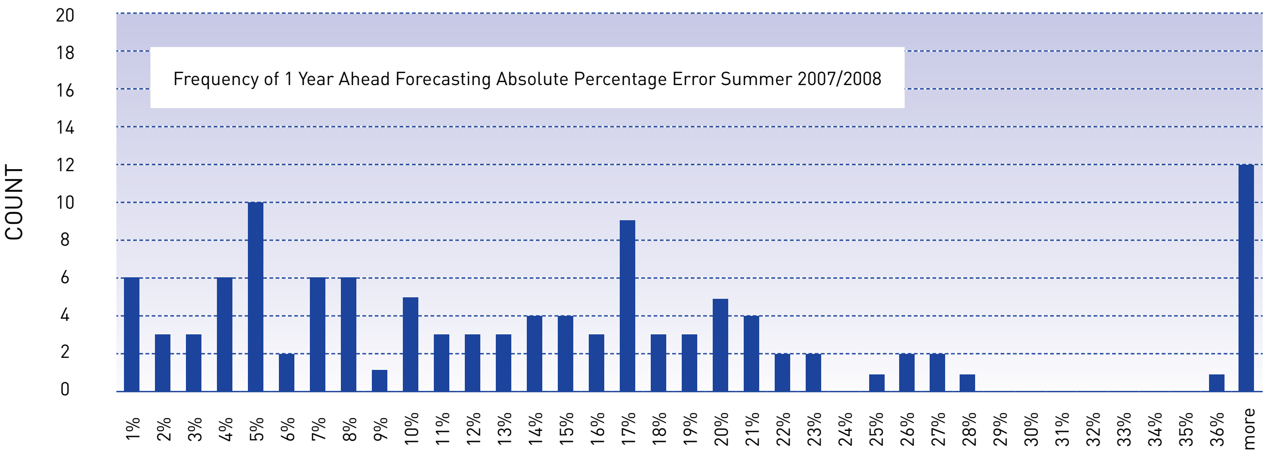
Figure 33: *Illustration of Total Weather Corrected Maximum Demands*



Source: NP&D

Figure 34 is a Pareto chart of the one year ahead forecasting errors (absolute percentage errors) of all substations and aggregations forecasted in 2007.

Figure 34: *Pareto Chart of One Year Ahead Forecasting Errors – 2007 Forecasts*



Source: NP&D

21.3.1.2 NIEIR's Forecasts

Ergon Energy annually engages NIEIR to prepare an econometric forecast of maximum demand to validate Network Forecasting & Development's internally produced forecasts. This involves NIEIR preparing 10 year forecasts using regionally based econometric models, which reference specific economic and demographic indicators as well as historical electricity usage. In particular, NIEIR has regard for: gross state product, population, employment, private consumption expenditure, dwellings investment and Government expenditure.

NIEIR is a well regarded independent modeller who annually prepares demand forecasts for most distribution and transmission network service providers in the NEM.

Section 5.2 and Appendix A of NIEIR's September 2008 "Maximum demand forecasts for Ergon Energy connection points to 2018" explain the methodology that NIEIR applies in preparing the maximum demand forecasts using its Energy Forecasting Model. Appendix A states that the main structural features of NIEIR's energy forecasting modelling system are:

- Primary and secondary energy is modelled at the regional (i.e. State) level;
- Energy demand is modelled on an industry/sectoral basis by State;
- Major energy intensive projects are explicitly taken into account;
- Environmental impacts in physical and dollar terms can be estimated;
- Energy prices and technological trends determine substitution between fuels in the different sectors of the economy; and
- Primary fuels used in electricity generation are modelled at the State level and include specific parameters for individual power stations within each State grid.

NIEIR sources its data from Ergon Energy and from Commonwealth Government agencies.

NIEIR produces the following forecasts by bulk supply point and zone sub station across each of Ergon Energy's six regions:

- Individual non-coincident maximum demand forecasts for summer and winter for each bulk supply point (i.e. connection point);
- State coincident maximum demand for each of the six regions for summer and winter; and
- Annual dispatch energy forecasts for each bulk supply point.

NIEIR's forecasts of maximum demand are prepared for:

- Summer and winter peaks;
- Three different economic growth scenarios - base, high and low; and
- 10 per cent and 50 per cent POE.

As noted above, Network Forecasting & Development compares the coincident maximum demand forecasts it has prepared with the forecasts produced by NIEIR and seeks to understand and reconcile any significant differences in assumptions that have been used and outputs that have been produced before finalising its coincident maximum demand forecasts. Appendix G of NIEIR's September 2008 'Maximum demand forecasts for Ergon Energy connection points to 2018' compares NIEIR's and Network Forecasting and Development's respective approaches to preparing their maximum demand forecasts.

While NIEIR's maximum demand forecasts are not directly used to prepare Ergon Energy's capital expenditure forecasts, they are used as a basis for reviewing, checking, testing and where necessary amending the demand forecasts prepared by Ergon Energy's Network Forecasting & Development Group.

21.3.1.3 Network Forecasting & Development's Strategic Planning Forecasts

Ergon Energy's Network Strategic Planning Group prepares 20 to 30 year demographic spatial load forecasts under various scenarios by applying projected load densities (obtained from Ergon Energy and Government sources) to land use zones within a defined geographic region.

To date, Network Strategic Planning has prepared forecasts based on assessments of Hervey Bay, South West Region including Toowoomba, Bundaberg, Cairns, Townsville and Mackay. Because these are high growth areas, Ergon Energy has closely examined where the existing distribution system is likely to be constrained in the coming years and what augmentation works are needed in order to continue to meet maximum demand.

Network Strategic Planning follows a five stage process to develop its spatial load forecasts.

Stage 1 involves merging local council zoning information with land parcel data to create a set of zoned land parcels.

Stage 2 involves a test of further development potential. An After Diversity Maximum Demand (ADMD) of 5 kVA is used for detached housing. The easiest way of representing this in the spatial model for developed areas is as a point load of 5 kVA. However, areas which are yet to be developed need to be modelled based on an assigned load density. Therefore, a test of land parcel size is used to determine when areas of land zoned for housing are fully developed or are yet to be developed.

Stage 3 involves assessing the electrical loading of land parcels. With the exception of developed housing areas, all other zones are modelled based on an assigned load density according to the zoning given by the local council. The load density can then be multiplied by the area of the land parcel to get the ADMD of the land parcel. This is represented in the spatial model by a point load on the land parcel centroid.

To ensure that the diversity between different load types is appropriately modelled a normalised load profile is applied to each land parcel according to whether the load type is residential, commercial and industrial.

Stage 4 involves preparing the spatial zone substation forecast. This involves representing the coverage area of the substation in the spatial model and then modelling the coverage area for the ideal case where each load is supplied by the closest zone substation.

Once the ideal coverage area of the zone substation is determined, all land parcel load profiles are summed which fall within the ideal coverage area of the zone substation. The zone substation spatial forecast of the maximum demand is then simply the maximum point on the resulting zone substation load profile.

Stage 5 involves an optimisation of the proposed zone substation sites. The method of optimising zone substation sites is based on minimising voltage drop. This is done by finding the electrical 'centre of gravity' of a proposed site's coverage area. The electrical 'centre of gravity' is found using the following:

> Given that the ADMD of all land parcels in a proposed zone substation site coverage area is $ADMD_1$, $ADMD_2$,....$ADMD_n$, with coordinates of (X_1,Y_1), (X_2,Y_2),....(X_n,Y_n) the optimum zone substation site (X, Y) is:

$$X = \frac{\sum ADMD_i x_i}{\sum ADMD_i}$$

$$Y = \frac{\sum ADMD_i y_i}{\sum ADMD_i}$$

The optimisation process is iterative in that the above formulae give the ideal location within the current site's coverage area. However, each time a better site is found the ideal site coverage area needs to be updated and the formulae applied again. This is repeated until the location of the zone substation site settles to the one ideal location.

These projections are incorporated by Network Forecasting & Development into the preparation of its SNAP and so feed into Ergon Energy's CIA capital expenditure forecasts for the sub-transmission system.

21.3.2 MMA's Elements of Good Forecasting

The AER has engaged McLennan Magasanik Associates (MMA) to undertake a preliminary assessment of Ergon Energy's demand forecasting method. MMA's report to the AER has been provided to Ergon Energy. This report includes what MMA considers are the criteria or elements of 'good' global and spatial demand forecasting. Table 42 and Table 43 provide an explanation of the way in which Ergon Energy applies these criteria/elements, or alternative methods that have been used.

Ergon Energy interprets MMA's terminology in the following way:

- 'Global' Demand Forecasting means a top-down holistic econometric forecast that considers broad matters such as demographic trends, worldwide commodity markets and labour markets. This analysis is applied similarly to a baseline-and-scope-change approach to arrive at a whole-of Ergon Energy forecast (albeit this forecast is described in the context of regions and bulk supply points). These forecasts are based on consideration of a number of exogenous drivers to determine an electrical demand and by definition do not require an analysis of the flows of energy within the electrical network; and
- 'Spatial' Demand Forecasting means a bottom-up site or location-specific forecast that builds up the forecast having regard for the land usage in the area, the population growth forecasts, reports produced by other authorities (e.g. local government, State infrastructure and departments etc) and historical demand at substations supplying the area. These forecasts require modelling of the flow of energy within the electrical network.

***Table 42:** MMA's Elements of Good Global Demand Forecasting – Ergon Energy's Application of the Criteria or Alternative Method*

MMA Element	MMA Description	Ergon Energy Approach/ Method/ Position	Justification for Ergon Energy Approach/ Method/ Position
Weather normalisation	As weather plays such a large part in maximum demand, appropriate weather normalisation is vital.	Ergon Energy uses the inherent weather normalisation that occurs in long term trend analysis (up to 10 years). This provides Ergon Energy-wide normalisation and incorporates all facets of weather effects including humidity and rainfall, in contrast to the single facet of temperature provided by explicit temperature correction. Ergon Energy's method inherently provides for changing consumer load patterns in response to weather triggers.	Explicit weather normalisation should involve reappraisal of weather correction patterns each year to account for changing consumer load patterns. This would involve a long-term trend analysis of temperature data and load data, followed by another trend analysis of the adjusted load data. Ergon Energy considers that this requires three times the data throughput to achieve a very similar result as that which occurs using Ergon Energy's trend analysis method, and does not factor in attributes such as humidity and rainfall. In addition, given the spread of locations where Ergon Energy's substations are situated, suitable weather data is not available for all locations.
Use of load research	To be able to better understand the contribution of different customer classes to system maximum demand.	Ergon Energy has subscribed to the Queensland household survey carried out by the Queensland Government Office of Economic and Statistical Research (OESR) for some years. Ergon Energy also has input from customer connection contracts (which nominate the nature of the load that is, or is intended to be, connected.	Ergon Energy considers that it does use load research methods to inform its demand forecasts.
Use of air conditioner penetration information	Growth in air conditioner penetration and usage has contributed significantly to maximum demand growth. Local inputs about historical growth and objective assessments of future growth are required.	Ergon Energy has used both internal and external studies of the effects of air conditioning on its demand. OESR surveys of household intentions are also studied and the analysis used to prepare forecasts.	Ergon Energy considers that it does use air conditioner penetration information to inform its demand forecasts.
Model construction	The model needs to have a logical structure and a level of detail that is commensurate with available information.	Ergon Energy has a set of integrated spreadsheets (i.e. a model) structured in accordance with network topology that are used to prepare the demand forecast.	Ergon Energy considers that it has an appropriate 'model' for preparing its demand forecasts.

MMA Element	MMA Description	Ergon Energy Approach/ Method/ Position	Justification for Ergon Energy Approach/ Method/ Position
Model validation	The form of the model used, and any changes proposed need to be validated and tested against alternative model forms. The accuracy of the model over a relevant historical period should be tested.	Ergon Energy commissions a top-down econometric forecast from NIEIR each year in addition to undertaking Ergon Energy's own bottom-up forecast. Both forecasting results for bulk supply points are compared and reconciled. Both forecasting methods have proven to give similar results.	Ergon Energy considers the annual cross-check with NIEIR validates the accuracy of Ergon Energy's model.
Reasonableness of forecast inputs	The key forecast inputs need to be both timely and reasonable. Key drivers need to be considered.	Ergon Energy goes to considerable lengths to cleanse load source data of anomalous events such as those due to unusual network switching or data equipment errors. Ergon Energy also factors in proposed load changes and transfers between substations, including assessed probability of occurrence. These spot loads are revised annually.	Ergon Energy considers that the forecast inputs used for its demand forecasts, adjusted if necessary, are reasonable.
Documentation	Detailed documentation of the model is required, in particular the validation of the peak demand model, including tables and figures, sufficient to enable a third party with access to relevant data to replicate the model and forecast. Without such documentation the modelling and forecasting process is incomplete.	Ergon Energy's documented load forecasting methodology has been applied consistently for many years. Whilst improvements are being introduced when appropriate (e.g. when new and improved sources of data is available), the fundamental approach now has significant history to validate the outcomes. Documentation of the method used, and adjustments to data sources that are made are embedded within the spreadsheets (i.e. the model) and not in separate stand-alone documentation.	Ergon Energy recognises that the lower level detailed documentation may need to be more extensive. However Ergon Energy believes that its forecasting method, and decisions made during the forecasting process, can be explained and audited using a spot-check random selection process.

***Table 43:** MMA's Elements of Good Spatial Demand Forecasting – Ergon Energy's Application of the Criteria or Alternative Method*

MMA Element	MMA Description	Ergon Energy Approach or Methodology	Justification for Ergon Energy Approach or Methodology
Documentation	The spatial forecast methodology including source of assumptions needs to be fully described and documented.	Documentation of the method used, and adjustments to data sources that are made are embedded within the spreadsheets (i.e. the model) and not in separate stand-alone documentation.	Ergon Energy recognises that the lower level detailed documentation may need to be more extensive. However, Ergon Energy believes that its forecasting method, and decisions made during the forecasting process, can be explained and audited using a spot-check random selection process.
Approach	The approach needs to be well-considered, objective and unbiased.	Ergon Energy's approach to preparing its bottom-up forecasts is as described in section 21.3.1 of this Regulatory Proposal.	Ergon Energy considers that its forecasting method is well-considered, objective and unbiased.
Evidence of application of methodology	There needs to be evidence that the methodology described is generally well-followed and consistently applied.	Ergon Energy's approach, and the spreadsheets (i.e. model) used, deliver consistency due to the way transformations and calculations are coded into the spreadsheets. In addition, only a small number of Network Planning and Forecasting staff actually work on the demand forecasts so this assists in achieving consistency in application of the methodology.	Ergon Energy considers that its application of its forecasting methodology is both consistent and well-followed.

MMA Element	MMA Description	Ergon Energy Approach or Methodology	Justification for Ergon Energy Approach or Methodology
Weather normalisation	As weather plays such a large part in spatial maximum demand, appropriate weather normalisation is considered important, even though difficult at the spatial level.	Ergon Energy uses the inherent weather normalisation that occurs in long term trend analysis (up to 10 years). This provides site specific normalisation and incorporates all facets of weather effects including humidity and rainfall, in contrast to the single facet of temperature provided by explicit temperature correction. Ergon Energy's method inherently provides for changing consumer load patterns in response to weather triggers.	Explicit weather normalisation should involve reappraisal of weather correction patterns each year to account for changing consumer load patterns. This would involve a long term trend analysis of temperature data and load data, followed by another trend analysis of the adjusted load data. Ergon Energy considers that this requires three times the data throughput to achieve a very similar result as that which occurs using Ergon Energy's trend analysis method, and does not factor in attributes such as humidity and rainfall. In addition, given the spread of locations where Ergon Energy's substations are situated, suitable weather data is not available for all locations.
Consideration of key drivers and reconciliation between global and spatial forecasts	The key drivers need to be recognised in the global forecast and then translated and reconciled with the spatial projections.	Ergon Energy's spatial forecasts are prepared on a bottom-up basis, substation-by-substation. The outcomes from these forecasts are compared with NIEIR's top-down econometric global forecasts. To the extent that there are differences, these are reconciled jointly between Ergon Energy and NIEIR. Typically variations are not significant. In addition, history has proven that Ergon Energy's forecasts are usually nearest to actual demand that occurs after the forecasts have been settled.	Ergon Energy considers that it takes into account drivers between the global and spatial forecasts.
Timely information	Timely information incorporating current understanding of key drivers and large new loads needs to be incorporated into forecasts.	Ergon Energy factors in the most recent information it can obtain when preparing its load forecasts. This includes any significant large load changes and known works (such as switching) on the distribution system.	Ergon Energy considers that it takes into account the most recent (timely) information possible when preparing its load forecasts.

21.3.3 Customer Numbers

There are three forecasts of customer numbers prepared by, or for, Ergon Energy. Two of these forecasts are prepared by NIEIR and the other is prepared by Ergon Energy's Network Pricing Group.

21.3.3.1 NIEIR's Forecasts

As part of its annual independent study for Ergon Energy, NIEIR prepares 14 year forecasts of:

- Population numbers – these forecasts are prepared by bulk supply point and zone substation across each of Ergon Energy's six regions under base, high and low growth scenarios. These forecasts are not directly used either for capital expenditure forecasting or pricing purposes; and
- Dwelling stock – these forecasts are prepared by bulk supply point and zone substation across each of Ergon Energy's six regions under base, high and low growth scenarios. These forecasts are only used to prepare Ergon Energy's customer initiated capital works forecasts for small customers for its Standard Control Services.

These forecasts are produced from NIEIR's Energy Forecasting Model, which uses as inputs State economic data, including in relation to industry output, capital stocks, major projects, household numbers and population growth.

As a consequence, only NIEIR's dwelling stock forecast is used for preparing Ergon Energy's expenditure forecasts for the next regulatory control period and this use is restricted to CICW forecasts for small customers for Standard Control Services. Population forecasts are not used to prepare any expenditure forecasts.

21.3.3.2 Ergon Energy's Network Pricing Group

Ergon Energy's Network Pricing Group annually projects customer numbers based on National Metering Identifiers (NMIs) (i.e. not population or dwelling stock, as is forecast by NIEIR) for the purposes of determining prices to recover Ergon Energy's regulated revenue cap and connection charges and Powerlink's transmission use of system charges.

Network Pricing undertakes its projections for one year only based on the customer classifications that it uses for pricing purposes – these are Individually Calculated Customers (ICC), Connection Asset Customers (CAC), Standard Asset Customers (SAC), Embedded Generators (EGs) and unmetered supplies.

The annual projections are based on extrapolations from one year to the next, with adjustments made for known additions and losses of NMIs.

Importantly, Network Pricing does not develop long-term projections of NMI numbers for pricing purposes during the course of the regulatory control period.

As a consequence, while annual NMI forecasts are prepared, they are only used by Network Pricing for pricing purposes. These forecasts are not used in any way by Ergon Energy for preparing expenditure forecasts for the next regulatory control period.

21.3.4 Energy

There are two forecasts of energy prepared by, or for, Ergon Energy. One is prepared by NIEIR and the other is prepared by Ergon Energy's Network Pricing Group.

21.3.4.1 NIEIR's Forecasts

As part of its annual independent study for Ergon Energy, NIEIR prepares 14 year forecasts of energy consumption (in MWh) by bulk supply point and zone substation across each of Ergon Energy's six regions under a base, high and low growth scenario.

Section 5.1 of the NIEIR's September 2008 "Maximum demand forecasts for Ergon Energy connection points to 2018" explains the methodology that it applies in preparing energy forecasts using its Energy Forecasting Model. This section states that:

> *Electricity sales data for Queensland was obtained from Ergon Energy and the Electricity Supply Association of Australia for the following customer classes:*
>
> - *residential;*
> - *commercial and industrial;*
> - *farm;*
> - *traction; and*
> - *public lighting.*
>
> *NIEIR's existing Queensland electricity forecasting model was used to drive the electrical energy projections. This model is an industry based model which uses the ABARE energy demand data and NIEIR's projections of gross state product and output by industry along with other variables.*
>
> *Table 5.1 shows the Australian Standard Industrial Classification (ASIC) categories included in NIEIR's Queensland electricity forecasting model. Table 5.1 also shows the concordance between customer class categories and ASIC industry categories. Electricity consumption forecasts are based on econometric models which link Queensland electricity sales by industry to real output growth by industry, electricity prices, and weather conditions. Residential sales are determined form a model including average consumption per dwelling, weather, real income, and electricity prices.*
>
> *The forecasts of Queensland electricity sales by class were therefore simply indexed to the sum of the relevant ASIC category forecasts.*

These forecasts are not directly used either for capital expenditure forecasting or pricing purposes.

21.3.4.2 Ergon Energy's Network Pricing Group

Ergon Energy's Network Pricing Group annually projects energy throughput for the purposes of determining prices to recover Ergon Energy's regulated revenue cap and connection charges and Powerlink's transmission use of system charges. This energy forecast is energy expected to be delivered through both the transmission network connection points and energy sent out by Embedded Generators into the distribution network.

Network Pricing undertakes its projection for one year only based on the customer classifications that it uses for pricing purposes – these are ICC, CAC, SAC, EG and unmetered supplies. The forecast for EGs is the amount of energy generated into Ergon Energy's distribution system. For all other customer classes, it is energy consumption that is being forecast.

The annual projections for all customer classes are based on extrapolations from one year to the next, with adjustments made for known additions and losses of load.

Importantly, Network Pricing does not develop long term projections of energy consumption for pricing purposes during the course of the regulatory control period.

As a consequence, while annual energy consumption forecasts are prepared they are only used by Network Pricing for pricing purposes – they are not used in any way by Ergon Energy for preparing expenditure forecasts for the next regulatory control period.

21.3.5 Conclusion

On the basis of the above, it is clear that the forecasts that are relevant to Ergon Energy's Regulatory Proposal are:

- All three maximum demand forecasts, which are used to prepare its CIA capital expenditure forecasts for Standard Control Services; and
- The customer dwelling stock forecast, which is used to prepare its CICW forecasts for Standard Control Services – it does not use customer NMI or customer population forecasts for this purpose.

Importantly, Ergon Energy:

- Does not use energy forecasts to prepare its operating expenditure forecasts for Standard Control Services; and
- Will subsequently use forecasts of customer NMIs and energy to prepare its Pricing Proposal, although this will follow the AER's release of its Distribution Determination.

21.4 DESCRIBE MODEL USED TO DEVELOP DEMAND FORECASTS FOR 2010-15

As required by section 2.3.8(a)(4) of the RIN, section 21.2.2 of this Regulatory Proposal describes the models that are used to develop Ergon Energy's demand forecast for the next regulatory control period.

21.5 INDEPENDENT VERIFICATION OF DEMAND FORECASTS FOR 2010-15, INCLUDING COPY OF REPORT

Section 2.3.8(a)(5) of the RIN requires Ergon Energy to state whether there has been any independent verification of its demand forecasts and, if so, to provide a copy of a report on that verification.

As noted above, Ergon Energy annually engages NIEIR to prepare independent forecasts of:

- Maximum demand – NIEIR prepares a 14 year top-down forecast of maximum demand to validate Network Forecasting & Development's internally produced forecasts. This involves NIEIR preparing 14 year forecasts using regionally based econometric models, which reference specific economic and demographic indicators as well as historical electricity usage. While NIEIR's maximum demand forecasts are not directly used to prepare Ergon Energy's capital expenditure forecasts, they are used as a basis for reviewing, checking, testing and where necessary amending the demand forecasts prepared by Ergon Energy's Network Forecasting & Development Group;
- Customer numbers – NIEIR prepares 14 year forecasts of:
  - → Population numbers – these forecasts are prepared by bulk supply point and zone substation across each of Ergon Energy's six regions under base, high and low growth scenarios. These forecasts are not directly used either for capital expenditure forecasting or pricing purposes; and
  - → Dwelling stock – these forecasts are prepared by bulk supply point and zone substation across each of Ergon Energy's six regions under base, high and low growth scenarios. These forecasts are only used to prepare Ergon Energy's CICW forecasts for small customers for its Standard Control Services.
- Energy consumption – NIEIR prepares 14 year forecasts of energy consumption (in MWh) by bulk supply point and zone substation across each of Ergon Energy's six regions under a base, high and low growth scenario.

A copy of NIEIR's September 2008 report entitled 'Maximum demand forecasts for Ergon Energy connection points to 2018 - Coincident and non coincident peaks for summer and winter by BSP' is provided in the data room of documents accompanying this Regulatory Proposal.

21.6 EXPLAIN HOW DEMAND FORECASTS HAVE BEEN USED TO DEVELOP THE DNSP'S CAPITAL AND OPERATING EXPENDITURE FORECASTS FOR 2010-15

Section 2.3.8(a)(6) of the RIN requires Ergon Energy to explain how its demand forecasts have been used to develop its capital and operating expenditure forecasts for 2010-15.

Ergon Energy's demand forecasts are only used to prepare its capital expenditure forecasts – they are not used to prepare its operating expenditure forecasts.

As is explained in section 21.2.2 of this Regulatory Proposal, the demand forecasts that are used to prepare Ergon Energy's capital expenditure forecasts are:

- The three maximum demand forecasts, which are used to prepare its CIA capital expenditure forecasts for Standard Control Services; and
- The customer dwelling stock forecast, which are used to prepare its small CICW forecasts for Standard Control Services.

21.6.1 Corporation Initiated Sub-transmission Augmentation Capital Expenditure

The maximum demand forecasts are reflected into Ergon Energy's ten year SNAPs for each of its six regions. These Plans describe the capital works that are required to meet the augmentation requirements of the sub-transmission network in order to accommodate the normal load forecasts for the next 10 years. As well as the demand forecasts, the SNAPS are prepared having regard for:

- The Network Planning Criteria NP02 and Security Criteria NPD05;
- The load flow analysis undertake in DINIS;
- Major CICW forecasts;
- Strategic sub-transmission planning studies;
- Joint Planning Studies between Ergon Energy and Powerlink;
- Distribution augmentation forecasts – discussed below;
- Demand Management Initiatives; and
- The current works plan.

The SNAPs are prepared annually and form the basis of the annual budget planning process, including the development of a Ten and Five Year Capital Works Plan. The five year forecasts for the next regulatory control period are loaded into the regulatory models via the Growth Forecast Spreadsheet. These forecasts are prepared by drawing on the Unit Rates Master List Spreadsheet.

21.6.2 Corporation Initiated Distribution Augmentation Capital Expenditure

The maximum demand forecasts are reflected into Ergon Energy's 10 year DNAPs for each of its six regions. These Plans describe the capital works required to meet the augmentation requirements of the distribution network in order to accommodate the normal load forecasts for the next 10 years. As well as the demand forecasts, the DNAPS are prepared having regard for:

- Distribution Network Current State Assessments;
- The Network Planning Criteria NP02 and Security Criteria NPD05;
- The identification of potential demand management initiatives; and
- Regional Distribution Capability Reviews and 10 year Distribution Augmentation Plans for Ergon Energy's six regions, which are themselves prepared on the basis of a Distribution Capability Report and Strategic Distribution Planning Studies

The DNAPs are prepared annually and form the basis of the annual budget planning process, including the development of a Ten and Five Year Capital Works Plan. The five year forecasts for the next regulatory control period are loaded into the regulatory models via the Growth Forecast Spreadsheet. These forecasts are prepared by drawing on the Unit Rates Master List Spreadsheet.

21.6.3 Small Customer Initiated Capital Expenditure

Ergon Energy has prepared forecasts of the number of SAC connections on the basis of both NIEIR's dwelling stock growth forecasts for the following three sub-categories of SAC connections:

- Commercial and Industrial;
- Domestic and Rural; and
- Subdivisions.

The percentage of total lots allocated to each category is determined based on historical actual lots for the years 2004-05 to 2007-08. The small CICW expenditure from 2008-09 to 2014-15 is forecast using the 2007-08 actual baseline and NIEIR dwelling stock growth rates. These figures exclude gifted assets and overheads. Small CICW expenditure for Domestic and Rural, and Commercial and Industrial, is further broken down to show an estimated allocation between overhead and underground works.

21.7 COPY OF CONSULTANT'S DEMAND FORECAST REPORT FOR 2010-15

Section 2.3.8(a)(7) of the RIN requires Ergon Energy to provide a copy of the consultant's report that has developed the demand forecast.

A copy of NIEIR's November 2007 report, NIEIR's September 2008 report and NIEIR's April 2009 report are provided in the data room of documents accompanying this Regulatory Proposal.

21. DEMAND FORECASTS (SYSTEM ONLY) – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice

QCA Documents

Nil

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR064	EE Network Planning Criteria – NP02, V2.03, 30 May 2000
AR065c	NIEIR November 2007 Maximum Demand Forecasts
AR128c	NIEIR September 2008 Maximum Demand Forecasts
AR175	EE Security Criteria - NPD05, 12 April 2005
AR283c	EE Distribution Network Augmentation Plans 2008
AR289	EE Regional Distribution Capability Reviews 2008
AR291	EE P51F01 Network Load Forecasting Procedure
AR292	EE P51F01B01 Manage Network Forecasting Statistical Metering Database Work Instruction, 1 August 2002
AR293	EE P51F01B02 Prepare Draft Forecast Work Instruction, 1 August 2002
AR294	EE P51F01B03 Generate Weather Corrected Base Values Work Instruction, 1 August 2002
AR374c	NIEIR April 2009 report "Economic Outlook for Australia and Queensland to 2018-19 – December 2008"
AR375c	EE Sub-transmission Network Augmentation Plans 2007
AR376c	EE Sub-transmission Network Augmentation Plans 2008
AR401	EE Network Management Plan, Summary, 2008-13
AR402	EE Network Management Plan, Part A 2008-09 to 2012-13
AR412c	EE Demand/Load Forecast Spreadsheets 2007-08
AR433c	EE AER Data,V7, Data Room, 28 May 2009
AR434c	EE Unit Rates Master List Spreadsheet, 5 May 2009
AR445	EE Network Management Plan, Part B 2008-09 to 2012-13
AR460	EE Distribution Capability Report 2008, V2, December 2008
AR540	EE Air Conditioning Penetration Trend, QHS 2008 Additional Analysis, 12Jun09

22. CAPITAL EXPENDITURE – HISTORICAL

Rules – Clauses 6.5.7(e)(5), S6.1.1(1) and (6)
RIN – Sections 2.2.1 and 2.4.4
RIN Pro forma – 2.2.1

This chapter details Ergon Energy's capital expenditure for the equivalent of Standard Control Services during the previous and current regulatory control periods. Clause 6.5.7(e)(5) of the Rules requires the Australian Energy Regulator (AER) to have regard for Ergon Energy's actual and expected capital expenditure during preceding regulatory control periods in deciding whether to accept Ergon Energy's capital expenditure forecasts for the next regulatory control period.

The Regulatory Information Notice (RIN) section 2.2.1(a)(1) also requires that the forecast of required capital expenditure by expenditure type for the next regulatory control period be provided. Ergon Energy has set this information out in Chapter 23 of this Regulatory Proposal.

The historical dollar values for 2001-02 to 2007-08 presented in this chapter:

- Exclude street lighting operating expenditure but include other operating expenditure relating to Excluded Distribution Services, which from 1 July 2010 will be classified as Alternative Control Services. It is not possible to remove actual operating expenditure for services that are in the future to be classified as Alternative Control Services. This is because Ergon Energy's historical records were not kept at an individual service level and, as a result, historic expenditure cannot be aligned to the new classification of services;
- Are in dollars of the day for each year (i.e. are nominal values so include inflation);
- Include Shared Costs (Overheads) for 2005-06 to 2007-08 that have been backcast using the AER's approved Allocation Methods and Procedures; and
- Include Shared Costs (Overheads) as reported to the Queensland Competition Authority (QCA) in Ergon Energy's Annual Regulatory Reporting Statements for 2001-02 to 2004-05 using the QCA approved Cost Allocation Methods and Procedures.

The forecast dollar values for 2008-09 and 2009-10 presented in this chapter:

- Only relate to Standard Control Services;
- Are in dollars of the day for each year (i.e. these are nominal values so include inflation); and
- Include Shared Costs (Overheads) that have allocated using the AER's approved Cost Allocation Method for 2008-09 to 2009-10.

22.1 ACTUAL CAPITAL EXPENDITURE FOR 2001-05 BY ASSET CLASS BY YEAR

Clause S6.1.1(6) of the Rules and section 2.2.1(a)(1) of the RIN requires Ergon Energy to provide details of its actual capital expenditure by asset class for each of the past years of the previous regulatory control period 1 July 2001 to 30 June 2005.

Ergon Energy's historical capital expenditure by asset class for the regulatory control period 1 July 2001 to 30 June 2005 is detailed in Table 44.

Table 44: *Capital Expenditure – 2001-05 Actual Expenditure by Asset Class ($M Nominal)*

	2001-02	2002-03	2003-04	2004-05	4 Year Total	Average of 4 Year Total
System assets						
Overhead Sub-transmission Lines	8.89	21.28	14.36	24.74	69.28	17.32
Overhead Distribution Lines	110.90	102.96	159.33	192.57	565.76	141.44
Substation Bays	16.87	37.04	30.96	56.22	141.09	35.27
Distribution Transformers	30.21	44.43	75.10	92.63	242.37	60.59
Low Voltage Services	20.44	32.02	13.14	13.78	79.37	19.84
Metering	5.68	7.04	6.41	5.93	25.07	6.27
Communications – Pilot Wires	1.08	1.68	2.02	15.60	20.38	5.09
Generation Assets	0.00	0.19	0.89	1.04	2.12	0.53
Other Equipment	0.07	0.00	0.00	0.00	0.07	0.02
Control Centre - SCADA	0.00	0.00	0.00	0.00	0.00	0.00
Land & Easements (System)	0.10	0.01	0.03	0.43	0.56	0.14
Buildings (System)	0.84	1.99	1.44	5.37	9.64	2.41
Subtotal	195.07	248.63	303.69	408.30	1,155.69	288.92
Non-System assets						
Communications	0.30	0.09	0.05	0.14	0.57	0.14
IT Systems	14.61	24.66	22.30	33.79	95.36	23.84
Office Equipment & Furniture	1.15	0.45	0.56	0.50	2.65	0.66
Motor Vehicles	12.72	25.69	18.22	21.93	78.55	19.64
Plant & Equipment	2.86	3.30	4.23	10.57	20.96	5.24
Buildings	3.43	4.58	6.42	11.66	26.08	6.52
Land & Easements	0.00	0.00	0.00	0.00	0.00	0.00
Land Improvements	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	35.05	58.75	51.78	78.58	224.17	56.04
Total Capital Expenditure	**230.12**	**307.38**	**355.47**	**486.89**	**1,379.86**	**344.96**

Source: Tables for Proposal 22.1

This information is also detailed in pro forma 2.2.1 of the AER's RIN.

22.2 ACTUAL CAPITAL EXPENDITURE FOR 2005-10 BY ASSET CLASS BY YEAR (WHERE AVAILABLE)

Clause S6.1.1(6) and clause 2.2.1(a)(1) of the RIN requires Ergon Energy to provide details of its actual capital expenditure by asset class for each of the past years of the current regulatory control period 1 July 2005 to 30 June 2010.

Ergon Energy's historical capital expenditure by asset class for the period 1 July 2005 to 30 June 2008, and forecast capital expenditure by asset class for the period 1 July 2008 to 30 June 2010, is detailed in Table 45.

Table 45: *Capital Expenditure – 2005-10 Actual and Forecast Expenditure by Asset Class ($M Nominal)*

	2005-06 (Actual)	2006-07 (Actual)	2007-08 (Actual)	2008-09 (Forecast)	2009-10 (Forecast)	5 Year Total	Average of 5 year Total
System assets							
Overhead Sub-transmission Lines	19.21	70.21	80.64	45.43	66.56	282.04	56.41
Underground Sub-transmission Cables	0.34	3.62	19.65	17.15	15.08	55.83	11.17
Overhead Distribution Lines	255.71	158.35	133.00	146.22	137.83	831.11	166.22
Underground Distribution Cables	17.18	90.87	88.97	96.50	96.19	389.71	77.94
Distribution Equipment	11.30	3.74	0.71	38.38	37.22	91.35	18.27
Substation Bays	47.37	68.14	122.29	56.90	68.81	363.50	72.70
Substation Establishment	15.14	28.84	5.33	23.83	29.82	102.95	20.59
Distribution Substation Switchgear	3.07	15.84	14.02	36.66	42.46	112.05	22.41
Zone Transformers	13.22	21.54	56.71	22.66	21.97	136.11	27.22
Distribution Transformers	82.20	105.39	102.50	110.40	115.68	516.16	103.23
Low Voltage Services	22.66	17.03	16.39	12.53	11.09	79.69	15.94
Metering	7.24	12.13	9.27	8.09	18.91	55.64	11.13
Communications – Pilot Wires	2.10	1.84	4.00	6.25	38.74	52.93	10.59
Generation Assets	0.93	0.00	0.00	0.00	0.07	1.00	0.20
Other Equipment	0.00	7.86	4.73	0.39	0.92	13.90	2.78
Control Centre - SCADA	6.08	12.39	17.55	6.16	11.14	53.31	10.66
Land & Easements (system)	0.00	0.61	1.63	24.02	16.31	42.56	8.51
Buildings (System)	0.00	0.00	0.00	8.65	11.15	19.80	3.96
Subtotal	503.72	618.41	677.37	660.20	739.92	3,199.62	639.93
Non-System assets							
Communications	0.07	5.74	0.25	0.00	0.00	6.06	1.21
IT Systems	73.64	35.99	14.97	7.12	25.60	157.32	31.46
Office Equipment & Furniture	0.84	1.98	6.58	0.76	0.52	10.68	2.14
Motor Vehicles	37.70	27.98	24.72	32.05	28.43	150.89	30.18
Plant & Equipment	11.43	28.44	35.53	6.92	7.37	89.70	17.94
Buildings	23.94	25.09	32.93	25.12	73.49	180.57	36.11
Land & Easements	0.16	10.61	1.13	0.51	1.49	13.90	2.78
Land Improvements	0.00	1.46	5.39	0.00	0.00	6.85	1.37
Subtotal	147.79	137.29	121.50	72.48	136.91	615.96	123.19
Total Capital Expenditure	**651.50**	**755.70**	**798.87**	**732.68**	**876.82**	**3,815.58**	**763.12**

Source: Tables for Proposal 22.2

This information is also detailed in pro forma 2.2.1 of the AER's RIN.

22.3 ACTUAL CAPITAL EXPENDITURE FOR 2001-2005 BY CATEGORY DRIVER BY YEAR

Clause S6.1.1(6) of the Rules and section 2.2.1(a)(2) of the RIN requires Ergon Energy to provide details of its actual capital expenditure by category driver for each of the past years of the previous regulatory control period 1 July 2001 to 30 June 2005.

Ergon Energy's historical capital expenditure by category driver for the regulatory control period 1 July 2001 to 30 June 2005 is detailed in Table 46.

Table 46: *Capital Expenditure – 2001-05 Actual Expenditure by Category Driver ($M Nominal)*

	2001-02	2002-03	2003-04	2004-05	4 Year Total	Average of 4 Year Total
System Capital Expenditure						
Asset Replacement	62.86	88.70	114.76	139.53	405.84	101.46
Corporation Initiated Augmentation	61.97	90.40	102.85	184.30	439.52	109.88
Customer Initiated Capital Works	43.40	63.62	64.59	56.97	228.58	57.15
Reliability & Quality Improvements	8.85	10.22	5.37	8.02	32.46	8.11
Other System Capital Expenditure	18.00	54.44	16.12	19.49	108.04	27.01
Subtotal	195.07	307.38	303.69	408.30	1,214.44	303.61
Non-System assets	35.05	0.00	51.78	78.58	165.42	41.36
Total	**230.12**	**307.38**	**355.47**	**486.89**	**1,379.86**	**344.97**

Source: Tables for Proposal 22.3

This information is also detailed in pro forma 2.2.1 of the AER's RIN.

22.4 ACTUAL CAPITAL EXPENDITURE FOR 2005-10 BY CATEGORY DRIVER BY YEAR (WHERE AVAILABLE)

Clause S6.1.1(6) of the Rules and section 2.2.1(a)(2) of the RIN requires Ergon Energy to provide details of its actual capital expenditure by category driver for each of the past years of the current regulatory control period 1 July 2005 to 30 June 2010.

The apparent dip in Ergon Energy's capital expenditure profile in 2008-09 is primarily due to year-to-date investment being well below the budget for that year because of a number of factors including, but not limited to:

- A delay in the UbiNet project approval;
- A change in CICW scoping, estimating and approval process;
- Resources being diverted to rectify damage caused by flooding;
- The work program being deferred by industrial action, decisions to reduce overtime and a drive to reduce staff's leave entitlements (resulting in staff being away on leave); and
- An underspend in non-system capital expenditure (particularly in the categories of Land and Buildings, Motor Vehicles and capital expenditure associated with the Change Program).

Ergon Energy plans to recover this situation over the next three years (2009-10 to 2011-12) and return to the capital expenditure profile seen in the first three years of the current regulatory control period. This profile of expenditure is reflected in the capital expenditure forecasts in this Regulatory Proposal.

Ergon Energy's historical capital expenditure by category driver for the period 1 July 2005 to 30 June 2008, and forecast capital expenditure by category driver for the period 1 July 2008 to 30 June 2010, is detailed in Table 47.

Table 47: Capital Expenditure – 2005-10 Actual and Forecast Expenditure by Asset Class ($M Nominal)

	2005-06	2006-07	2007-08	2008-09 Estimate	2009-10 Estimate	5 Year Total	Average of 5 Year Total
System assets							
Asset Replacement	160.29	137.27	107.09	117.29	141.92	663.86	132.77
Corporation Initiated Augmentation	118.89	176.92	248.01	219.55	233.09	996.47	199.29
Customer Initiated Capital Works	197.87	282.69	280.33	268.42	276.90	1,306.22	261.24
Reliability & Quality Improvements	6.98	10.71	13.60	10.06	8.87	50.22	10.04
Other System Capital Expenditure	19.69	10.82	28.34	44.88	79.14	182.86	36.57
Subtotal	503.72	618.41	677.37	660.21	739.92	3,199.62	639.91
Non-System Assets	147.79	137.29	121.50	72.48	136.91	615.96	123.19
Total	**651.50**	**755.70**	**798.87**	**732.68**	**876.82**	**3,815.58**	**763.10**

Source: Tables for Proposal 22.4

This information is also detailed in pro forma 2.2.1 of the AER's RIN.

22.5 TOTAL CAPITAL EXPENDITURE REQUESTED AND APPROVED FOR 2005-10 BY YEAR

Clause S6.1.1(6) of the Rules and section 2.2.1(a)(4) of the RIN requires Ergon Energy to provide details of the total amounts of capital expenditure that it requested, and the QCA approved, for each of the past years of the current regulatory control period 1 July 2005 to 30 June 2010.

Table 48 details, for the current regulatory control period:

- The total capital expenditure that Ergon Energy requested from the QCA in its February 2005 submission in response to the QCA's Draft Determination;
- The capital expenditure that Ergon Energy requested as cost pass throughs in the years in which the requests were made;
- The total capital expenditure that the QCA approved in its April 2005 Final Determination; and
- The capital expenditure that was reflected in the QCA's revenue adjustment approval for cost pass throughs in the years in which the revenue adjustment was made.

Table 48: Capital Expenditure – 2005-10 Requested and Approved Expenditure ($M Nominal)

	2005-06	2006-07	2007-08	2008-09	2009-10	5 Year Total
Capital Expenditure requested by DNSP at reset (1)	554.70	606.79	662.45	681.43	693.87	3,199.24
Pass through requested (2)	0.00	12.10	0.00	27.17	0.00	39.27
Total Capital Expenditure requested	554.70	618.89	662.45	708.60	693.87	3,238.51
Capital Expenditure approved by regulator at reset (3)	524.50	574.40	627.80	645.80	657.40	3,029.90
Pass through approved during reset (4)	0.00	0.00	0.00	33.02	0.00	33.02
Total Capital Expenditure approved by regulator	524.50	574.40	627.80	678.82	657.40	3,062.92

Source:

1. Table 3.7, "Ergon Energy Submission, QCA Draft Determination, 25 February 2005", page 19. Real 2004 dollars converted to nominal using 2.76% per annum CPI as approved by the QCA.
2. Ergon Energy cost pass through submissions to the QCA.
3. Table 4.18, "QCA Final Determination 2005-10", April 2005, page 93.
4. QCA approval letters to Ergon Energy and associated Final Decisions.

Tables for Proposal 22.5

This information is also detailed in pro forma 2.2.1 of the AER's RIN.

22. CAPITAL EXPENDITURE - HISTORICAL – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005
AR415	QCA Draft Determination, 23 December 2004
AR527	QCA Final Decision on Cyclone Larry

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR119c	EEAnnual Regulatory Accounts for 2001-02
AR120c	EE Annual Regulatory Accounts for 2002-03
AR121c	EE Annual Regulatory Accounts for 2003-04
AR122c	EE Annual Regulatory Accounts for 2004-05
AR123c	EE Annual Regulatory Accounts for 2005-06
AR124c	EE Annual Regulatory Accounts for 2006-07
AR314	EE Cost Allocation Method, AER Approved
AR370c	EE Annual Regulatory Accounts for 2007-08
AR391	EE Cost Allocation Methods and Procedures approved by QCA, 2 May 2006
AR416	EE Ergon Energy Response to QCA Draft Determination, 25 February 2005

23. CAPITAL EXPENDITURE – FORECAST AND JUSTIFICATION

Rules – Clauses 6.12.1(3) and S6.1.1
RIN – Sections 2.2.1, 2.2.4 and 2.3.10(b)(5)
RIN Pro forma - 2.2.1 and 2.2.4
CAG – Section 5.1(b)(2)

This chapter overviews Ergon Energy's capital expenditure forecasts for Standard Control Services for the regulatory control period 1 July 2010 to 30 June 2015. Forecasts have been prepared in accordance with the Australian Energy Regulator's (AER's) Cost Allocation Guidelines (CAG) clause 5.1(b)(2) in that Ergon Energy's approved Cost Allocation Method (CAM) has been applied in preparing the forecasts.

Ergon Energy has two types of capital expenditure:

- System capital expenditure; and
- Non-system capital expenditure.

System capital expenditure comprises:

- Asset replacement – which comprises defect and condition-based expenditure;
- Corporation Initiated Augmentation (CIA) – which comprises sub-transmission and distribution expenditure;
- Customer Initiated Capital Works (CICW) – which comprises customer driven expenditure on the shared network for small customer connections;
- Reliability and quality improvements – which comprises reliability and power quality related expenditure; and
- Other system – which comprises expenditure related to communications, protection, Single Wire Earth Return (SWER) and undergrounding and other programs.

Non-system capital expenditure comprises:

- Tools and equipment – which comprises those purchases which are over $1,000 and are recorded in the asset register in the categories of tools and ladders;
- Fleet – which comprises purchases of vehicles and mobile equipment that constitute tools of trade;
- Property – which comprises non-network related expenditure for buildings, land and easements;
- IT systems – which comprises expenditure on multi-function devices, laptops and other equipment that are not provided by Sparq Solutions Pty Ltd (SPARQ); and
- Other – which comprises expenditure on communications, office equipment and furniture as well as land improvements.

23.1 FORECAST CAPITAL EXPENDITURE FOR 2010-15 BY CATEGORY DRIVER BY YEAR

Clause S6.1.1(2) of the Rules requires information about the 'method' used for developing the capital expenditure forecast. Ergon Energy's 'method' is the same as the 'estimation process' that is requested to be described in the RIN section 2.3.10(a).

Table 49 details Ergon Energy's forecast capital expenditure for 2010-15 by category driver by year.

Table 49: Forecast Capital Expenditure – by Category Driver – 2010-15 ($M Real $2009-10)

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	Total	Average of 5 Year Total
Asset Replacement	177.44	212.68	250.03	274.81	299.18	1,214.14	242.83
Corporation Initiated Augmentation	267.84	339.38	401.26	463.58	518.89	1,990.95	398.19
Customer Initiated Capital Works	336.11	354.99	315.56	328.70	359.63	1,694.99	339.00
Reliability and Quality Improvement	18.29	20.89	24.50	28.28	30.43	122.39	24.48
Other System	105.62	72.94	50.78	50.39	51.65	331.38	66.28
Non-System	180.90	199.03	135.19	82.27	81.70	679.10	135.82
Total	**1,086.20**	**1,199.90**	**1,177.32**	**1,228.03**	**1,341.49**	**6,032.94**	**1,206.59**

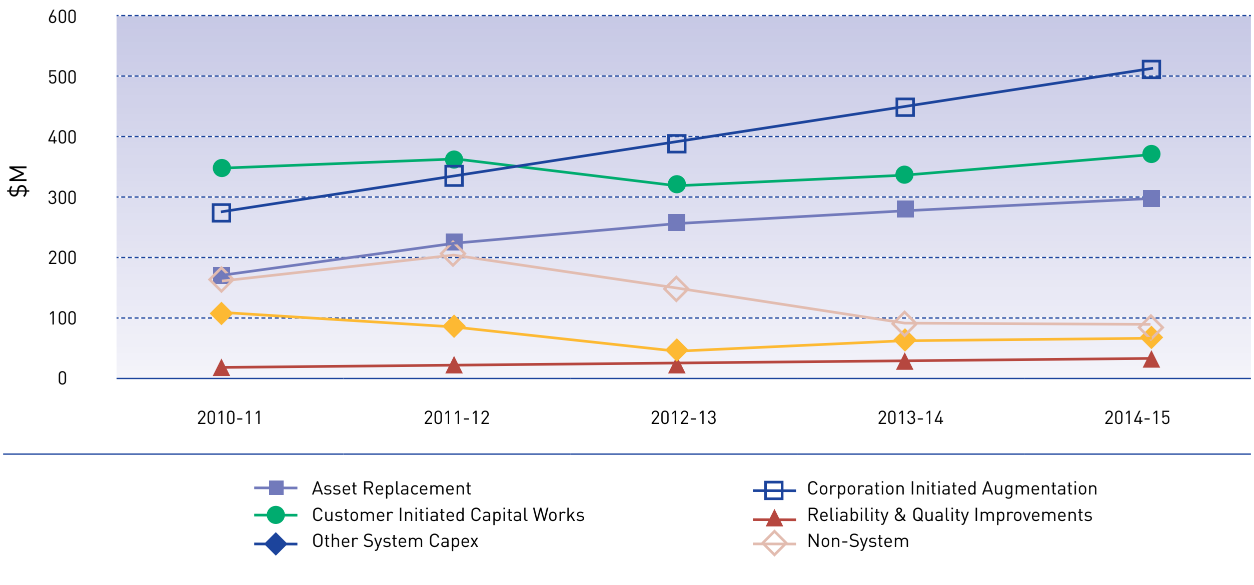
Source: Tables for Proposal 23.1

The forecast dollar values presented in this chapter:

- Only relate to Standard Control Services; and
- Include direct costs and Shared Costs (Overheads). The Shared Costs (Overheads) have allocated using the AER's approved CAM for 2008-09 to 2009-10, as discussed in Chapter 34;

Section 2.3.10(b)(6) of the AER's RIN requires Ergon Energy to explain how the profile of the expenditure for different types of projects and programs have been developed. Figure 35 shows the profile that has been developed. The explanation of how each forecast has been prepared, and thus the profile of expenditure, is explained in the sections about each type of capital expenditure forecast.

Figure 35: Forecast Capital Expenditure – by Category Driver – 2010-15- Expenditure Profile $M ($M Real $2009-10)



Source: Tables for Proposal 23.1

23.2 CAPITAL EXPENDITURE – ASSET REPLACEMENT

23.2.1 Forecast 2010-15

Ergon Energy's Capital Expenditure – Asset Replacement forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 50.

Table 50: *Capital Expenditure – Asset Replacement – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
111.96	117.29	141.92	177.44	212.68	250.03	274.81	299.18	1,214.14	242.83

Source: Tables for Proposal 23.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10)

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

The Capital Expenditure – Asset Replacement forecast is explained in the sections below in two categories:

- Defects; and
- Condition-based.

23.2.2 What this Forecast Relates to

Failure rates increase as assets age. This leads to an increased need for Corrective and Forced Maintenance, which involves operating expenditure.

Ergon Energy's Capital Expenditure-Asset Replacement program focuses on assets that are in poor condition and therefore are most likely to fail in service. These are generally assets approaching the end of their lives, but also include assets that are failing early. Increasing Asset Replacement expenditure will reduce the average lives of Ergon Energy's assets. This, in turn, will reduce the number of failures requiring Corrective and Forced Maintenance and so improve reliability and public safety.

23.2.2.1 Defects

This type of capital expenditure relates to assets that have failed or are imminently about to fail. It therefore seeks to avoid Corrective and Forced Maintenance expenditure associated with assets in poor condition or beyond their economic or useful lives by providing for equipment to be replaced and refurbished in an orderly manner, based on Ergon Energy's Network Defect Classification Manual.

This expenditure predominantly relates to line assets with capital works being determined from defects identified through the inspection program that is undertaken as part of Operating Expenditure – Preventive Maintenance. Ergon Energy's Network Defect Classification Manual provides asset inspectors with guidelines on when an asset should be proposed for replacement based on the condition that is measured or identified in the field. This Network Defect Classification Manual has been reviewed on several occasions in recent years to re-evaluate the risk profile and optimise the replacement expenditure program.

Ergon Energy considers that it does not have discretion in undertaking this defect-related Asset Replacement expenditure that derived from its proposed Preventive Maintenance program. This is because the current risk management framework that is reflected in its Asset Management Defect Policy and Network Defect Classification Manual requires that high risk defects be addressed within defined periods, in accordance with regulatory requirements.[34] Lower priority defects are monitored at the next inspection cycle and not included in these forecasts.

"Defects" also include repair and replacement following the failure of major items of plant, such as underground cables and power transformers.

[34] For example, the Electrical Safety Act 2002, the Electrical Safety Regulation 2002, the Code of Practice – Works (Protective earthing, underground cable systems and maintenance of supporting structures for powerlines) and the Guidelines for Design and Maintenance of Overhead Distribution and Transmission Lines.

23.2.2.2 Condition Based

This type of capital expenditure seeks to avoid the escalation of Corrective and Forced Maintenance expenditure by providing for equipment to be replaced and refurbished based on condition assessments.

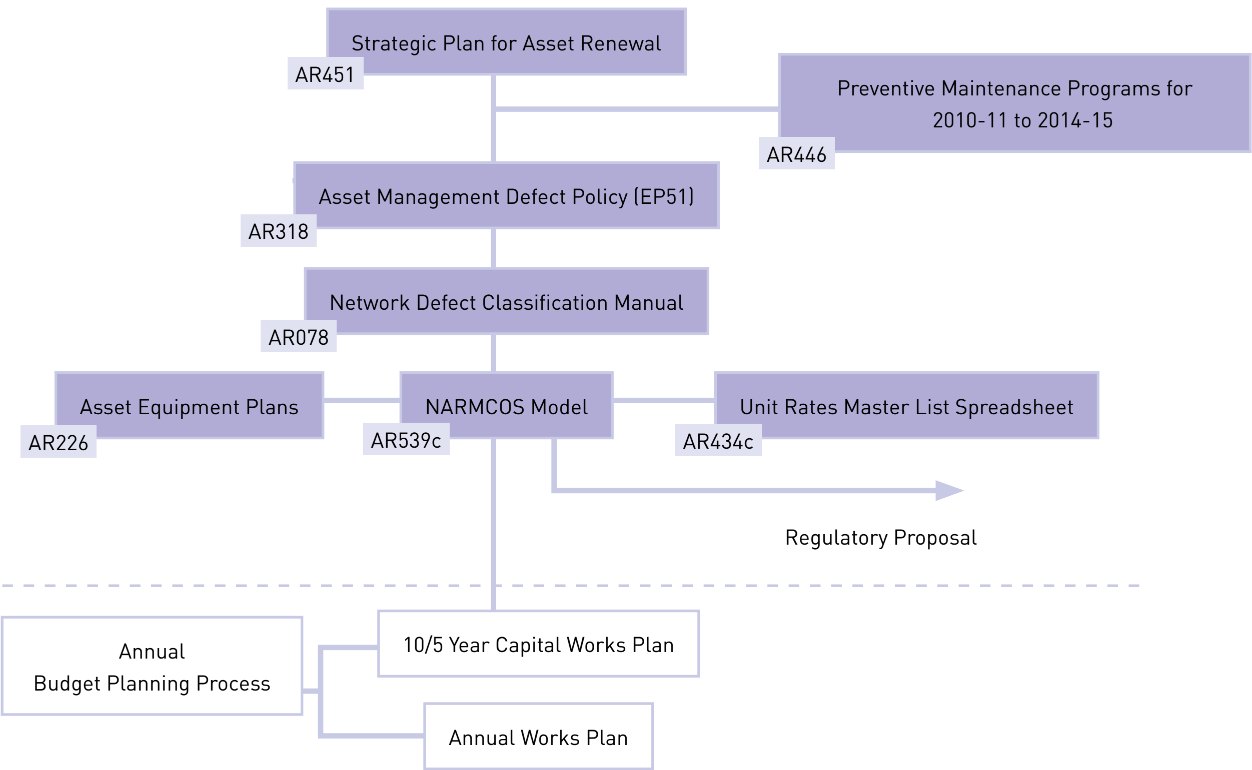
This category of asset renewal expenditure does not involve undertaking works based on Ergon Energy's Defect Management Policy or Network Defect Classification Manual. Rather, this expenditure is driven by specific condition-based issues, such as: failure characteristics of assets, failure rates and risk (such as safety, environment, financial and customer outages), unserviceability, obsolescence, replacement of whole assets rather than component parts, bulk replacements, unavailability of spare parts, asset life, assets not being fit for purpose; premature ageing, fault rating increases leading to faster ageing and the impact of failures on public safety and system security.

This expenditure predominantly relates to sub-transmission zone substations and secondary systems assets.

23.2.3 Estimation Process

23.2.3.1 Defects

Figure 36: *Capital Expenditure – Asset Replacement – Defects*



The Defect Management Policy details how Ergon Energy will assess when asset replacements are needed in order to avoid an asset failing prior to its next inspection and to mitigate the need for forced operating expenditure.

The Strategic Plan for Asset Renewal commits Ergon Energy to keeping its network assets fit for purpose and in a safe and environmentally sound condition so as to minimise the risk of condition based and age-related failures.

The document entitled 'Preventive Maintenance Programs for 2010-11 to 2014-15' outlines the maintenance cycles underpinning the Preventive Maintenance programs and work plans within Ergon Energy for the five years commencing from 2010-11. While this document details Operating Expenditure – Preventive Maintenance programs and work plans, these drive the Capital Expenditure – Asset Replacement – Defects requirements.

The Asset Equipment Plans (AEPs) set out the asset management methodology for each of Ergon Energy's 26 asset equipment types. The AEPs provide detailed discussions of growth rates, and cycle times, for each of the 26 asset equipment types and identify new Preventive Maintenance programs, which are reflected in Capital Expenditure – Asset Replacement – Defects.

The Asset Management Defect Policy describes the way in which Ergon Energy will classify its defects and sets timeframes in which classified defects will be repaired.

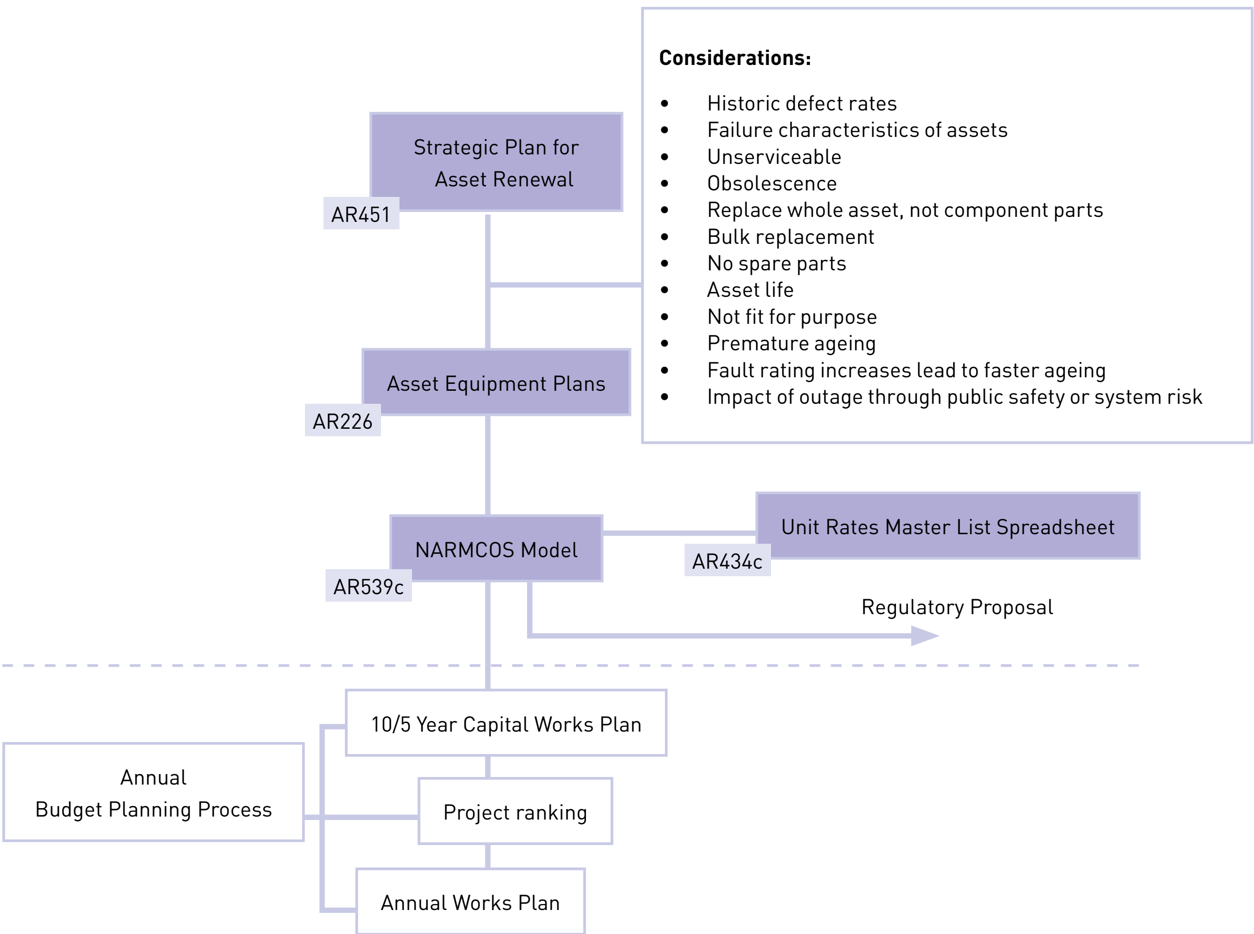
The Network Defect Classification Manual is designed to assist asset inspectors to identify defects accurately in the field across all of Ergon Energy's classes of system assets. It details the way in which inspections and assessments are to be undertaken for each class of system assets.

The Network Assets Replacement Maintenance Capital Expenditure Operating Expenditure Summary (NARMCOS) model forecasts Asset Replacement expenditure based on Ergon Energy's Network Defect Classification Manual across the appropriate classes of system assets. These forecasts are prepared by drawing on the Preventive Maintenance programs, estimated defect rates and the Unit Rates Master List Spreadsheet.

The forecasts from the NARMCOS model are reflected in the budget planning process, including the development of a Ten and Five year Capital Works Plan and an Annual Works Plan. These form the basis for the five-year forecasts for the next regulatory control period that are included in this Regulatory Proposal (see Figure 36).

23.2.3.2 Condition Based

Figure 37: *Capital Expenditure – Asset Replacement – Condition Based*



The Strategic Plan for Asset Renewal commits Ergon Energy to keeping its network assets fit for purpose, and in a safe and environmentally sound condition, so as to minimise the risk of condition-based and age-related failures.

The AEPs set out the asset management methodology for each of Ergon Energy's 26 asset equipment types. These plans identify the drivers of condition-based asset renewal activity for each asset equipment type. The AEPs address the current situation, the maintenance policy, issues and challenges, and strategies for change and improvement. Each AEP drives a long-term annual expenditure plan extending out until at least 2017.

The NARMCOS model forecasts the expenditure for condition-based asset refurbishment and renewals across the appropriate classes of system assets, based on the number of units to be refurbished or replaced and the unit rates of doing so. These forecasts are prepared by drawing on the Unit Rates Master List Spreadsheet and the AEP documents.

The forecasts from the NARMCOS model are reflected in the budget planning process, including the development of a Ten and Five Year Capital Works Plan. A process of project ranking is then undertaken in order to develop an Annual Works Plan. These form the basis for the five-year forecasts for the next regulatory control period that are included in this Regulatory Proposal (see Figure 37).

23.2.4 Assumptions

The assumptions underlying the Capital Expenditure – Asset Replacement forecast include:

- The Network Defect Classification Manual reflects the risk profile that Ergon Energy is adopting for the 2010-15 regulatory control period. Defect-related capital expenditure represents an out-working of the Preventive Maintenance inspection program;
- Defect remediation is capitalised based on Ergon Energy's current capitalisation procedures and criteria contained within the documents entitled Capitalisation Accounting Policy: Property, Plant and Equipment and Capitalisation Accounting Policy: Intangible Assets; and
- Capital Expenditure – Asset Replacement – Defect forecasts are based on estimated defect rates arising from the quantity of inspections to be undertaken. This category includes failed in service replacement costs of major items of plant such as power transformers, distribution transformers, capacitor banks, underground cables, regulators and enclosed switches.

23.2.5 Capital Expenditure / Operating Expenditure Interactions

There is a strong relationship between the Capital Expenditure – Asset Replacement forecast and:

- The Preventive Maintenance program, which drives the defect-related Asset Replacement capital expenditure forecast. For example, if more inspections are undertaken, it is likely that more defects will be identified requiring rectification. The converse is also true if fewer inspections are undertaken. However, if inspections are not carried out to identify defects, more unplanned failures will result;
- Defect expenditure offsets Corrective and Forced Maintenance expenditure. Reducing defect expenditure will likely result in a need for increased Corrective and Forced Maintenance because asset defects will need to be addressed. This will increase the probability of assets failing, which will need to be addressed through the other maintenance programs. Corrective and Forced Maintenance is forecast to remain relatively stable over the next regulatory control period on the basis that failure rates will also remain stable as a result of the delivery of the Asset Replacement program;
- Reducing defect expenditure will increase the risk of asset failures in service, increase Dangerous Electrical Events and cause hazards to staff and public and increase System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) performance; and
- Condition based replacement or refurbishments are determined on the basis of the expected failure rates and risks of failure. The timing of failures is not known in advance, but failing to predict and manage the replacement of assets at the end of their lives will result in increased unplanned failures. This would lead to increased Corrective and Forced Maintenance expenditure.

23.2.6 Justification of the Forecasts

Ergon Energy seeks to rectify defects and condition-based deterioration before assets fail, however this expenditure involves replacing assets that have failed or are assessed as likely to fail before the next inspection.

Asset Replacement expenditure is therefore designed to ensure that Ergon Energy:

- Minimises interruptions and quality of supply problems for customers, as well as safety risks to the public and Ergon Energy staff, by undertaking pre-emptive expenditure;
- Avoids the need to incur Corrective and Forced Maintenance expenditure to address asset failures. The planned management of Asset Replacement results in operating expenditure savings and avoids the need for Asset Replacements under emergency conditions, including by avoiding callouts and overtime;

- Meets various regulatory and other obligations, such as:
  - The Code of Practice for Works (Protective Earthing, Underground Cable Systems and Maintenance of Supporting Structures for Powerlines), which includes a requirement that unserviceable poles must be replaced or reinstated within six months in keeping with the design principle and regulatory requirements for protective earthing;
  - The Electricity Distribution and Service Delivery Review (EDSD Review) requirements to replace ageing 7/.064 copper conductor in order to reduce voltage-drop related problems;
  - Meeting Electricity Safety Office requirements for service cables; and
  - Meeting the minimum service standards under the Electricity Industry Code;
- Maintain the average age of its assets in line with its targeted age profile in order to ensure that its future asset replacement expenditure can be managed in an orderly manner.

23.2.6.1 Defects

In relation to defect-related capital expenditure, the AEPs explain the key parameters that were used in the NARMCOS model to develop the forecast for each of the 26 classes of system assets. These explanations are unique to each class of system assets. A number of changes are proposed to the Preventive Maintenance program, as detailed in the AEPs and summarised in section 26.3, which will lead to a need for more defect related capital expenditure. The key Preventive Maintenance changes in the next regulatory control period relate to pole tops and customers' overhead services. Changes in defect volumes identified from inspections are also forecast for underground cables, lightning arrestors and earth repairs.

The AEPs set out the asset management methodology for each of Ergon Energy's 26 asset equipment types. The NARMCOS model forecasts asset renewal expenditure across the 26 classes of system assets, based on the number of units to be refurbished or replaced and the unit rate of doing so.

Key changes in defect related Asset Replacement capital expenditure from the current regulatory control period are summarised below. Further detail about these works is provided in the AEPs.

- Pole top replacements – Ergon Energy has increased this expenditure as a result of an increase in the number of unassisted failures and dangerous electrical events relating to cross arms;
- Underground cables – Ergon Energy has increased this expenditure as a result of an increase in the number of high voltage cables that have failed in service and the need to replace high voltage XLPE cables;
- Lightning arrestors - Ergon Energy has increased its expenditure as a result of changing its defect classification criteria for failed lightning arrestors. When field crews identify failed lightning arrestors during emergency situations the practice is to cut them away and not to replace them immediately. Historically, Ergon Energy would return and replace the cut away lightning arrestors as part of its Preventive Maintenance program. However, the change defect classification criteria requires that replacement occur within 26 weeks;
- Overhead services – Ergon Energy has increased its expenditure on the replacement of its customers' overhead service lines. This initiative seeks to reduce the number of electric shocks experienced by the public in the current regulatory control period. Ergon Energy will undertake a full service inspection program from 2012-13 on a 12 year cycle. This will replace the current visual inspection program;
- Earth remediation – Ergon Energy has increased its expenditure on earth remediation in order to better address the requirements of the Code of Practice Works under the Electrical Safety Act 2002. This reflects a change in the classification of earth remediation works in Ergon Energy's Network Defect Classification Manual; and
- Meters – Ergon Energy has increased its expenditure on the replacement of non-compliant meters in accordance with its Meter Asset Management Plan.

23.2.6.2 Condition Based

Key changes in Ergon Energy's condition based Asset Replacement capital expenditure from the current regulatory control period are summarised below:

- Distribution Lines:
  - Overhead conductor replacement – Ergon Energy has increased its expenditure on certain types of overhead conductors in accordance with the recommendations of the EDSD Review and the subsequent Queensland Government-initiated 2008 Operational Review. This is an extension of the conductor replacement program that began in 2008-09. Specifically, Ergon Energy is replacing 7/.064 copper for a number of reasons, including reduced cross section area through corrosion, annealing following clashing and lightning damage. There have also been a number of dangerous electrical events involving 7/.064 copper, 7/.080 copper and 3/12 steel conductors. This has been caused by local environmental conditions, such as corrosion, damage from cane fires, vibration, annealing and lightning strikes; and
  - Replacement of liquid filled fuses – Ergon Energy has increased its expenditure on the replacement of these fuses in order to address safety risks that have been identified during the current regulatory control period.

- Sub-transmission Lines:
  - Pole tops – Ergon Energy has increased its expenditure on the refurbishment of sub-transmission feeder pole tops on the basis of condition assessments, feeder performance and assessed risks to the network; and
  - Sub-transmission line rebuilds – Ergon Energy has increased its expenditure on rebuilding sub-transmission lines that were originally constructed in the 1950s and 1960s. Whilst these lines have been subjected to regular inspections and maintenance, the conductors are not replaced as part of this work. These sub-transmission line rebuilds are required to meet service performance requirements.
- Substation plant and equipment - Ergon Energy has increased its expenditure on variety of substation plant and equipment, including:
  - Zone substation transformers refurbishment and replacement;
  - Circuit Breakers and switchboard refurbishment and replacement;
  - Current Transformers and Voltage Transformers;
  - Outdoor switchyards refurbishment – this relates to air break switches, safety clearances, NOMAD connection points for portable generators and earth grid refurbishment;
  - Capacitors and static Volt Ampere Reactive (VAR) compensators;
  - Protection equipment; and
  - Supervisory Control and Data Acquisition (SCADA) and Load control equipment.
- Communications systems

23.2.7 Risk Considerations

There are a large number of inspection and maintenance programs undertaken as part of the Operating Expenditure – Preventive Maintenance works in order to ensure that defect-related capital expenditure is undertaken for each class of asset prior to assets failing. Each of the inspection and maintenance programs, and associated defect capital expenditure programs, has been tailored to address the specific known, or expected, risks associated with each class of asset. Examples of the inspection and maintenance programs include asset inspections, pole top inspections, earth testing, service inspections, and air break switch maintenance.

The condition-based capital expenditure is driven by specific condition-based issues that are known, or expected, to relate to different asset equipment types. These programs are informed by Ergon Energy's experience in managing and operating its distribution system. The Asset Equipment Plans set out the asset management methodology for each of Ergon Energy's 26 asset equipment types. These plans identify the drivers of condition based asset renewal activity for each asset equipment type. In this way, Ergon Energy seeks to manage the known, or expected, risks associated with each asset equipment types.

Additional considerations include the failure characteristics of assets, unserviceability, obsolescence, replacement of whole assets rather than component parts, bulk replacements, unavailability of spare parts, asset life, assets not being fit for purpose, premature ageing, fault rating increases leading to faster ageing, and the impact of outages on public safety and system security.

23.2.8 Customer Outcomes

Ergon Energy's Asset Replacement forecasts for the next regulatory control period will deliver the following outcomes for customers:

- Improved public safety, in particular as a result of more comprehensive overhead service inspections, changing defect classification for earth remediation, increased inspection and replacement of pole tops and the replacement of overhead conductors (in particular copper); and
- Improved reliability performance, in particular as a result of accelerating the time for the replacement of lightning arrestors, the replacement of overhead conductors (in particular copper), refurbishing pole tops on, and re-building, sub-transmission lines and upgrading various plant and equipment.

23.3 CAPITAL EXPENDITURE – CORPORATION INITIATED AUGMENTATION

23.3.1 Forecast 2010-15

Ergon Energy's forecast CIA capital expenditure for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 51.

The Capital Expenditure – CIA forecast is explained in the sections below in two categories:

- Sub-transmission; and
- Distribution.

23.3.2 What the Forecast Relates to

This type of expenditure relates to the capital works that are needed to meet the augmentation requirements of Ergon Energy's sub-transmission and distribution networks based on normal load forecasts.

23.3.2.1 Sub-transmission

Ergon Energy's sub-transmission network is generally that which is 33 kV and above. Despite relating to a sub-transmission voltage, these assets are part of Ergon Energy's distribution network.

23.3.2.2 Distribution

These assets relate to that part of Ergon Energy's distribution network that is generally 33 kV and below.

Table 51: *System Capital Expenditure – Corporation Initiated Augmentation – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
259.29	219.55	233.09	267.84	339.38	401.26	463.58	518.89	1,990.95	398.19

Source: Tables for Proposal 23.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10)

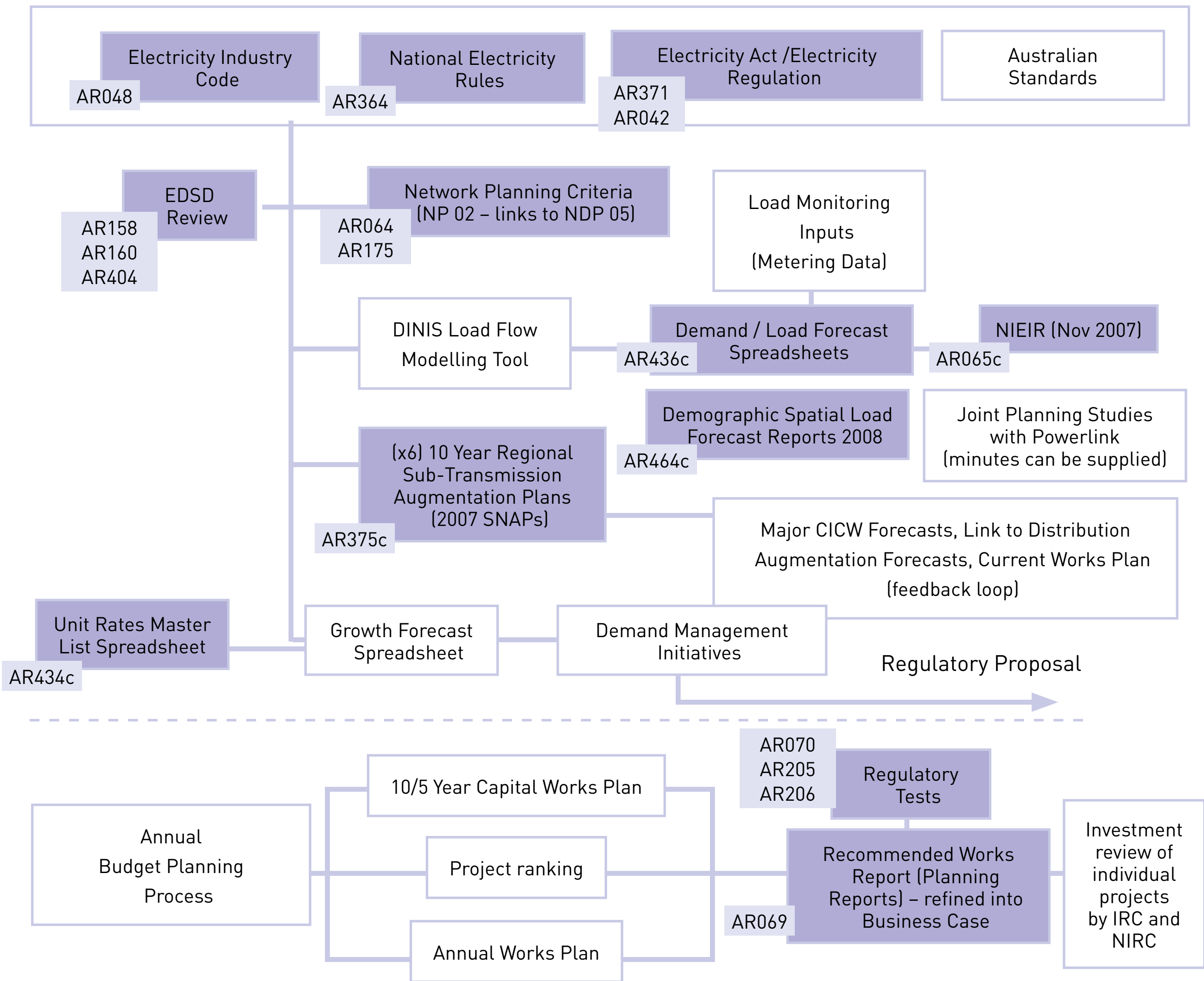
1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

It should be noted that some 33 kV assets are used for a sub-transmission function and some are used for a distribution function.

23.3.3 Estimation Process

23.3.3.1 Sub-transmission

Figure 38: *Capital Expenditure – Corporation Initiated Augmentation – Sub-transmission*



The Security Criteria Network Planning NPD05 and Network Planning Criteria NP02 (see Figure 38) are used to assess the capacity in Ergon Energy's sub-transmission network assets and to determine the need for, and timing of, network reinforcement or reconfiguration works. These criteria are discussed in section 12.1.1 of this Regulatory Proposal and have been prepared having regard for the requirements of:

- The EDSD Review;
- The Queensland Electricity Industry Code;
- The National Electricity Rules (NER);
- The Electricity Act and Electricity Regulation; and
- Relevant Australian Standards.

Ergon Energy prepares its demand forecasts for its sub-transmission assets in the manner described in Chapter 21 of this Regulatory Proposal, which includes:

- Applying load monitoring inputs from metering data into Demand/Load Forecast Spreadsheets in order to produce long-term load forecasts;
- Adjusting these forecasts based on National Institute of Economic and Industrial Research (NIEIR) report entitled "Maximum demand forecasts for Ergon Energy connection points to 2017 – Coincident and Non-Coincident Peaks for Summer and Winter by BSP"; and
- Inputting the load forecasts into the DINIS Load Flow Modelling Tool. This tool is used to undertake simulations of Ergon Energy's distribution network under different scenarios in order to identify capacity constraints and augmentations requirements.

On the basis of this analysis, Ergon Energy prepares 10-year Sub-transmission Augmentation Plans (SNAPs) for each of its six regions. These plans describe the capital works that are needed to augment the sub-transmission network in order to accommodate the normal load forecasts for the next 10 years. The Plans are prepared having regard for:

- Construction standards;
- The Network Planning Criteria NP02 and Security Criteria NPD05;
- The Demand Load Forecast Spreadsheets;
- The load flow analysis undertaken in DINIS;
- Major CICW forecasts;
- Demographic Spatial Load Forecast Reports;
- Joint Planning Studies between Ergon Energy and Powerlink;
- Distribution augmentation forecasts – discussed below;
- Demand Management Initiatives; and
- The current works plan.

The SNAPs are prepared annually and form the basis of the annual budget planning process, including the development of a Ten and Five Year Capital Works Plan. These forecasts are prepared by drawing on the Unit Rates Master List Spreadsheet. The five-year forecasts for the next regulatory control period are included in this Regulatory Proposal and are 'loaded' into the Regulatory Proposal models via the Growth Forecast Spreadsheet.

Ten and Five Year Capital Works Plans incorporate any reductions in demand that can be achieved through efficient Demand Management Initiatives.

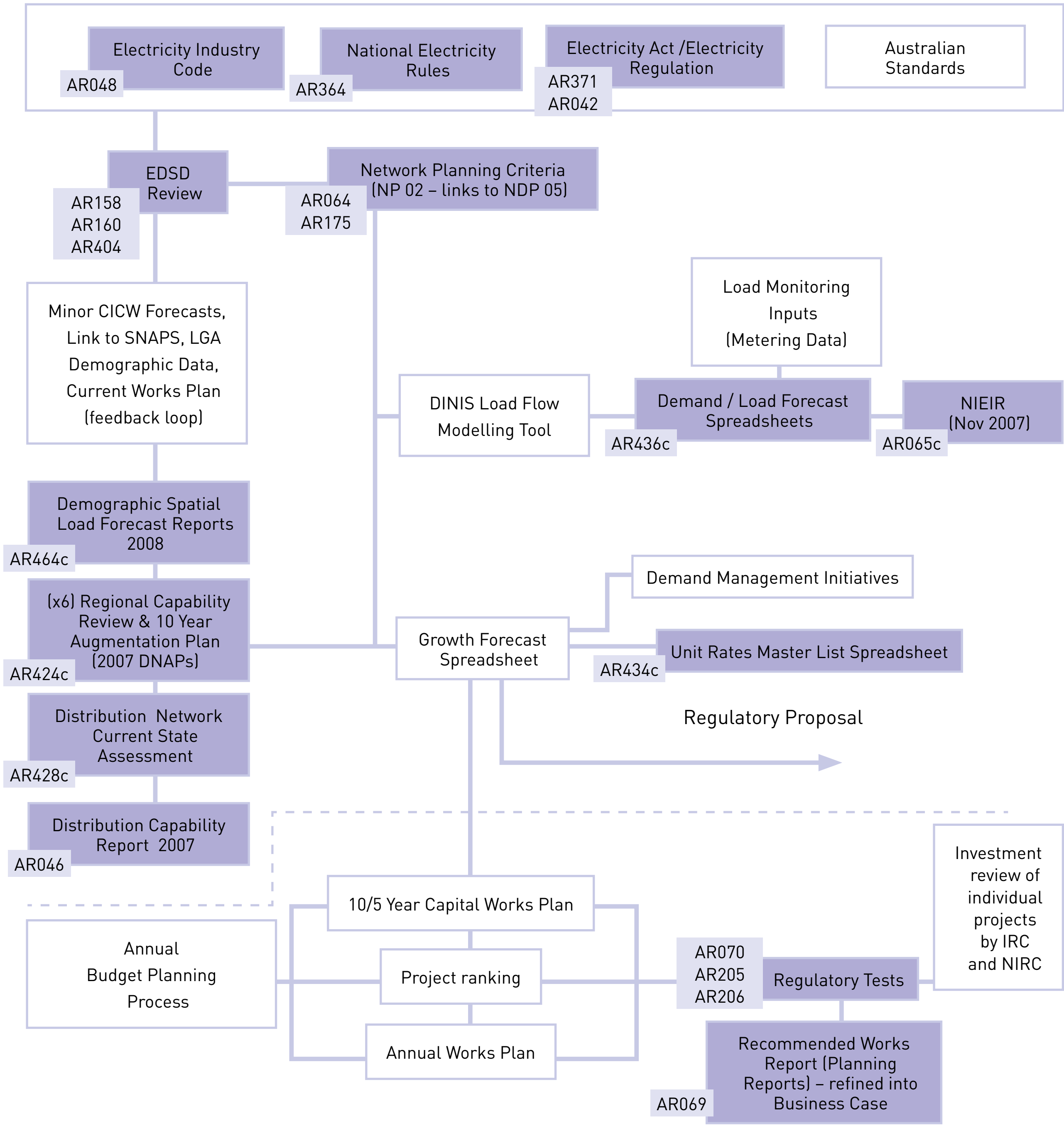
A process of project ranking is undertaken in order to develop an Annual Works Plan from the Ten and Five Year Capital Works Plans. In preparing project approvals in the works plan, Ergon Energy prepares a Recommended Works Report describing the nature and costs of proposed works, on a project by project basis. The Recommended Works Report includes the results of any Regulatory Tests that have been carried out in accordance Chapter 5 of the NER. Ergon Energy's Network Investment Review Committee (NIRC) and Investment Review Committee (IRC) review business cases based on the Recommended Works Reports and make decisions about the basis on which a project will (or will not) proceed.

23.3.3.2 Distribution

Ergon Energy prepares separate 10-year Regional Distribution Network Augmentation Plans (DNAPs) for its six regions (see Figure 39). These plans provide a detailed listing and description of the capital works that are needed to meet the augmentation requirements of the distribution network, in order to accommodate the normal load forecasts for the next 10 years. These DNAPs are prepared drawing on:

- Distribution Network Current State Assessments (Excel spreadsheets) which examine the nature, rating, capacity, utilisation and constraints of key assets across Ergon Energy's distribution network. These assessments therefore identify where the network needs to be augmented in the future in order to continue to meet future demand;
- The Network Planning Criteria NP02 and Security Criteria NPD05, which are used to assess the capacity in Ergon Energy's distribution network assets and to determine the need for, and timing of, network reinforcement or reconfiguration works. These criteria have been prepared having regard for the requirements of:
  - → The EDSD Review;
  - → The Queensland Electricity Industry Code;
  - → The NER;
  - → The Electricity Act and Electricity Regulation; and
  - → Relevant Australian Standards.
- The demand forecasts for its distribution assets are developed in the manner same manner as for sub-transmission assets. The development of these forecasts is described in Chapter 21 of this Regulatory Proposal and includes:
  - → Applying load monitoring inputs from metering data into Demand/Load Forecast Spreadsheets in order to produce long-term load forecasts;

Figure 39: *Capital Expenditure – Corporation Initiated Augmentation – Distribution*



- → Adjusting these forecasts based on NIEIR's report entitled "Maximum demand forecasts for Ergon Energy connection points to 2017 – Coincident and Non-Coincident Peaks for Summer and Winter by BSP"; and
- → Inputting the load forecasts into the DINIS Load Flow Modelling Tool. This tool is used to undertake simulations of Ergon Energy's distribution network under different scenarios in order to identify capacity constraints and augmentations requirements.

- The identification of potential demand management initiatives;
- Strategic Distribution Planning Studies, which are identified in the Distribution Capability Report. These studies:
  - → List the distribution projects (one to two years), tactical (five to 10 years) and strategic (10 to 20 years) planning studies based on draft 10 year sub-transmission and distribution augmentation programs;
  - → Draw upon forecasts of small customer initiated capital works, the SNAPS, Local Government Association demographic data and Ergon Energy's current works plan; and
  - → Typically involve the expansion of

existing networks by installing additional feeders, re-configuration of existing networks and development of new feeders where new sub-transmission zone substations have been proposed.

- Regional Distribution Capability Reviews and 10 year DNAPs for Ergon Energy's six regions. These documents review the present status of each region's distribution system and the effect of forecast future load growth for the next 10 years. Critical feeders are examined to determine if they are capable of supplying forecast loads while maintaining acceptable voltages and ensuring the ratings of any system components are not exceeded; and
- A Distribution Capability Report for Ergon Energy which summarises the Regional Capability Reviews. This report is prepared annually.

The DNAPs are prepared annually and form the basis of the annual budget planning process, including the development of a Ten and Five Year Capital Works Plan. These forecasts are prepared by drawing on the Unit Rates Master List Spreadsheet for specified projects. An annual provision is made based on historical averages for small unspecified projects, which arise in response to contact from customers. The five-year forecasts for the next regulatory control period are included in this Regulatory Proposal and are 'loaded' into the Regulatory Proposal models via the Growth Forecast Spreadsheet.

Ten and Five Year Capital Works Plans incorporate any reductions in demand that can be achieved through efficient Demand Management Initiatives.

A process of project ranking is undertaken in order to develop an Annual Works Plan from the Ten and Five Year Capital Works Plans. In preparing project approvals in the works plan, Ergon Energy prepares a Recommended Works Report describing the nature and costs of proposed works, on a project by project basis. The Recommended Works Report includes the results of any Regulatory Tests that have been carried out in accordance Chapter 5 of the National Electricity Rules (NER). Ergon Energy's Network Investment Review Committee and Investment Review Committee review business cases developed from the Recommended Works Reports and make decisions about the basis on which a project will (or will not) proceed.

23.3.4 Assumptions

The assumptions underlying the Capital Expenditure – CIA forecast are that:

- Detailed Demand Forecasts are developed for each connection point, bulk supply point, zone substation and feeder. These demand forecasts are used to prepare the Sub-transmission Augmentation Plans and Distribution Capability Reports, which outline where the distribution network needs to be augmented. Demand/Load Forecasts take into account annual assessments that are prepared by NIEIR. The Demand/Load Forecast varies across the distribution network;
- The expenditure forecasts draw upon the 2007 SNAPs, DNAPs and existing Strategic Plans. The SNAPs and DNAPs (as well as the NIEIR Report) have been updated in 2008 but have not been reflected in the forecasts in this Regulatory Proposal. The SNAPs and DNAPs were prepared for ten years from 2007 to cover the periods before, during and after the next regulatory control period;
- The expenditure forecasts are based on the expected work program as at June 2007. Any late delivery of projects between 2007 and 2010 will mean the work projects on which the forecast is based may be different but the quantum of work and expenditure will remain the same;
- The Network Planning Criteria NP02 and Security Criteria NPD05 have been used to prepare the expenditure forecasts;
- When a constraint is identified from the load forecast, action is taken to address it through CIA works;
- Ergon Energy will not be achieving full N-1 as it enters the next regulatory control period. However, it is assumed that Ergon Energy's forecasts will address constraints that are forecast to occur during the next regulatory control period;
- Infrastructure proposed to meet an N-1 constraint is in accordance with Ergon Energy's planning philosophy to build infrastructure and generally solve a constraint for 10 to 15 years;
- The forecast has not been adjusted for any of the following:
  - The economic downturn – the forecast was developed 12 months before this was apparent;
  - Communications works required for projects – these are included in the Communications Network Augmentation Plans, which are covered in the Other Capital Expenditure;
  - Augmentation to the SWER network – this is also included under Other Capital Expenditure; and
  - Savings in capital expenditure due to demand management initiatives, given that potential savings are the subject of trials, the outcomes of which cannot be forecast with confidence.
- There has been a smoothing of the annual capital expenditure over the five year forecast period based on Ergon Energy's work delivery capability. Therefore, the expenditure forecasts do not necessarily reflect when the projects are physically required.

Forecasts are prepared on the basis of projects required for the regulatory control period and detailed cash flows have not been prepared based on when expenditure will be incurred. Ergon Energy has a rolling works program across financial years and regulatory periods. The total project life cycle from planning to project completion may span up to three years.

For the larger sub-transmission projects that span the current and next regulatory control period, an estimate has been made of the proportion to be undertaken in each period. Distribution augmentation projects are allocated to single years even though they may, in fact, span several years.

As a consequence, Ergon Energy's capital expenditure budget may vary from any capital expenditure building block approved by the AER:

- This forecast is prepared on the basis of system planners' cost estimates using unit rates without the benefit of detailed scopes of work. These detailed scopes of work, which are necessary to prepare firm project estimates, are typically not prepared more than two years before the works are undertaken;
- Typically sub-transmission projects are large (e.g. establishment of a zone substation) and separate 'projects' are used for each component of work within the overall project. The units used to forecast sub-transmission projects refer to fully completed 'projects'. This is in contrast to the units used to forecast distribution projects being the up to five components that typically comprise each project; and
- A limited number of units have been used in order to simplify the capital expenditure estimation process having regard for the wide variety of design requirements and conditions in which projects are delivered. It has been necessary to select standard unit rates in order to limit the number of units used to prepare the forecasts. Where complex projects are known in advance, Ergon Energy has increased the standard unit rate in order to more appropriately reflect the anticipated actual cost of the projects.

23.3.5 Capital Expenditure / Operating Expenditure Interactions

The key interactions between CIA capital expenditure and operating expenditure are that inadequate augmentation expenditure will result in Ergon Energy's distribution system failing to comply with the Network Planning Criteria NP02 and Security Criteria NPD05. The failure of plant may then result in outages to significant numbers of customers, until repairs can be made. These interruptions may last several weeks and require rotational load shedding. If N-1 is met, there is a reduced likelihood of high consequence events. Additional Forced Maintenance expenditure would be required to manage these contingencies and limit customer inconvenience.

23.3.6 Justification of the Forecasts

Ergon Energy's CIA capital expenditure forecasts for both its sub-transmission and distribution assets for the next regulatory control period are necessary in order to ensure that Ergon Energy distribution system meets:

- The Demand/Load Forecast. As discussed in Chapter 21 of this Regulatory Proposal, the key drivers of demand in Ergon Energy's supply area in the next regulatory control period are expected to be:
  - → Population growth;
  - → Major new industry or commercial developments;
  - → Economic growth; and
  - → Climatic effects and air conditioning penetration.
- The Network Planning Criteria NP02 and Security Criteria NPD05. There is no significant change to the criteria from the methodology adopted in the current regulatory control period. Ergon Energy will not be achieving full N-1 as it enters the next regulatory control period. However, Ergon Energy's forecasts are necessary to enable constraints that are forecast to occur during the next regulatory control period to be addressed. This will enable Ergon Energy to continue to move towards the recommendations of the EDSD review. Ergon Energy's approach to meeting these criteria is detailed in its annual Network Management Plan (NMP), which is required under the Electricity Industry Code.

23.3.7 Risk Considerations

Ergon Energy has recognised that its highest risk exposure occurs during summer. This is because when assets are operated near their capacity limits for sustained periods in high temperatures, they are more prone to failure. In addition, the storm and cyclone season occurs over summer, which increases the risk of asset failure. Because Ergon Energy has not yet achieved full N-1, there are risks that need to be managed during summer.

Ergon Energy prepares an annual Summer Preparedness Plan, which includes initiatives to mitigate the risks to its distribution system over summer.

Ergon Energy's forecast CIA expenditure is intended to build additional capacity into the existing distribution system, and to build new assets, which will enable it to target an N-1 outcome. This will reduce the risk of outages to customers.

23.3.8 Customer Outcomes

The key customer outcomes that will be achieved as a result of delivering this forecast CIA capital expenditure are that Ergon Energy's network will be capable of meeting:

- The Demand/Load Forecast; and
- The Network Planning Criteria NP02 and Security Criteria NPD05.

If this forecast were not approved and implemented then there would be a loss of load risk at times of system peak whereby supply could be interrupted to large numbers of customers for considerable periods of time until a contingency plan could be invoked or repairs completed.

23.4 CAPITAL EXPENDITURE – CUSTOMER INITIATED CAPITAL WORKS (CICW)

Ergon Energy's forecast of Capital Expenditure CICW relates to works required to service new or upgraded customer connections that have been requested by customers. It covers both:

- (Shared) Network Services, including subdivision assets and any shared network associated with new CICW Large customers; and
- (Small Customer) Connection Services.

Large Customer Connection Services[35] are an Alternative Control Service and described in Chapter 54 of this Regulatory Proposal.

23.4.1 Forecast 2010-15

Ergon Energy's forecast Capital Expenditure CICW for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 52. The capital contributions that are forecast to be received by Ergon Energy as cash payments and gifted assets are detailed in Chapter 47.

Table 52: *Capital Expenditure – CICW – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
293.08	268.42	276.90	336.11	354.99	315.56	328.70	359.63	1,694.99	339.00

Source: Tables for Proposal 23.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10).

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

23.4.2 What the forecast relates to

Ergon Energy's Capital Expenditure CICW includes:

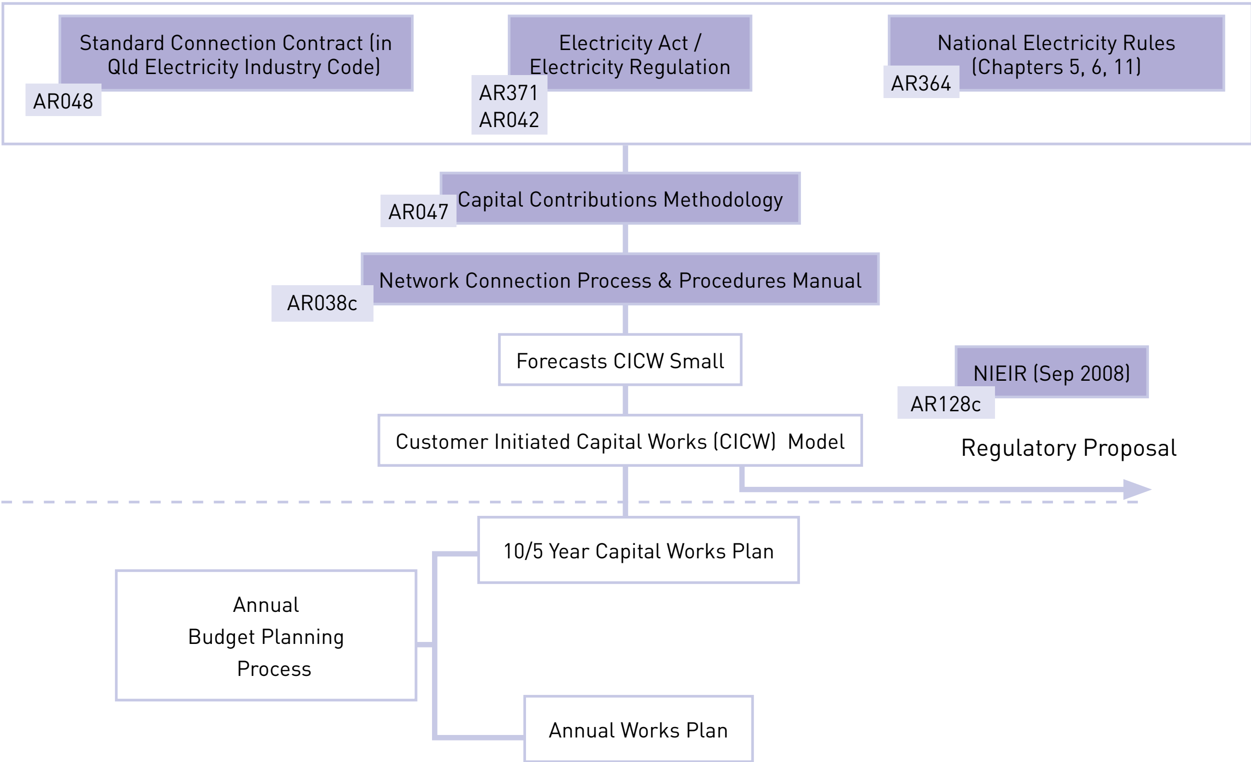
- Works that are undertaken by:
  - → Ergon Energy, or by someone acting on its behalf; and
  - → Developers and other service providers, where the assets are 'gifted' to Ergon Energy.
- Works that are funded by:
  - → Ergon Energy, where it, or someone acting on its behalf, undertakes the works;
  - → A customer or developer paying a cash capital contribution to Ergon Energy, where Ergon Energy, or someone acting on its behalf, undertakes the works; and
  - → A developer or other service provider, where the assets that they build are 'gifted' to Ergon Energy and accounted for by Ergon Energy as a capital contribution.
- Building:
  - → New customer connection assets;
  - → New distribution network assets, for example subdivision assets, requested by customers or developers; and
  - → Augmentations to the upstream distribution network, where the augmentation directly relates to a new or upgraded customer connection.

This type of expenditure does not include costs of network augmentations that are not directly related to new, or upgraded, customer connections.

[35] Large Customer Connection Services encompass the design and construction of connection assets (but exclude shared assets necessary to connect new large customers) for new large customers (i.e. those customers that Ergon Energy has classified for pricing purposes to be Individually Connected Customers, Connection Asset Customers and Embedded Generators).

23.4.3 Estimation Process

Figure 40: *Capital Expenditure – Corporation Initiated Capital Works*



Ergon Energy is required to connect all customers to its distribution network in accordance with clause 5.3.1(c) of the Rules, section 43 of the Electricity Act 1994, the Electricity Regulation 2006 and clause 5.1 of the Standard Connection Contract (Annexure A to the Queensland Electricity Industry Code). It also has a legislative monopoly to undertake the final connection of the new connection assets to its distribution network, whether they are constructed by it or a registered professional, including to undertake any tests required before commissioning the assets (see Figure 40).

Small customer connections to Ergon Energy's distribution network can be funded in one of three ways, through:

- Distribution Use of System (DUOS) charges. Section 7 of Ergon Energy's Capital Contributions Methodology and Chapter 6 of Ergon Energy's Network Connection Process and Procedures Manual set out when and how Ergon Energy will contribute to the cost of new or augmented small customer connections;
- A cash contribution, which is a form of capital contribution:
  - → All SAC Commercial and Industrial customers and Domestic and Rural customers (but not developers of subdivisions) are required to contribute to any additional costs of new connections and/ or augmentations of existing connections that are above the average DUOS charges for SACs. Customers do this by paying a cash capital contribution. This capital contribution is calculated using a formula set out in section 7 of Ergon Energy's Capital Contributions Methodology; and
  - → Developers of subdivisions are required to contribute all costs of making supply available to each allotment in a subdivision as set out in section 8 of Ergon Energy's Capital Contributions Methodology:
    - » Developers are responsible for all costs (internal and upstream) associated with making an electricity supply (to Ergon Energy's specifications) available to each allotment...; and
    - » The cost of subdivision electrical reticulation is payable as a cash capital contribution if Ergon Energy performs the work...;
- Gifted assets, which are an alternative form of capital contribution. This involves a developer funding and undertaking the work to build assets to Ergon Energy's technical standards and then 'gifting' the completed assets to Ergon Energy for it to own, maintain, operate and manage. Section 8 of Ergon Energy's Capital Contributions Methodology provides that:

- → The developer may choose whether to have Ergon Energy carry out all the internal electrical reticulation works necessary for the subdivision (excluding civil works) or whether to undertake all the electrical reticulation works itself; and
- → If the developer organises for the work to be carried out in accordance with Ergon Energy's technical and design requirement, then the assets are 'gifted' and treated as non-cash capital contributions.

Ergon Energy has prepared forecasts of Capital Expenditure CICW expenditure for 2008-09 to 2014-15 by:

- Taking the 2007-08 actual baseline expenditure;
- Adjusting the baseline for updates to the CICW price book (to reflect current costs);
- Applying the NIEIR dwelling stock growth forecasts in NIEIR's 2008 "Maximum demand forecasts for Ergon Energy connection points to 2018 – Coincident and Non-Coincident Peaks for Summer and Winter by BSP"; and
- Applying adjustments, to reflect known scope changes as appropriate.

The Capital Expenditure CICW expenditure forecasts for SAC connections are broken down between:

- Commercial and Industrial;
- Domestic and Rural; and
- Subdivisions.

The Capital Expenditure CICW forecast expenditure is prepared in the CICW Model. The process for developing these forecasts is described in Forecasts CICW.

The CICW Model is updated annually and forms the basis of the annual budget planning process. The five-year forecasts for the next regulatory control period are included in this Regulatory Proposal and are 'loaded' into the Regulatory Proposal models via the CICW Model.

23.4.4 Assumptions

The assumptions underlying the Capital Expenditure CICW forecast include:

- Ergon Energy's Capital Contribution Methodology, which predominantly relates to small connection services, will remain unchanged;
- Ergon Energy will apply clause 11.16.3 of the NER in relation to treatment of the regulatory asset base. This provides for the full value of cash capital contributions and gifted assets for small connection services to continue to be treated as a reduction to Ergon Energy's Annual Revenue Requirement (ARR) and for these assets to be recorded in the Regulatory Asset Base (RAB) at value;
- 'Contestability' will be extended from URD subdivisions to connection assets works relating to Commercial and Industrial SACs. This will result in a contestability uptake rate of approximately 50 per cent. This will be reflected in a decline in cash contributions and an offsetting increase in gifted assets;
- Ergon Energy will apply the 2007-08 actual expenditure as a baseline for forecasting its Capital Expenditure CICW for the next regulatory control period; and
- Ergon Energy will develop its forecasts by making adjustments to this baseline to reflect the impacts of contestability and NIEIR's September 2008 econometric forecasts of dwelling stock growth. NIEIR's forecast is detailed in its "Maximum demand forecasts for Ergon Energy connection points to 2018 – Coincident and Non-Coincident Peaks for Summer and Winter by BSP".

23.4.5 Capital Expenditure / Operating Expenditure Interactions

There are no significant Capital Expenditure/Operating Expenditure interactions for Capital Expenditure CICW other than that all new assets that result from the Capital Expenditure CICW program will result in ongoing operating expenditure in order that they can be operated and maintained.

23.4.6 Justification of the Forecasts

Ergon Energy is required to connect customers to its distribution system in accordance with:

- Clause 5.3.1(c) of the Rules, which states that "any person wishing to establish a connection to the network may elect to follow the procedures in this clause 5.3"; and
- Section 43(1) of the Queensland Electricity Act 1994, which requires that "...it is also a condition of a distribution authority that the distribution entity must allow as far as technically and economically practicable for the distribution entity, a person to connect supply to its supply network, or to take electricity from its supply network, on fair and reasonable terms..."; and
- Clause 5.1 of the Standard Connection Contract[36], which provides that, subject to relevant electricity legislation and various qualifications detailed in clause 5.2 of the Contract, Ergon Energy will provide for:
  - → Connection of the premises to the supply network to allow the supply of electricity from the supply network to the premises; and
  - → Supply of electricity from the supply network to the premises.

[36] This contract was initially approved by the Queensland Government, and any amendments must now be approved by the QCA.

Ergon Energy also has a legislative monopoly to undertake the final connection of the new connection assets to its distribution network, whether constructed by either itself or a registered professional. It is also required to undertake any tests required before commissioning the assets. This is established by:

- Section 230 of the Electricity Act 1994 which provides that "A person must not wilfully and unlawfully interfere with an electricity entity's works" and section 232 of Act, which states that "A person must not unlawfully connect or disconnect supply electricity to a customer or interfere with supply of electricity to a customer";
- Clause 5.3 of the Standard Connection Contract which provides that requires that:

  Subject to the electricity legislation, we (Ergon Energy) must provide, install and maintain equipment for the provision of customer connection services at the premises in a manner which is safe and in accordance with the electricity legislation.

  Our (Ergon Energy's) obligations extend up to the supply point for the delivery of electricity from the supply network for the premises and not beyond.

Ergon Energy has applied a "baseline scope change" approach to forecasting its Capital Expenditure CICW expenditure, given that there is no feasible basis for doing so on a bottom-up basis. It considers that the most appropriate basis for preparing its forecasts is to start with the 2007-08 actual expenditure and to make adjustments for:

- Updates to the CICW price book, to reflect the current costs of CICW;
- Applying the NIEIR dwelling stock growth forecasts in NIEIR's "Maximum demand forecasts for Ergon Energy connection points to 2018 as a basis for escalating the 2007-08 base year expenditure; and
- Adjusting the forecasts for the increased take up of Urban Residential Development (URD) subdivisions being built by alternative providers during 2007-08 and 2008-09, and the extension of the alternative provider model to Commercial and Industrial works from 2010.

The expansion of contestability has two implications.

Firstly, Ergon Energy is forecasting a significant drop-off in the level of cash contributions for small CICW from 2010-11 as alternative providers successfully compete with Ergon Energy to provide Commercial and Industrial work. This is in addition to an expected drop-off in cash contributions from URD subdivisions from 2008-09 as developers increasingly undertake this work. Ergon Energy expects that, by 2010, alternative providers will be undertaking half of the available contestable Commercial and Industrial work and that this level will continue throughout the next regulatory control period. This is similar to the uptake of URD contestability in 2007 and 2008.

It has been assumed, for forecasting purposes, that the contestability model for Commercial and Industrial work will be similar to that used for the URD alternative provider model. This will mean that contestability is restricted to just work on the connection assets (i.e. excluding headworks, and testing and commissioning), which will continue to be undertaken by Ergon Energy.

Secondly, Ergon Energy is forecasting that the value of gifted assets will increase in the next regulatory control period as more work is undertaken by alternative providers. It is noted that Ergon Energy only began taking this type of capital contribution from mid-2007 with the introduction of full contestability for URD subdivisions by alternative providers. As such, only a small amount of works was completed through the full alternative provider model by the end of 2007-08 and recorded as gifted assets for that financial year. This small amount is not considered reflective of future gifted assets, as the amount of work delivered through the alternative provider model is still increasing to its steady state. For 2010-11 to 2014-15, gifted assets associated with subdivisions have been forecast to reflect both NIEIR's dwelling stock growth forecast and the forecast uptake rate of contestability of 50 per cent from 2009-10 throughout the next regulatory control period.

23.4.7 Risk Considerations

Ergon Energy is required to connect all network users who request new connections and the requested works will be delivered regardless of the forecast amounts ultimately approved by the AER in its Distribution Determination.

The risk to Ergon Energy is that it needs to undertake more CICW for SAC customers than it has forecast. This could be the case for a variety of reasons, including that:

- Total volumes turn out to be higher than forecast in this Regulatory Proposal;
- Alternative providers ultimately undertake a smaller share of work than the 50 per cent that Ergon Energy has forecast, because the uptake rate for Commercial and Industrial customers is lower than for URD subdivisions. As a result, given it has an obligation to connect customers, Ergon Energy would need to undertake more work for SAC customers than it has currently forecast.

This would mean that Ergon Energy would need to re-cast its capital expenditure program in order to ensure that all Capital Expenditure CICW is deliverable. If this was required, it would do this by prudently rebalancing its other programs of capital work.

23.4.8 Customer Outcomes

The key customer outcomes that would be achieved through the Capital Expenditure CICW program would be that:

- All SAC customers would continue to be connected to Ergon Energy's distribution system;
- Subdivision developers would continue to be able to choose whether to use Ergon Energy or an alternative provider to connect construct subdivision electrical infrastructure;
- Commercial and Industrial customers would be extended the option to choose whether to use Ergon Energy or an alternative provider to construct their connection assets (under similar arrangements as urban residential subdivision developments); and
- Ergon Energy would retain an obligation to connect customers to its distribution system, including in the event that no alternative provider is prepared to do so.

23.5 CAPITAL EXPENDITURE – RELIABILITY AND QUALITY IMPROVEMENTS

23.5.1 Forecast 2010-15

Ergon Energy's forecast Reliability and Quality Improvements capital expenditure for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 53.

Table 53: *Capital Expenditure – Reliability and Quality Improvements – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
14.22	10.06	8.87	18.29	20.89	24.50	28.28	30.43	122.39	24.48

Source: Tables for Proposal 23.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10)

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

23.5.2 What the forecast relates to

This type of capital expenditure relates to works that are directly targeted at addressing reliability or quality of supply issues across the distribution system in order to meet externally and internally imposed service standards.

Ergon Energy's internally imposed service standards have been set solely for the purpose of ensuring that all of the minimum service standards in the Queensland Electricity Industry Code can be achieved.

There is therefore no difference between Ergon Energy's internal and external service standard requirements.

23.5.3 Estimation Process

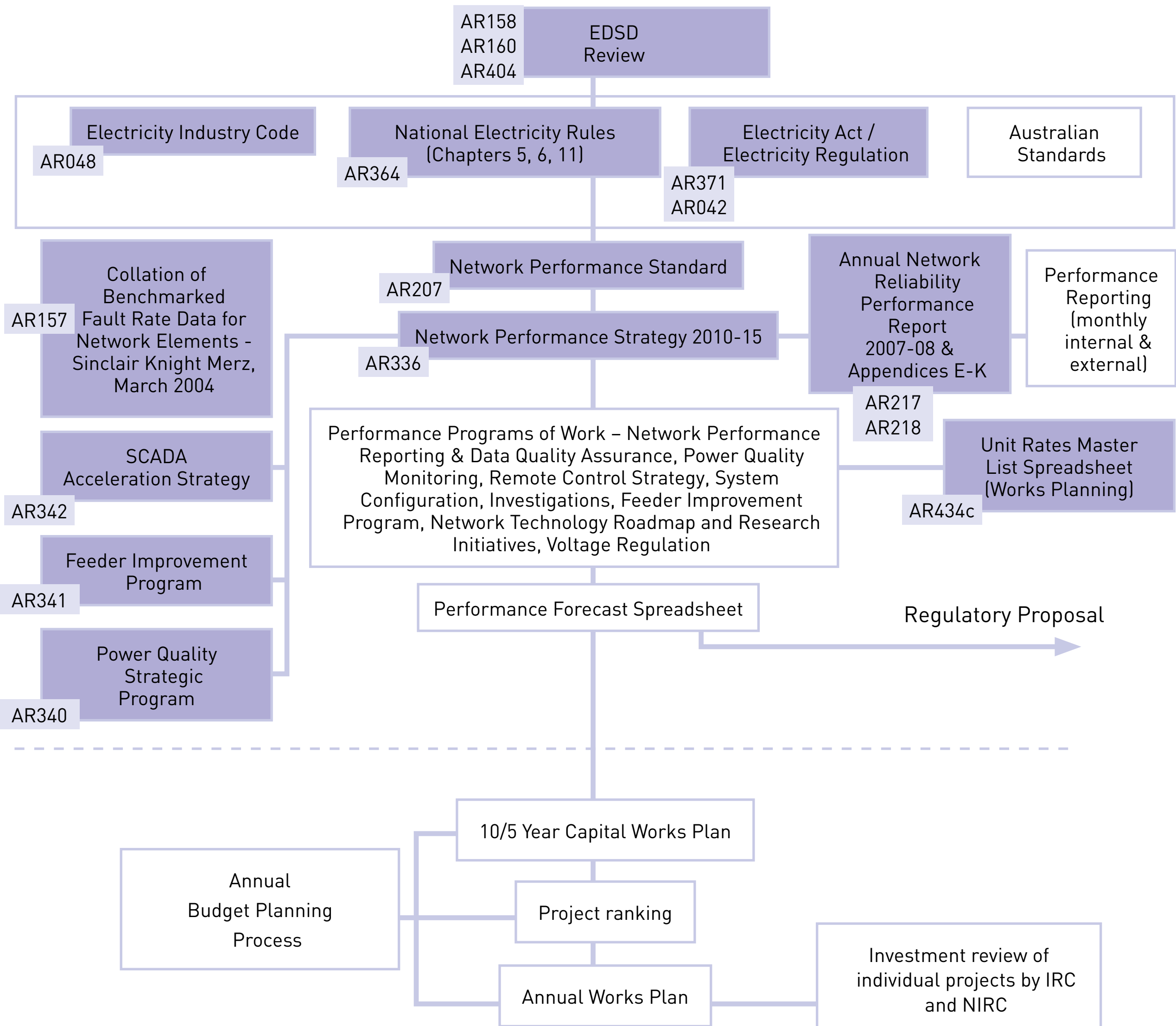
Chapter 12 of this Regulatory Proposal details Ergon Energy's externally and internally imposed service standard obligations, which are expressed in terms of security of supply, reliability of supply, quality of supply, safety and customer service.

Ergon Energy's Network Performance Standard details:

- Its performance parameters by reference to the:
  - → Electricity Act 1994 and Electricity Regulation 2006;
  - → NER;
  - → Queensland Electricity Industry Code;
  - → The EDSD Review;
  - → Relevant Australian Standards; and
  - → Other applicable instruments.
- The assessment methods to be used in applying these performance parameters; and
- The minimum performance standards that customers can expect at their connection point with Ergon Energy's distribution system.

Figure 41 depicts the expenditure estimation process for Reliability and Quality Improvements.

Figure 41: *Capital Expenditure – Reliability and Quality Improvements*



In particular, this standard is used to:

- Assess network performance on a routine and case-specific basis;
- Provide advice to customers on service quality;
- Check contractual requirements;
- Establish responsibilities should litigation occur; and
- Determine if network augmentations are required.

Ergon Energy's Network Performance Strategy describes the long-term strategy for improving its network performance through planning, design and operating practices that meet customer expectations for supply reliability at optimal cost. The strategy has regard for:

- The Annual Network Reliability Performance Report;
- Monthly internal and external Performance Reports (such as Regulatory Test reports e.g. Regulatory Test-Bowen Area Final Report); and
- Collation of Benchmarked Fault Rate Data for Network Elements – SKM (March 2004);
- The SCADA Acceleration Strategy;
- The Feeder Improvement Program; and
- The Power Quality Strategic Program.

The Network Performance Strategy identifies the following key initiatives for achieving performance improvements, which are reflected in its Performance program of works:

- Network Performance Reporting and Data Quality Assurance;
- Power Quality Monitoring;
- Remote Control Strategy;
- System Configuration;
- Investigations;
- Feeder Improvement Program;
- Network Technology Roadmap and Research Initiatives; and
- Voltage Regulation.

A process of project ranking is undertaken in order to develop the program of works. Ergon Energy's NIRC and IRC review projects from the Performance program of works and make decisions about the basis on which a project will (or will not) proceed. This program is prepared annually and forms the basis of the budget planning process, including the development of a Ten and Five Year Capital Works Plan and an Annual Works Plan.

These forecasts are prepared by either by:

- Drawing on the Unit Rates Master List Spreadsheet; or
- Allocating an annual expenditure amount for programs – this estimate is prepared without using unit rates and quantities.

The five-year forecasts for the next regulatory control period are included in this Regulatory Proposal and are 'loaded' into the Regulatory Proposal models via the Performance Forecast Spreadsheet.

23.5.4 Assumptions

The assumptions underlying the Capital Expenditure – Reliability and Quality Improvements forecast include that:

- Ergon Energy is planning to meet the minimum services standards detailed in the Queensland Electricity Industry Code. This expenditure forecast therefore represents Ergon Energy's assessment of what is required to meet, but not to exceed, these standards. Any decision by Ergon Energy to exceed these standards will not be funded by network charges; and
- Stage 1 of the UbiNet project proceeds in order to provide communications for improved protection and SCADA to high priority assets across the distribution system, and to provide opportunities for additional operational initiatives to exploit the improved remote control capabilities. This will reduce the amount of downtime customers experience as a result of faster enablement of systems and projects. The nature of the UbiNet project, and the protection upgrades that coordinate with the SCADA program, are discussed further in section 23.6 of this Regulatory Proposal;
- It is expected that Ergon Energy would focus on its 50 worst performing feeders over the course of the next regulatory control period;
- Ergon Energy estimates that the average cost to fix a worst performing (red) feeder is approximately $1 million; and
- Not all performance improvement will come from the reliability expenditure. The continuation of the Asset Replacement, CIA and network maintenance programs will contribute significantly to Ergon Energy's achievement of its service standard targets. It is noted that significant reliability performance improvements have been achieved during the current regulatory control period from the defect related Asset Replacement program and relatively mild weather.

23.5.5 Capital Expenditure / Operating Expenditure Interactions

The key interactions between the Capital Expenditure – Reliability and Quality Improvements forecast and the Operating Expenditure program are that:

- Expanded remote control and restoration capability will reduce the Forced Maintenance and the amount of downtime customers experience; and
- Each of the Preventive and Corrective Maintenance programs will positively contribute to improved reliability performance of the distribution system.

The Capital Expenditure – Reliability and Quality Improvements forecast will not, of itself, enable Ergon Energy to meet its minimum service standard targets. Other capital expenditure, such as CIA, Asset Replacement and other system capital expenditure, in particular for UbiNet and protection systems, will also play important roles in meeting these targets.

The Capital Expenditure and Operating Expenditure programs have therefore been designed to complement each other to ensure that Ergon Energy is able to meet its minimum service standard requirements under the Queensland Electricity Industry Code.

23.5.6 Justification of the Forecasts

The Network Performance Strategy and related documents describe in detail how the Capital Expenditure – Reliability and Quality Improvements forecast is designed to:

- Enable Ergon Energy to meet its minimum service standard requirements under the Queensland Electricity Industry Code. Pro-active rectification of power quality issues will minimise the need for reactive responses arising from unplanned interruptions;
- Improve the reliability of Ergon Energy's worst performing distribution feeders in accordance with the requirements of the EDSD Review;
- Ergon Energy will be seeking to further reduce the duration of outages for unplanned events, whilst consolidating the existing frequency of events;
- Gain greater visibility of network power quality through an improved monitoring program;
- The extended coverage of the SCADA program will focus on providing remote control, particularly in Ergon Energy's South West, Mackay and Wide Bay regions, where there is currently limited SCADA penetration. This will enable Ergon Energy to harness value from the control centre infrastructure installed by the LINK program and will contribute to achieving Ergon Energy's vision and strategy of moving towards a smart grid; and
- Avoid being penalised under the STPIS for degradations in reliability performance.

The expenditure proposed for the next regulatory control period is required to meet the increasingly onerous minimum service standard requirements under the Electricity Industry Code and to address worst performing feeders. They key programs will relate to:

- The rollout of SCADA to around 90 per cent of all customers;
- Actioning the feeder improvement program; and
- Extending the network monitoring program.

23.5.7 Risk Considerations

The Capital Expenditure – Reliability and Quality Improvements forecast is seeking to:

- Prevent any non-compliance with Ergon Energy's minimum service standard requirements under the Queensland Electricity Industry Code;
- Improve the reliability of the poorly performing sections of the network; and
- Prevent Ergon Energy losing revenue under the Service Target Performance Incentive Scheme, as a result of having inadequate reliability performance.

23.5.8 Customer Outcomes

The benefit to customers of the Capital Expenditure – Reliability and Quality Improvements forecast will be to improve network reliability performance and customer service through improved fault isolation times as well as restoration times, particularly for the currently worst performing distribution feeders.

This will contribute, together with the operating expenditure program, to Ergon Energy being able to meet the minimum service standard requirements under the Queensland Electricity Industry Code.

If Ergon Energy reduced expenditure on SCADA penetration it would reduce its ability to significantly reduce the duration of its outages.

Similarly, reducing expenditure on worst performing feeders would mean that Ergon Energy would not meet its EDSD Review obligations and that customers that are serviced from these feeders would not have their reliability performance progressively improved as recommended in 2004 by that Review.

23.6 SYSTEM CAPITAL EXPENDITURE – OTHER

23.6.1 Forecast 2010-15

Ergon Energy's Capital Expenditure – Other System forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 54.

Table 54: *System Capital Expenditure – Other – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
29.63	44.88	79.14	105.62	72.94	50.78	50.39	51.65	331.38	66.28

Source: Tables for Proposal 23.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10)

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

The Capital Expenditure – Other System forecast is explained in the sections below in five categories:

- Communications;
- Protection;
- Single Wire Earth Return (SWER);
- Undergrounding; and
- Other programs, which comprise low voltage fuse retrofits, low voltage spreaders, substation security, oil containment bunding and alternate substation AC supplies.

These programs are described in the Asset Equipment Plans and are forecast in the NARMCOS model.

23.6.2 What the Forecast Relates to

23.6.2.1 Communications

Ergon Energy has begun the first stage of rolling out a contiguous telecommunications backbone network, known as the "Ubiquitous Network", or "UbiNet", throughout its distribution area.

UbiNet will have a primary backbone, which will enable the future deployment of a multipoint network solution to service intelligent network devices and deliver enhanced monitoring and control of the distribution network. Where it is not economic to construct the internal telecommunication platform, commercial carrier services, such as satellites, will be integrated into the UbiNet solution.

UbiNet will satisfy a range of Ergon Energy's telecommunications requirements including SCADA, network monitoring and control, fixed and mobile staff communications and, if required, connectivity to customer meters.

UbiNet Stage 1 involves investing in the core telecommunications backbone network across Ergon Energy's distribution area. This stage will be implemented between 2008-09 and 2011-12, which means that it is included in forecasts for the first two years of the next regulatory control period. This is the only stage of UbiNet that has been approved by Ergon Energy's Board at the time of making this Regulatory Proposal. No other stages of the UbiNet development have been included in the forecast capital expenditure for the next regulatory control period.

Stage 1 of UbiNet, is intended to fill the current 'missing links' in the communications system between:

- The 'distribution islands' that comprise the main centres in each of Ergon Energy's six sub-regions – Cairns, Townsville, Mackay, Rockhampton, Maryborough-Bundaberg-Hervey Bay and Toowoomba; and
- The medium sized centres with bulk supply connections and populations greater than 5,000 people.

UbiNet Stage 1 is an acceleration of a longer-term plan to complete the 'Core Network'. By filling these gaps in the 'Core Network', future network augmentations will only need to fund the communication assets required in the remaining lower voltage parts of the distribution system.

23.6.2.2 Protection

This type of capital expenditure relates to the following programs of work:

- Retrofitting auto-reclose protection on existing feeders;
- Retrofitting sensitive earth fault protection on existing feeders; and
- Undertaking protection reviews and ensuring protection equipment adequately protects the public, staff and equipment following faults.

23.6.2.3 SWER

Ergon Energy operates and maintains a 63,827 km SWER network that distributes single-phase power to more than 26,000, or 4 per cent, of Ergon Energy's customers.

These 19.1 kV, 12.7 kV or 11 kV SWER systems can extend from ten to 400 km or more in length. They cover diverse geographic areas, from coastal hinterlands to some of western Queensland's most isolated cattle stations.

SWER comprises approximately 73 per cent of Ergon Energy's total line lengths for long rural feeders and approximately 15 per cent of its total line lengths for short rural feeders. SWER components on any feeder are therefore naturally included in reliability reporting by feeder category.

This type of capital expenditure relates to works required to augment the SWER network in order to meet customers' capacity, reliability and quality of supply needs. The nature of these works is detailed in Ergon Energy's draft 20-year Strategic Plan for SWER.

23.6.2.4 Undergrounding

This type of capital expenditure relates to the following programs of work:

- Cyclone Area Reliability Enhancement (CARE) program, under which Ergon Energy invests in undergrounding critical high voltage infrastructure in cyclone prone areas;
- Community Powerline Project (CPP) Fund, under which Ergon Energy funds the undergrounding of assets in community areas on a shared funding basis with local councils; and
- Toowoomba Trees Program, which is a joint initiative with Toowoomba City Council, to improve the reliability and security of electricity supply in harmony with Toowoomba City vegetation.

23.6.2.5 Other

The other programs included in this Capital Expenditure – Other System forecast relate to:

- A substation security program for high risk and critical sites, and a longer term program for low risk sites;
- Retrofitting low voltage fuses to distribution transformers in those regions where low voltage fuses have not previously been fitted as a standard. This practice originally commenced as part of the CARE program;
- A substation bunding program for upgrading oil containment with substations being prioritised on the basis of risk;
- Improving the reliability of substation alternating current supplies, which were identified from the review following Severe Tropical Cyclone Larry; and
- Fitting low voltage spreaders to prevent conductor clashing and failure. This practice originally commenced as part of the CARE program.

23.6.3 Estimation Process

23.6.3.1 Communications

Ergon Energy has developed a Communications Network Augmentation Plan to fill the missing links in Ergon Energy's communications system between:

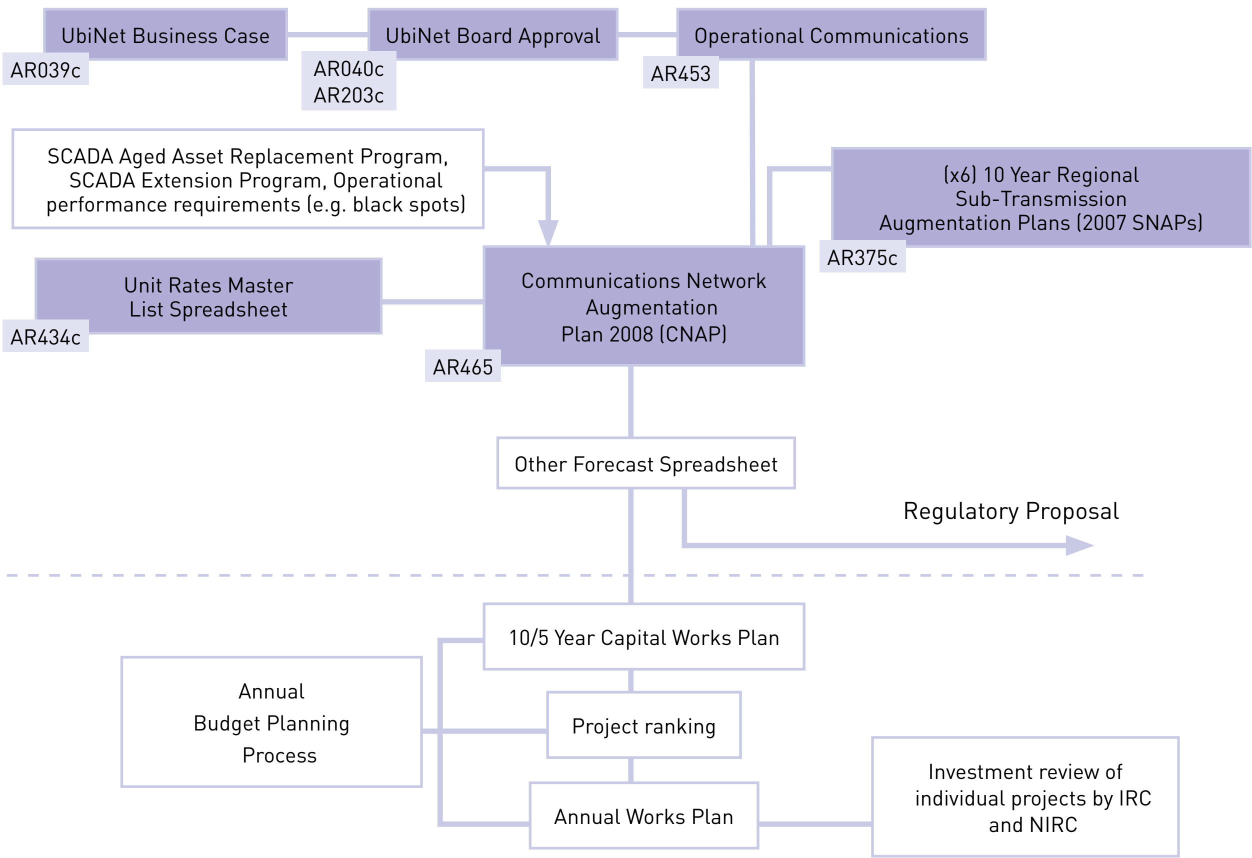
- The 'distribution islands' that comprise the main centres in each of Ergon Energy's six regions (Cairns, Townsville, Mackay, Rockhampton, Maryborough-Bundaberg-Hervey Bay and Toowoomba); and
- The medium sized centres with bulk supply connection and populations greater than 5,000 people.

The Communications Network Augmentation Plan builds the network to meet the current requirements and the future network development contained in the SNAPs (see Figure 42).

In addition, Ergon Energy developed a UbiNet Business Case in May 2008, which involved a three-stage implementation approach:

- Stage 1 involves the rollout of the core telecommunications backbone network throughout Ergon Energy's distribution area. It is intended that this occur between 2008-09 and 2011-12;
- Stage 2 involves the development of a multipoint cellular network with planned coverage of over 80 per cent of Ergon Energy's electrical network assets. It is proposed that this occur between 2011-12 and 2013-14, although no allowance has been included in Ergon Energy's Capital Expenditure – Other System forecast; and
- Stage 3 involves the 'last mile' connectivity to homes and meters. It is intended that this occur as and when required after 2013-14, although no allowance has been included in Ergon Energy's Capital Expenditure – Other System forecast.

Figure 42: Capital Expenditure – Other – Communications



In May 2008, Ergon Energy's Board approved the UbiNet Business Case and the implementation of Stage 1.

The Operational Communications – Strategy Overview Infrastructure Design (UbiNet) describes the proposed development of Ergon Energy's communications network.

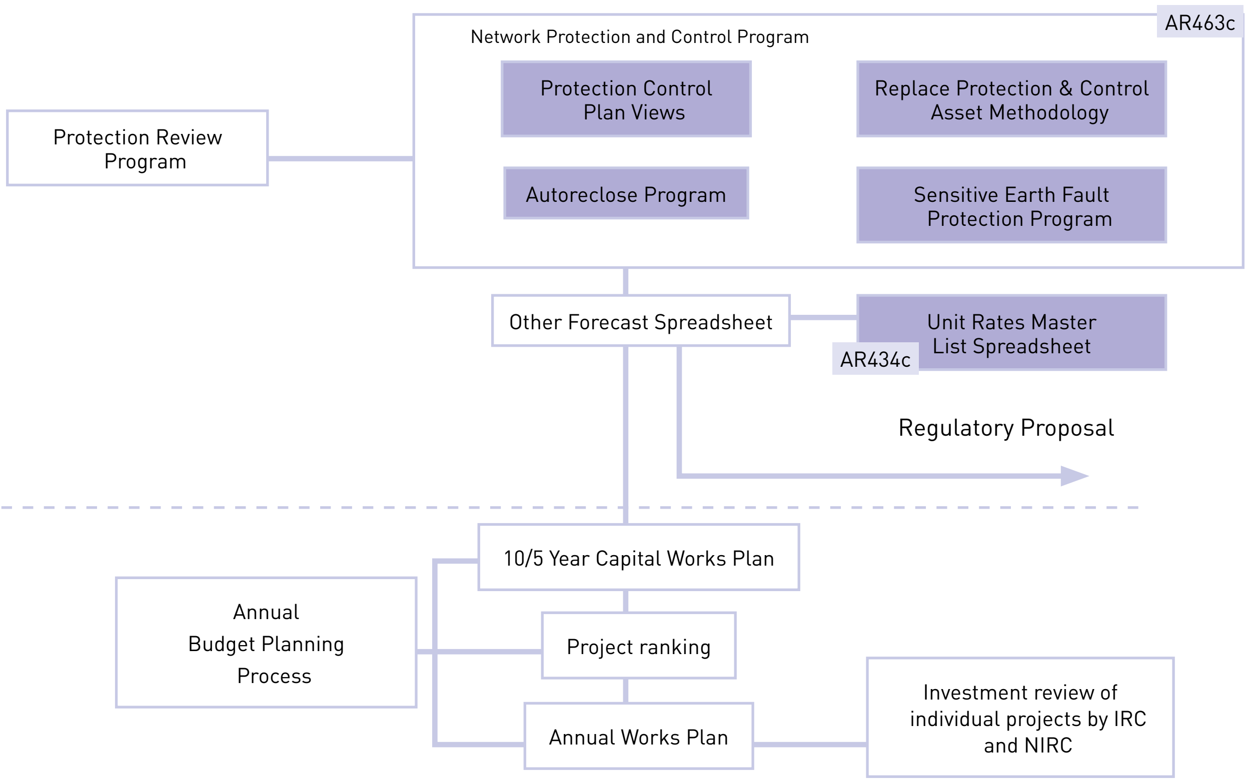
UbiNet Stage 1 advances a longer term communications development plan into a three-year period in order to provide a communications platform on which Ergon Energy can develop a smart network.

As part of the Communications Network Augmentation Plan, a model was developed that details the nature, timing and cost of communications-related expenditure over 10 years. The communication infrastructure forecast for the five years is therefore based on the total forecast based on the Communications Network Augmentation Plan and the completion of UbiNet Stage 1.

This Plan forms the basis of Ergon Energy's budget planning process, including the development of a Ten and Five Year Capital Works Plan and an Annual Works Plan. These forecasts are prepared by drawing on the Unit Rates Master List Spreadsheet. The 2010-15 forecasts are loaded into the models used to prepare this Regulatory Proposal via the Other Forecast Spreadsheet.

23.6.3.2 Protection

Figure 43: *Capital Expenditure – Other – Protection*



Ergon Energy has developed a Network Protection and Control Program (see Figure 43). The following parts are modelled in an Excel spreadsheet that is part of the Other Forecast Spreadsheet:

- Retrofitting autoreclose protection on existing feeders;
- Retrofitting sensitive earth fault protection on existing feeders; and
- Undertaking protection reviews.

The Network Protection and Control Program includes the following three other programs, which are forecast in other models:

- Replacing protection equipment – this is included in the Asset Replacement forecast;
- Installing SCADA equipment in new substations – this is included in the Reliability and Quality Improvement Forecast; and
- Replacing SCADA equipment in existing substations – this is included in the Asset Replacement forecast.

Protection work is coordinated between these programs on a site by site basis to ensure that it is delivered in the most efficient way.

The Network Protection and Control Program is supported by documents describing the first two items:

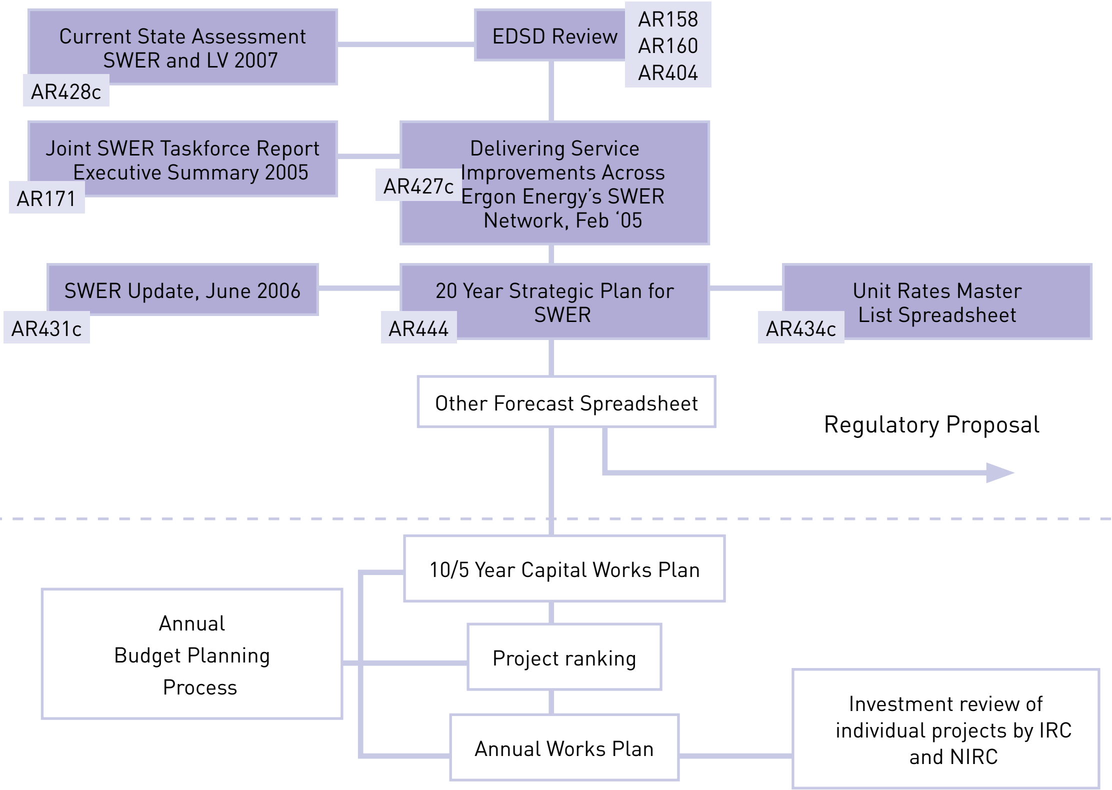
- The Autoreclose Program involves retrofitting autoreclose protection on 73 of Ergon Energy's feeders, which currently do not have this capability. This program, which is designed to improve the reliability of these feeders, is being undertaken on a prioritised basis over seven years in accordance with Ergon Energy's autoreclose standards; and
- The Sensitive Earth Fault Protection Program involves retrofitting sensitive earth fault protection on 210 of Ergon Energy's feeders that currently do not have this capability. This program is designed to help mitigate public safety risks associated with fallen high voltage overhead conductors on multiphase distribution feeders.

The protection forecasting model coordinates and prioritises work within substations. This may result in some works being completed at a different time to that which was otherwise forecast. The protection programs also rely on the Asset Replacement program being completed.

The Network Protection and Control Program forms the basis of Ergon Energy's budget planning process, including the development of a Ten and Five Year Capital Works Plan and an Annual Works Plan. These forecasts are prepared by drawing on the Unit Rates Master List Spreadsheet. The 2010-15 forecasts are loaded into the models used to prepare this Regulatory Proposal via the Other Forecast Spreadsheet.

23.6.3.3 SWER

Figure 44: *Capital Expenditure – Other – SWER*



The 2004 EDSD Review recommended that the "Government and Ergon Energy should establish a joint taskforce to consider options for improving the reliability of supply in areas currently serviced by SWER lines."[37] This recommendation was accepted by the Queensland Government and Ergon Energy is obliged to implement it.

Since then, various documents have been prepared, and considerable expenditure has been incurred, in order to address this recommendation to improve the services that customers receive from the SWER network (see Figure 44).

In February 2005, the SWER Taskforce prepared a report entitled Delivering Service Improvements across Ergon Energy's SWER Network and the Joint SWER Taskforce Report Executive Summary to the Queensland Government. This report sought to address immediate priority issues and to develop long-term solutions in order to address the gap between the performance of the SWER network and customers' expectations.

In June 2006, Ergon Energy prepared a Single Wire Earth Return (SWER) Update for the Department of Energy and the SWER Taskforce on how Ergon Energy had:

- Accelerated and increased the existing refurbishment and upgrade programs in key areas; and
- Commenced work on longer term innovative programs to significantly enhance the performance of the SWER network.

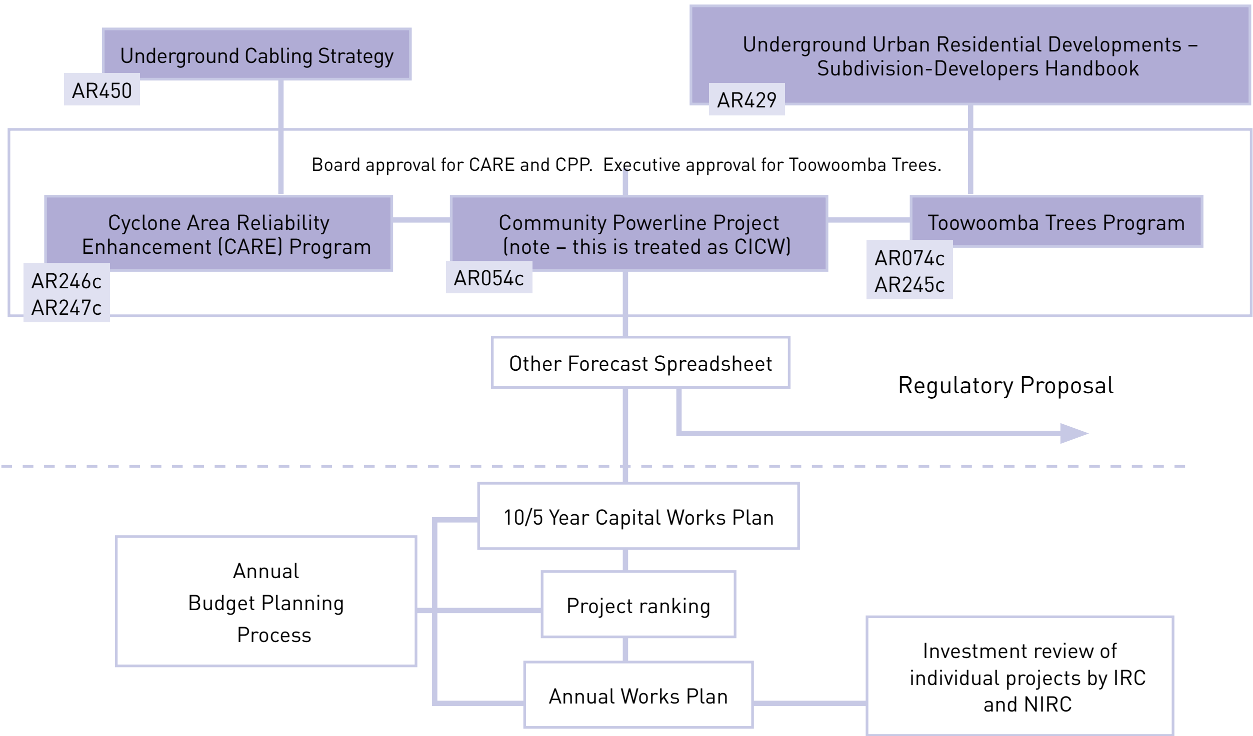
A 20 Year Strategic Plan for SWER has been developed by the SWER Improvement Group having regard for the Current State Assessments SWER and Distribution 2007. This spreadsheet detailed a strategic framework for the management of the SWER network in order to support a future program of works to ensure that the SWER network is operated as intended for the present loading peak as well as meeting incremental load growth, performance targets, customer needs and safety requirements.

On the basis of this analysis, Ergon Energy has prepared a detailed capital expenditure program for its SWER network, which is reflected in the development of the Ten and Five Year Capital Works Plan and an Annual Works Plan. These forecasts are prepared by drawing on the Unit Rates Master List Spreadsheet. The five-year forecasts for the next regulatory control period are included in this Regulatory Proposal and are loaded into the Regulatory Proposal models via the Other Forecast Spreadsheet.

[37] EDSD Review, "Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland", July 2004, page 202

23.6.3.4 Underground

Figure 45: *Capital Expenditure – Other – Undergrounding*



Ergon Energy's network contains approximately 4,240 km of high voltage and low voltage underground mains serving approximately 110,000 customers.

URD is the most common application of underground distribution within Ergon Energy. Ergon Energy's "Underground Urban Residential Developments – Subdivision Developers Handbook" (Developers' Handbook) details its policies and processes for managing the connection of a URD connection (see Figure 45). In particular, it:

- Provides details to enable developers to undertake the internal design and construction of the electrical reticulation of subdivisions in accordance with prescribed technical standards; and
- Details Ergon Energy's role in connecting the internal electrical reticulation of the subdivision that has been built by a developer to Ergon Energy's distribution system.

The costs of these works are generally met by the developer as part of the subdivision process, with the new underground mains being transferred to Ergon Energy as a gifted asset for it to own, operate and maintain.

In addition, Ergon Energy has an Underground Cabling Strategy, which covers underground mains that it, rather than a third party such as a developer, builds. The strategy is to install overhead not underground lines, except in urban residential developments (subdivision) estates, where Local Government requires undergrounding. Undergrounding is used where it is not feasible to use overhead lines or where it is directly funded by the requesting party. The underground programs in place either have high community value or are partly funded by the community through Local Government.

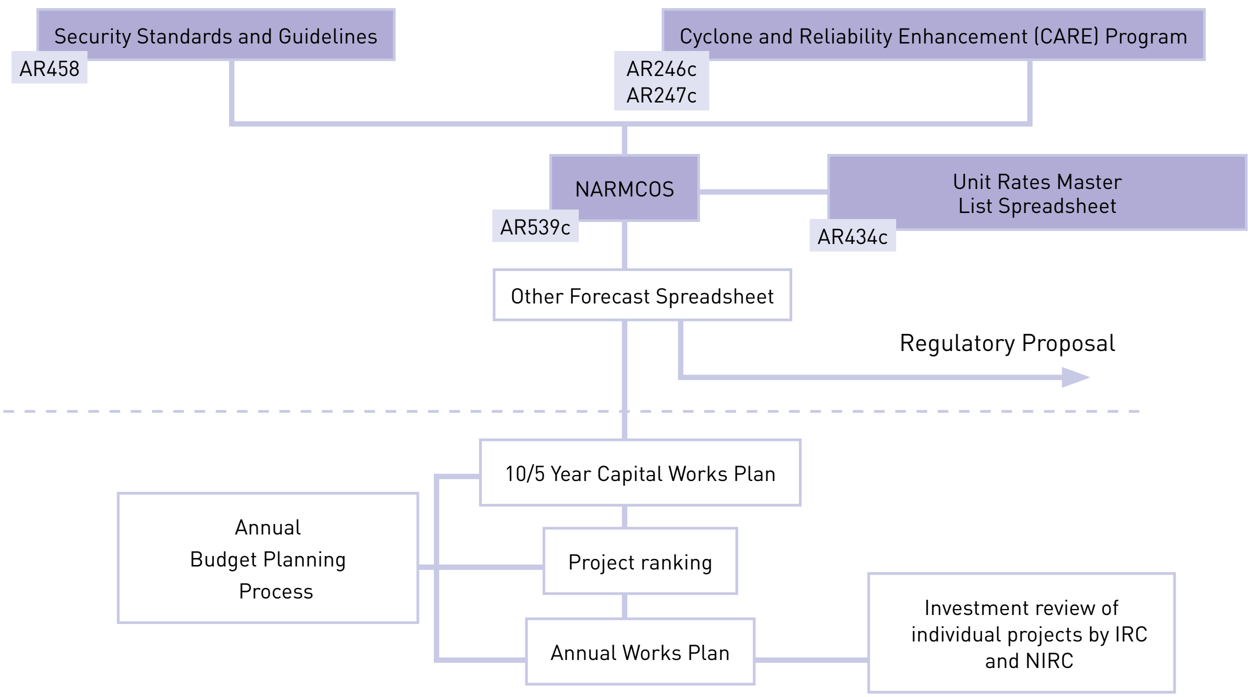
Ergon Energy has established the following community undergrounding programs in accordance with its Undergrounding Cabling Strategy:

- Cyclone Area Reliability Enhancement Program (CARE), under which Ergon Energy invests in undergrounding critical high voltage infrastructure in cyclone prone areas to minimise the impacts of natural disasters;
- Community Powerline Project Fund, under which Ergon Energy funds the undergrounding of assets in community areas on a shared funding basis with Local Governments where they are undertaking significant beautification works; and
- Toowoomba Trees Program, which is a joint initiative with Toowoomba City Council, to improve the reliability and security of electricity supply in harmony with Toowoomba City vegetation.

Ergon Energy has prepared a detailed capital expenditure program for its undergrounding works, which is reflected in the development of the Ten and Five Year Capital Works Plan and an Annual Works Plan. These forecasts are based on current program levels. The five year forecasts for the next regulatory control period are included in this Regulatory Proposal and are loaded into the Regulatory Proposal models via the Other Forecast Spreadsheet.

23.6.3.5 Other Programs

Figure 46: *Capital Expenditure – Other – Other Programs*



The other programs included in this Capital Expenditure – Other System forecast are all developed in NARMCOS (see Figure 46):

- The substation security program relates to improving security for high risk and critical sites, and a longer-term program for low risk sites. The substation security program commenced in the current regulatory control period with substation keys and locks being replaced and the forecast for the next regulatory control period is to spend a similar amount on the continuation of the program. Ergon Energy's Security Standards and Guidelines is relevant to this program;
- The program to retrofit low voltage fuses to distribution transformers is based on expenditure in the current regulatory control period. This program was commenced for cyclone areas as part of the CARE program;
- The substation bunding program for upgrading oil containment is based on expenditure in the current regulatory control period, with an increase in quantifies factored into the forecast;
- The program to improve the reliability of substation alternating current supplies will commence in 2010-11 as a result of the internal review following Cyclone Larry; and
- The program to fit low voltage spreaders to prevent conductor clashing and failure is based on expenditure in the current regulatory control period. This program was commenced for cyclone areas as part of the CARE program.

These forecasts are prepared by drawing on the Unit Rates Master List Spreadsheet. The five-year forecasts for the next regulatory control period are included in this Regulatory Proposal. Unit quantities for the programs multiplied by unit rates provides the forecast expenditure and are loaded into the Regulatory Proposal models via the Other Forecast Spreadsheet.

23.6.4 Assumptions

The key assumptions underlying the Capital Expenditure – Other System forecast are as follows.

23.6.4.1 Communications

Ergon Energy has assumed that:

- Only expenditure on UbiNet Stage 1 will be reflected into the forecasts for the next regulatory control period. This expenditure will occur in 2010-11 because UbiNet Stage 1 is assumed to commence in the second half of 2008-09 and to continue for three years; and

- The Communications forecasts are based on the forecast expenditure and works for network development. While UbiNet Stage 1 advances this work, there will be a need for ongoing communications expenditure after UbiNet Stage 1 has been completed.

23.6.4.2 Protection

The protection program has been developed on the basis of a co-ordinated program of protection asset replacement, sensitive earth fault, autoreclose, protection reviews, and SCADA program (asset replacement and SCADA extension). It is assumed that the Asset Replacement program continues as forecast. Any reduction in Asset Replacement expenditure would mean that some protection programs would take longer to complete.

23.6.4.3 SWER

It is assumed that the SWER expenditure is to be undertaken in accordance with the 20 Year Strategic Plan for SWER, as detailed in the document entitled Delivering Service Improvements Across Ergon Energy's SWER Network.

This reflects an assumption that the Queensland Government will continue to require Ergon Energy to focus on SWER improvements in accordance with the recommendations of the EDSD Review.

23.6.4.4 Undergrounding

It is assumed that the three existing undergrounding programs will be retained without any expansion on the basis that undergrounding will not be extended across Ergon Energy's distribution system except for the current three programs.

23.6.5 Capital Expenditure / Operating Expenditure Interactions

The key Capital Expenditure / Operating Expenditure interactions related to the Capital Expenditure – Other System forecast are that:

- Undergrounding reduces operating expenditure, although it does not necessarily result in a lower life cycle cost, as the operating expenditure associated with underground assets is still significant. The proposed underground programs either have a customer contribution element or are of high community value, for example by improving cyclone disaster response and reducing traffic accidents;
- Communication infrastructure will reduce operational communication costs and improve operational response times, thereby reducing Forced Maintenance costs;
- Autoreclose will reduce sustained outages and thereby reduce Forced Maintenance costs;
- Improved substation security will reduce theft and reduce safety risks following unauthorised entry to substations;
- Substation bunding will reduce environmental clean-up costs;
- Low voltage spreaders will reduce conductor clashing, supply interruptions and Forced Maintenance expenditure and improve public safety; and
- Additional operating expenditure will be required to maintain new communications infrastructure.

There will be no significant reduction in Forced Maintenance costs in the regulatory control period as Capital Expenditure – Other System forecast must be implemented before Forced Maintenance benefits can be achieved.

23.6.6 Justification of the Forecasts

Ergon Energy's Capital Expenditure – Other System forecast are justified on the following basis.

23.6.6.1 Communications

A communication network is required to enable protection and remote control and monitoring within substations. In some cases, NEMMCO requires communications to enable duplicate protection systems.

In the past, communications infrastructure was undertaken as part of major substation developments and was included in the system augmentation costs.

The capital expenditure forecast for Communications is designed to enable Ergon Energy to establish a primary communications backbone, UbiNet, which will enable the future deployment of a multipoint network solution to service intelligent network devices in order to deliver enhanced monitoring and control of the distribution network. A dedicated program of work is needed to ensure that the communications capability is delivered in a co-ordinated and timely manner. The alternative approach would be to retain the current practice of installing communications infrastructure as part of major substation developments and including these costs as part of the broader system augmentation program. This approach would not allow Ergon Energy to satisfy the range of telecommunications requirements that can be addressed by UbiNet, including SCADA, network monitoring and control, fixed and mobile staff communications and, if required, connectivity to customer meters.

UbiNet will reduce operational communication costs and provide an enabler for further remote control and monitoring in the network. UbiNet Stage 1 is a first step in providing the infrastructure to move Ergon Energy's network towards its 20 vision and roadmap of a smart grid. This Stage 1 will build the core network for future stages to enable further control and monitoring of new devices such as smart meters, switches, distributed generators, demand management systems. Improved fault response times will be a key benefit of this investment.

23.6.6.2 Protection

The protection review program is currently underway. This forecast estimates the expenditure required to improve protection system design in order to ensure public and staff safety and to protect Ergon Energy's assets. This program is viewed as a compliance program so that Ergon Energy can ensure it provides a distribution network that will clear faults and dangerous situations in a timely manner. Additional protection programs currently underway and continuing in the next regulatory control period are:

- The autoreclose program, which is designed to reduce unnecessary permanent outages and outage costs and thereby improve SAIDI and SAIFI performance; and
- The sensitive earth faults program, which is designed to reduce public safety risks that occur when conductors fall to the ground and remain live because fault currents are low.

23.6.6.3 SWER

The capital expenditure forecasts for the SWER program is a direct response to the 2004 EDSD Review, which highlighted the need to examine ways of improving the reliability and quality of supply in areas currently serviced by SWER lines. The proposed program of works is intended to deliver on the 17 strategies detailed in the January 2008 document entitled 20 Year Strategic Plan for SWER that was prepared by the SWER Improvement Group.

The SWER plan includes trials of many new technologies with the aim of implementing lower cost alternatives to traditional infrastructure.

23.6.6.4 Undergrounding

The capital expenditure forecasts for undergrounding are built on a series of programs that are currently underway. The Undergrounding Cabling Strategy details that while overhead is the preferred option, undergrounding is used in the following situations:

- Urban residential developments (subdivisions);
- Where there is limited availability of overhead line routes, limited clearances or high capacity;
- In order to provide higher reliability, particularly in the event of cyclone disasters;
- In high community value locations, where the undergrounding is partly funded by the community; and
- Where customers pay the life cycle cost difference between overhead and underground lines.

Cyclone Area Reliability Enhancement Program (CARE)

The CARE program was introduced in December 2000 to apply to coastal areas north and inclusive of Mackay.

This followed a state-wide review of undergrounding that was initiated by the Minister for Mines and Energy following Tropical Cyclones Tessi and Steve in and around Townsville and Cairns. These were Category 1-2 tropical cyclones that caused relatively minor property damage but widespread damage to the overhead distribution network.

Analysis of the primary causes of network outages, the impediments to speedy restoration and the effect on essential services identified the need for the introduction of the CARE program. It was designed to provide:

- A more secure supply to essential services, such as water and sewerage supplies and hospitals;
- A progressive improvement of security to high voltage 'backbone' feeders and interconnection points around provincial cyclone prone cities;
- A means for minimising the damage to local area low voltage networks from cyclones;
- Encouragement of property owners to retrofit their overhead property services underground;
- Retrofitting of low voltage fuses to distribution transformers; and
- For the installation of low voltage spreaders on small conductors.

Following Category 5 Cyclone Larry in 2006, a further independent review was carried out to assess the success of the program. This made several recommendations including consideration of whether to expand the program. As a result of this, the annual expenditure was increased to $10 million per annum but no further increase in the total expenditure was recommended. The conclusion was that while undergrounding assets was not the preferred option in normal circumstances, the high community value from a CARE program supported continuing the current level of investment.

Additional value is gained from the CARE program by co-ordinating with augmentation programs where new high voltage distribution feeders are required. These are established as underground to meet the requirements of the CARE aims.

Community Powerline Project Fund

As a result of the review of undergrounding in 2000, the Community Powerline Project (CPP) Fund was established to link with community improvement programs being undertaken by Local Government. This fund has an annual budget of $4 million funded equally by Ergon Energy and Local Government (i.e. $2 million each).

An independent CPP committee has been formed to assess applications from Local Government for funding under the CPP Fund. The committee includes representatives from the Queensland Department of Employment, Economic Development and Innovation - Mines and Energy, the Environmental Protection Agency, the Royal Australian Planning Institute as well as Ergon Energy. The CPP committee uses a set of established guidelines for assessing Local Government applications.

Toowoomba Trees Program

The Toowoomba Trees Program was approved by the Ergon Energy Board at a total cost of $12 million. This program will commence in 2009-10 and continue into the next regulatory control period. The program involves the development of a joint Ergon Energy and Toowoomba City Council program for the Toowoomba City Area to reduce the impact of powerline infrastructure on the vegetation in Toowoomba. It also aims to address damage to existing vegetation on the main gateways to Toowoomba.

23.6.6.5 Other

The other elements of Ergon Energy's Capital Expenditure – Other System forecast are required to:

- Deliver a substation security program to minimise risks and bring the security of Ergon Energy's substations in line with the required Code of Practice;
- Complete the low voltage fuse retrofit program on transformers, which started as part of the CARE program, and expand to other areas;
- Undertake substation bunding in order to meet Ergon Energy's environmental obligations;
- Improve substation reliability by securing alternating current supplies, which were identified as an issue following the review of network performance during Cyclone Larry in 2006; and
- Complete the installation of low voltage spreaders on small low voltage conductors, which started as part of the CARE program and expand to other areas, in order to reduce supply interruptions and the risk of asset failure following conductor clashing from high winds and vegetation.

23.6.7 Risk Considerations

The Capital Expenditure – Other System forecast is seeking to:

- Fill 'missing links' in its communications system in order to enable the future deployment of a multipoint network solution to service intelligent network devices and deliver enhanced monitoring and control of the distribution network. Without this capability, Ergon Energy will not be able to meet its customers' evolving expectations from the distribution system, which can be delivered through SCADA, network monitoring and control, fixed and mobile staff communications and, if required, connectivity to customer meters;
- Upgrade and augment Ergon Energy's protection systems in order to improve its reliability performance and to help mitigate safety risks to the public and its staff;
- Address the relatively poor reliability and quality of supply to customers serviced from Ergon Energy's worst performing SWER feeders, in line with customers' future demand and expectations;
- Complete specific undergrounding programs, which provide higher reliability following cyclones, have been identified as necessary in order to promote public safety and prudent asset management; and
- Deliver a variety of discrete programs to address specific safety, environmental, security and performance risks.

23.6.8 Customer Outcomes

The Capital Expenditure – Other involves a variety of programs that will deliver improved reliability, quality and safety of supply to customers by making improvements in Ergon Energy's existing distribution system.

This expenditure forecasts comprise a mix of new and existing programs. The key programs are:

- The Cyclone Area Reliability Enhancement Program, Community Powerline Project Fund, and Toowoomba Trees Program;
- The protection review program;
- The autoreclose and SEF programs;
- The Stage 1 deployment of UbiNet;
- SWER improvement programs;
- The low voltage fuse retrofit program on transformers;
- The substation security program;
- The substation bunding program;
- Substation alternating current supply reliability improvement program; and
- The low voltage spreader program.

23.7 CAPITAL EXPENDITURE – NON-SYSTEM – PLANT AND EQUIPMENT

23.7.1 Forecast 2010-15

Ergon Energy's Capital Expenditure – Non-System – Plant and Equipment forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 55.

***Table 55:** Capital Expenditure – Non-System – Plant and Equipment – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
37.15	6.92	7.37	7.53	7.64	7.76	7.88	8.01	38.82	7.76

Source: Tables for Proposal 23.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10).

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

23.7.2 What the forecast relates to

The plant and equipment included in the capital expenditure program relate directly to the delivery of work on the distribution system to ensure Ergon Energy employees can work in a safe and efficient manner.

Plant and equipment purchases valued at less than $1,000 are excluded from this capital expenditure forecast because they are expensed and are captured as Shared Costs (Overheads) in this Regulatory Proposal.

The Capital Expenditure – Non-System – Plant and Equipment program also specifically excludes fleet, office equipment and computer equipment, which are forecast separately.

23.7.3 Estimation Process

Ergon Energy's Managing Tools and Equipment Framework (see Figure 47) overviews the protocols, procedures, reporting and safety performance measures in relation to its tools and equipment, in particular tools and equipment that require safety testing.

The Tools and Equipment Manual (http://intranet/Docs/BS_Provide%20Business%20Management%20Support/BS0017Published/BS001701R100/Output%20files/default.htm) itemises the tools and equipment that have been approved by Ergon Energy for use by personnel to perform work tasks. It contains a range of information on each item including: a description of use, product specifications, testing, inspection and maintenance requirements, disposal information and the method of purchase. By specifying the standards for each type of tool and equipment, the Manual seeks to ensure that Ergon Energy's tools and equipment are fit for purpose and are the most cost effective option available. This also supports standardisation of the vehicle types and body kits (and hence delivers cost savings), as vehicles are more likely to carry similar standard tools.

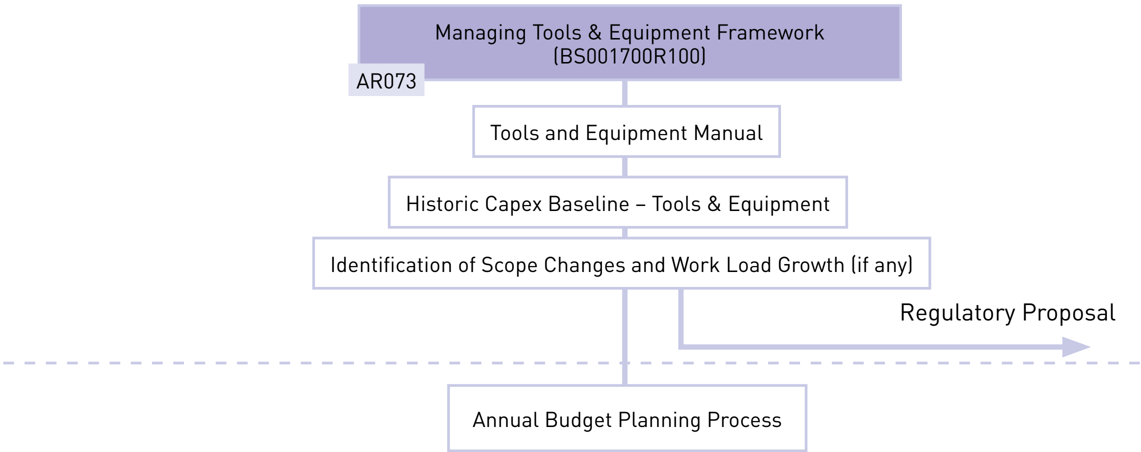
Ergon Energy's actual 2007-08 capital expenditure for Capital Expenditure – Non-System – Plant and Equipment is used as the baseline in the preparation of forecasts for the next regulatory control period. The baseline has been assessed against prior years' actuals to understand whether it is reflective of the overall trend. Ergon Energy's analysis has concluded that 2007-08 actuals (as reported in Ergon Energy's audited Regulatory Reporting Statements) is higher than a typical year.

The 2007-08 expenditure is explainable because it is strongly correlated to the significant increase in capital expenditure and workforce growth over the period up to 2007-08, which required additional plant and equipment to be purchased. As the growth in capital expenditure programs and the workforce peaked, and the required level of tools and equipment was reached, ongoing capital expenditure on plant and equipment was reduced to levels which are expected to more closely reflect replacement of existing tools and equipment.

Ergon Energy's forecasts for plant and equipment for the next regulatory control period have therefore been reduced from the 2007-08 year.

Ergon Energy's finance budget is the source of the five-year forecasts for the next regulatory control period that are included in this Regulatory Proposal.

Figure 47: *Capital Expenditure – Plant and Equipment*



23.7.4 Assumptions

The assumptions underlying the Capital Expenditure – Tools and Equipment forecast include:

- The current practice of capitalising certain tools and equipment and expensing others will continue. In general, tools and equipment over $1,000 are capitalised while those under $1,000 are expensed;
- Existing standards for tools (or at least the overall costs to deliver them) will not change materially between the current and the next regulatory control periods; and
- Future capital expenditure on tools and equipment will be closely aligned with expenditure on the system-related capital works program, less an annual productivity improvement factor.

23.7.5 Capital Expenditure / Operating Expenditure Interactions

There are no material interactions between Ergon Energy's capital expenditure forecasts for tools and equipment and its operating expenditure program.

Increases in capital plant and equipment may result in minor increases in overheads expenditure where safety testing or other maintenance of those additional plant and equipment is required.

23.7.6 Justification of the Forecasts

Tools and equipment are necessary enablers of the broader system capital and operating expenditure programs that are required to support the safe and efficient delivery of standard, alternative and unclassified works. There is therefore a close relationship between the tools and expenditure (capital and operating expenditure) forecasts and the forecasts of Ergon Energy's system-related capital and operating expenditure program.

On this basis, Ergon Energy's non-system capital expenditure forecasts for tools and equipment has been developed by:

- Applying its actual capital expenditure on tools and equipment for 2007-08 as the base year; and
- Adjusting the base year in line with forecast changes in the system-related capital and operating expenditure programs for the next regulatory control period.
- Adjusting downward to reflect a productivity improvement factor for tools and equipment.

23.7.7 Risk Considerations

Ergon Energy needs to ensure that its staff have tools and equipment that comply with relevant standards, as well as safety, testing and reporting requirements.

23.7.8 Customer Outcomes

There are no direct customer implications of Ergon Energy's non-system capital expenditure forecasts for tools and equipment, other than that Ergon Energy will have the necessary tools and equipment to provide its Standard Control Services in a safe and efficient manner.

23.8 MOTOR VEHICLES

23.8.1 Forecast 2010-15

Ergon Energy's Capital Expenditure – Non-System – Motor Vehicles forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 56.

Table 56: *Capital Expenditure – Non-System – Motor Vehicles – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
25.85	32.05	28.43	30.88	30.30	32.01	32.33	34.98	160.50	32.10

Source: Tables for Proposal 23.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10)

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

23.8.2 What the Forecast Relates to

This category of capital expenditure relates to the procurement of the following types of fleet that are used for the provision of Standard Control Services: elevating work platform, crane borer plant, trucks - heavy rigid, trucks - medium rigid, trucks - light rigid, light service trucks, 4WD light commercial vehicles, 2WD light commercial vehicles, passenger vehicles, trailers, forklifts, all terrain vehicles, vehicle loading cranes and other/light plant.

23.8.3 Estimation Process

In 2006, Ergon Energy prepared a Fleet Management Strategic Plan (see Figure 48) that details the way in which it will operate and manage its fleet assets, including:

- Its commitment to adhere to Ergon Energy's purchasing policies, guidelines, and procedures and the State Purchasing Policy[38]; and
- The depreciated lives (in years), replacement cycles (in years) and scheduled maintenance intervals for each class of fleet asset.

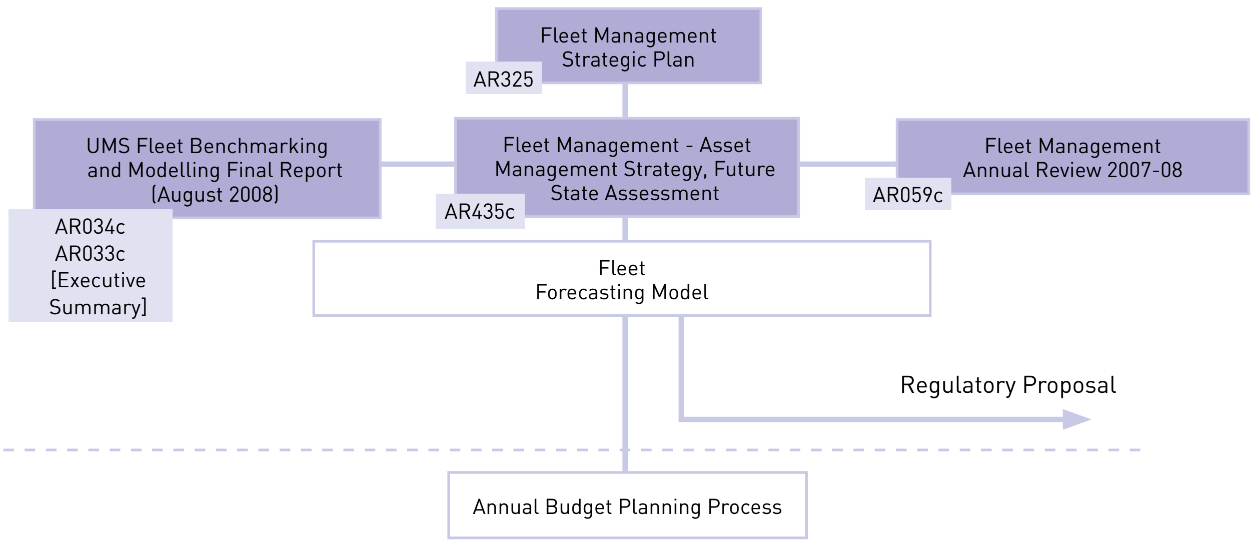
Ergon Energy undertakes a Fleet Management – Annual Review, which examines the status of each class of fleet asset, as well as their performance and operations, during the previous financial year.

Ergon Energy has prepared a Fleet Management - Asset Management Strategy - Future State Assessment, which details:

- The number, history and age profile for each class of fleet asset;
- The strategy for managing each class of fleet asset;
- The scheduled replacement program for each class of fleet asset over a five and 15-year horizon and the associated capital and operating expenditure programs; and
- Asset management strategies, which complement those in the Fleet Management Strategic Plan.

[38] Available from http://www.qgm.qld.gov.au/02_policy/spp.htm

Figure 48: *Capital Expenditure – Motor Vehicles*



The required numbers of vehicles over the next regulatory control period are estimated using Ergon Energy's Fleet Forecasting Model, having regard for the numbers of staff and size of the delivered work programs. The forecasting method is described in the Fleet Forecast Report. The capital forecasts are reflected in the development of the Ten and Five Year Capital Works Plan and an Annual Works Plan. The five year forecasts for the next regulatory control period are included in this Regulatory Proposal.

23.8.4 Assumptions

The assumptions underlying the Capital Expenditure – Non-System – Motor Vehicles forecast include:

-
- Future changes in vehicle numbers and expenditure will be related to changes in the work programs to be delivered; and
- Established key performance indicators in relation to fleet asset acquisition, replacement and disposal will be maintained during the next regulatory control period. In particular:
  - The annual replacement program will occur in accordance with established replacement cycles;
  - Fleet assets will be purchased in accordance with established arrangements; and
  - Fleet assets will be disposed of in accordance with established arrangements.

23.8.5 Capital Expenditure / Operating Expenditure Interactions

The management of Ergon Energy's required fleet, including procurement, maintenance, replacement and disposal and associated standards, is managed by Ergon Energy's Fleet Management Group in accordance with the Fleet Management Team's Strategic Plan and Motor Vehicle Use Policy.

There is a direct relationship between capital expenditure to procure fleet and the expenditure required to operate and maintain them. Once it has been purchased, an item of fleet will incur some or all of the following operating costs: depreciation, management support, fuel, scheduled and unscheduled maintenance, tyres, accident costs and registration.

23.8.6 Justification of the Forecasts

Ergon Energy is committed to providing efficient and cost effective fleet units which complement the business's strategic direction and deliver high standards of safety and environmental responsibility to employees and the community. The overarching business rules governing the management of the fleet assets is contained in the Fleet Strategy.

Ergon Energy's capital expenditure on fleet during between 2005-06 and 2007-08 was significantly higher than the long-term average due to substantial growth in the system and customer work programs. The number of vehicles of all types has increased by 171 (or 6.51 per cent) between 2005-06 to 2007-08.

Ergon Energy has prepared its Capital Expenditure – Non-System – Fleet forecasts for 2010-11 to 2014-15 by taking the 2007-08 actual baseline expenditure and applying adjustments following external benchmarking by UMS, internal modelling and a policy decision to extend the replacement age of light vehicles (excluding light service trucks) from three to four years.

23.8.7 Risk Considerations

Ergon Energy needs to ensure that it has a fleet that complies with relevant standards, as well as safety, environmental, testing and reporting requirements.

23.8.8 Customer Outcomes

There are no direct customer implications of Ergon Energy's non-system capital expenditure forecasts for fleet, other than that Ergon Energy will have the necessary fleet to provide its Standard Control Services in an efficient and effective manner.

23.9 INFORMATION COMMUNICATION AND TELECOMMUNICATIONS (ICT) SYSTEMS

23.9.1 Forecast 2010-15

Ergon Energy's Capital Expenditure – Non-System – ICT Systems forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 57.

Table 57: *Capital Expenditure – Non-System – ICT Systems – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
15.65	7.12	25.60	20.30	18.88	18.24	17.14	18.36	92.92	18.58

Source: Tables for Proposal 23.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10).

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

23.9.2 What the forecast relates to

This forecast relates to certain ICT assets which Ergon Energy, rather than SPARQ, continues to own. These assets broadly fall into two distinct categories:

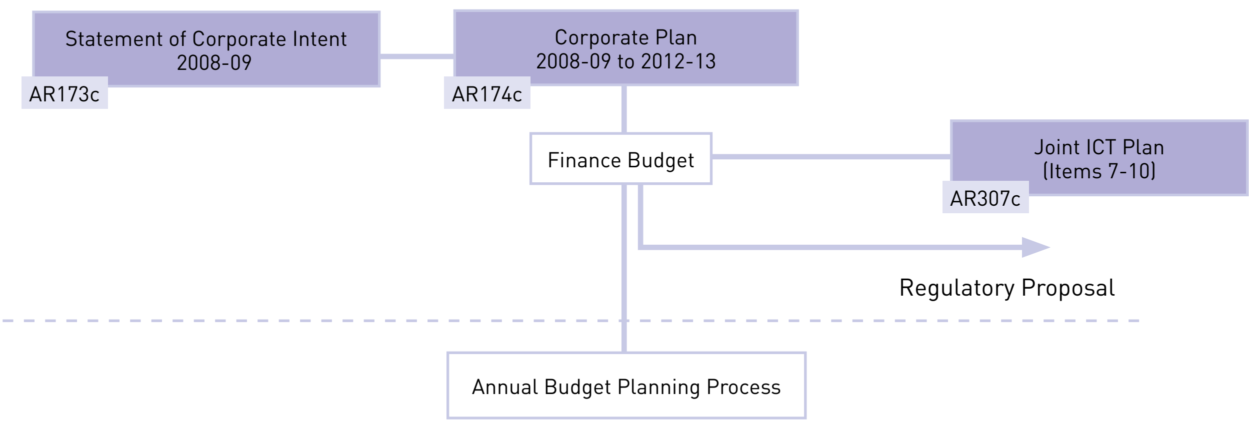
- Desktop and laptop personal computers and smaller ICT devices, such as printers and multi-function devices; and
- Legacy assets where the original application asset was held by Ergon Energy prior to the formation of SPARQ and it is not cost effective to perform an asset transfer from Ergon Energy to SPARQ.

23.9.3 Estimation Process

Ergon Energy engages SPARQ to assist in the preparation of Ergon Energy's ICT Systems capital expenditure forecast. SPARQ quantifies the expected costs for Ergon Energy to purchase its ICT devices. This is set out in the Joint ICT Plan (items 7 to 10). These forecast costs are then reconciled against Ergon Energy's Statement of Corporate Intent and Corporate Plan in the annual budget cycle (see Figure 49).

Ergon Energy's Finance five-year budget forecasts are used for this Regulatory Proposal.

Figure 49: *Capital Expenditure – ICT Systems*



23.9.4 Assumptions

The key assumption underlying the Capital Expenditure – Non-System - ICT Systems forecast is that Ergon Energy will continue to purchase and own desktop and laptop personal computers, smaller ICT devices as well as other legacy assets, in the next regulatory control period. It will not transfer responsibilities for these assets to SPARQ.

23.9.5 Capital Expenditure / Operating Expenditure Interactions

The key interaction between Ergon Energy's Capital Expenditure – Non-System - ICT Systems and its operating expenditure forecasts concerns the assets owned by Ergon Energy and the assets owned, and the services provided to Ergon Energy, by SPARQ.

Ergon Energy's ICT services are generally provided through SPARQ, the joint venture ICT service provider for Ergon Energy and ENERGEX, which began operating from 1 July 2004. SPARQ therefore holds most of the ICT assets that are used by Ergon Energy.

SPARQ levies operating expenditure charges on Ergon Energy (and ENERGEX) in order to recover its asset (i.e. return on asset and depreciation) and non-asset related costs. Ergon Energy includes SPARQ's operating expenditure charges in its operating expenditure building block. This subsection of the Regulatory Proposal does not deal with this category of expenditure.

Rather, this subsection of the Regulatory Proposal deals only with the capital expenditure that Ergon Energy incurs itself to purchase certain ICT assets. There is not a direct relationship between the level of this expenditure and the operating expenditure charges levied on Ergon Energy by SPARQ.

23.9.6 Justification of the Forecasts

SPARQ, Ergon Energy and ENERGEX have developed a Joint ICT Plan based on the major system requirements to support the businesses into the future. The plan has been used in conjunction with knowledge of the existing systems architecture to prepare a forecast of system replacement and upgrade investments.

As a general rule, application upgrades have been forecast to occur every three years. This will ensure that applications remain within the support windows of the respective vendors, remain current with respect to business changes and evolve as underlying technology matures.

In addition to the application upgrades, it has been assumed that major application upgrades or replacements will occur every six or nine years. For more mature applications and technologies, a nine-year replacement cycle has been assumed. For less mature products, the forecast has been prepared with a six-year replacement cycle.

Similarly, forecasts have been prepared for replacement of ICT Infrastructure based on expected life cycles and acceptable risks, especially in relation to the risk of failure of the infrastructure.

As discussed in section 34.3.2 of this Regulatory Proposal, there is a mix of ownership for ICT assets used by Ergon Energy to fulfil its business requirements. There is a decreasing reliance by Ergon Energy on ICT assets held in its own right. Under the current model, the size of this asset base will trend down for the life of this forecast though will not reach zero.

The values shown for Ergon Energy ICT assets in this forecast reflect the appropriate components of the ICT Blueprint which necessitate an investment in the Ergon Energy ICT assets:

- Desktop and laptop personal computers and smaller ICT devices, such as printers and multi-function devices; and
- Legacy assets where the original application asset was held by Ergon Energy prior to the formation of SPARQ and it is not cost effective to perform an asset transfer from Ergon Energy to SPARQ.

23.9.7 Risk Considerations

Ergon Energy needs to ensure that it has the necessary ICT assets to enable it to undertake its operations in an efficient and effective manner. This includes maintaining the ICT infrastructure fleet at a suitable age to ensure stable operations.

Asset Replacement guidelines have been developed to describe replacement cycles for the various categories of ICT assets. Fixed replacement cycles are not enforced for less critical devices such as a desktop PC. Asset Replacement cycles are more strongly followed for core and critical ICT infrastructure.

23.9.8 Customer Outcomes

There are no direct customer implications of Ergon Energy's non-system capital expenditure forecasts for ICT assets, other than that Ergon Energy will have the necessary ICT assets to provide its Standard Control Services and Customer Services in an efficient and effective manner.

23.10 BUILDINGS, LAND AND EASEMENTS

23.10.1 Forecast 2010-15

Ergon Energy's Capital Expenditure – Non-System – Buildings, Land and Easements forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 58.

Table 58: *Capital Expenditure – Non-System – Buildings, Land and Easements – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
35.61	25.63	74.98	121.67	141.69	76.65	24.39	19.83	384.23	76.85

Source: Tables for Proposal 23.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10).

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

23.10.2 What the forecast relates to

This category of capital expenditure relates to Ergon Energy's non-system property, relating to buildings, land and easements. It includes the 'fit-out' of new buildings, including office equipment and furniture.

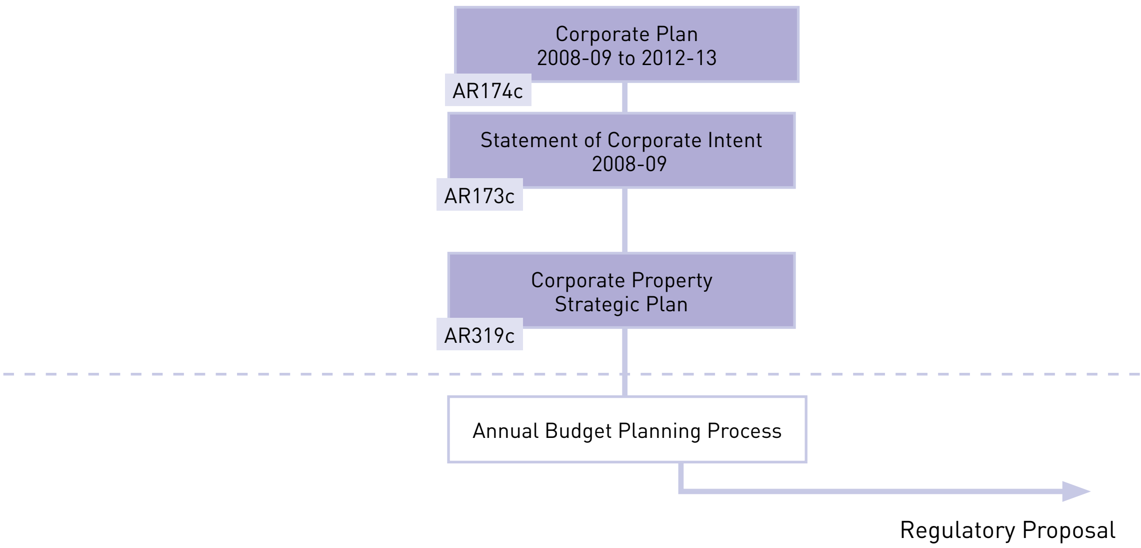
Ergon Energy has a large portfolio of real property assets dispersed geographically across Queensland. The portfolio ranges from commercial office space to smaller depot sites with a comparatively minor property value but significant operational value. Properties are held in a mixture of freehold, leasehold and reserve tenures.

The Ergon Energy property portfolio is split as follows:

- Network-managed property assets include substations, power stations and communications sites. These assets are managed by Ergon Energy's Transmission and Distribution Services (TaDS) business unit and are not the subject of this category of expenditure; and
- Ergon Energy's Corporate Property business unit manages all other land and building assets, including depots, offices, warehouses, houses and the provision of property assets in support of corporate initiatives. These are the subject of this category of expenditure.

23.10.3 Estimation Process

Figure 50: *Capital Expenditure – Non-System – Buildings, Land and Easements*



It is important to note that:

- Ergon Energy's Corporate Property business unit's forecasts for new Building Land and Easements described in this section 23.10 includes the cost of the property plus the fit-out (including Office Equipment and Furniture); however
- Ergon Energy's actual expenditure reported in the audited Regulatory Reporting Statements is the only the value of the property component. The fit-out costs are reported against Office Equipment and Furniture.

This means that there is a 'switch' between the forecast and actuals for the two categories of capital expenditure.

Taken together, the Buildings Land and Easements and Office Equipment and Furniture forecasts and actuals occur as set out in Table 59.

Table 59: *Forecast and Actual Treatment for Building Land and Easements and Office Equipment and Furniture*

Forecast	Building Land and Easements – refer section 23.10	• Property • Fit-Out (including Office Equipment and Furniture for new buildings)
Forecast	Office Equipment and Furniture – refer section 23.11	• Office Equipment and Furniture (for existing buildings)
Actuals	Building Land and Easements	• Property value only
Actuals	Office Equipment and Furniture	• All Office Equipment and Furniture value (Fit-Out of new buildings + replacement items in existing buidlings)

Therefore the 2007-08 actuals will reflect only the property value, whilst the 2010-15 forecasts will reflect both the property value and the fit-out value.

Ergon Energy has a five-year Corporate Plan for 2008-09 to 2012-13 (see Figure 50 on previous page). This Corporate Plan details Ergon Energy's purpose, vision and values and sets the key strategic direction for the business in three planning horizons. The Statement of Corporate Intent is an annual document that details the strategies that Ergon Energy will implement during the relevant year in order to: operate its core business, pursue its corporate and operational objectives, implement defined corporate strategies (having regard for a series of key performance drivers), and measure its performance against key result areas. The Statement of Corporate Intent is annually approved by Ergon Energy's shareholder, the Queensland Government.

One of the key corporate strategies that supports the Statement of Corporate Intent is the Corporate Property Strategic Plan.

The Corporate Property Strategic Plan was developed in 2005-06 and has a 15-year horizon for managing Ergon Energy's non-network property assets. The following are key drivers of Ergon Energy's Corporate Property Strategic Plan:

- Hub and Spoke Model – Ergon Energy will move to performing all administrative functions, not directly associated with fieldwork, at hubs and large spokes. The major hubs (in Townsville, Rockhampton and Toowoomba) will contain all organisational functions and specialist areas (i.e. call centres, control centres, major warehouses and main training facilities). The smaller spokes (in Mackay, Maryborough and Cairns) will contain area management, TaDS work crews, warehousing distribution, administration, local training facilities and local support;
- Consolidation of Sites – Ergon Energy will consolidate sites where possible, having regard for matters including community expectations; and
- Business Functions – Ergon Energy's business functions will generally not change significantly over time.

The Corporate Property Strategy contains location plans across Ergon Energy's supply area, which relate to Ergon Energy's property requirements over a 15 year period.

Ergon Energy has prepared a 15 year Property Capital Budget on the basis of its Corporate Property Strategy. This is an Excel spreadsheet that details the nature of capital expenditure required by site across each of Ergon Energy's regions over period 2008-09 to 2022-23. The forecasts for 2010-11 to 2014-15 are reflected into the capital expenditure forecasts for Buildings, Land and Easements in this Regulatory Proposal for the next regulatory control period.

23.10.4 Assumptions

The key assumptions underlying the Capital Expenditure – Other - Buildings, Land and Easements forecast are that:

- Forecasts are based on current market conditions;
- There will be a decrease in white collar staff of approximately five per cent over the regulatory control period and a small increase in blue and near blue collar staff;
- The number of depot locations will not change;
- Townsville, Rockhampton and Toowoomba will contain all organisational functions and specialist areas – call centres, control centres, major warehouses and major training facilities;
- The three other main locations – Cairns, Mackay and Maryborough – will contain most organisational functions and some specialist areas but these will reduce over time;
- There will be a continuing move towards open plan offices and shared facilities, such as lunch rooms, workshops, training facilities and meeting rooms;
- Ergon Energy will continue to provide employee housing in areas where it is difficult to attract staff;
- Executive Managers will reside in Brisbane and Townsville only;
- There will be an increasing requirement to demonstrate sustainable building credentials both in energy and environmental solutions; and
- Employees will have an increasing expectation of facilities that support a modern technology based workforce.

23.10.5 Capital Expenditure / Operating Expenditure Interactions

There is a direct relationship between Ergon Energy's capital and operating expenditure programs for land, buildings and easements. Once land has been purchased and a building has been constructed there is a need for:

- Condition-based assessments of all buildings on a three yearly inspection cycle. More frequent inspections are undertaken of major equipment items, such as air conditioners, lifts, fire systems, air quality and cooling towers. The associated reports form the basis of the 'corrective works plan';
- Annual building condition assessments are undertaken, which identify and prioritise maintenance work; and
- Forced Maintenance, which covers all expenditure resulting from building and equipment failure. This can either be addressed immediately or programmed for future action.

23.10.6 Justification of the Forecasts

When Ergon Energy formed its Corporate Property business unit in 2006, Ergon Energy faced the following challenges:

- There was a diverse and geographically dispersed portfolio of assets with no specific strategy, asset management plan or guidelines to manage property assets;
- There were property assets that were inappropriate for current and future operational requirements;
- There were ageing property assets that required significant investment for total redevelopments or refurbishments;
- There were past maintenance programs that were not completed and inconsistent processes used across the Ergon Energy's regions;
- There were significant discoveries of environmental issues such as contaminated land and asbestos products in buildings;
- There was a history of under performance in delivery of investment in property assets; and
- There was rapid, unexpected growth in materials storage requirements, training facilities (both classroom and field), and significant growth in employee numbers and vehicle numbers.

The development and implementation of the Corporate Property Strategic Plan with a planned ongoing capital program to bring property assets to an acceptable standard continues to be the key platform into the next regulatory control period.

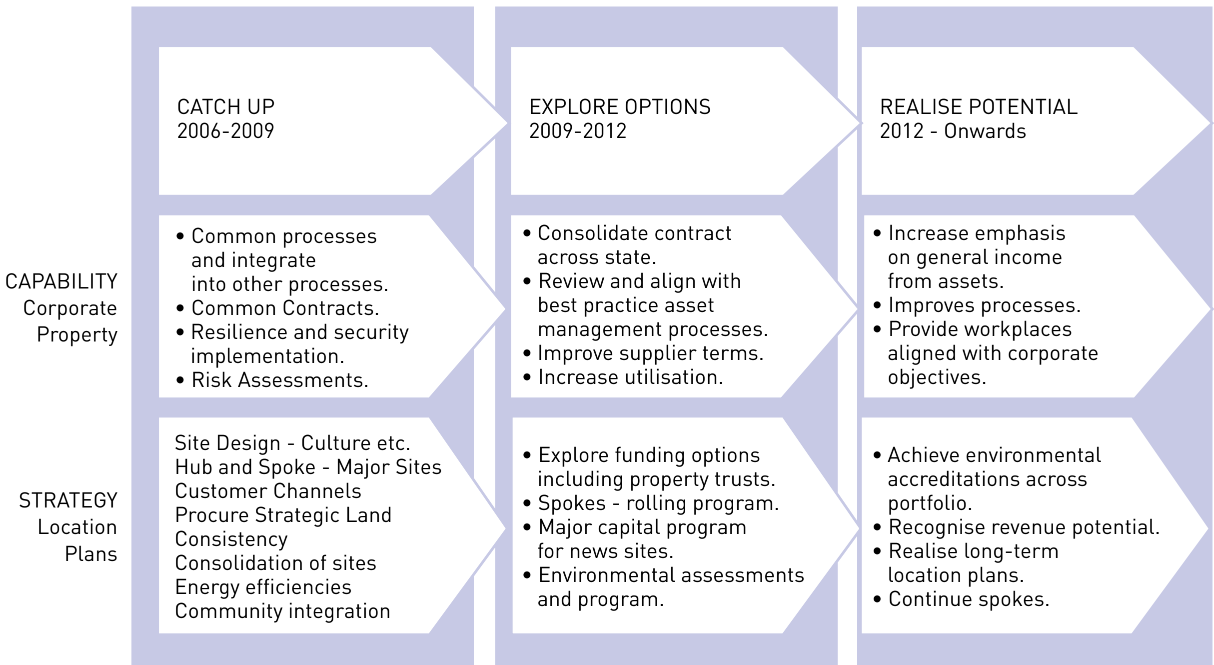
The Corporate Property Strategic Plan was developed in 2006 and has a 15-year horizon. Each year the property plan is updated and undertaken in the next financial year.

The property plan contains:

- A prioritised list of projects with full details to be approved for capital and operating budget purposes for the following year;
- A list of projects in the five years immediately ahead that are expected to be definite projects;
- A list of projects that are considered likely to eventuate in the period five to 15 years ahead; and
- A list of projects considered as possibilities in the period five to 15 years ahead.

The Corporate Property Strategic Plan has three phases as depicted in Figure 51.

Figure 51: *Ergon Energy Corporate Property Strategy Three Phases*



- 2006 - 2009 - Catch up – The objectives of this phase include:
  - Address the current challenges by undertaking a step change catch-up program for both corporate property capabilities and location strategies, including a focus on resilience and security implementation;
  - Procure strategic land, commence the consolidation of sites, focus on energy efficiencies and common site designs;
  - Develop professional sourcing arrangements for external service providers; and
  - Deliver projects on-time, within budget and to plan (including validated customer expectations).
- 2009 – 2012 – Explore Options – Maintain assets, explore asset potential (including the full utilisation of surplus assets) and secure longer-term location plans – The objectives of this phase include:
  - Provide further efficiencies in terms of Corporate Property capabilities including consolidation of contracts, increased utilisation and reviewing processes;
  - Continue the rolling program for depots and finalise the major capital building projects at new sites;
  - Instigate environmental assessments; and
  - Develop an accommodation and interior design manual.
- 2012 – 2020 - Realise Potential - Location plans and review for future opportunities – The objectives of this phase include:
  - Achieve environmental accreditations across portfolio;
  - Recognise revenue potential and increase emphasis on generating income from assets;
  - Realise long term location plans; and
  - Continuously improve processes and corporate property capabilities.

Implementation outcomes of the Corporate Property Strategic Plan deliverables in the period to early 2009 have been:

- The purchase of land in Cairns, Townsville, Mackay, Maryborough, Hervey Bay, Warwick, Ingham, Mossman and Normanton. Further land purchases will be made from time to time as required;
- Master planning of six major sites across the state. Concept design work on these sites is approximately 60 per cent complete;
- Development of a 'Green Star Rating' tool for combined office/depot facilities;
- Energy audits have been carried out in all locations across the state and areas of improvement have been identified;
- Appointment of a single service provider to carry out maintenance programs across the state;
- Refurbishment and / or redevelopment of a number of depots across the state. In particular the total redevelopment of Ness Street Mackay depot, which will incorporate all Mackay staff, is due for completion by 31 December 2010;
- Updating of the Ellipse equipment register and implementation of a works management system;
- A strategic asset management plan is under development and proposed finalisation is anticipated to be 1 July 2009;
- Development of a standardised Accommodation and Interior Design Manual is nearing completion; and
- Development of further processes including detailed reporting and auditing have been implemented for individual capital projects.

Capital expenditure in the next regulatory control period will primarily be related to:

- Preparing master plans and concept designs for the major sites; and
- The construction of a dedicated data centre building.

These projects represent 72 per cent of the forecast Capital Expenditure – Buildings, Land and Easements forecasts for the next regulatory control period. The dissection of the forecast is set out below.

23.10.6.1 Townsville - $60 Million

The rapid growth in operational requirements and office staff numbers has outgrown the Townsville Garbutt site and a parcel of land has been purchased at Ingham Road, Mt St John to become the Townsville depot. Construction work on this site will predominantly occur after July 2010, however in order to be in a position to commence work immediately in the next regulatory control period, the civil works and services installation will be carried out in the current regulatory control period.

In addition to the Ingham Road development, additional office accommodation will be constructed at the existing Garbutt site to cater for the expected staffing levels and to enable approximately 350 staff from leased buildings across several locations in the city to relocate to the Garbutt site.

23.10.6.2 Cairns - $20 Million

Cairns McLeod Street depot, which is the major operational centre in Cairns, is heavily congested and this will worsen as the city continues to grow. It is located on the fringe of the CBD which is an inappropriate location for an operational centre. A second operational centre is located in Hartley Street.

Cairns white collar employees are accommodated in the CBD Lake Street building. This building is old and requires a total refurbishment if it is be used for the medium term.

Importantly, all these locations are at risk because they are in the tidal surge zone.

A property has been purchased at Swallow Road, Edmonton, which is above the tidal surge zone, and it is planned to consolidate the all of Ergon Energy's operations in Cairns to this site in a staged redevelopment over five to seven years.

23.10.6.3 Rockhampton - $54 Million

The buildings at the Rockhampton Glenmore Road site are, in general, life expired, contain a substantial amount of asbestos material and are inappropriate for modern operational use. Ideally redevelopment of this site should be undertaken immediately however budget constraints have forced a delay into the next regulatory control period. The Master Plan for Glenmore Road is a staged redevelopment over five to seven years.

Any further delay in these projects will result in expenditure to set up demountable accommodation as buildings become unusable. This is now the case in building 16 (previously a garage) where Ergon Energy is accommodating staff in a demountable building as a result of being unable to keep vermin and birds out of their current building.

23.10.6.4 Maryborough - $25 Million

Ergon Energy's Maryborough white-collar employees are accommodated in the Adelaide Street building which is a three-storey building in the CBD. The building is in good condition and no major expenditure is necessary in the medium term. It is considered that it would be uneconomic for Ergon Energy to move out of this CBD premises.

The second Maryborough site is at Searle Street which is the main operational depot for Maryborough. This site is congested and Ergon Energy has recently purchased land adjoining the depot. The office accommodation at the depot site is very poor with most staff housed in demountable buildings. The facilities for blue and near blue collar employees are sub-standard.

23.10.6.5 Toowoomba - $12 Million

All of Ergon Energy's Toowoomba operations are at one site at South Street. This is an appropriate location and most buildings are in good to reasonable condition. An adjacent block of land with a large industrial shed was purchased two years ago and will cater for future growth. The office accommodation is congested with a number of staff in demountable buildings. A refurbishment of the old warehouse building is being undertaken in the current regulatory control period to provide accommodation relief in the short term. This refurbishment is in line with the Master Plan for the site.

23.10.6.6 Data Centre - $20 Million

Ergon Energy is planning to establish a Data Centre in the next regulatory control period and has forecast the costs to be $20 million.

The remaining 28 per cent of the Ergon Energy's forecast capital expenditure is spread across all the other depots, hubs and spokes across the state. Work planned for these sites includes depot redevelopments, building refurbishments, housing upgrades, wash-down bays, bunded areas and pole storage facilities.

This category of expenditure is designed to ensure that Ergon Energy has the necessary property assets, to support the Energy Services business requirements.

The Corporate Property projects and supporting details are described in the Corporate Property Strategic Plan.

23.10.7 Risk Considerations

Ergon Energy needs to ensure that its properties meet operational requirements and comply with relevant standards and regulations, including occupational, health, safety, environmental, securityand resilience requirements.

The legal compliance obligations associated with the management of buildings and facilities cannot be overstated. Non compliance carries both an unacceptable risk to staff and buildings and also significant fines and penalties.

The Ergon Energy risk profile for building and facilities management is high due to the age and condition of the asset portfolio. It is therefore critical that Ergon Energy outworks its Corporate Property Strategic Plan over the next regulatory control period and beyond.

23.10.8 Customer Outcomes

There are no direct customer implications of Ergon Energy's non-system capital expenditure forecasts for land, buildings and easements, other than that Ergon Energy will have the necessary resources to provide its Standard Control Services in an efficient and effective manner.

23.11 OFFICE EQUIPMENT AND FURNITURE

23.11.1 Forecast 2010-15

Ergon Energy's Capital Expenditure – Non-System – Office Equipment and Furniture forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 60.

***Table 60:** Capital Expenditure – Non-System – Office Equipment and Furniture – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
6.87	0.76	0.52	0.53	0.52	0.52	0.52	0.52	2.61	0.52

Source: Tables for Proposal 23.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10).

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

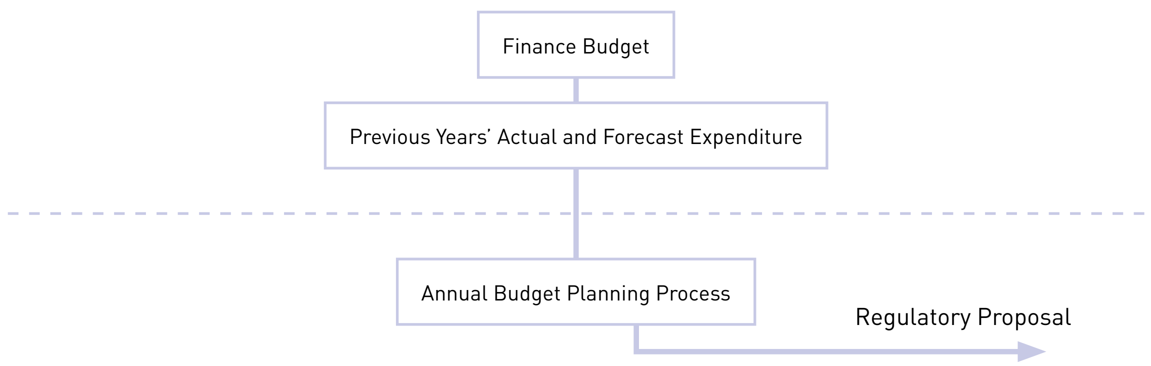
23.11.2 What the Forecast Relates to

This category of capital expenditure relates to Ergon Energy's office equipment and furniture that is required for its existing offices and depots such as electronic whiteboards, televisions, shredders and compactors.

23.11.3 Estimation Process

Ergon Energy forecasts its Capital Expenditure – Other - Office Equipment and Furniture with reference to its historical expenditure, as shown in Figure 52.

***Figure 52:** Capital Expenditure - Non-System - Office Equipment and Furniture*



2007-08 actual expenditure (in total) is not an appropriate base year for the preparation of forecasts because:

- Ergon Energy's Corporate Property business unit's forecasts for new Building Land and Easements described in section 23.10 includes the cost of the property plus the fit-out (including Office Equipment and Furniture); however
- Ergon Energy's actual expenditure reported in the audited Regulatory Reporting Statements is the total value of all Office Equipment and Furniture (in both new buildings and existing buildings).

This means that there is a 'switch' between the forecast and actuals for the two categories of capital expenditure.

Taken together, the Buildings Land and Easements and Office Equipment and Furniture forecasts and actuals occur as set out in Table 61.

***Table 61:** Forecast and Actual Treatment for Building Land and Easements and Office Equipment and Furniture*

Forecast	Building Land and Easements – refer section 23.10	• Property • Fit-Out (including Office Equipment and Furniture for new buildings)
Forecast	Office Equipment and Furniture – refer section 23.11	• Office Equipment and Furniture (for existing buildings)
Actuals	Building Land and Easements	• Property value only
Actuals	Office Equipment and Furniture	• All Office Equipment and Furniture value (Fit-Out of new buildings + replacement items in existing buildings)

Therefore only that part of the 2007-08 base year that relates to Office Equipment and Furniture expenditure for existing buildings is used to prepare the forecasts for the next regulatory control period.

23.11.4 Assumptions

The key assumption underlying the Capital Expenditure – Other - Office Equipment and Furniture forecast is that Ergon Energy will require the same levels of expenditure throughout the next regulatory control period as it is forecasting to spend in 2009-10.

23.11.5 Capital Expenditure / Operating Expenditure Interactions

There are no significant capital and operating expenditure interactions relating to this expenditure.

23.11.6 Justification of the Forecasts

As noted above, Ergon Energy has based its Capital Expenditure – Other - Office Equipment and Furniture forecast for the next regulatory control period on a continuation of the expenditure that it has budgeted for 2009-10. The 2009-10 expenditure levels are considered to provide a sustainable baseline of expenditure for the next regulatory control period.

23.11.7 Risk Considerations

Ergon Energy needs to ensure that its office equipment and furniture meet operational requirements and comply with relevant standards and regulations, including in relation to occupational, health and safety.

23.11.8 Customer Outcomes

There are no direct customer implications of Ergon Energy's non-system capital expenditure forecasts for office equipment and furniture, other than that Ergon Energy will have the necessary assets to provide its Standard Control Services in an efficient and effective manner.

23.12 VARIATIONS IN CAPITAL EXPENDITURE

Section 2.2.4 of the AER's RIN requires Ergon Energy to identify and explain significant variations in its proposed forecast expenditure from historical expenditure for Standard Control Services. The AER has defined a significant variation as being a 10 per cent variation between the actual expenditure in 2007-08 and the average of the five years' forecast expenditure for 2010-11 to 2014-15.

23.12.1 Variations by Asset Category

Pro forma 2.2.1 of the AER's RIN requires Ergon Energy to present its capital expenditure forecasts on the basis of asset categories, expenditure purposes and cost categories. Pro forma 2.2.4 of the AER's RIN shows that for a variety of asset categories there is a greater than 10 per cent variation between the actual expenditure in 2007-08 and the average of the five years' forecast expenditure for 2010-11 to 2014-15.

Ergon Energy has explained all of its capital expenditure in this Regulatory Proposal by reference to expenditure purpose and cost categories and not by reference to asset categories. For this reason, Ergon Energy has not sought to explain the variations in expenditure for each asset category identified in pro forma 2.2.4 of the RIN. Rather, sections 23.12.2 and 23.12.3 respectively explain Ergon Energy's variations on the basis of its expenditure purpose and cost categories.

However, Ergon Energy notes that Table 90 in Chapter 33 of this Regulatory Proposal details the nominal cost escalation factors for its 27 asset categories that have been applied to its capital expenditure forecasts for the 2010-11 to 2014-15 regulatory control period.

23.12.2 Variations by Expenditure Purpose

Table 62 provides an extract from pro forma 2.2.4 of the completed RIN, which shows that there is a greater than ten per cent variation between the actual capital expenditure in 2007-08 and the average annual forecast capital expenditure for 2010-11 to 2014-15 for all system capital expenditure purpose categories and for total capital expenditure.

Table 62: *Variation between Actual 2007-08 and Forecast 2010-11 to 2014-15 Capital Expenditure by Category Driver ($M Real $2009-10)*

Expenditure Purpose	Significant variance	2010-11 to 2014-15 Average	2007-08
System Assets			
Asset Replacement	Explain	242.83	111.96
Corporation Initiated Augmentation	Explain	398.19	259.29
Customer Initiated Capital Works	Explain	339.00	293.08
Reliability & Quality Improvements	Explain	24.48	14.22
Other System Capital Expenditure	Explain	66.28	29.63
Subtotal System Assets	Explain	1,070.77	708.18
Non-System Assets	n/a	135.82	127.02
Total Capital Expenditure	**Explain**	**1,206.59**	**835.20**

Source: Tables for Proposal 23.12.2

Clause S6.1.1(7) of the Rules requires an explanation of any significant variations in the forecast capital expenditure from historical capital expenditure. The remainder of this subsection explains the reasons for the variations in each expenditure purpose category for system-related capital expenditure. The subtotals and totals have not been separately explained because the same reasons apply to these variations as for the expenditure purposes categories.

The variations in each expenditure purpose category are caused by a combination of changes in direct costs, Shared Costs (Overheads) and cost escalations. The discussion below relates only to direct costs.

The changes in Shared Costs (Overheads) allocated to each expenditure purpose category relate to changes in the relative share of total direct capital expenditure between the expenditure purpose categories over the next regulatory control period. These allocations are made in accordance with Ergon Energy's approved Cost Allocation Method.

Some of the variations are also attributable to cost escalations. These cost escalations have been applied given Ergon Energy's belief that the consumer price index (CPI) will not accurately reflect movements in costs associated with Ergon Energy's forecast expenditure programs. Ergon Energy engaged consultants Sinclair Knight Mertz (SKM) to develop cost escalation factors for its 27 asset categories to be applied to its capital expenditure forecasts for the period 2004-05 to 2014-15. The nominal cost escalation factors are detailed in Table 90 in Chapter 33.

23.12.2.1 Asset Replacement

Section 23.2.6 of this Regulatory Proposal discusses the key reasons for increases in the level of asset replacement capital expenditure between the current and next regulatory control periods for defect and condition based expenditure.

Defect-based expenditure will increase as a result of increased work being undertaken, and increased direct costs being incurred, on:

- Pole top replacements to address more unassisted failures and dangerous electrical events relating to cross arms;
- Underground cables to address the large number of high voltage cables that have failed in service and the need to replace high voltage XLPE cables;
- Lightning arrestors as a result of changing its defect classification criteria for failed lightning arrestors;
- Customers' overhead service lines in order to reduce the number of electric shocks experienced by the public;
- Earth remediation in order to better address the requirements of the Code of Practice Works under the Electrical Safety Act 2002;
- The replacement of non-compliant meters in accordance with the Meter Asset Management Plan.

Condition-based expenditure will increase as a result of increased work being undertaken on:

- Overhead conductor replacement in accordance with the recommendations of the EDSD Review and the subsequent Queensland Government-initiated 2008 Operational Review;
- The replacement of liquid-filled fuses in order to address identified safety risks;
- The refurbishment of sub-transmission feeder pole tops on the basis of condition assessments, feeder performance and assessed risks to the network;
- Sub-transmission line rebuilds relating to sub-transmission lines in order to meet service performance requirements; and
- A variety of substation plant and equipment, including: zone substation transformers refurbishment and replacement; circuit breakers and switchboard refurbishment and replacement; current transformers and voltage transformers; outdoor switchyards refurbishment; capacitors and static VAR compensators; protection equipment; and SCADA and load control equipment.

23.12.2.2 Corporation Initiated Augmentation

Section 23.3.6 of this Regulatory Proposal discusses the key reasons for increases in the level of CIA expenditure between the current and next regulatory control periods for sub-transmission and distribution related expenditure. In particular, CIA expenditure will increase as a result of increased work being undertaken, and increased direct costs being incurred, in order to enable Ergon Energy to:

- Meet the maximum demand/load forecasts discussed in Chapter 21 of this Regulatory Proposal, which are expected to be driven by strong population growth, major new industrial or commercial developments, economic growth, and climatic effects and air conditioning penetration; and
- Implement its Network Planning Criteria NP02 and Security Criteria NPD05.

23.12.2.3 Customer Initiated Capital Works

Section 23.4.6 of this Regulatory Proposal discusses the key reasons for increases in the level of CICW between the current and next regulatory control periods.

Ergon Energy has prepared its CICW forecasts by making adjustments to the 2007-08 actual expenditure for:

- Updates to the CICW price book, on the basis that the current price book has been systematically under-estimating the costs of CICW;
- Applying the NIEIR dwelling stock growth forecasts in NIEIR's 'Maximum demand forecasts for Ergon Energy connection points to 2018 – Coincident and Non-Coincident Peaks for Summer and Winter by BSP' as a basis for escalating the 2007-08 base year expenditure; and

- Adjusting the forecasts for the increased uptake of URD subdivisions being built by alternative providers during 2007-08 and 2008-09, and the extension of the alternative provider model to Commercial and Industrial works from 2010.

As discussed in section 23.4 of this Regulatory Proposal, it is expected that the increased contestability of CICW will result in:

- A significant drop-off in the level of cash contributions for other small CICW from 2010-11 as alternative providers successfully compete with Ergon Energy to provide Commercial and Industrial work. This will be on top of an expected drop-off in cash contributions from URD subdivisions from 2008-09 as developers increasingly undertake this work;
- An increase in the value of gifted assets as more work is undertaken by alternative providers.

23.12.2.4 Reliability & Quality Improvements

Section 23.5.6 of this Regulatory Proposal discusses the key reasons for increases in the level of reliability and quality improvements expenditure between the current and next regulatory control periods.

In particular, reliability and quality improvements expenditure will increase to enable Ergon Energy to meet the increasingly onerous minimum service standard requirements under the Electricity Industry Code and to address its worst performing feeders. Increased work will be undertaken, and increased direct costs will be incurred, on:

- The rollout of SCADA to around 90 per cent of all customers;
- Actioning the feeder improvement program; and
- Extending the network monitoring program.

23.12.2.5 Other System Capital Expenditure

Section 23.6.6 of this Regulatory Proposal discusses the key reasons for increases in the level of other system capital expenditure between the current and next regulatory control periods. In particular, increased work will be undertaken, and increased direct costs will be incurred, on other system capital expenditure to:

- Establish a primary communications backbone, UbiNet, which will enable the future deployment of a multipoint network solution to service intelligent network devices in order to deliver enhanced monitoring and control of the distribution network. A dedicated program of work is needed to ensure that the communications capability is delivered in a coordinated and timely manner;
- Improve protection system design to clear faults and dangerous situations in a timely manner in order to ensure public and staff safety and to protect Ergon Energy's assets; and
- Deliver on the 17 strategies for the SWER system that were detailed in the January 2008 document entitled 20 Year Strategic Plan for SWER prepared by the SWER Improvement Group.

23.12.3 Variations by Cost Category

Table 63 provides an extract from pro forma 2.2.4 of the completed RIN, which shows that there is a greater than 10 per cent variation between the actual capital expenditure in 2007-08 and the average of the five years' forecast capital expenditure for 2010-11 to 2014-15 for the four cost categories – labour, materials, contractors and other. As a result of these items, there is also a significant variation in the total operating expenditure program.

Table 63: *Variation between Actual 2007-08 and Forecast 2010-11 to 2014-15 Capital Expenditure by Cost Category ($M Real $2009-10)*

Expenditure Purpose	Significant variance	2010-11 to 2014-15 Average	2007-08
Labour	Explain	290.86	233.41
Materials	Explain	273.88	174.27
Contractors	Explain	183.86	117.82
Other	Explain	457.99	309.71
Total	**Explain**	**1,206.59**	**835.20**

Source: Tables for Proposal 23.12.3

The remainder of this subsection explains the reasons for the variations in each cost category for system-related capital expenditure between the current and next regulatory control periods. The total has not been separately explained because the same reasons apply to this variation as for the individual cost categories.

23.12.3.1 Labour

Labour costs are forecast to increase across the next regulatory control period as a result of more Ergon Energy labour being required to undertake more work in all expenditure categories.

A further cause of the labour cost increases is the higher wage escalation rates reflected in the new Ergon Energy Union Collective Agreement 2008.

The nature, and drivers, of the labour cost increases that were used to prepare the capital expenditure forecasts are discussed further in:

- Chapters 32 and 33 of this Regulatory Proposal, which deal with Ergon Energy's unit rates and escalations respectively; and
- Two reports that were prepared for Ergon Energy by SKM in 2008, entitled "Capital Works Project Cost Escalation Factors for the period 2005-2015" and "Electricity Industry Labour, Commodity and Asset Price Cost Indices".

23.12.3.2 Contractors

Contractor costs are forecast to increase across the next regulatory control period as a result of Ergon Energy significantly increasing the amount of work being undertaken by contractors, particularly in relation to CICW and CIA works. Two other causes of the contractor cost increases are expected to be higher prices resulting from a continuing tight contractor market and the higher wage escalation rates that have been reflected in the new Ergon Energy Union Collective Agreement 2008, which flow through to contractors.

The nature, and drivers, of the contractor cost increases that were used to prepare the capital expenditure forecasts are discussed further in:

- Chapters 32 and 33 of this Regulatory Proposal, which deal with Ergon Energy's unit rates and escalations respectively; and
- Two reports that were prepared for Ergon Energy by SKM in 2008, entitled "Capital Works Project Cost Escalation Factors for the period 2005-2015" and "Electricity Industry Labour, Commodity and Asset Price Cost Indices".

23.12.3.3 Materials

The material costs of plant and equipment are discussed in:

- Chapters 32 and 33 of this Regulatory Proposal, which deal with Ergon Energy's unit rates and escalations respectively; and
- Two reports that were prepared for Ergon Energy by SKM in 2008, entitled "Capital Works Project Cost Escalation Factors for the period 2005-2015" and "Electricity Industry Labour, Commodity and Asset Price Cost Indices".

23.12.3.4 Other Costs

The other costs that are used to prepare the capital expenditure building blocks include:

- Plant and equipment, which are discussed in section 23.7 of this Regulatory Proposal. These are necessary enablers of the system capital expenditure program and are required to support the safe and efficient delivery of the works program. The increase in tools and equipment expenditure is in line with the increase in the system capital expenditure program;
- Motor vehicles, which are discussed in section 23.8 of this Regulatory Proposal.
- ICT systems, such as desktop and laptop personal computers and smaller ICT devices as well as legacy assets, which are discussed in section 23.9 of this Regulatory Proposal. Average expenditure between 2010-11 and 2014-15 will be more than 10 per cent above 2007-08 levels, although it will be below 2008-09 levels based on routine application upgrades occurring every three years and major application upgrades or replacements occurring every six or nine years;
- Buildings, land and easements, which are discussed in section 23.10 of this Regulatory Proposal. Upgrades of buildings at key sites – Townsville, Cairns, Rockhampton, Maryborough and Toowoomba – as well as a new data centre, are the key reasons for expenditure increases in the next regulatory control period; and
- Office equipment and furniture, which are discussed in section 23.11 of this Regulatory Proposal. Expenditure in this category is not expected to increase in the next regulatory control period.

23. CAPITAL EXPENDITURE – FORECAST AND JUSTIFICATION – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR042	Electricity Regulation 2006 (Qld)
AR371	Electricity Act 1994 (Qld)
AR405	Electrical Safety Act 2002 (Qld)

AER Documents

AR367c & 368c	AER Regulatory Information Notice
AR 396 & 397	AER Final Decision STPIS, June 2008 & AER Appendix C STPIS, June 2008
AR417 & 418	AER Cost Allocation Guidelines, Final Decision and Guidelines, 26 June 2008

QCA Documents

Nil

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR158	"Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland" (EDSD Review), July 2004
AR209	Electrical Safety Act - Code of Practice for Works (Protective Earthing, Underground Cable Systems and Maintenance of Supporting Structures for Powerlines)
AR364	National Electricity Rules
AR404	Qld Govt "An Action Plan for Queensland Electricity Distribution" (EDSD Action Plan), 23 August 2004
AR439	Qld Govt Report on the Operational Review of Queensland Electricity Distributors, 23 June 2008

Ergon Energy Documents

AR033c & AR034c	UMS Fleet Benchmarking and Modelling Executive Summary and Final Report, 7 August 2008
AR038c	EE Network Connection Process and Procedures Manual
AR039c	EE UbiNet Business Case
AR040c	EE Board Paper 0805-09 UbiNet Project Phase 1, Resolution, 30 May 2008
AR046	EE Distribution Capability Report 2007, January 2008
AR047	EE Capital Contributions Methodology (QCA Approved), 20 April 2005
AR049	EE Annual Network Reliability Performance Report 2006-07, 5 December 2007
AR054c	EE Board Paper Community Powerline Project, 10 November 2003
AR059c	EE Fleet Management Annual Review 2007-08, V4, 22 August 2008
AR064	EE Network Planning Criteria – NP02, V2.03, 30 May 2000
AR065c	NIEIR November 2007 Maximum Demand Forecasts
AR069	EE Recommended Works Report Sample, Townsville Port Sub 66kV Reinforcement, 14 June 2006
AR070	EE Regulatory Test Sample - Bowen Area Final Report 22 August 2008
AR073	EE BS001700R100, Managing Tools and Equipment Framework, V2, 12 September 2007
AR074c	EE Board Paper 0713-13 Toowoomba Trees Program, 26 October 2007
AR075	EE NA000900R102 Meter Asset Management Plan, V3, 1 February 2008
AR078	EE Network Maintenance Defect Classification Manual
AR128c	NIEIR September 2008 Maximum Demand Forecasts
AR135	EE Summer Preparedness Plan 2008-09
AR151	EE Annual Network Performance Report – Power Quality 2006-07, 26 October 2007
AR157	SKM "Collation of Benchmarked Fault Rate Data for Network Elements", 19 March 2004
AR160	EE "The powerful new deal for regional Queensland customers – Ergon Energy's response to the Independent Review Panel Report Electricity Distribution and Service Delivery for the 21st Century – August 2004"
AR169	SKM Electricity Industry Labour, Commodity and Asset Price Indices, Model Outputs, 9 October 2008
AR171	EE Joint SWER Taskforce Report Executive Summary, 2005

C CONFIDENTIAL INFORMATION

AR173c	EE Statement of Corporate Intent 2008-09, 29 May 2008
AR174c	EE Corporate Plan 2008-09 to 2012-13, 28 May 2008
AR175	EE Security Criteria Network Planning NPD05, 12 April 2005
AR203c	EE Board Paper 0805-09 UbiNet Project Phase 1, 30 May 2008
AR205	EE Regulatory Test Sample, Berserker Area Final Report, 15 May 2008
AR206	EE Regulatory Test Sample, Cairns Area Final Report, 2 September 2008
AR207	EE STNP001 Network Performance Standard, V3, 25 October 2008
AR217	EE Annual Network Reliability Performance Report 2007-08, 5 November 2008
AR218	EE Annual Network Reliability Performance Report 2007-08 – Appendices E-K, 31 October 2008
AR226	EE Asset Equipment Plans 2009
AR245c	EE Board Paper 0713-13 Toowoomba Trees Program – Resolution, 26 October 2007
AR246c	EE Board Paper 0012-5-6 Powerlines Undergrounding Project (CARE) – Resolution, 8 December 2000
AR247c	EE Board Paper 0012-5-6 Powerlines Undergrounding Project (CARE), 8 December 2000
AR284	EE Capitalisation Accounting Policy Property Plant & Equipment, March 2009
AR285	EE Capitalisation Accounting Policy Intangible Assets, March 2009
AR289	EE Regional Distribution Capability Reviews 2008
AR307c	EE Joint ICT Plan, Sep08 baseline,V1.2, 19 January 09
AR314	EE Cost Allocation Method, AER Approved
AR318	EE EP51 Asset Management Defect Policy, 1 May 2008
AR319c	EE Corporate Property Strategic Plan, V23, 28 August 2006
AR325	EE Fleet Management Strategic Plan, V5, 23 March 2009
AR336	EE Network Performance Strategy 2010-15, 24 March 2009
AR340	EE Power Quality Strategic Program, 1 April 2009
AR341	EE Feeder Improvement Program, 1 April 2009
AR342	EE SCADA Acceleration Strategy, 1 April 2009
AR374c	NIEIR April 2009 report "Economic Outlook for Australia and Queensland to 2018-19 – December 2008"
AR375c	EE Sub-transmission Network Augmentation Plans 2007
AR401	EE Network Management Plan, Summary, 2008-13
AR402	EE Network Management Plan, Part A 2008-09 to 2012-13
AR413c	EE Current State Assessments SWER, Distribution & LV, 2008
AR424c	EE Distribution Network Augmentation Plans 2007
AR427c	EE "Delivering Service Improvements across Ergon Energy's SWER Network", February 2005
AR428c	EE Current State Assessments SWER & Distribution 2007
AR429	EE PW000101R104 Underground Urban Residential Developments – Subdivision Developers Handbook, V4, 18 March 2009
AR430	EE EP78 Motor Vehicle Use Policy, V1, 11 April 2006
AR431c	EE Single Wire Earth Return (SWER) Update, June 2006
AR432	EE BS001700R100 Tools & Equipment Framework, V2, 12 September 2007
AR434c	EE Unit Rates Master List Spreadsheet, 5 May 2009
AR435c	EE Fleet Management - Asset Management Strategy, Future State Assesment, V5, 20 March 2009
AR436c	EE Demand/Load Forecast Spreadsheets 2006-07
AR438	SKM Electricity Industry Labour, Commodity & Asset Price Cost Indices, St 2 (updated for GFC), 6 October 2008
AR444	EE 20 Year Strategic Plan for Single Wire Earth Return, V1.0.7, 30 November 2007
AR445	EE Network Management Plan, Part B 2008-09 to 2012-13
AR446	EE Preventive Maintenance Programs for 2010-11 to 2014-15, V7, May 2009
AR447c	EE Tools & Equipment Forecast Report, 16 February 2009
AR450	EE Underground Cabling Strategy, 31 March 2009

AR451	EE Strategic Plan for Asset Renewal, 3 April 2009
AR453	EE Operational Communications – Strategy Overview Infrastructure Design (UbiNet)
AR455	EE Operational Communications Development Strategy, V1.1, 28 November 2008
AR458	EE P89Y09R02 Security Standards & Guidelines, V2, 3 September 2006
AR460	EE Distribution Capability Report 2008, V2, December 2008
AR461	SKM Electricity Industry Labour, Commodity & Asset Price Cost Indices, St 2 (Jan09 Update of Escalators), 14 January 2009
AR462c	EE CICW SCS Forecasts
AR463c	EE Network Protection and Control Program
AR464c	EE Demographic Spatial Load Forecast Reports 2008
AR465	EE Communications Network Augmentation Plan, Rev 0.7, 1 May 2009
AR511c	EE Ltr to Minister Wilson, Response to Operational Review, 18 July 2008
AR512c	EE Response to Operational Review, 18 July 2008
AR536c	EE Corporate Plan 2009-10 to 2013-14, May 2009
AR537c	EE Statement of Corporate Intent 2009-10, May 2009
AR539c	EE Regulatory Proposal Models, NARMCOS Model

24. CAPITAL EXPENDITURE – OBJECTIVES, CRITERIA AND FACTORS

Rules – Clause 6.5.7

This chapter demonstrates how Ergon Energy's forecast capital expenditure for the next regulatory control period achieves the capital expenditure objectives, having regard for the capital expenditure criteria and capital expenditure factors. It also provides certain other information that is required in relation to its capital expenditure forecasts under the Rules.

The Regulatory Information Notice (RIN) pro forma 2.2.3 ("Projects") addresses the requirement of the Rules clause 6.5.7(b)(4) to specify whether proposed expenditures are for options that have satisfied the Regulatory Test. Ergon Energy has provided this information in this RIN pro forma (Column L) for those projects for which a Regulatory Test has been carried out.

24.1 JUSTIFICATION OF FORECASTS AGAINST CAPITAL EXPENDITURE OBJECTIVES

Clause 6.5.7(a) of the Rules states that:

> *A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider (DNSP) considers is required in order to achieve each of the following (the capital expenditure objectives):*
>
> 1. *meet or manage the expected demand for standard control services over that period;*
> 2. *comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
> 3. *maintain the quality, reliability and security of supply of standard control services;*
> 4. *maintain the reliability, safety and security of the distribution system through the supply of standard control services.*

24.1.1 Interpretation of Clause 6.5.7(a)

Ergon Energy interprets clause 6.5.7(a) of the Rules as requiring it to demonstrate that its forecast capital expenditure will enable it to achieve certain performance outcomes relating to its distribution system and its distribution services in the next regulatory control period. These performance outcomes become the 'objectives' that Ergon Energy's capital expenditure must achieve.

However, this clause, of itself, does not require Ergon Energy to justify the costs that have been used to develop its forecast capital expenditure. Rather, the nature and level of costs will be justified in addressing the requirements of clauses 6.5.7(c) and 6.5.7(e) of the Rules.

Therefore, this section focuses on how the activity to be undertaken through the capital expenditure programs will deliver the required performance outcomes required by clause 6.5.7(a) rather than whether the dollar value of the capital expenditure forecasts is 'the right number'.

The performance outcomes that clause 6.5.7(a) of the Rules requires Ergon Energy's forecast capital expenditure to relate only to Standard Control Services. Ergon Energy proposes, in Chapter 14 of this Regulatory Proposal, that its Standard Control Services in the next regulatory control period should be network services, connection services and metering services.

Ergon Energy interprets clause 6.5.7(a)(1) of the Rules to mean that its forecast capital expenditure must be capable of resulting in capital activity that meets or manages the demand for:

- Network services that are provided over the distribution network to all network users that are connected to that network. The demand for network services can be measured in terms of the levels of maximum demand and energy consumption from the distribution network and the number of customer connections to the distribution network;
- Connection services that are provided through connection assets, such as a padmount transformer or a service line for metered or unmetered connections. The demand for connection services can be measured in terms of the number of customer connections; and
- Metering services that are provided in relation to Type 5 to 7 metering installations. The demand for metering services can be measured in terms of the number of new meter installations, scheduled and unscheduled meter readings and metering investigations that are required.

Ergon Energy interprets clause 6.5.7(a)(2) of the Rules to mean that its forecast capital expenditure must be capable of resulting in capital works that ensure that it complies with the legislative and regulatory instruments relevant to the provision of Standard Control Services. Chapter 10 of this Regulatory Proposal identifies the key legislative and regulatory instruments that will apply to Ergon Energy in the (current and) next regulatory control period. These instruments include Queensland and national:

- Legislation and regulations;
- Contracts and agreements;
- Authorities and Codes; and
- Economic regulatory instruments.

Ergon Energy considers that clause 6.5.7(a)(3) of the Rules is framed problematically, because it requires the forecast capital expenditure to "maintain the quality, reliability and security of supply of standard control services". A problem arises because the phrases "quality, reliability and security of supply" are typically used in the electricity distribution industry to refer to assets, not services. Indeed, of the five types of service standards referred to in Chapter 12 of this Regulatory Proposal – security of supply, reliability of supply, quality of supply, safety and customer service – only the last relates to standards that individual customers are entitled to receive. The other four relate to standards that Ergon Energy must meet across its distribution system generally.

This suggests that there is an overlap between this clause and clause 6.5.7(a)(4) of the Rules, which requires Ergon Energy to "maintain the reliability, safety and security of the distribution system through the supply of standard control services".

Taken together, Ergon Energy interprets clauses 6.5.7(a)(3) and 6.5.7(a)(4) of the Rules to mean that its forecast capital expenditure must be capable of:

- Resulting in capital works that ensure that its distribution system, that is used to provide its Standard Control Services, complies with the quality, reliability, safety and security of supply standards detailed in Chapter 12 of this Regulatory Proposal; and
- Funding the works program to deliver the customer service standards that individual customers are entitled to receive through the Guaranteed Service Level (GSL) regime under the Electricity Industry Code.

24.1.2 Meeting the Requirements of Clause 6.5.7(a)

Ergon Energy considers that its forecast capital expenditure will enable it to deliver the performance outcomes in the next regulatory control period that are required by clause 6.5.7(a)(1) to (4) of the Rules. This means that its forecast capital expenditure will result in capital works so that Ergon Energy can:

- Meet or manage the demand for network, connection and metering services;
- Comply with regulatory obligations that apply to its network, connection and metering services;
- Have a distribution system that complies with quality, reliability, safety and security of supply standards that apply to its distribution system; and
- Fund the customer service standards that individual customers are entitled to receive under the Queensland GSL regime.

Ergon Energy believes its forecast capital expenditure will deliver these outcomes because of:

- The nature of the activities that it will undertake through its capital expenditure program;
- The nature of the plans, policies, procedures and strategies that it has in place to support the development and delivery of its capital expenditure program;
- The estimation processes that it has used to prepare its capital expenditure forecasts; and
- Its ability to physically deliver the capital expenditure program.

These justifications are discussed in turn.

24.1.2.1 Nature of activities

As discussed in Chapter 23 of this Regulatory Proposal, Ergon Energy's capital expenditure comprises:

- Asset Replacement – this program relates to existing assets, which are most likely to fail in service. These are particularly assets over 25 years of age. Increasing Asset Replacement expenditure will reduce the average lives of Ergon Energy's assets. This, in turn, will reduce the number of asset failures requiring Corrective and Forced Maintenance and so improve reliability and public safety.

  This program comprises defect and condition based expenditure. Defect-based expenditure involves identifying assets that have failed or are imminently about to fail so that they can be replaced before the next inspection. Condition-based expenditure seeks to avoid the escalation of Corrective and Forced Maintenance expenditure by providing for equipment to be replaced and refurbished based on condition assessments that are undertaken as part of the Preventive Maintenance program.

  The activity that is undertaken as part of this program is therefore critical to ensuring the long term serviceability of the distribution system, especially to meet safety and reliability requirements.

- Corporation Initiated Augmentation (CIA) – this program relates to the capital works that are needed to meet the augmentation requirements of Ergon Energy's sub-transmission and distribution networks based on its normal load forecasts.

  The activity that is undertaken as part of this program is therefore designed to address constraints as they are identified to ensure that Ergon Energy distribution system meets:

  → The Demand/Load Forecast – as discussed in Chapter 21 of this Regulatory Proposal, the key drivers of demand in Ergon Energy's supply area in the next regulatory control period are expected to be population growth, major new industry or commercial developments, economic growth and climatic effects and air conditioning penetration.

  → The Network Planning Criteria NP02 and Security Criteria NPD05 – there is no significant change to the criteria proposed for the next regulatory control period from the methodology adopted in the current regulatory control period.

- Customer Initiated Capital Works (CICW) – this program relates to works required to service new or upgraded customer connections that have been requested by customers. It covers:

  → Works that are undertaken by:

    » Ergon Energy, or by someone acting on its behalf; and

    » Developers and other service providers, where the assets are 'gifted' to Ergon Energy.

  → Works that are funded by:

    » Ergon Energy, where it, or someone acting on its behalf, undertakes the works;

    » A customer or developer paying a cash capital contribution to Ergon Energy, where Ergon Energy, or someone acting on its behalf, undertakes the works; and

    » A developer or other service provider, where the assets that they build are 'gifted' to Ergon Energy and accounted for by Ergon Energy as a capital contribution.

  → Building:

    » New customer connection assets;

    » New distribution network assets, for example subdivision assets, requested by customers or developers; and

    » Augmentations to the upstream distribution network, where the augmentation directly relates to a new or upgraded customer connection.

  This type of expenditure does not include costs of network augmentations that are not directly related to new, or upgraded, customer connections.

- Reliability and Quality Improvements – this program relates to works that are directly targeted at addressing reliability or quality of supply issues across the distribution system in order to meet externally and internally imposed service standards.

  The activity that is undertaken as part of this program is particularly designed to meet the increasingly onerous minimum service standard requirements under the Electricity Industry Code and to address worst performing feeders. The key programs will relate to:

  → The rollout of Supervisory Control and Data Acquisition (SCADA) to around 90 per cent of all customers;

  → Actioning the feeder improvement program; and

  → Extending the network monitoring program.

- Other System – this program relates to the following five categories:

  → The communications works involve the first stage of rolling out a contiguous telecommunications backbone network, known as the 'Ubiquitous Network', or 'UbiNet', throughout its distribution area;

  → The protection works involve retrofitting autoreclose protection and sensitive earth fault protection on existing feeders as well as undertaking protection reviews and ensuring protection equipment adequately protects the public, staff and equipment following faults;

  → The Single Wire Earth Return (SWER) works involve augmenting the SWER network in order to meet customers' capacity, reliability and quality of supply needs;

  → The undergrounding works involve three programs: the Cyclone Area Reliability Enhancement program, the Community Powerline Project Fund and the Toowoomba Trees Program; and

  → Various other programs, which relate to substation security, retrofitting low voltage fuses to distribution transformers, substation bunding for upgrading oil containment, improving the reliability of substation alternating current supplies and fitting low voltage spreaders to prevent conductor clashing and failure.

- Non-system – there are several programs of non-system related expenditure:
  - Plant and equipment relates to the delivery of work on the distribution system to ensure Ergon Energy employees can work in a safe and efficient manner;
  - Motor vehicles relate to the procurement of a variety of types of fleet that are used for the provision of Standard Control Services;
  - ICT systems relate to certain ICT assets which Ergon Energy, rather than SPARQ, continues to own;
  - Buildings, land and easements relate to Ergon Energy's non-system property, relating to buildings, land and easements;
  - Office equipment and furniture relates to Ergon Energy's office equipment and furniture that is required across its offices and depots.

Ergon Energy therefore believes that the nature of the activities that it will undertake through its capital expenditure program will contribute directly to it achieving all four of the capital expenditure objectives in the next regulatory control period, provided for under clause 6.5.7(a) of the Rules.

24.1.2.2 Plans, policies, procedures and strategies

As discussed in Chapters 17 and 23 of this Regulatory Proposal, Ergon Energy has a large number of plans, policies, procedures and strategies that are used to develop and implement its capital expenditure program for the next regulatory control period.

Ergon Energy's policies provide concise, broad, formal statements that establish guiding principles or rules by which it will make its capital expenditure decisions. Key policies relevant to its capital expenditure forecasts include its:

- Risk Management Policy;
- Defect Management Policy;
- Capital Contributions Policy;
- Underground Cabling Strategy; and
- Network Planning Criteria.

Ergon Energy's strategies reflect approaches to issues that are designed to deliver particular capital expenditure-related outcomes or goals. Key strategies relevant to its capital expenditure forecasts include its:

- Network Performance Strategy;
- Operational Communications Strategy Overview Infrastructure Design (UbiNet); and
- Corporate Property Strategy.

Ergon Energy's plans detail its planned activities, achievements and outcomes over time. They set out the action that Ergon Energy will take, and the outcomes that it will achieve:

- To deliver against the internal and external drivers and factors influencing strategic asset management;
- Having regard for the current state of the distribution network; and
- Based on its policies, strategies and procedures.

Ergon Energy's Asset Management Plan categorises plans into two types – 'Plans What' and 'Plans How'.

'Plans What' are the plans that deal with 'what' needs to be done. These plans include:

- Asset Equipment Plans (AEPs) – there is a plan for each asset equipment type;
- Sub-transmission Network Augmentation Plans (SNAPs);
- Distribution Network Augmentation Plans (DNAPs);
- Meter Asset Management Plan;
- Fleet Management - Asset Management Strategy, Future State Assessment; and
- Delivering Service Improvements across Ergon Energy's SWER Network.

'Plans How' are the plans that deal with 'how' Ergon Energy will undertake its work. These plans include:

- Network Defect Classification Manual; and
- Strategic Workforce Plan 2008-18.

Ergon Energy believes that, taken together, the collection of plans, policies, procedures and strategies that it uses to develop its capital expenditure program support the development of capital expenditure forecasts that will achieve all four of the capital expenditure objectives in the next regulatory control period. This is because these plans, policies, procedures and strategies ensure that Ergon Energy's capital expenditure forecasts have regard for:

- Ergon Energy's and customers' drivers of capital expenditure;
- The need to comply with relevant regulatory obligations; and
- The service standards that Ergon Energy must deliver.

24.1.2.3 Estimation process to prepare capital expenditure forecasts

Chapter 23 of this Regulatory Proposal details the estimation processes that Ergon Energy has used to prepare each sub category of its capital expenditure forecasts. This chapter illustrates and describes how Ergon Energy has prepared its capital expenditure forecasts by:

- Using, where relevant, forecasts of maximum demand, energy consumption and customer numbers;

- Taking into account external legislative and regulatory requirements as well as the recommendations of the 2004 EDSD Review;
- Applying its plans, policies, procedures and strategies;
- Drawing on external inputs, such as NIEIR's report entitled "Maximum demand forecasts for Ergon Energy connection points to 2017 – Coincident and Non-Coincident Peaks for Summer and Winter by BSP";
- Preparing internal expenditure forecasting models;
- Undertaking regulatory tests, where relevant; and
- Having regard, where relevant, to demand management initiatives.

Ergon Energy believes that the expenditure estimation processes support the development of capital expenditure forecasts that will achieve all four of the capital expenditure objectives in the next regulatory control period. This is because:

- The forecasts are based on the plans, policies, procedures and strategies discussed above, which promote the achievement of the capital expenditure objectives; and
- Ergon Energy has used a combination of robust bottom-up or top-down approaches to translate the plans, policies, procedures and strategies into capital expenditure forecasts for the next regulatory control period.

24.1.2.4 Deliverability of expenditure program

Chapter 35 of this Regulatory Proposal explains that Ergon Energy has forecast that its proposed total capital and operating expenditure program for the 2010-15 regulatory control period will, on average, require a 6.5 per cent annual increase in work to be performed, compared with its actual 2007-08 work levels.

Allowing for annual productivity improvement, Ergon Energy has assessed that the successful delivery of this level of growth in work requires a peak workforce increase of up to 332 full time equivalent employees and contractors. This is significantly less than the peak growth of 368 full time equivalent employees and contractors that Ergon Energy successfully achieved in 2006-07, during a period of strong economic activity and a tight labour market. The 2006-07 increase was needed in order to meet the sustained increase in demand for Distribution Services.

On this basis, and for the reasons that are further explained in Chapter 35 of this Regulatory Proposal, Ergon Energy considers that it can readily physically deliver the work program in the next regulatory control period associated with its forecast capital expenditure.

It follows, given the justifications of the forecast capital expenditure provided above, that Ergon Energy also believes that the physical delivery of its capital expenditure program will ensure that it achieves all four of the capital expenditure objectives detailed in clause 6.5.7(a) of the Rules in the next regulatory control period.

24.2 FORECAST CAPITAL EXPENDITURE COMPLIANCE REQUIREMENTS

Ergon Energy confirms that its capital expenditure forecasts in Chapter 23 of this Regulatory Proposal:

- Comply with the requirements of the RIN issued by the AER to Ergon Energy on 22 April 2009, as is required by clause 6.5.7(b)(1) of the Rules. Ergon Energy has provided the AER with a completed version of the RIN pro formas at the same time as providing this Regulatory Proposal. In addition, the Regulatory Proposal Skeleton document provided with this Regulatory Proposal details where Ergon Energy's addresses the various regulatory requirements, including under the RIN;
- Are for expenditure that has been allocated to Standard Control Services in accordance with its Cost Allocation Method (CAM) approved by the AER, as is required by clause 6.5.7(b)(2) of the Rules. Chapter 34 of this Regulatory Proposal describes how Shared Costs (Overheads) have been applied in developing Ergon Energy's capital and operating expenditure forecasts for its Standard Control Services;
- Include the total of the forecast capital expenditure for the next regulatory control period, 2010-15, as is required by clause 6.5.7(b)(3)(i) of the Rules; and
- Include the forecast capital expenditure for each year of the next regulatory control period, 2010-15, as is required by clause 6.5.7(b)(3)(ii) of the Rules.

24.3 CAPITAL EXPENDITURE REFLECTS CAPITAL EXPENDITURE CRITERIA HAVING REGARD FOR CAPITAL EXPENDITURE FACTORS

Clause 6.5.7(c) of the Rules requires that:

> *The AER must accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects:*
>
> 1. *the efficient costs of achieving the capital expenditure objectives; and*
> 2. *the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the capital expenditure objectives; and*
> 3. *a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.*
>
> *(the capital expenditure criteria).*

Clause 6.5.7(e) of the Rules requires that:

> *In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the following (the capital expenditure factors):*
>
> 1. *the information included in or accompanying the building block proposal;*
> 2. *submissions received in the course of consulting on the building block proposal;*
> 3. *analysis undertaken by or for the AER and published before the distribution determination is made in its final form;*
> 4. *benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period;*
> 5. *the actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;*
> 6. *the relative prices of operating and capital inputs;*
> 7. *the substitution possibilities between operating and capital expenditure;*
> 8. *whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;*
> 9. *the extent the forecast of required capital expenditure of the Distribution Network Service Provider is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms;*
> 10. *the extent the Distribution Network Service Provider has considered, and made provision for, efficient non-network alternatives.*

24.3.1 Interpretation of Clauses 6.5.7(c) and 6.5.7(e)

24.3.1.1 Clause 6.5.7(c) of the Rules

Ergon Energy interprets clause 6.5.7(c) of the Rules as requiring the AER to accept Ergon Energy's capital expenditure forecasts for the next regulatory control period if they represent the efficient costs that a prudent operator would incur in Ergon Energy's circumstances, based on realistic demand forecasts and cost inputs, in order to achieve the capital expenditure objectives.

Ergon Energy's capital expenditure must therefore be efficient and must reflect the behaviour of a prudent operator in Ergon Energy's circumstances. However, efficiency and prudency are not absolute concepts that can either be directly observed or objectively quantified. This is particularly the case when they are applied to expenditure forecasts, which are by their nature concerned with future, rather than historic, events.

In Ergon Energy's view, the AER's assessment of the efficiency of its capital expenditure forecasts needs to have regard for section 7A of the National Electricity Law, which provides that "A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs". This means that clause 6.5.7(c)(1) of the Rules should not be interpreted as necessarily requiring a least cost outcome, such as what might in theory be achieved in a perfectly competitive market. Rather, the AER's assessment should consider whether Ergon Energy is producing the 'right' outcomes (i.e. allocative efficiency), at the 'right' costs (i.e. productive efficiency), over time (i.e. dynamic efficiency). For the reasons set out in section 24.3.2, Ergon Energy considers that it will achieve the 'right' outcomes at the 'right' costs over time.

Unlike efficiency, prudency is not an economic concept. Rather, it concerns whether, in seeking to fulfil its obligations and requirements, Ergon Energy is:

- Acting in good faith;
- Exercising reasonable care; and
- Diligently applying knowledge, skill and foresight.

In Ergon Energy's view, the AER's assessment of Ergon Energy's capital expenditure for the purposes of clause 6.5.7(c)(2) of the Rules should be concerned with whether Ergon Energy is exhibiting these behavioural characteristics.

Both efficiency and prudency are dynamic concepts and therefore need to be considered over time, rather than at specific moments. Achieving efficient and prudent outcomes requires Ergon Energy to constantly exercise sound judgment and to make subjective assessments. As contemplated by clause 6.5.7(c)(2) of the Rules, this requires giving due consideration to the specific circumstances that impact on Ergon Energy's capital expenditure needs.

In addition to efficiency and prudency, clause 6.5.7(c)(3) of the Rules requires the AER to consider whether Ergon Energy's capital expenditure forecasts reflect a realistic demand forecast and realistic cost inputs.

Ergon Energy interprets clause 6.5.7(c)(3) of the Rules as requiring the AER to be satisfied that Ergon Energy's expenditure forecasts reflect realistic demand forecasts. As noted in section 27.1.1, Ergon Energy interprets the demand for:

- Network services to be concerned with the levels of maximum demand and energy consumption from the distribution network and the number of customer connections to the distribution network;
- Connection services to be concerned with the number of customer connections; and

- Metering services to be concerned with the number of new meter installations, scheduled and unscheduled meter readings and metering investigations that are required.

Ergon Energy also interprets clause 6.5.7(c)(3) of the Rules as requiring the AER to be satisfied that, where unit rates have been used to develop Ergon Energy's expenditure forecasts, they are reasonable and have been developed in a prudent and justifiable manner.

24.3.1.2 Clause 6.5.7(e) of the Rules

Clause 6.5.7(e) of the Rules details the factors that the AER must have regard to in deciding whether or not it is satisfied that Ergon Energy's capital expenditure forecasts for the next regulatory control period reasonably reflect the capital expenditure criteria under clause 6.5.7(c) of the Rules.

Clause 6.5.7(e)(1) of the Rules provides that one of the factors that the AER must have regard to is "the information included in or accompanying the building block proposal". Ergon Energy interprets this to mean that, in addition to the other matters detailed in clause 6.5.7(e)(2) to (10) of the Rules, the AER must consider everything that Ergon Energy includes in, or attaches to, this Building Block Proposal when assessing its capital expenditure forecasts.

Ergon Energy considers that clause 6.5.7(e)(6) of the Rules is framed problematically and considers that it is not clear what is meant by "the relative prices of operating and capital inputs". Ergon Energy has interpreted "prices" in this clause to mean the unit rates used in developing capital and operating expenditure forecasts. However, it is not possible for Ergon Energy to compare the unit rates that it has used to prepare its capital and operating expenditure forecasts. This is because the units are fundamentally different in nature and are specific to the capital or operating activities being undertaken. The different nature of, and approaches used to prepare, Ergon Energy's unit rates are discussed in Chapter 32 of this Regulatory Proposal. Ergon Energy considers that the unit rates that it has used to prepare its capital expenditure are efficient and have been developed in a prudent manner. This is a factor that the AER should consider in assessing Ergon Energy's capital expenditure forecasts against the capital expenditure criteria.

It is not clear to Ergon Energy what clause 6.5.7(e)(8) of the Rules is intended to address. This is because labour costs are only one element of Ergon Energy's capital and operating expenditure forecasts and Ergon Energy does not understand how it could demonstrate that these costs are consistent with the incentives under the Service Target Performance Incentive Scheme. Ergon Energy has therefore not provided information to the AER to address this matter.

24.3.2 Meeting the Requirements of Clause 6.5.7(c) and clause 6.5.7(e)

Ergon Energy considers that its forecast capital expenditure is consistent with the efficient costs that a prudent operator would incur in Ergon Energy's circumstances to achieve the capital expenditure objectives, based on realistic demand forecasts and cost inputs.

Ergon Energy will demonstrate that its capital expenditure forecasts reflect the capital expenditure criteria by reference to:

- The circumstances in which Ergon Energy operates – this information is provided in accordance with clause 6.5.7(e)(1);
- The estimation processes that Ergon Energy uses to prepare its forecasts – this information is provided in accordance with clause 6.5.7(e)(1);
- The reasonableness of the assumptions used to prepare the capital expenditure forecasts – this information is provided in accordance with clause 6.5.7(e)(1);
- The efficiency of the unit rates used to prepare the capital expenditure forecasts – this information is provided in accordance with clause 6.5.7(e)(1);
- The efficiency of the escalators used to prepare the capital expenditure forecasts – this information is provided in accordance with clause 6.5.7(e)(1); and
- A comparison of the forecast capital expenditure against actual and forecast capital expenditure in previous regulatory control periods – this information is provided in accordance with clause 6.5.7(e)(5).

These justifications are discussed in turn in this section.

The following other capital expenditure factors are dealt with elsewhere in this Regulatory Proposal:

- The substitution possibilities between capital and operating expenditure – this information is provided in accordance with clause 6.5.7(e)(7) and is dealt with in Chapter 29;
- Total labour costs being consistent with the incentives provided by the applicable Service Target Performance Incentive Scheme in accordance with clause 6.5.7(e)(8) of the Rules is discussed in Section 24.3.1 and Section 27.3.1;
- The use of supply arrangements with related parties – this information is provided in accordance with clause 6.5.7(e)(9) and is dealt with in Chapter 5; and
- The consideration of non-network alternatives – this information is provided in accordance with clause 6.5.7(e)(10) and is dealt with in Chapter 30.

24.3.2.1 Circumstances in which Ergon Energy operates

The circumstances in which Ergon Energy operates are a factor that the AER should consider under clause 6.5.7(e)(1) of the Rules in assessing whether Ergon Energy's capital expenditure forecasts meet the capital expenditure criteria under clause 6.5.7(c) of the Rules.

As discussed in section 4.19 of this Regulatory Proposal, the circumstances of Ergon Energy's operations are:

- A service area of 1,698,100 square kilometres, which covers 97 per cent of the Queensland land mass – an area approximately six times the size of the State of Victoria. Vast distances and low customer density result in significant geographic isolation in large parts of Ergon Energy's service area;
- Significant summer-winter and day-night temperature variations, which translate into large variability in seasonal and daily electricity demand;
- High rainfall, which can adversely affect asset condition, for example by causing pole top rot, and restrict access for operational purposes, for example in the Channel Country, which is prone to prolonged flooding coming from hundreds of kilometres away;
- Extreme winds, including cyclones, which can cause extensive damage to assets across vast areas. Cyclones are particularly prevalent along the northern coastal strip of Queensland;
- Lightning and summer storms, which require lightning arresters and additional earth protection to be installed. These events are particularly prevalent in the south west and south east of Ergon Energy's supply area;
- Vegetation whose types, density and growth rates adversely affect the operation of assets and limit access for operational purposes. This requires an extensive vegetation management program;
- Topography, which can affect the type of assets that need to be built as well as the approach to, and cost of, construction works;
- Soil conditions, including soil instability in areas such as the Darling Downs; and
- Wildlife, including termite infestations, which can adversely affect the condition and integrity of assets, such as wooden poles.

Ergon Energy's electricity distribution system is built to accommodate, as well as possible, these circumstances, and is characterised by:

- A large radial network, including approximately 65,000 kilometres of Single Wire Earth Return (SWER) lines, operating at three voltage levels (11, 12.7 and 19.1 kV) and servicing around 26,000 customers. Over 68 per cent of Ergon Energy's feeder powerlines are classified as non-urban;
- Connection to Powerlink's high voltage transmission network at 48 transmission network connection points and direct connection to, and supply from, a small number of embedded generators;
- Low load density and a high geographic spread of customers. Ergon Energy has the lowest customer density of any network in the western world for the 100,000 kilometres of line west of the Great Dividing Range;
- High numbers of new customer connections, due to strong population growth and high levels of investment in the industrial and mining sectors. This results in increased pressures to meet customer expectations regarding connection times and, for major customer loads, difficulties in predicting the timing and magnitude of the load to be serviced. Ergon Energy's forecast growth in customer numbers is discussed in Chapter 21 of this Regulatory Proposal;
- Shifts in end-usage patterns to include larger loads (e.g. air conditioning) and more sophisticated and complex electronic equipment. The standards and technologies upon which the network has been based may not be capable of meeting customer expectations as to the future reliability and quality of supply; and
- A sustained increase in maximum demand. Maximum demand for Ergon Energy's grid connected network is forecast to grow rapidly (at an average of 3.61 per cent) from the 2006-07 maximum demand level of 2,584 MW. Capital investment is required to ensure that network utilisation remains within appropriate bounds. Ergon Energy's forecast growth in maximum demand is discussed in Chapter 21 of this Regulatory Proposal.

These circumstances affect all aspects of Ergon Energy's capital investment decision making in relation to its distribution system, including the nature of the corporation and CIA capital expenditure requirements. The plans, policies, procedures and strategies referred to in Chapter 23 of this Regulatory Proposal provides further detail about how Ergon Energy's circumstances are reflected in its forecasts.

24.3.2.2 Ergon Energy's estimation processes

Ergon Energy's estimation processes are a factor that the AER should consider under clause 6.5.7(e)(1) of the Rules in assessing whether Ergon Energy's capital expenditure forecasts meet the capital expenditure criteria under clause 6.5.7(c) of the Rules.

Chapter 23 of this Regulatory Proposal details the estimation processes that Ergon Energy has used to prepare each subcategory of its capital expenditure forecasts. This Chapter illustrates and describes how Ergon Energy has applied its plans, policies, procedures and strategies to prepare its capital expenditure forecasts. It also explains why and how Ergon Energy has, where relevant:

- Used forecasts of maximum demand, energy consumption and customer numbers;
- Taken into account external legislative and regulatory requirements as well as the recommendations of the 2004 Electricity Distribution and Service Delivery (EDSD) Review;
- Applied its plans, policies, procedures and strategies;
- Drawing on external inputs, such as NIEIR's report entitled 'Maximum demand forecasts for Ergon Energy connection points to 2017 – Coincident and Non-Coincident Peaks for Summer and Winter by BSP';
- Prepared internal expenditure forecasting models;
- Undertaken regulatory tests; and
- Had regard to demand management initiatives.

Ergon Energy believes that its expenditure estimation processes reflect the behaviour of a prudent operator in its circumstances and result in efficient costs. This is because:

- The forecasts are based on the plans, policies, procedures and strategies, which promote the achievement of the capital expenditure objectives; and
- Ergon Energy has used a combination of robust bottom-up or top-down approaches to translate the plans, policies, procedures and strategies into capital expenditure forecasts for the next regulatory control period.

24.3.2.3 Reasonableness of assumptions used to prepare capital expenditure forecasts

The assumptions that Ergon Energy has made are a factor that the AER should consider under clause 6.5.7(e)(1) of the Rules in assessing whether Ergon Energy's capital expenditure forecasts meet the capital expenditure criteria under clause 6.5.7(c) of the Rules.

Chapter 23 of this Regulatory Proposal details the assumptions that Ergon Energy has made in preparing each subcategory of its capital expenditure forecasts. Ergon Energy has used assumptions as substitutes for facts or inputs in order to prepare its capital expenditure forecasts, where facts or inputs are not known with certainty or cannot reasonably be derived from other data. Ergon Energy has therefore developed assumptions where it has not otherwise had an objectively verifiable factual basis on which to prepare its capital expenditure forecasts.

Different assumptions have been used in relation to each category of capital expenditure. The assumptions principally relate to:

- The nature of the activity that needs to be undertaken for particular categories of capital expenditure;
- The workloads associated with particular categories of capital expenditure;
- The regulatory obligations and other requirements that will apply, and the plans, policies, strategies and procedures that will be used, as the basis for preparing particular categories of capital expenditure; and
- The nature, and use, of different approaches to preparing particular categories of expenditure within the overall capital expenditure program.

The assumptions in Chapter 23 of this Regulatory Proposal build on, and complement, the key assumptions that are detailed in Chapter 15 of this Regulatory Proposal.

Ergon Energy believes that its assumptions are consistent with a prudent operator in its circumstances. This is because the assumptions are:

- Necessary for Ergon Energy to make its capital expenditure forecasts;
- Consistent with Ergon Energy acting in good faith and with reasonable care in preparing its capital expenditure forecasts; and
- Reasonable in the circumstances of Ergon Energy's operations.

24.3.2.4 The efficiency of unit rates

Ergon Energy's unit rates used to prepare its capital expenditure forecasts are a factor that the AER should consider under clause 6.5.7(e)(1) of the Rules in assessing whether Ergon Energy's capital expenditure forecasts meet the capital expenditure criteria under clause 6.5.7(c) of the Rules.

Chapter 32 of this Regulatory Proposal details the way in which Ergon Energy has developed and applied its unit rates for the purposes forecasting its capital expenditure.

As discussed in detail in Chapter 32 of this Regulatory Proposal, Ergon Energy believes that the unit rates that it has applied in developing its capital expenditure program are efficient because:

- Ergon Energy has well established technical standards for undertaking the design and construction of works, as well as to maintain its assets;
- Ergon Energy has robust and well tested procurement processes that are applied when labour and materials are purchased from the market. The outcomes are efficient because of this market competition;
- A significant proportion of the key cost components on which the unit rates (and capital and operating expenditure forecasts) are based are market tested;
- The key cost components are consistently applied in Ergon Energy's internal estimating tools to produce both the unit rates used for forecasting capital and operating expenditure and the cost estimates of projects; and

- There is a feedback loop between historic and market costs that is reflected into the unit rates that have been used to develop the capital and operating expenditure forecasts. This means that the unit rates reflect current market conditions.

24.3.2.5 The efficiency of escalators

Ergon Energy's escalators used to prepare its capital expenditure forecasts are a factor that the AER should consider under clause 6.5.7(e)(1) of the Rules in assessing whether Ergon Energy's capital expenditure forecasts meet the capital expenditure criteria under clause 6.5.7(c) of the Rules.

Section 33.3.1 of this Regulatory Proposal details the way in which Ergon Energy has developed and applied its escalators for the purposes forecasting its capital expenditure.

Ergon Energy engaged Sinclair Knight Mertz to develop nominal cost escalation factors for its 27 asset categories to be applied to its capital expenditure forecasts for the period 2004-05 to 2014-15. As described in detail in section 33.3.1 of this Regulatory Proposal, SKM followed the following process to develop these forecasts:

- Step 1 – SKM assessed the key factors influencing costs of inputs;
- Step 2 - SKM assigned individual cost component weightings to each project component;
- Step 3 – SKM applied standard project building blocks for plant, equipment and materials;
- Step 4 – SKM updated movements in key cost drivers for plant, equipment and materials;
- Step 5 – SKM developed cost escalation factors for non-network equipment assets;
- Step 6 – SKM developed long-term forecasts of escalators for Ergon Energy's 27 asset categories;
- Step 7 – Ergon Energy rebased the SKM real forecasts from 2004-05 to 2010-11;
- Step 8 – Ergon Energy applied Ergon Energy's inflation forecasts to derive nominal forecasts;
- Step 9 – Ergon Energy applied nominal inflators to capital expenditure forecasts; and
- Step 10 – SKM review of application of cost escalation factors.

***Table 64:** Comparison of QCA's Capital Expenditure Building Blocks and Actual/Forecast Capital Expenditure for 2005-10 ($M Nominal)*

		2005-06	2006-07	2007-08	2008-09 Estimate	2009-10 Estimate	Total
1.	QCA Capital Expenditure Building Block (CAMP)	524.50	574.40	627.80	645.80	657.40	3,029.90
2.	Less Street Lighting (CAMP)	2.81	10.32	9.83	1.60	2.51	27.07
3.	QCA Adjusted Capital Expenditure Building Block - net of Street Lighting (CAMP)	521.69	564.08	617.98	644.20	654.89	3,002.83
4.	Total Capital Expenditure - excluding Street Lighting and including large CICW (CAM)	651.50	755.70	798.87	732.68	876.82	3,815.58
5.	Variance QCA Building Block (CAMP) to Total Capital Expenditure (CAM) - excluding Street Lighting and Excluded Services	-129.82	-191.62	-180.89	-88.48	-221.94	-812.75
6.	Change in actual Capital Expenditure by moving from CAM to CAMP (positive value equates to reduction in Capital Expenditure)	31.17	30.58	71.25	72.45	76.20	281.65
7.	**Variance QCA Building Block (CAMP) to Total Capital Expenditure (CAMP)** - excluding Street Lighting (negative value equates to overspend against QCA building block)	**-98.65**	**-161.04**	**-109.65**	**-16.03**	**-145.74**	**-531.10**

Source: Tables for Proposal 24.3.2

Capital expenditure escalators have been applied to all of Ergon Energy's asset categories.

Ergon Energy's escalators are considered efficient because Ergon Energy has, through the engagement of independent engineering consultant SKM, utilised recent, publicly available data and forecasts to derive escalators that are appropriate for Ergon Energy's asset categories and capital expenditure programs.

Ergon Energy considers that this approach has resulted in an efficient set of capital expenditure escalators.

24.3.2.6 Comparison of actual and expected capital expenditure

Clause 6.5.7(e)(5) of the Rules requires the AER to have regard for Ergon Energy's actual and expected capital expenditure during any preceding regulatory control period in assessing whether Ergon Energy's capital expenditure forecasts meet the capital expenditure criteria under clause 6.5.7(c) of the Rules.

Table 64 details the differences between the QCA's capital expenditure building blocks and Ergon Energy's actual (and forecast) capital expenditure in the current regulatory control period.

There are several matters that are important to understand in analysing Table 64:

- The QCA's capital expenditure building blocks (detailed in Row 1) that were approved in its 2005 Final Determination were based on Ergon Energy's Cost Allocation Methods and Procedures (CAMP), which was approved by the QCA. These building blocks included allowances for street lighting, given that it was classified as a prescribed distribution service in the Final Determination;

  The QCA's Final Determination did not make explicit what amount of the capital expenditure building blocks related to street lighting. Ergon Energy has estimated this amount (in Row 2) by applying the proportion of actual (and forecast) annual street lighting expenditure of the actual (and forecast) total annual capital expenditure to the annual capital expenditure building blocks.

  Ergon Energy has therefore deducted its estimate of street lighting capital expenditure (detailed in Row 2) from the QCA's capital expenditure building blocks (in Row 1) in order to determine revised building block amounts (detailed in Row 3). These revised amounts are based on the application of Ergon Energy's CAMP.

  However, the revised capital expenditure building blocks also include amounts for large CICW, which are to be classified as Alternative Control Services in the next regulatory control period. This is because the QCA's Final Determination did not make these amounts explicit and Ergon Energy cannot accurately estimate what they might have been. As a result, the revised capital expenditure building blocks relate both to the equivalent of Standard Control Services and large CICW.

- The AER's RIN requires Ergon Energy to backcast its total actual (and forecast) capital expenditure for 2005-06 to 2009-10 by applying its Cost Allocation Method (CAM), which has been approved by the AER (i.e. not the QCA approved CAMP). These backcast total actual (and forecast) amounts, excluding expenditure on street lighting, relate to Standard Control Services plus large CICW, and are detailed in Row 4;
- Row 5 details an expected overspend of $812.75 million for 2005-06 to 2009-10 between the total actual (and forecast) capital expenditure (in Row 4) for Standard Control Services plus CICW and the revised QCA capital expenditure building blocks (in Row 3). However, the values in Row 3 are based on the application of the QCA-approved CAMP, whereas the values in Row 4 (which have been prepared in accordance with the AER's RIN) are based on the application of the AER-approved CAM. Ergon Energy therefore considers that this is not the amount that requires explanation for the purposes of clause 6.5.7(e)(5) of the Rules;
- Row 6 details the amounts overheads that would reduce Ergon Energy's total actual (and forecast) capital expenditure amounts if the QCA approved CAMP, rather than the AER approved CAM, was applied. It shows that an expected $281.65 million would be deducted from Ergon Energy's total actual (and forecast) capital expenditure for 2005-06 to 2009-10 by applying the CAMP; and
- Row 7 details an expected overspend of $531.10 million for 2005-06 to 2009-10 between the total actual (and forecast) capital expenditure for 2005-06 to 2009-10 for Standard Control Services and the revised QCA capital expenditure building blocks, if both sets of values are based on the QCA-approved CAMP. Ergon Energy considers that this is the amount that requires explanation for the purposes of clause 6.5.7(e)(5) of the Rules, because all values are based on the QCA-approved CAMP, albeit that they relate to expenditure on Standard Control Services plus large CICW. Ergon Energy can only compare actual (and forecast) expenditure against the QCA's capital expenditure building block allowances on the basis of the QCA's CAMP, not the CAM, because it cannot present the QCA's capital expenditure building block allowances on the basis of the CAM, only the CAMP.

There are several factors that have contributed to the temporary reduction in capital expenditure during 2008-09, including:

A reduction in CICW associated with subdivisions and domestic and rural expenditure resulting from slowing in building and construction (approximately $16 million);

- A delay in the UbiNet project approval, which shifted significant expenditure to 2009-10 (approximately $50 million);
- A delay of smart meter trials due to uncertainties around technology, which shifted expenditure to 2009-10 (approximately $10 million);
- The diversion of resources to rectify damage caused by flooding during the second half of 2008. Flooding also delayed site access and recommencement of work. Ergon Energy also provided support for ENERGEX during the major storms in November 2008;
- A delay resulting from industrial action during negotiation of the Ergon Energy Collective Agreement 2008;
- Imbalances between work and capability in some locations resulting from the rapid onset of the economic downturn, which necessitated the redeployment of staff and contractors at short notice and resulting in short-term productivity losses;
- Certain "Get Fit" enabling strategies, including:
  - → A reduction in staff availability to more sustainable levels by reducing overtime;
  - → An initiative to reduce accumulated annual leave during a period of stabilised demand, which temporarily resulted in more staff on leave;
  - → Leveraging of identified savings in forecast non-system capital expenditure, particularly in the categories of land and buildings, motor vehicles and capital expenditure associated with Ergon Energy's Change Program, which reduced expenditure in these areas;
  - → A temporary suspension of live line work to review work practices and safety procedures, which resulted in temporary delays due to additional switching, training and other requirements;
  - → Delays in the delivery of several major projects while project scopes and estimates were reviewed to ensure accuracy and value-for-money; and
  - → The diversion of staff to strategic projects to update estimating and forecasting of capital project works, to support continuous improvement of future planning and delivery of work.

The causes of the $531.1 million overspend detailed in Row 7 of Table 64 can be explained as follows:

- Labour, materials, contractors and other costs:
  - → Labour costs have increased across the current regulatory control period as a result of more labour being required to undertake more work in all expenditure categories, other than condition-based asset replacement expenditure and reliability and quality improvement expenditure. A further cause for the labour cost increases has been the higher wage escalation rates reflected in the new Ergon Energy Union Collective Agreement 2008;
  - → Contractor costs have also increased across the current regulatory control period as a result of Ergon Energy significantly increasing the amount of work being undertaken by contractors, particularly in relation to CICW and CIA works. Two further causes of the contractor cost increases have been the higher prices resulting from a tight contractor market and the higher wage escalation rates that have been reflected in the new Ergon Energy Union Collective Agreement 2008, which flow through to contractors;
  - → Materials costs have increased above the forecasts that were used to prepare the capital expenditure building blocks, particularly the essential high volume items of distribution transformers, cables and poles. The nature and drivers of these increases are detailed in two reports that were prepared for Ergon Energy by SKM in 2008, entitled "Capital Works Project Cost Escalation Factors for the period 2005-2015" and "Electricity Industry Labour, Commodity and Asset Price Cost Indices"; and
  - → Other costs have increased above the forecasts that were used to prepare the capital expenditure building blocks, particularly property, ICT and fleet due to Ergon Energy's employee numbers increasing from 3,652 in June 2005 to 4,489 in June 2008 (on the basis of headcount). In addition, Project Jet, which is the project that introduced Ergon Energy's Enterprise Resource Planning solution in 2006, cost in excess of $70 million, which was not included in building block allowances.

- Direct and shared costs:
  - → Direct costs have increased across the current regulatory control period, as a result of more work being undertaken, and higher prices and unit rates being incurred, than was assumed in preparing the capital expenditure building blocks. This has occurred in all expenditure categories, other than condition-based asset replacement expenditure and reliability and quality improvement expenditure; and
  - → Shared Costs (Overheads) being higher than were forecast in preparing the capital expenditure building blocks, especially as a result of Ergon Energy employee numbers increasing from 3,652 in June 2005 to 4,489 in June 2008 (on the basis of headcount). It should be noted that for the same period external fixed term resource numbers fell from 768 to 320 (on the basis of headcount).
- Quantities and unit rates:
  - → There has been more work undertaken during the current regulatory control period than was assumed in preparing the capital expenditure building blocks. This has occurred in all expenditure categories, other than condition-based asset replacement expenditure and reliability and quality improvement expenditure; and
  - → Labour, contractor and material costs have been higher than were forecast in preparing the capital expenditure building blocks:
- Higher labour escalation rates have resulted from the new Ergon Energy Union Collective Agreement 2008;
- Higher contractor rates have resulted from a tight contractor market as well as higher wage escalation rates that have been reflected in the new Ergon Energy Union Collective Agreement 2008, which flow through to contractors; and
- Materials costs have particularly increased for the essential high volume items of distribution transformers, cables and poles.
- Expenditure programs:
  - → The QCA's Final Determination did not provide a breakdown of capital expenditure for 2005-06 to 2009-10. In order to provide a basis for explaining the variance during the current regulatory control period, Ergon Energy has broken down the capital expenditure building blocks based on the proportions accepted by Burns and Roe Worley (BRW), who were the engineering consultants that advised the QCA for the last regulatory reset;
  - → Several observations can be made about the variance during the current regulatory control period between actual (and forecast) capital expenditure and the broken down QCA capital expenditure building blocks:
    - » For the current regulatory control period Ergon Energy's total system capital expenditure exceeded the QCA's building block forecasts predominantly driven by the uncontrollable number of new CICW. New connections to the network also drive expenditure on the shared network in the category of CIA. To the extent it could, without compromising the reliability, quality or safety of supply, Ergon Energy has curtailed its more discretionary system expenditure in order to fund and resource new customer connections and ensure supply was not interrupted in times of peak demand. The reasons for variations are:
      - › Asset Replacement expenditure has been reduced in total, although this has occurred exclusively at the expense of condition-based asset replacement work. Defect-based asset replacement work has increased on the basis of the Preventive Maintenance inspection programs;
      - › CIA has been increased on the basis of higher than forecast peak demand in certain locations and years across the regulatory control period, particularly 2006-07;
      - › Reliability and quality improvements expenditure has been reduced in order to meet the higher than forecast CIA, and CICW requirements, although it is noted that reliability improvements have been achieved as a result of undertaking the defect-based asset replacement program, the CIA program and the Corrective Maintenance program; and
      - › Other system capital expenditure has been increased in order to meet electrical safety and environmental requirements.
    - » Ergon Energy's actual (and forecast) CICW are expected to significantly exceed the QCA's broken down capital expenditure building blocks. There are a number of causes of this overspend:

- Domestic and rural customer connections have grown continually over the regulatory control period and in some years, especially 2005-06 and 2007-08, have significantly exceeded the forecasts that were used as the basis of the QCA's capital expenditure building blocks. These customer connections are expected to stabilise from 2007-08 for the remainder of the regulatory control period;
- The cost of delivering domestic and rural customer connection works has increased in the period 2005-06 to 2007-08. This has been caused by more contractors being used so that Ergon Energy can meet its 180-day customer connection target. In addition, the cost of distributions transformers, cables and poles have increased dramatically during the current regulatory control period – these are fundamental materials used in the supply of customer connections;
- The cost of subdivision works has increased in the current regulatory control period because Ergon Energy is doing significantly doing more subdivision work than was forecast in preparing the QCA's capital expenditure building block proposal. These works are not immediately reflected into increased customer connections. The higher cost of contractors and materials has also increased these project costs. From 2007-08, developers have begun to undertake these works and gift them to Ergon Energy, although these gifted assets are also included in the CICW forecasts; and
- The costs of commercial and industrial customer connections have increased above forecast in the current period because the average size of load of these customers has increased as a result of the resources boom, which has flowed through into increased project costs. The higher cost of materials has also increased these project costs. It is noted that CICW relates both to the cost of new connection assets for new commercial and industrial customer connections, as well as the cost of new shared network assets that are needed to service the new connections.
- Ergon Energy's non-system costs have increased above the forecasts that were used to prepare the capital expenditure building blocks, particularly as a result of:
  - Ergon Energy's employee numbers increasing from 3,652 in June 2005 to 4,489 in June 2008 (on the basis of headcount). This has driven large increases in property, ICT and fleet costs; and
  - Project Jet, which is the project that introduced Ergon Energy's Enterprise Resource Planning solution in 2006, cost in excess of $70 million, which was not included in capital expenditure building block allowances.

- Abnormalities and one-off events:

There have been several significant one-off events that have increased the actual (and forecast) capital expenditure during the current regulatory control period above the capital expenditure building blocks, including:

- Severe Tropical Cyclone Larry and the SunWater and Isaac Plains projects, which resulted in increased capital expenditure of $60.46 million during the current regulatory control period;
- An increase in labour and contractor costs arising from a 0.5 percentage point annual increase under the Ergon Energy Union Collective Agreement 2008 from 4.0 per cent to 4.5 per cent from 2008;
- Project Jet, which is the project that introduced Ergon Energy's Enterprise Resource Planning solution in 2006, which cost more than $70 million. This was paid for by Ergon Energy, rather through its ICT service provider, SPARQ;
- Changes in the treatment of ICT costs, which were previously included as capital expenditure and depreciated, whereas ICT costs are now treated as Shared Costs (Overheads) and spread across capital and capital expenditure. This means that some costs are expensed that were previously capitalised.

24. CAPITAL EXPENDITURE – OBJECTIVES, CRITERIA AND FACTORS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR158	"Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland" (EDSD Review), July 2004
AR364	National Electricity Rules

Ergon Energy Documents

AR047	EE Capital Contributions Methodology (QCA Approved), 20 April 2005
AR064	EE Network Planning Criteria – NP02, V2.03, 30 May 2000
AR065c	NIEIR November 2007 Maximum Demand Forecasts
AR075	EE, NA000900R102, Meter Asset Management Plan, V3, 1 February 2008
AR077	EE EP26 Risk Management Policy, V2, 8 May 2007
AR078	EE Network Maintenance Defect Classification Manual
AR094	Ergon Energy Union Collective Agreement 2008
AR175	EE Security Criteria - NPD05, 12 April 2005
AR226	EE Asset Equipment Plans 2009
AR268c	EE Strategic Workforce Plan 2008-18, May 2008
AR314	EE Cost Allocation Method, AER Approved
AR318	EE EP51 Asset Management Defect Policy, 1 May 2008
AR319c	EE Corporate Property Strategic Plan, V23, 28 August 2006
AR336	EE Network Performance Strategy 2010-15, V4, 24 March 2009
AR375c	EE Sub-transmission Network Augmentation Plans 2007
AR424c	EE Distribution Network Augmentation Plans 2007
AR427c	EE "Delivering Service Improvements across Ergon Energy's SWER Network", February 2005
AR435c	EE Fleet Management Asset Management Strategy, Future State Assessment, V5, 20 March 2009
AR450	EE Underground Cabling Strategy, 31 March 2009
AR453	EE Operational Communications Strategy Overview Infrastructure Design (UbiNet), 28 November 2008
AR467c	EE Regulatory Proposal Skeleton, June 2009

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25. OPERATING EXPENDITURE - HISTORICAL

Rules – Clauses 6.5.6(e)(5) and S6.1.2
RIN – Sections 2.2.2 and 2.4.4
RIN Pro forma - 2.2.2

This chapter details Ergon Energy's operating expenditure for the equivalent of Standard Control Services during the previous and current regulatory control periods. Clause 6.5.6(e)(5) of the Rules requires the Australian Energy Regulator (AER) to have regard for Ergon Energy's actual and expected operating expenditure during preceding regulatory control periods in deciding whether to accept Ergon Energy's operating expenditure forecasts for the next regulatory control period.

The Regulatory Information Notice (RIN) section 2.2.2(a)(1) also requires that the forecast of required operating expenditure by expenditure type for the next regulatory control period be provided. Ergon Energy has set this information out in Chapter 26 of this Regulatory Proposal.

The historical dollar values for 2001-02 to 2007-08 presented in this chapter:

- Exclude street lighting operating expenditure but include other operating expenditure relating to Excluded Distribution Services, which from 1 July 2010 will be classified as Alternative Control Services. It is not possible to remove actual operating expenditure for services that are in the future to be classified as Alterative Control Services. This is because Ergon Energy's historical records were not kept at an individual service level and, as a result, historic expenditure cannot be aligned to the new classification of services;
- Are in dollars of the day for each year (i.e. are nominal values so include inflation);
- Include Shared Costs (Overheads) for 2005-06 to 2007-08 that have been back cast using the AER's approved Allocation Methods and Procedures; and
- Include Shared Costs (Overheads) as reported to the Queensland Competition Authority (QCA) in Ergon Energy's Annual Regulatory Reporting Statements for 2001-02 to 2004-05 using the QCA approved Cost Allocation Methods and Procedures.

The forecast dollar values for 2008-09 and 2009-10 presented in this chapter:

- Only relate to Standard Control Services;
- Are in dollars of the day for each year (i.e. these are nominal values so include inflation); and
- Include Shared Costs (Overheads) that have allocated using the AER's approved Cost Allocation Method for 2008-09 to 2009-10.

25.1 ACTUAL OPERATING EXPENDITURE FOR 2001-05 BY EXPENDITURE TYPE BY YEAR

Clause S6.1.2(7) of the Rules and section 2.2.2(a)(1) of the RIN requires Ergon Energy to provide details of its actual operating expenditure by expenditure type for each of the past years of the previous regulatory control period 1 July 2001 to 30 June 2005.

Ergon Energy's is not able to provide a breakdown of its historical operating expenditure by expenditure type for the regulatory control period 1 July 2001 to 30 June 2005 into the programs that are used for the forecasts for the 1 July 2010 to 30 June 2015 regulatory control period. This is because Ergon Energy's historical records were not categorised in the same manner as is now being used to present information to the AER. However, Table 65 provides Ergon Energy's total operating expenditure for the 1 July 2001 to 30 June 2005 regulatory control period.

Table 65: *Operating Expenditure – 2001-05 Actual Expenditure ($M Nominal)*

	2001-02	2002-03	2003-04	2004-05	4 Year Total	Average of 4 Year Total
Network Operations & Maintenance	100.41	123.54	147.52	142.07	513.55	128.39
Other	34.61	35.47	42.00	52.99	165.08	41.27
Total	**135.03**	**159.01**	**189.52**	**195.06**	**678.63**	**169.66**

Source: Tables for Proposal 25.1

This information is also detailed in pro forma 2.2.2 ofthe AER's RIN.

25.2 ACTUAL AND FORECAST OPERATING EXPENDITURE FOR 2005-10 BY EXPENDITURE TYPE BY YEAR

Clause S6.1.2(7) of the Rules and section 2.2.2(a)(1) of the RIN requires Ergon Energy to provide details of its actual operating expenditure by expenditure type for each of the past years of the current regulatory control period 1 July 2005 to 30 June 2010.

Ergon Energy's historical operating expenditure by expenditure type for the period 1 July 2005 to 30 June 2008, and forecast operating expenditure for the period 1 July 2008 to 30 June 2010, is detailed in Table 66.

Table 66: *Operating Expenditure – 2005-10 Actual and Forecast Expenditure by Category Driver ($M Nominal)*

	2005-06	2006-07	2007-08	2008-09 (Estimate)	2009-10 (Estimate)	5 Year Total	Average of 5 Year Total
Network Operating Costs	15.92	24.94	30.59	26.67	26.18	124.30	24.86
Network Maintenance Costs							
Preventive Maintenance	51.13	55.65	97.10	86.06	94.59	384.53	76.91
Corrective Maintenance	79.31	106.93	72.02	100.07	98.49	456.82	91.36
Forced Maintenance	52.31	20.43	42.37	42.29	40.43	197.83	39.57
Subtotal	182.74	183.01	211.50	228.41	233.51	1,039.17	207.83
Other costs							
Meter Reading	8.48	10.15	10.59	11.73	11.60	52.54	10.51
Customer Services	31.62	27.23	25.10	28.77	27.85	140.57	28.11
Other Operating Costs – Training Costs (for 2010-15 also includes DMIA and Self Insurance)	17.98	19.48	18.89	24.97	24.89	106.20	21.24
Subtotal	58.07	56.86	54.58	65.46	64.34	299.31	59.86
Total	**256.73**	**264.81**	**296.67**	**320.54**	**324.02**	**1,462.78**	**292.55**

Source: Tables for Proposal 25.2

This information is also detailed in pro forma 2.2.2 of the AER's RIN.

25.3 TOTAL OPERATING EXPENDITURE REQUESTED AND APPROVED FOR 2005-10 BY YEAR

Clause S6.1.2(7) of the Rules and section 2.2.2(a)(3) of the RIN requires Ergon Energy to provide details of the total amounts of operating expenditure that it requested, and the QCA approved, for each of the past years of the current regulatory control period 1 July 2005 to 30 June 2010.

Table 67 details, for the current regulatory control period:

- The total operating expenditure that Ergon Energy requested from the QCA in its February 2005 submission in response to the QCA's Draft Determination;
- The operating expenditure that Ergon Energy requested as cost pass throughs in the years in which the requests were made;
- The total operating expenditure that the QCA approved in its April 2005 Final Determination; and
- The operating expenditure that was reflected into the QCA's revenue adjustment approval for cost pass throughs in the years in which the revenue adjustment was made.

Table 67: *Operating Expenditure – 2005-10 Requested and Approved Expenditure ($M Nominal)*

	2005-06	2006-07	2007-08	2008-09 Estimate	2009-10 Estimate	5 Year Total
Operating Expenditure requested by DNSP at reset (1)	276.13	289.83	298.17	278.78	290.13	1,433.04
Pass through requested (2)	0.00	15.89	0.00	0.00	0.00	15.89
Total Operating Expenditure requested	276.13	305.72	298.17	278.78	290.13	1,448.93
Operating Expenditure approved by regulator at reset (3)	266.70	279.60	286.50	262.70	271.90	1,367.40
Pass through approved (4)	0.00	0.00	0.00	7.85	0.00	7.85
Total Operating Expenditure approved by regulator	**266.70**	**279.60**	**286.50**	**270.55**	**271.90**	**1,375.25**

Source:

1. Table 3.13, "Ergon Energy Submission, QCA Draft Determination, 25 February 2005", page 27. Real 2004 dollars converted to nominal using 2.76% per annum CPI as approved by the QCA.
2. Ergon Energy cost pass through submissions to the QCA.
3. Table 7.12, "QCA Final Determination 2005-10", April 2005, page 165.
4. QCA approval letters to Ergon Energy and associated Final Decisions.

Tables for Proposal 25.3

This information is also detailed in pro forma 2.2.2 of the AER's RIN.

25. OPERATING EXPENDITURE - HISTORICAL – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice
AR417 & 418	AER Cost Allocation Guidelines, Final Decision and Guidelines, 26 June 2008

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005
AR415	QCA Draft Determination, 23 December 2004

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR119c	EE Annual Regulatory Accounts for 2001-02
AR120c	EE Annual Regulatory Accounts for 2002-03
AR121c	EE Annual Regulatory Accounts for 2003-04
AR122c	EE Annual Regulatory Accounts for 2004-05
AR123c	EE Annual Regulatory Accounts for 2005-06
AR124c	EE Annual Regulatory Accounts for 2006-07
AR314	EE Cost Allocation Method, AER Approved
AR370c	EE Annual Regulatory Accounts for 2007-08
AR391	EE Cost Allocation Methods and Procedures approved by QCA, 2 May 2006
AR416	EE Response to QCA Draft Determination, 25 February 2005

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26. OPERATING EXPENDITURE – FORECAST AND JUSTIFICATION

Rules – Clauses 6.1.2(1) and (2), 6.4.3(a)(7), 6.4.3(b)(7), 6.5.6(e)(5), 6.12.1(4) and S6.1.2
RIN – Sections 2.2.2, 2.3.10(a), 2.3.10(b)(5) and 2.4.4
RIN Pro forma - 2.2.2
CAG – Section 5.1(b)(1)

This chapter provides an overview of Ergon Energy's operating expenditure forecasts for Standard Control Services for the regulatory control period 1 July 2010 to 30 June 2015.

Clause 6.4.3(a) of the Rules provides that Ergon Energy's annual revenue requirement for each year of the next regulatory control period must be calculated using a building block approach. Clause 6.4.3(a)(7) of the Rules provides that one of the building blocks to be used in this approach is to be forecast operating expenditure. Clause 6.4.3(b)(7) of the Rules requires this forecast to be determined in accordance with clause 6.5.6 of the Rules. Clause 6.5.6(e)(5) of the Rules requires the Australian Energy Regulator (AER) to have regard for Ergon Energy's actual and expected operating expenditure during preceding regulatory control periods in deciding whether to accept Ergon Energy's operating expenditure forecasts for the next regulatory control period.

Clause S6.1.2(1) of the Rules and section 2.2.2(a)(1) of the Regulatory Information Notice (RIN) require Ergon Energy's Building Block Proposal to include forecasts of its operating expenditure by programs or types for the next regulatory control period.

Clause S6.1.2(2) of the Rules requires Ergon Energy's Building Block Proposal to include information about the method used to develop its operating expenditure forecasts for the next regulatory control period.

Section 2.3.10(a) of the RIN requires Ergon Energy to overview the expenditure estimation processes it has used to develop its operating expenditure forecasts for the next regulatory control years and to explain any differences from the processes it used in developing its previous regulatory proposal.

Clause 5.1(b)(1) of the AER's Cost Allocation Guidelines requires Ergon Energy to apply its Cost Allocation Method (CAM) in preparing its forecast operating expenditure to be submitted to the AER in accordance with clause 6.5.6 of the Rules.

Ergon Energy's operating expenditure comprises:

- Network Operations – which relates largely to operating support services and some activity associated with the reconfiguration of the distribution network;
- Network Maintenance – there are three categories of network maintenance that are forecast in aggregate in this chapter – Preventive, Corrective and Forced Maintenance. The aggregate forecast expenditure is broken into 26 asset equipment types. Supporting justification for the expenditure forecasts for the 26 asset equipment types is documented in Ergon Energy's Asset Equipment Plans, which have been separately provided to the AER:
  - → Preventive Maintenance – which comprises scheduled inspection and maintenance activity. This work is carried out at predetermined intervals, or in accordance with prescribed criteria, in order to minimise the probability of network failure, minimise total life cycle costs, meet required operating conditions and performance standards, and keep Ergon Energy's staff and the public safe. Work that is identified from this program can be undertaken as either asset renewal (defect manual) capital expenditure or Corrective Maintenance, so that Forced Maintenance can be averted;
  - → Corrective Maintenance – which involves planned repair work identified and assessed as defects from Preventive Maintenance or customer reports in order to prevent an unplanned outage or dangerous electrical event. This category of work is planned and carried out regularly. The largest element of Ergon Energy's Corrective Maintenance program relates to vegetation management;
  - → Forced Maintenance – which involves unplanned repair, replacement or restoration work that is carried out as quickly as possible after the occurrence of an unexpected event or failure in order to bring the distribution network to at least its minimum acceptable and safe operating condition. Although it is unplanned, an annual provision must be made for this category of expenditure; and

- Other Operating Expenditure – this includes Ergon Energy's self insurance program, Demand Management Innovation Allowance (DMIA), meter reading in Ergon Energy's capacity as a Metering Data Provider for Types 5, 6 and 7 metering installations and customer service activity only in Ergon Energy's capacity as a Distribution Network Service Provider (DNSP).

26.1 FORECAST OPERATING EXPENDITURE FOR 2010-15 BY EXPENDITURE TYPE BY YEAR

The Rules clause 6.1.2(2) requires information about the 'method' used for developing the operating expenditure forecast. Ergon Energy's 'method' is the same as the 'estimation process' that is requested to be described in the RIN section 2.3.10(a).

Table 68 details Ergon Energy's forecast Operating Expenditure for 2010-15 by expenditure type by year.

***Table 68:** Forecast Operating Expenditure – by Category Driver – 2010-15 ($M Real $2009-10)*

Category Driver	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Network Operating Costs	26.36	26.33	26.67	27.21	27.51	134.08	26.82
Network Maintenance Costs							
Preventive Maintenance	108.82	119.56	120.15	123.36	121.68	593.57	118.71
Corrective Maintenance	121.88	121.48	122.82	117.94	105.66	589.78	117.96
Forced Maintenance	41.00	40.85	41.34	41.42	41.08	205.69	41.14
Subtotal	271.70	281.89	284.31	282.72	268.42	1,389.04	277.81
Other Costs							
Meter Reading	11.75	11.81	12.03	12.31	12.48	60.38	12.08
Customer Services	19.82	19.86	20.19	20.60	20.81	101.28	20.26
Other Operating Costs (includes DMIA and Self Insurance)	40.47	41.59	42.29	43.85	45.48	213.68	42.74
Subtotal	72.04	73.26	74.51	76.76	78.77	375.34	75.07
Total	**370.10**	**381.48**	**385.49**	**386.69**	**374.70**	**1,898.46**	**379.70**

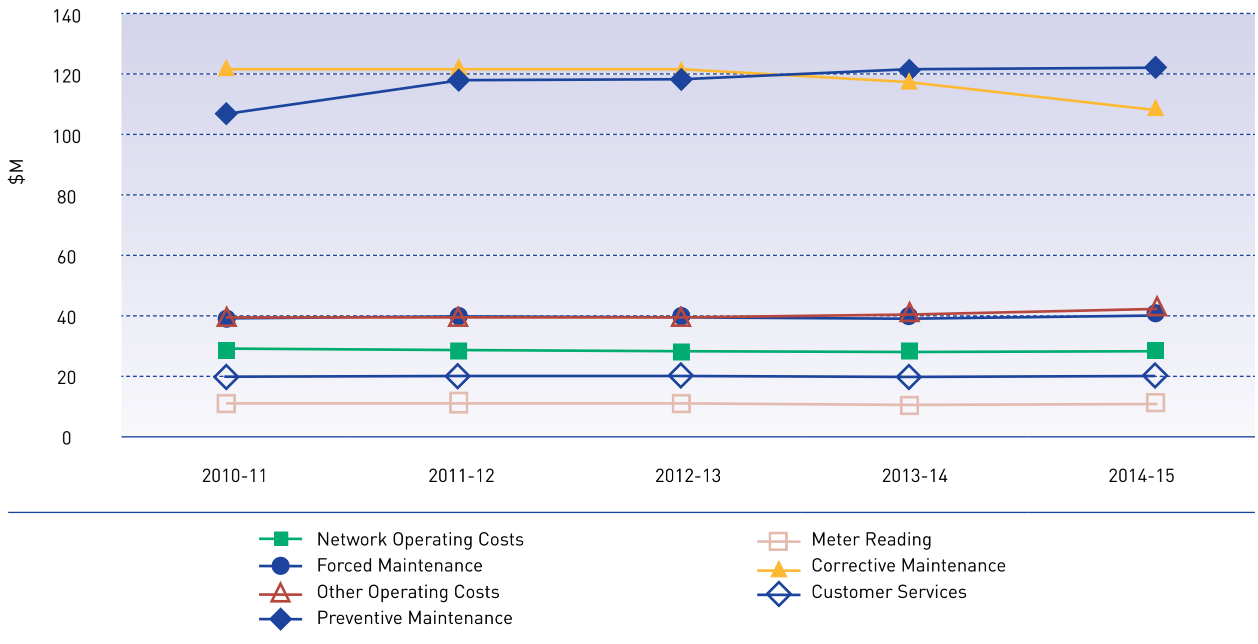
Source: Tables for Proposal 26.1

The forecast dollar values presented in this chapter:

- Only relate to Standard Control Services; and
- Include direct costs and Shared Costs (Overheads). The Shared Costs (Overheads) have allocated using the AER's approved CAM for 2008-09 to 2009-10, as discussed in Chapter 34;

Section 2.3.10(b)(5) of the AER's RIN requires Ergon Energy to explain how the profile of the expenditure for different types of projects and programs have been developed. Figure 53 illustrates the profile of the expenditure. The explanation of how each forecast has been prepared, and thus the profile of expenditure, is explained in the sections about each type of operating expenditure forecast.

***Figure 53:** Ergon Energy Forecast Operating Expenditure Profile ($M Real $2009-10)*



Source: Tables for Proposal 26.1

26.2 NETWORK OPERATIONS

26.2.1 Forecast 2010-15

Ergon Energy's Operating Expenditure – Network Operations forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 69.

***Table 69:** Operating Expenditure – Network Operations – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
31.99	26.67	26.18	26.36	26.33	26.67	27.21	27.51	134.08	26.82

Source: Tables for Proposal 26.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10).

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

26.2.2 What this Forecast Relates to

Expenditure for Network Operations relates to monitoring and controlling the distribution network from two Operations Control Centres in Townsville and Rockhampton. The major activities of Network Operations include:

- Switching and outage co-ordination;
- Managing energy flows by co-ordinating network configuration;
- Co-ordinating with National Electricity Market Management Company (NEMMCO) for managing the entire network; and
- Ensuring appropriate procedures are in place to ensure the proper co-ordination of supply.

Small amounts of field work associated with the management and reconfiguration of the network are also included for local switching operations, changes to protection settings, changes to communications equipment, and support for Supervisory Control and Data Acquisition (SCADA) and data communications.

26.2.3 Estimation Process

Figure 54 overviews the key elements of how Ergon Energy has prepared its Network Operations forecast for the next regulatory control period. The nature of each of these elements is explained below.

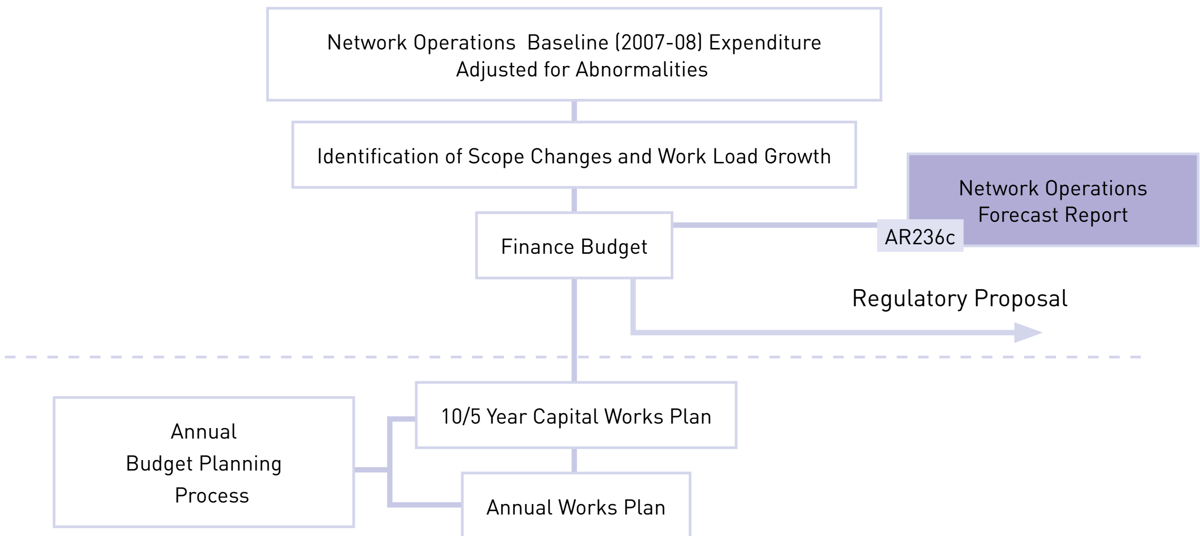
The forecasts have been developed in Ergon Energy's Finance budget models using the 2007-08 actual Network Operations expenditure as the baseline after adjustment (down) for abnormalities. In the current regulatory control period abnormalities arose as a result of:

- Implementation of Project LINK, which resulted in staff being moved from decentralised operations areas into two centralised Network Operations control centres in Rockhampton and Townsville; and
- Increases in the amount of switching and control resulting from increases in the system capital expenditure programs over the period.

No further significant growth in expenditure is required now that Project LINK is completed and growth in the capital works program has peaked. Any further growth in workload for the Network Operations group is expected to be absorbed through efficiency gains resulting from realisation of the benefits of Project LINK.

The document entitled "Network Operations (Works Planning), 17 December 2008" was used to inform the Finance budget forecasts.

Figure 54: *Operating Expenditure – Network Operations*



26.2.4 Assumptions

It is assumed that Network Operations will:

- Continue to operate in the current manner (business-as-usual); and
- Absorb most forecast increases in workload for the group through efficiency gains, thus helping to minimise costs.

26.2.5 Capital Expenditure / Operating Expenditure Interactions

Not applicable to Network Operations as this is an operational service.

26.2.6 Justification of the Forecasts

Ergon Energy considers that the forecast amount for the next regulatory control period is necessary to continue to:

- Deliver services to customers on time in order to communicate unplanned outages with customers and to monitor and manage load to prevent unnecessary outages;
- Provide effective and efficient switching and outage coordination in order to minimise outages and operational risks, promote industry, safety and environmental standards, and manage and maintain load shedding sequences; and
- Provide high quality network monitoring and response in order to respond to faults and alarms, enact disaster recovery practices and investigate incidents.

26.2.7 Risk Considerations

Ergon Energy does not consider that there are any new risks associated with the Network Operations forecast as it is based on business-as-usual activity.

26.2.8 Customer Outcomes

This forecast is largely based on business-as-usual operations, which will continue to support ongoing incremental improvements to customer service outcomes.

26.3 PREVENTIVE MAINTENANCE

26.3.1 Forecast 2010-15

Ergon Energy's Operating Expenditure – Preventive Maintenance forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 70.

Table 70: *Operating Expenditure – Preventive Maintenance – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
101.52	86.06	94.59	108.82	119.56	120.15	123.36	121.68	593.57	118.71

Source: Tables for Proposal 26.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10)

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

26.3.2 What this Forecast Relates to

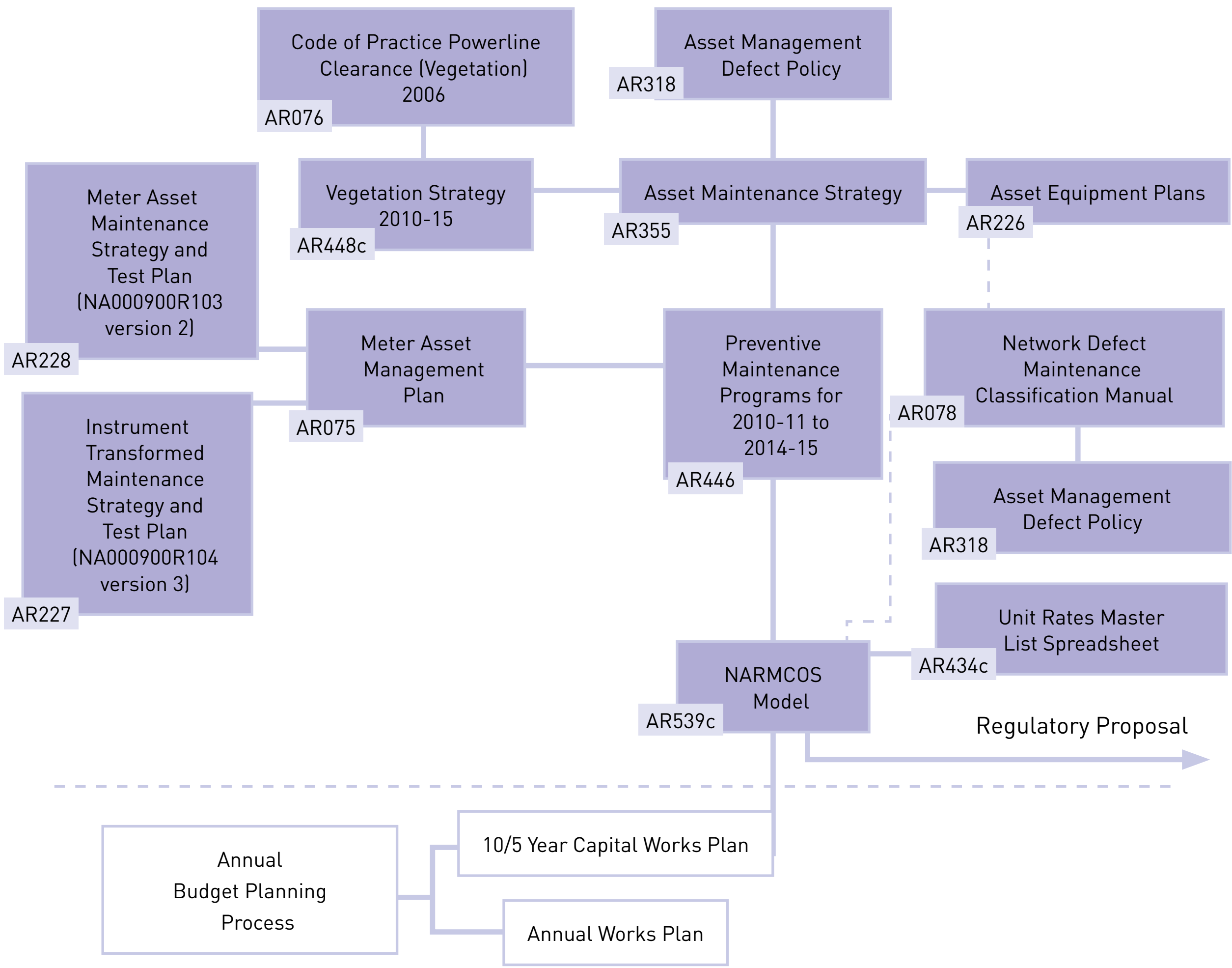
Operating Expenditure - Preventive Maintenance comprises scheduled inspection and maintenance activity. It is carried out at predetermined intervals, or in accordance with prescribed criteria, in order to minimise the probability of network failure, minimise total life cycle costs, meet required operating conditions and performance standards, and keep staff and the public safe. Maintenance reduces the probability of failure or the degradation of the performance of an asset and therefore the need for Forced Maintenance.

Work that is identified from the Preventive Maintenance program can be undertaken as either Asset Replacement (defects) capital expenditure or Corrective Maintenance, so that Forced Maintenance is minimised and total maintenance expenditure is optimised.

26.3.3 Estimation Process

Figure 55 overviews the key elements of how Ergon Energy has prepared its Preventive Maintenance forecasts for the next regulatory control period. The nature of each of these elements is explained below.

Figure 55: *Operating Expenditure – Preventive Maintenance*



The Asset Management Defect Policy sets out the basis on which Ergon Energy will repair and remediate defects identified in its distribution system in order to ensure that assets are maintained in a safe condition. This policy sets the prioritisation criteria that are used to classify defects as a result of inspection work.

The Asset Maintenance Strategy commits Ergon Energy to the effective maintenance of its network assets in order to keep them fit for purpose, and in a safe and environmentally sound condition, so as to minimise the risk of condition-based and age-related failures.

The Vegetation Strategy commits Ergon Energy to the effective management of vegetation around powerlines, and along access tracks, in order to promote public safety, reliable electricity supply and compliance with regulatory obligations.

The Asset Equipment Plans set out the asset management methodology for each of Ergon Energy's 26 classes of system assets. These plans identify the drivers of condition-based asset renewal activity for each asset equipment type. The Asset Equipment Plans address the current situation, the maintenance policy, issues and challenges, and strategies for change and improvement. Each Asset Equipment Plan drives a long-term annual expenditure plan extending out until at least 2017.

The document entitled Preventive Maintenance Programs for 2010-11 to 2014-15 outlines the maintenance cycles underpinning the Preventive Maintenance programs and work plans within Ergon Energy for the five years commencing from 2010-11. This document details Operating Expenditure – Preventive Maintenance programs and work plans, which in turn dictate the Capital Expenditure – Asset Replacement – Defects and Operating Expenditure - Corrective Maintenance requirements.

The EP51 Asset Management Defect Policy describes the way in which Ergon Energy will classify its defects and sets timeframes in which classified defects will be repaired. The Network Defect Classification Manual is designed to assist asset inspectors to identify defects accurately in the field across all of Ergon Energy's classes of system assets. It details the way in which inspections and assessments are to be undertaken for each class of system assets.

The Meter Asset Management Plan[39] documents the methodology for technical and operational performance of Ergon Energy's metering assets. The Plan has been determined in accordance with the Rules and has been approved by NEMMCO. Compliance with, and progress against, the Plan is audited by NEMMCO.

The Network Assets Replacement Maintenance Capex Opex Summary (NARMCOS) model forecasts Operating Expenditure – Preventive Maintenance expenditure using the same approach for all 26 classes of system assets. The NARMCOS model does this by:

- Identifying the different types of Preventive Maintenance work that need to be undertaken for each asset equipment type;
- Identifying the amount of Preventive Maintenance work (i.e. in units) that needs to be undertaken for each asset equipment type for each of the five years;
- Identifying the total cost of undertaking a single unit of work for the different types of work required for each type of Preventive Maintenance. The unit rates do not change over the five years and are drawn from the Unit Rates Master List Spreadsheet however escalations are applied in accordance with Chapter 33 of this Regulatory Proposal;
- Calculating the total cost of each type of Preventive Maintenance work for each of the 26 classes of system assets for each of the five years; and
- Aggregating the total Preventive Maintenance work required for each of the 26 classes of system assets for each of the five years.

The Asset Equipment Plans provide a discussion of the asset population, growth rate, cycle times and, where relevant, new programs for each of the 26 classes of system assets. Data for the Preventive Maintenance programs are drawn from the Ellipse Asset Management system.

The estimated volume of vegetation work required in the next regulatory control period has been based on the sampling condition assessments carried out by VEMCO (an external vegetation management expert company). Ergon Energy's P55C06R01 Code of Practice Powerline Clearance (Vegetation) 2006 is the standard to which the vegetation works necessary have been estimated. However the cost of the works for the next regulatory control period have been based on an average of the unit rates that VEMCO provided (based on their costs to undertake vegetation work in Victoria) and the higher historical actual unit rates that Ergon Energy has paid to contractors in the current regulatory control period.

The forecasts from the NARMCOS model are reflected into the budget planning process, including the development of a Ten and Five Year Maintenance Works Plan and an Annual Works Plan. These form the basis for the five year forecasts for the next regulatory control period that are included in this Regulatory Proposal.

[39] MAMP Information Paper available from NEMMCO's website: http://nemmco.com.au/met_sett_sra/630-0033.html

26.3.4 Assumptions

The key assumptions underlying the Operating Expenditure – Preventive Maintenance forecast are that:

- The document entitled Preventive Maintenance Programs for 2010-11 to 2014-15 is applied as the basis for the Preventive Maintenance forecast. Importantly, this document summarises the Preventive Maintenance inspection and maintenance intervals and other criteria used to generate the annual maintenance work plans and budgets;
- There will be no changes to current Codes of Practice and Electrical Safety Office requirements that apply to Ergon Energy;
- There will be no changes in shareholder requirements that will impact the Preventive Maintenance program; and
- No additional equipment or material defects that are unknown at time of preparing the expenditure forecasts are subsequently identified.

26.3.5 Capital Expenditure / Operating Expenditure Interactions

There is a strong relationship between the Operating Expenditure – Preventive Maintenance forecasts and:

- The Capital Expenditure - Asset Replacement - Defect program because the Operating Expenditure – Preventive Maintenance program identifies where there are defective assets that need to be replaced by undertaking capital works;
- The Operating Expenditure Corrective program because the Operating Expenditure – Preventive Maintenance program identifies where there are defective assets that need to be maintained through specific Corrective Maintenance activity; and
- The Operating Expenditure Forced program because, if the Operating Expenditure – Preventive Maintenance program does not identify defective assets that need either to be replaced or otherwise maintained, then there may be a need to increase Forced Maintenance in order to remedy assets that have failed.

26.3.6 Justification of the Forecasts

The NARMCOS model forecasts the Operating Expenditure – Preventive Maintenance expenditure for all of Ergon Energy's 26 classes of system assets, having regard for the Asset Management Defect Policy, the Asset Maintenance Strategy, the Vegetation Strategy, the Asset Equipment Plans, the Preventive Maintenance Programs for 2010-11 to 2014-15, the Network Defect Management Policy, the Network Defect Classification Manual and the Meter Asset Management Plan.

The maintenance strategies consider safety, environmental, financial and reliability performance risks, compliance with Codes of Practice, legislative obligations and recommendations of the 2004 Electricity Distribution and Service Delivery (EDSD) Review and the 2008 Operational Review.

The Asset Equipment Plans explain the key parameters that were used in NARMCOS to develop the forecast for each of the 26 classes of system assets. These explanations are unique to each class of system assets.

The key program changes that are included in the Preventive Maintenance expenditure forecasts are summarised below. The Asset Equipment Plans provide a detailed explanation of these changes.

26.3.6.1 Pole Top Inspections

A pole top detailed inspection program has been commenced using a combination of mast-mounted cameras, aerial helicopter inspections and elevating platform vehicle inspections. This will address the limitations of the current ground-based pole top inspection programs, which are not detecting all required failure modes.

The purpose of the program is to:

- Reduce pole top assembly failures, including crossarms, and thereby reduce the number of dangerous electrical events;
- Identify defects that are difficult to determine and prioritise from ground-based inspections; and
- Gather detailed data on conditions for determining defect refurbishment or line replacement strategies.

In the current regulatory control period, Preventive Maintenance focussed on reducing unassisted pole failures by undertaking the pole inspection program. This program has been successful with Ergon Energy's pole reliability improving by 78 per cent since 2004 and continuing to trend in a positive direction.

Ergon Energy is now targeting assets with high failure rates, in particular pole top assemblies.

The number of reported unassisted asset failures and subsequent dangerous electrical events caused by crossarm failures has increased since 2005-06. Crossarm failures represented 21 per cent of reported unassisted asset failures causing dangerous electrical events in 2007-08.

In 2008-09, Ergon Energy began deploying detailed aerial pole top inspections of sub-transmission and critical distribution poles. These inspections target locations with a history of unassisted crossarm failures. In 2010-11, Ergon Energy will deploy mast-mounted camera inspections in urban areas. It will target locations with a history of unassisted crossarm failures.

In the 2015-20 regulatory control period Ergon Energy will consider introducing a cyclic inspection of all pole tops on an eight-year cycle using either aerial or mast-mounted camera methods.

26.3.6.2 Service Inspections

Ergon Energy will continue the current approach of visually inspecting, and reporting on defects related to overhead customer services. The current cycle time of four years will allow a visual inspection of about 120,000 overhead services per year. Ergon Energy will commence a full service inspection program from 2012-13 on a 12 year cycle.

Ergon Energy's objective is to reduce public electric shock incidents arising from overhead services. In addition, it will ensure compliance with the Queensland Electrical Safety Regulation 2002, which requires Ergon Energy to undertake periodic inspections and maintenance of the insulation of the consumer terminal's clamp or apparatus attaching to the overhead service.

26.3.6.3 Underground Pillar Internal Inspections

Underground pillars are currently inspected as part of the asset inspection program and are largely undertaken as a visual inspection of the external cover.

A sample program of internal inspection of 500 pillars has commenced and a full program of internal inspection on an eight year cycle is proposed to start from 2010-11. This will ensure that underground pillars remain in a serviceable condition.

26.3.6.4 Ring-main Unit Maintenance

Historically, Ergon Energy has undertaken minimum routine maintenance of ring-main units (RMU), which are ground-mounted enclosed switches. Ergon Energy has experienced some catastrophic failures of these assets and, in particular, oil-insulated RMU, which have been the subject of operating restrictions since September 2007 unless they have been maintained.

All ground-mounted enclosed switches were inspected in 2007-08 through a dedicated RMU data capture project. This project determined the nameplate details and maintenance requirements of ground-mounted enclosed switches. In 2008-09 and 2009-10, priority will be given to oil-insulated equipment over 12 years of age in order to reduce the risk of asset failure and to minimise switching restrictions.

The rollout of a full program of maintenance on a 12 year cycle will follow in 2010-11.

26.3.6.5 Vegetation Management

Ergon Energy has a vast operating area with many different vegetation types, densities and growth rates, which adversely affect the operation of its assets and limit access for operational purposes. As a consequence, Ergon Energy requires an extensive vegetation management program.

Vegetation management is most efficient and effective if it is delivered as part of a co-ordinated program of work. However, in the current regulatory control period, there has been a significant amount of reactive tree clearing, in response to:

- Customer requests; and
- Improvement Notices issued by the Electrical Safety Office, under section 148 of the Electricity Safety Regulation 2002. These notices relate to trees contacting overhead power lines.

26.3.6.6 Access Track Maintenance

A number of new programs have been forecast in relation to access track maintenance in the next regulatory control period:

- Cultural heritage and environment checks – this program addresses Ergon Energy's duty of care obligations under the Aboriginal Cultural Heritage Act 2003;
- Additional environmental programs – these programs will include risk assessments to determine endangered, vulnerable and rare species, the application of permits under the Nature Conservation Act and the provision of offsets where destruction of these species is unavoidable;
- Signage – this program is to install standard signage on access tracks to assist staff with the location of assets, particularly during fault finding.

26.3.6.7 Protection Testing

Protection schemes and transducer and panel meters are currently maintained on a four-year cycle.

Ergon Energy is introducing a new program for automatic circuit recloser and sectionaliser protection systems from 2010-11. This new program of testing focuses on Ergon Energy's growing population of smart reclosers and will detect premature failures of batteries. The testing will be carried out on a two year cycle.

26.3.6.8 Communication System Maintenance

Additional communication systems maintenance will be required on equipment installed through the UbiNet Stage 1 project that is discussed in section 23.6.2.1 of this Regulatory Proposal.

The Asset Equipment Plan for Communications identifies that the traditional site-based inspection programs will be replaced by a number of stand-alone programs. This does not change the forecast but reflects an improvement in the maturity of communication maintenance plans.

26.3.6.9 Meter Testing

Routine maintenance of meters for both market and non-market customers is regulated under Clause S7.3 of the Rules[40] and the National Metrology Procedure Part A[41] .

Ergon Energy's Meter Asset Management Plan[42] has been determined in accordance with the Rules and has been approved by NEMMCO. Compliance with, and progress against, the Plan is audited by NEMMCO.

Meter maintenance is non-discretionary if Ergon Energy is to fulfil its role as the Responsible Person and is to retain its accreditation as a Metering Provider by meeting NEMMCO's service level requirements.

Ergon Energy will commence the following new programs from 2008-09 and in the next regulatory control period:

- Low voltage revenue current transformer maintenance program – this new testing program was introduced from 2008-09 in order to comply with Clause S7.3 of the Rules, and thereby ensure that Ergon Energy meets NEMMCO's accreditation requirements;
- Receiving inspection sample program – this new program will start in June 2009 and will coincide with the commencement of new meter equipment supplier contracts. Equipment Receiving Inspection/Testing Inspection check lists will ensure suppliers are delivering products fit for purpose and in accordance with contract provisions. A visual inspection of one meter item of each delivery will be made by each of the Logistics Stores. Additional electrical tests will be performed on a minimum of four items per delivery in the Meter Workshop/Laboratory in Rockhampton;
- Ripple and Time Control Device Maintenance Program - The average age of Ergon Energy's in-service ripple and time control devices is increasing with 50 per cent of the population expected to exceed its notional 20 year life by 2010. Given the average age of the assets, this program will ensure switching devices control customer loads in accordance with tariff provisions. A sampling plan based on receiver/time-switch make, type and age will be used to assess the failure rate of these devices in order to determine the need for targeted asset replacement.

26.3.6.10 Maintenance contract for SCADA equipment

A new maintenance program has been established for the SCADA Master Station and related equipment that was introduced through Project LINK. Whilst the equipment has recently been installed, it still needs to be inspected and maintained.

26.3.7 Risk Considerations

There are a large number of inspection and maintenance programs that make up the Operating Expenditure - Preventive Maintenance forecast. These programs are necessary to ensure the asset condition of all of the assets across the distribution network is monitored and that repairs, refurbishment and renewal are identified prior to failure. Each of the inspection and maintenance programs has therefore been tailored to address the specific risks associated with each class of asset. Theses risk include safety, legal, financial, reliability, environmental, customer and regulatory. These are discussed in each of the 26 Asset Equipment Plans.

Examples of the key inspection and maintenance programs that address the highest risks include: asset inspections; pole-top inspections; earth testing; air break switch (ABS) inspections, RMU maintenance; service inspections; vegetation management; protection system testing; substation plant oil testing and maintenance. These programs have been designed to minimise dangerous electrical events resulting from unassisted asset failures and to reduce outages so as to improve customer reliability.

26.3.8 Customer Outcomes

Preventive Maintenance is intended to minimise the probability of network failure, minimise total life cycle cost, meet required operating conditions and performance standards, meet codes of practice, guidelines and legislation, and keep Ergon Energy's staff and the public safe. By reducing unplanned asset failures, Ergon Energy seeks to reduce outages to customers.

A cut in the Preventive Maintenance forecast would reduce or remove condition monitoring of some types of system assets, and thereby leave them to run to failure without information about their condition. It could be expected that this would have negative customer service impacts, including increased supply interruptions. It could also lead to an increase in dangerous electrical events.

Ergon Energy undertakes an annual review of its inspection cycle times in order to ensure that they remain consistent with good maintenance practices. The recommended optimum cycle times have been used as the basis for this Operating Expenditure – Preventive Maintenance forecast.

Key Preventive Maintenance programs include asset inspection program, earth testing, vegetation management, ABS testing, RMU inspections, substation maintenance, protection testing, communications system maintenance, access track maintenance, meter tests, oil sampling of major plant and PCB testing.

[40] Available from the AEMC's web site: http://www.aemc.gov.au/rules.php

[41] Available from NEMMCO's website: http://www.nemmco.com.au/met_sett_sra/640-0106.html

[42] MAMP Information Paper available from NEMMCO's website: http://nemmco.com.au/met_sett_sra/630-0033.html

26.4 CORRECTIVE MAINTENANCE

26.4.1 Forecast 2010-15

Ergon Energy's Operating Expenditure – Corrective Maintenance forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 71.

Table 71: *Operating Expenditure – Corrective Maintenance – 2010-15 Forecast ($M Real $2009-10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
75.30	100.07	98.49	121.88	121.48	122.82	117.94	105.66	589.78	117.96

Source: Tables for Proposal 26.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10).

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

26.4.2 What this Forecast Relates to

Operating Expenditure - Corrective Maintenance involves planned repair and replacement work that is carried out after defects are identified, in order to fix the defect and prevent an outage or a dangerous electrical event occurring. Corrective Maintenance also includes repair or replacement works following temporary repairs, involving Forced Maintenance, to restore supply following an outage. This category of work is planned and carried out regularly. Ergon Energy's capitalisation accounting policies provide guidelines on whether the defect is repaired and expensed as Corrective Maintenance or capitalised as Asset Replacement.

The largest elements of Ergon Energy's Corrective Maintenance program relate to vegetation management and access track remediation – these programs represent approximately two-thirds of the total forecast.

26.4.3 Estimation Process

Figure 56 overviews the key elements of how Ergon Energy has prepared its Corrective Maintenance forecast for the next regulatory period.

The Asset Maintenance Strategy commits Ergon Energy to the effective maintenance of its network assets in order to keep them fit for purpose, and in a safe and environmentally sound condition, so as to minimise the risk of condition-based and age-related failures.

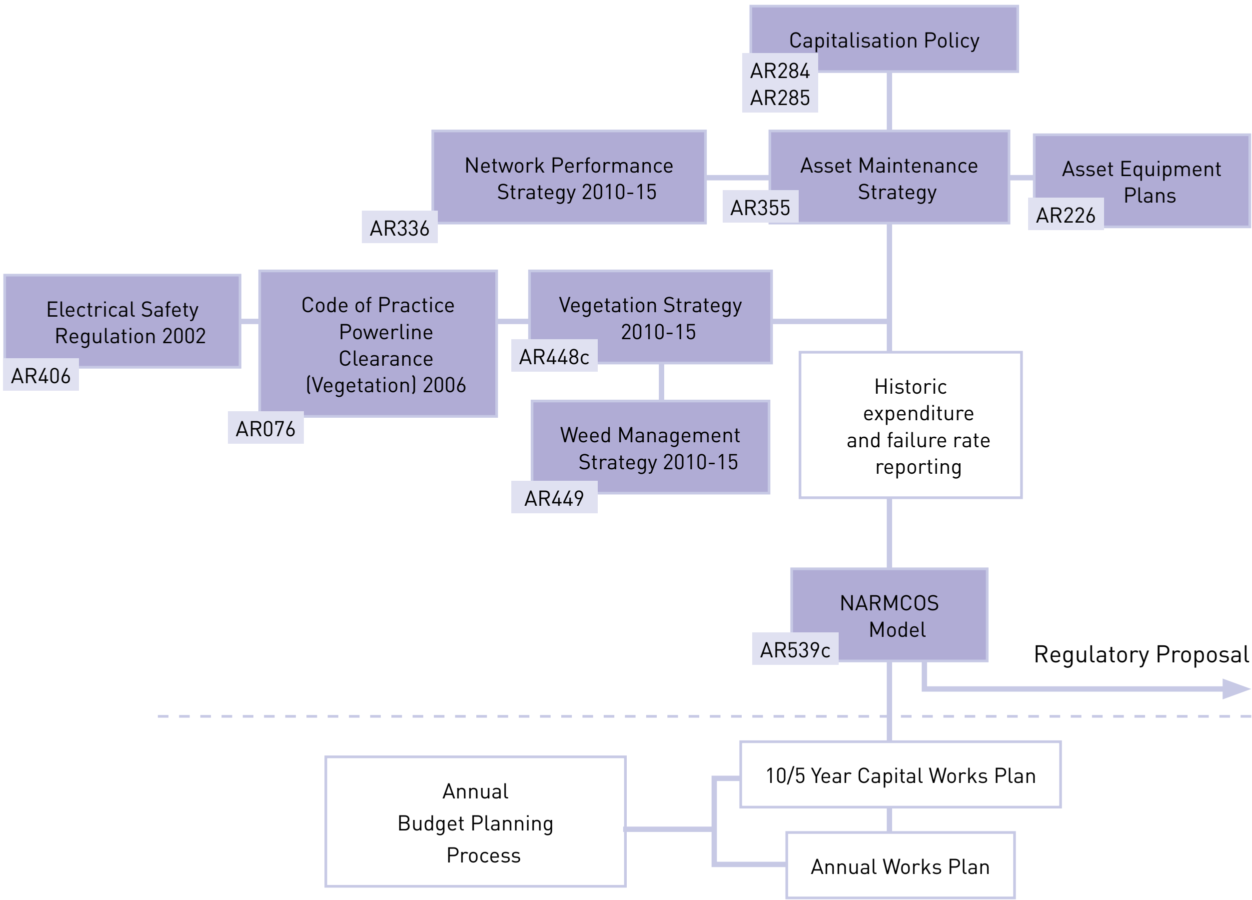
The Network Performance Strategy 2010-15 describes the long-term strategy for network performance improvement for Ergon Energy at a summary and concept level.

The Asset Equipment Plans explain the nature of the Corrective Maintenance activity for each of the 26 classes of system assets. These explanations are unique to each class of system assets.

The Electrical Safety Regulation 2002 creates legal responsibilities to maintain safe clearances between vegetation and powerlines, in particular under sections 75, 137 and 148. The Vegetation Strategy commits Ergon Energy to the effective management of vegetation around powerlines, and along access tracks, in order to promote public safety, reliable electricity supply and compliance with regulatory obligations.

Ergon Energy has a Code of Practice Powerline Clearance (Vegetation) 2006. The Code gives effect to the Vegetation Strategy and the Weed Management Strategy 2010-15 by setting out minimum safety clearances that must be maintained between vegetation and powerlines. It also details the practices Ergon Energy will employ to ensure that safe clearances are maintained as well as Ergon Energy's obligations to its customers and the community to maintain safe clearances.

Figure 56: *Operating Expenditure – Corrective Maintenance*



The Code also details vegetation management and planting practices that Ergon Energy's customers and the community generally should adopt to minimise the risk of vegetation contacting powerlines.

Operating Expenditure - Corrective Maintenance (with the exception of vegetation and access tracks) can only be forecast in advance on the basis of history of failure rates or historical expenditure because it is reactive maintenance and cannot be planned in advance.

The vegetation and access tracks forecast, which accounts for approximately 71 per cent of the total Operating Expenditure - Corrective Maintenance forecast, was developed from a bottom-up approach and not on a base-line-and-scope-change approach. The estimated volume of vegetation and access track work required in the next regulatory control period has been based on the sampling condition assessments carried out by VEMCO. Ergon Energy's P55C06R01 Code of Practice Powerline Clearance (Vegetation) 2006 is the standard to which the vegetation works necessary have been estimated.

However, the cost of the works for the next regulatory control period have been based on an average of the unit rates that VEMCO provided (based on their costs to undertake vegetation work in Victoria) and the higher historical actual unit rates that Ergon Energy has paid to contractors in the current regulatory control period.

The remaining 29 per cent of Ergon Energy's Operating Expenditure - Corrective Maintenance forecasts has been based on Ergon Energy's 2007-08 actual costs for Lines, Substations, Secondary Systems, Meters and Public Lighting. 2006-07 and 2007-08 actual expenditure was analysed and found to be reflective of 'typical' Operating Expenditure - Corrective Maintenance expenditure. No abnormal items were identified in the 2007-08 data.

Whilst Ergon Energy undertook higher than average Operating Expenditure - Forced Maintenance expenditure in 2007-08 due to the nature of many outages resulting from flooding, it was considered that 2007-08 did not present above average Operating Expenditure - Corrective Maintenance expenditure as most forced outages were repaired under Operating Expenditure - Forced Maintenance.

The 2005-06 and 2006-07 Operating Expenditure - Corrective Maintenance expenditures were not directly useable as comparative information for determining the 2007-08 base year because they were pre-Ellipse when the definition of some Operating Expenditure - Corrective Maintenance activities were different. However, the 2005-06 and 2006-07 data was used to assist the disaggregation of the total Operating Expenditure - Corrective Maintenance across asset classes.

Scope changes for a number of additional items (which did not occur in the 2007-08 base year) have been added to develop the forecast for the 2008-09 budget and for the 2010-15 regulatory control period forecasts.

These items were an estimate of the additional reactive Operating Expenditure - Corrective Maintenance that was likely to occur during 2008-09 for which costs had not previously been incurred.

These additional items, which amount to 4 per cent of total Corrective Maintenance including vegetation, or 11 per cent of the remainder of Corrective Maintenance excluding vegetation, were:

- Allowance for repairing issues identified following incidents and investigations which are managed in the ESafe (safety incident) system;
- Dismantling of old lines which have been replaced;
- Asbestos cleanup in ground mounted and chamber substations; and
- A 1 per cent increase in expenditure per annum for increasing failure rates of meters.

It is proposed that the scope-changed level of Operating Expenditure - Corrective Maintenance expenditure will continue throughout the remainder of the current and next regulatory control periods. The type of reactive maintenance within this level cannot be predicted in advance but other items which have a high probability of occurring are:

- RMU maintenance resulting from identification of equipment that may fail explosively on operation; and
- Continued dismantling and removal of old lines and substations including cleanup of contaminated land.

The aggregate adjusted (for scope changes) 2007-08 base year expenditure for Operating Expenditure - Corrective Maintenance was then split in NARMCOS between the 26 asset equipment classes in the following manner:

- Firstly using the actual 2007-08 expenditure information where it was available for individual asset equipment types; and
- The balance was allocated between the remaining asset equipment types based on known historical expenditure trends, expected failure rates (units x unit cost) and on the basis of subject matter expertise.

As a result of this process, Ergon Energy broke down the 2007-08 base year Operating Expenditure - Corrective Maintenance expenditure between its 26 asset equipment types and this is used for the forecasts in this Regulatory Proposal.

The Operating Expenditure - Corrective Maintenance forecasts are reflected in the budget planning process, including the development of a Ten and Five Year Maintenance Works Plan and an Annual Works Plan. These form the basis for the five year forecasts for the next regulatory control period that are included in this Regulatory Proposal. The NARMCOS model provides an estimate of Corrective Maintenance expenditure for each asset class.

26.4.4 Assumptions

A key assumption is that 2007-08 provides a sound basis for preparing the Opex – Corrective Maintenance forecast. Changes have been made to the 2007-08 expenditure to account for anomalies in that year. In addition, scope changes have been applied to the adjusted base year in order to prepare the expenditure forecasts for the next regulatory control period.

26.4.5 Capital Expenditure / Operating Expenditure Interactions

Operating Expenditure - Corrective Maintenance are those defect repairs which are not capitalised. The distinction between capital and operating expenditure is defined in Ergon Energy's capitalisation policies. Ergon Energy has a choice whether to rectify a defect as Corrective Maintenance work, or instead bundle similar work together in order to create a capital expenditure project as part of the Asset Replacement program.

There is a strong relationship between the Operating Expenditure – Preventive Maintenance program and the Operating Expenditure - Corrective Maintenance program. Ergon Energy undertakes "preventive" inspections and testing in order to identify assets with defects requiring work. Ergon Energy then decides whether to rectify the item as an Operating Expenditure - Corrective Maintenance cost, or instead to bundle work together and to create a capital expenditure project under the Asset Replacement – Defect Manual program of work. Any reduction in Preventive Maintenance program will result in defects not being identified, increased outages and dangerous electrical events and a need for increased Operating Expenditure - Forced Maintenance.

There is a strong relationship between the defect-related Asset Replacement capital expenditure and Operating Expenditure - Corrective Maintenance. Any reduction in capital expenditure will result in an equivalent increase in Operating Expenditure - Corrective Maintenance.

Changing the Operating Expenditure - Corrective Maintenance building block allowance, other than Vegetation management, will not change Ergon Energy's actual Corrective Maintenance expenditure requirements as these requirements will be largely based on an established baseline.

Reducing vegetation management Corrective Maintenance would mean that Ergon Energy would be at risk of not fulfilling its obligations under the Electrical Safety Regulation 2002 to manage vegetation near its distribution system.

26.4.6 Justification of the Forecasts

Operating Expenditure - Corrective Maintenance is an estimate of likely defect work that will occur based on history.

Operating Expenditure - Corrective Maintenance involves planned repair or replacement work after a defect has been identified before this leads to an outage or a dangerous electrical event. Corrective Maintenance also includes repair or replacement works following temporary repairs to restore supply following an outage. Repairing defects in a planned manner results in lower total costs. Therefore, expenditure undertaken in a planned and managed way prevents customers experiencing outages and the need for repairs having to be undertaken in emergency (unplanned) situations.

The Operating Expenditure - Corrective Maintenance program is structured to ensure that Ergon Energy effectively:

- Maintains its network assets in order to keep them fit for purpose, and in a safe and environmentally sound condition, so as to minimise the risk of condition-based and age-related failures; and
- Manages its vegetation around powerlines, and along access tracks, in order to promote public safety, reliable electricity supply and compliance with regulatory obligations. Access track work improves the ability of staff to access assets for maintenance and replacement. Failure to undertake vegetation management results in unplanned outages to customers and repairs that cost more in the long run than the cost of Corrective Maintenance.

26.4.7 Risk Considerations

The Operating Expenditure - Corrective Maintenance forecasts are structured to mitigate the risk of:

- Condition-based and age-related failures of network assets through a controlled program of works; and
- Non-compliance with electrical safety and environmental legislation.

Reducing the Operating Expenditure - Corrective Maintenance forecasts would require re-prioritising programs of work and force work to be completed following an asset failure and outage. This would increase Ergon Energy's risk profile and mean that it would not meet the Electrical Safety Office and the Queensland Government's expectations for public safety. For example, reducing vegetation forecasts would mean more trees would be likely to grow within approach limits. This would expose Ergon Energy to risks of breaching legislation and provide an unsafe condition for public and staff.

26.4.8 Customer Outcomes

The Operating Expenditure - Corrective Maintenance forecast provide an efficient basis for effectively promoting:

- Public safety by repairing or replacing assets after defects have been identified in order to eliminate dangerous conditions; and
- Reliable electricity supply by ensuring that network assets are fit for purpose and that vegetation is effectively managed around powerlines and along access tracks.

26.5 FORCED MAINTENANCE

26.5.1 Forecast 2010-15

Ergon Energy's Operating Expenditure – Forced Maintenance forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 72.

***Table 72:** Operating Expenditure – Forced Maintenance – 2010-15 Forecast ($M Real $2009 10)*

2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
44.30	42.29	40.43	41.00	40.85	41.34	41.42	41.08	205.69	41.14

Source: Tables for Proposal 26.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10).

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

26.5.2 What this Forecast Relates to

Operating Expenditure - Forced Maintenance involves unplanned repair, replacement or restoration work that is carried out as quickly as possible after the occurrence of an unexpected event or failure in order to bring the network to at least its minimum acceptable and safe operating condition. If temporary works are undertaken as Operating Expenditure - Forced Maintenance then subsequent permanent repairs typically require Operating Expenditure - Corrective Maintenance or Capital Expenditure – Asset Replacement depending on the capitalisation policies.

Although it is unplanned, an annual provision must be made for this category of expenditure.

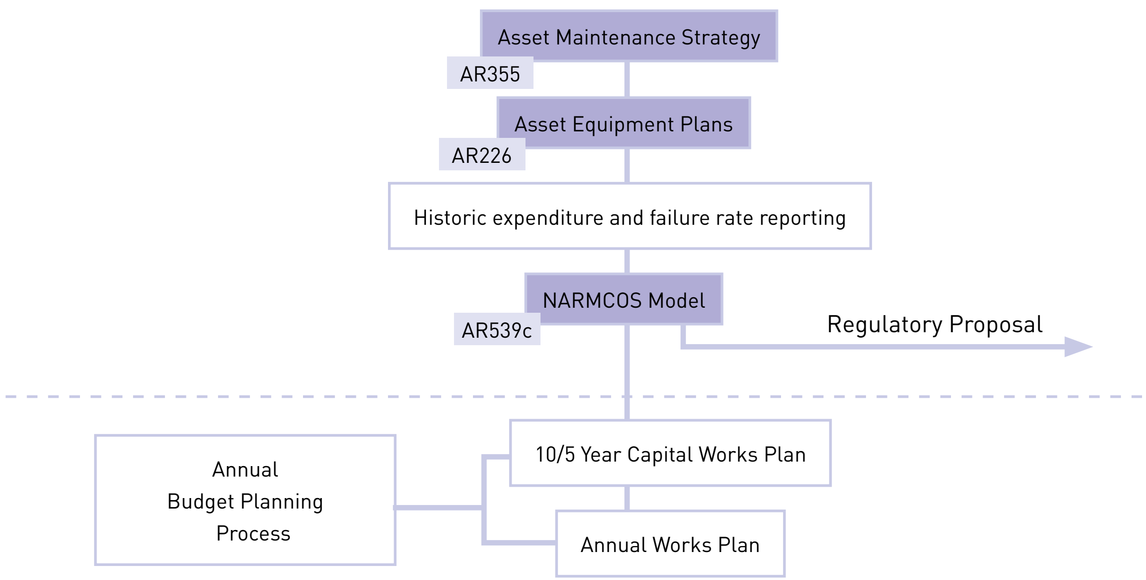
26.5.3 Estimation Process

Figure 57 overviews the key elements of how Ergon Energy has prepared its Forced Maintenance forecast for the next regulatory period.

The Asset Maintenance Strategy commits Ergon Energy to the effective maintenance of its network assets in order to keep them fit for purpose, and in a safe and environmentally sound condition, so as to minimise the risk of condition based and age related failures. This includes undertaking unplanned maintenance to address unexpected events or failures.

The Asset Equipment Plans explain the nature of the Forced Maintenance activity for each of the 26 classes of

Figure 57: *Operating Expenditure – Forced Maintenance*



system assets. These explanations are unique to each class of system assets.

The Operating Expenditure - Forced Maintenance forecasts are prepared at the aggregate level using a top-down/baseline-and-scope-change approach based on Ergon Energy's actual 2007-08 expenditure. Operating Expenditure - Forced Maintenance is weather dependant and typically varies about an average.

The 2007-08 year was considered high and therefore not a representative base year due to the impact of floods (which occurred again in the 2008-09 year). Therefore the 2007-08 year has been adjusted down by 7 per cent to be representative of a 'typical' year.

Explanations relevant to other years are:

- The low actual expenditure for 2006-07 is due to crediting of $10 million of costs for materials that had previously been 'booked out', but later were returned to Ergon Energy's store (inventory); and
- The 2008-09 year is currently tracking below both the 2007-08 and 2008-09 actual expenditures due to the higher than normal weather related outages in both these years.

Ergon Energy has forecast that Operating Expenditure - Forced Maintenance will remain flat throughout the next regulatory control period. There have been no scope changes to the Operating Expenditure - Forced Maintenance forecast. In addition, no allowance has been made for an increasing asset base.

The aggregate adjusted 2007-08 base year expenditure for Operating Expenditure - Forced Maintenance is then split in NARMCOS between the 26 asset equipment classes in the following manner:

- Firstly using the actual 2007-08 expenditure information where it was available for individual asset equipment types; and
- The balance was allocated between the remaining asset equipment types based on known historical expenditure trends, expected failure rates (units x unit cost) and subject matter expertise.

As a result of this process, Ergon Energy has broken down the adjusted 2007-08 base year Operating Expenditure - Forced Maintenance expenditure between its 26 asset equipment types.

The forecasts are reflected in the budget planning process, including the development of a Ten and Five Year Maintenance Works Plan and an Annual Works Plan. These form the basis for the five year forecasts for the next regulatory control period that are included in this Regulatory Proposal. The NARMCOS model provides an estimate of Forced Maintenance expenditure for each asset class.

26.5.4 Assumptions

A key assumption is that 2007-08 provides a sound basis for preparing the Operating Expenditure – Forced Maintenance forecast. Reductions have been made to the 2007-08 expenditure to account for anomalies in that year. No scope changes have been applied to the adjusted base year in order to prepare the expenditure forecasts for the next regulatory control period.

26.5.5 Capital Expenditure Operating Expenditure Interactions

Ergon Energy's Operating Expenditure - Forced Maintenance forecasts are largely driven by adverse weather conditions affecting its distribution system, particularly during the summer storm season, including the impact of cyclones and floods.

There is a strong relationship between the Operating Expenditure – Forced Maintenance forecasts, the Capital Expenditure - Asset Replacement - Defect program and the Operating Expenditure – Preventive and Corrective Maintenance programs. This is because these programs identify where specific capital or maintenance activity needs to be undertaken to minimise the probability of network failure, minimise total life cycle cost, meet required operating conditions and performance standards, and keep staff and the public safe.

If Asset Replacement capital and other maintenance activity is inadequate, it is likely that there will be a greater need for unplanned repair, replacement or restoration work by way of Operating Expenditure – Forced Maintenance in order to bring the network to at least its minimum acceptable and safe operating condition. Ergon Energy considers that this would not be consistent with good engineering or asset management practice and is likely to lead to a less safe and reliable distribution system that is, in the longer term, more expensive to manage.

By the same token, Ergon Energy does not expect that the proposed Asset Replacement capital expenditure and other maintenance activity will significantly reduce its Operating Expenditure-Forced Maintenance expenditure requirements. This is because Ergon Energy's Operating Expenditure - Forced Maintenance forecasts are largely driven by adverse weather conditions, which cannot readily be prevented by any pre-emptive action, whether involving capital or operating expenditure. In this sense, the Operating Expenditure - Forced Maintenance forecast, and the amount ultimately approved by the AER, will not change the work that actually needs to happen on a 'forced' basis. Ergon Energy will simply need to undertake the works as the need arises following an unexpected event or failure.

26.5.6 Justification of the Forecasts

Operating Expenditure - Forecast Maintenance is an estimate of likely unplanned repair, replacement or restoration work that will be required based on the unexpected events or failures that are likely to occur on Ergon Energy's distribution system. This estimate is largely driven by severe weather conditions adversely impacting the distribution system, although assets, even in good condition, can be destroyed. Forced Maintenance is therefore generally required in response to, rather than in anticipation of, interruptions to supply. It can help to limit the extent of, but not to eliminate altogether, these interruptions.

Storm activity varies from year-to-year and so Forced Maintenance costs do not have a direct relationship to other maintenance and replacement programs. It is not possible to forecast accurately the extent of the Forced Maintenance that will be required to address weather impacts. For this reason, Operating Expenditure - Forced Maintenance forecast is based on historic trends at a high level. This is considered to be the most accurate way of forecasting this kind of expenditure given that Ergon Energy has an extensive asset base that spans a wide geographic regional area with diverse weather types and patterns.

The Operating Expenditure - Forced Maintenance program is structured to ensure that Ergon Energy, as quickly as possible, brings its distribution system back to at least its minimum acceptable and safe operating condition following unexpected events or failures.

Changing other maintenance expenditure programs, or undertaking Capital Expenditure - Asset Replacement expenditure, has in the past proven to have very limited impact on Ergon Energy's Forced Maintenance expenditure requirements.

Ergon Energy therefore considers that it has limited ability to influence its Forced Maintenance expenditure requirements.

26.5.7 Risk Considerations

There are no specific risk considerations associated with the Operating Expenditure - Forced Maintenance forecast, other than that under-funding Asset Replacement capital and other maintenance expenditure is likely to increase the need for unplanned repair, replacement or restoration work by way of Operating Expenditure – Forced Maintenance. This is because, if the under-funding is translated into under-spending, there is likely to be an increased incidence of unexpected events or failures. The level of Forced Maintenance expenditure varies and Ergon Energy must repair the distribution network in order to restore supply and safe conditions.

However, as noted above, the Operating Expenditure - Forced Maintenance forecast, and the amount ultimately approved by the AER, will not change the work that actually needs to happen on a 'forced' basis. Ergon Energy will simply need to undertake the works regardless as the need arises following an unexpected event or failure. The Operating Expenditure - Forced Maintenance forecast therefore seeks to ensure that Ergon Energy is appropriately funded to undertake the works that are expected to be necessary.

26.5.8 Customer Outcomes

When Operating Expenditure - Forced Maintenance is required, an unexpected event or failure has occurred which typically results in outages for customers. The purpose of Operating Expenditure - Forced Maintenance is to ensure that Ergon Energy brings its distribution system back to at least its minimum acceptable and safe operating condition following any such events or failures. This ensures that the duration of outages experienced by customers is minimised.

There are no major changes in the Operating Expenditure - Forced Maintenance forecast between the current and the next regulatory control periods.

26.6 OTHER OPERATING EXPENDITURE

26.6.1 Forecast 2010-15

Ergon Energy's Operating Expenditure – Other Operating Expenditure forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 73.

Table 73: *Operating Expenditure – Other Operating Expenditure – 2010-15 Forecast ($M Real $2009-10)*

	2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
Meter Reading	11.07	11.73	11.60	11.75	11.81	12.03	12.31	12.48	60.38	12.08
Customer Services	26.24	28.77	27.85	19.82	19.86	20.19	20.60	20.81	101.28	20.26
Other Operating Costs[5]	19.75	24.97	24.89	40.47	41.59	42.29	43.85	45.48	213.68	42.74
Total	**57.07**	**65.46**	**64.34**	**72.04**	**73.26**	**74.51**	**76.76**	**78.77**	**375.34**	**75.08**

Source: Tables for Proposal 26.2

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10).
5. Includes Trainings Costs, DMIA, Self Insurance, Demand Management Operating Expenditure and GSLs.

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

26.6.2 What this Forecast Relates to

Operating Expenditure – Other Operating Expenditure relates to meter reading in Ergon Energy's capacity as a Metering Data Provider for Type 5, 6 and 7 metering installations, customer service activity in Ergon Energy's capacity as a DNSP and various other operating expenditure activities.

26.6.2.1 Meter reading

This type of operating expenditure relates to Ergon Energy's role as a Metering Data Provider for Types 5, 6 and 7 metering installations, which involves collecting, processing, loading and publishing meter data "to the market". This role does not relate either to metering provision or Metering Data Agent services for Types 1 to 4 metering installations.

Ergon Energy's meter reading obligations are detailed in various regulatory instruments including Chapter 7 of the Rules and the National Electricity Market Metrology Procedure[43].

26.6.2.2 Customer service

This type of operating expenditure relates to a variety of activities for customers that are ancillary to the provision of Ergon Energy's broader network, connection and metering services, including:

- Cold water report (where Ergon Energy rather than the customer is at fault);
- Check inspections (except where Ergon Energy needs to do a re-test);
- Revenue protection;
- Customer support;
- Managing compliance with electrical safety legislation; and
- Customer advisory services.

26.6.2.3 Other operating costs

This type of operating expenditure relates to a variety of other costs, including:

- Self insurance;
- DMIA;
- Demand Management Operating Expenditure;
- Guaranteed Service Levels (GSLs); and
- Training.

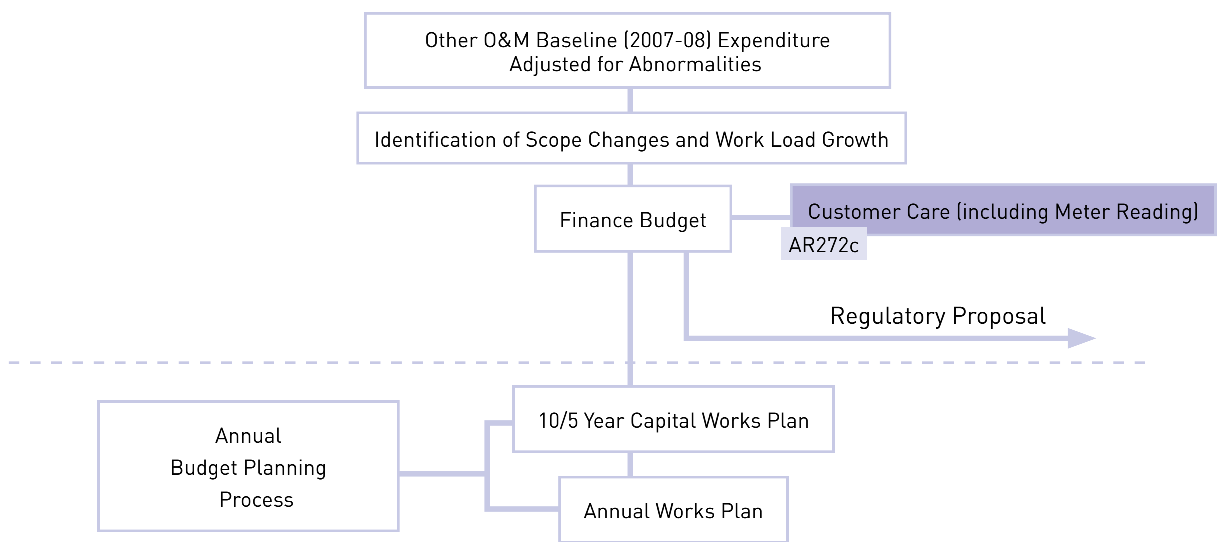
26.6.3 Estimation Process

26.6.3.1 Meter reading, customer service and other operating expenditure

The operating expenditure forecasts for Meter Reading, Customer Service and Other Operating Costs are prepared using 2007-08 expenditure as base year. Forecasts are developed to remove any abnormalities (an example of which is ongoing impacts from the recent introduction of Full Retail Competition (FRC) in the Queensland electricity market) and to adjust for expected scope changes. An expected meter reading scope change is an increase in volumes for specific services as a result of the introduction of FRC. An overview of the forecasting process is provided in Figure 58.

The document entitled "Customer Care including Meter Reading" was used to inform the Finance budget forecasts.

Figure 58: *Operating Expenditure – Other Operating Expenditure – Meter Reading, Customer Services and Other Operating Expenditure*



[43] The Metrology Procedure is available from NEMMCO's website at http://www.nemmco.com.au/met_sett_sra/640-0106.html

26.6.3.2 Self Insurance

Self insurance is a new item (scope change) to the Operating Expenditure – Other Operating Expenditure forecasts. Ergon Energy has based its self insurance forecast on a self insurance review conducted by Synergies Economic Consulting in partnership with Finity Consulting, an actuarial and insurance consultant. The detailed nature of Ergon Energy's self insurance arrangements, including how they meet the AER's requirements, is set out in Chapter 28 of this Regulatory Proposal.

26.6.3.3 Demand Management Innovation Allowance

The Demand Management Innovation Allowance (DMIA) is a new item (scope change) to the Operating Expenditure – Other Operating Expenditure forecasts. This type of operating expenditure relates to Ergon Energy's DMIA program, which is discussed in detail in Chapter 45 of this Regulatory Proposal. The DMIA allowance of $1 million (nominal) per annum is based on the notional amount provided for Ergon Energy in the AER's F&A Stage 2.

26.6.3.4 Demand Management

The Demand Management forecast is a new item (scope change) to the Operating Expenditure – Other Operating Expenditure forecasts. This type of operating expenditure relates to Ergon Energy's demand management program, which is discussed in detail in Chapter 30 of this Regulatory Proposal.

26.6.3.5 GSLs

This type of operating expenditure relates to the cost of Ergon Energy operating under the GSL regime under the Queensland Electricity Industry Code.

26.6.3.6 Training

During the current regulatory control period training costs were included as part of the shared costs pool. Due to a change in accounting treatment, training costs of approximately $20 million per annum will be completely expensed as operating expenditure. Ergon Energy is legally obliged to conduct a large amount of training, particularly to ensure that safe work practices are used in the field. Training will also target skills for SCADA and communications systems.

26.6.4 Assumptions

The key assumptions used to develop the Operating Expenditure – Other Operating Expenditure forecast are as follows:

- The Meter Reading forecast does not include any allowance for the rollout of smart meters. As noted in Chapter 46, it is assumed that the capital and operating expenditure associated with any requirement to rollout smart meters will be treated as a cost pass through in the next regulatory control period; and
- The Self Insurance forecast of $20.1 million for 2010-15 assumes that certain risks that Ergon Energy bears in providing its Distribution Services are not compensated through the weighted average cost of capital. Instead, they will be funded through a combination of Corrective and Forced Maintenance expenditure, cost pass throughs, market-based insurance and self insurance.

26.6.5 Capital Expenditure / Operating Expenditure Interactions

Capital Expenditure/Operating Expenditure interactions are not relevant to Customer Service and Meter Reading as they are operating services, and not capital expenditure.

At the same time as undertaking the DMIA, Ergon Energy has considered efficient non-network alternatives in preparing its operating and capital expenditure forecasts, is required under clause 6.5.6 and 6.5.7 of the Rules. This is discussed in Chapters 24, 27 and 30 of this Regulatory Proposal.

26.6.6 Justification of the Forecasts

Operating Expenditure – Other Operating Expenditure relates to a series of programs of work that are fundamental to the provision of Ergon Energy's Distribution Services:

- Ergon Energy believes the Meter Reading forecasts represent the prudent and efficient costs of Ergon Energy fulfilling its regulatory obligations as the Metering Data Provider for Types 5, 6 and 7 metering installations within its distribution area. Forecasts include an efficiency factor to help minimise costs;
- Ergon Energy believes that the Customer Service forecasts reflect the costs of undertaking a variety of regulated activities that are ancillary to the provision of Ergon Energy's broader network, connection and metering services;
- The Self Insurance program funds Ergon Energy for the residual risks it faces in providing its Distribution Services. The nature, scope and amount of this forecast is justified in Chapter 28 of this Regulatory Proposal;
- The DMIA is based on the amount that has been proposed by the AER for Ergon Energy to undertake a series of demand management projects and programs throughout the regulatory control period. Expenditure will be undertaken in accordance with the AER's Demand Management Incentive Scheme Guideline;
- The Demand Management expenditure relates to the provision of Ergon Energy's Distribution Services. The nature, scope and amount of this forecast are justified in Chapter 30 of this Regulatory Proposal;
- The GSL forecast relates to payments to customers that Ergon Energy is required to make under the Queensland Electricity Industry Code. These payments are mandatory; and

- Training costs forecasts are necessary because in 2005-06, the International Financial Reporting Standards changed the accounting standard such that training costs could no longer be capitalised. Prior to 2005-06 training costs were included in Ergon Energy's Shared Costs (Overheads) and allocated to capital and operating expenditure using the approved cost allocation method.

26.6.7 Risk Considerations

Ergon Energy does not consider that there are any new risks associated with the Operating Expenditure – Other Operating Expenditure forecast as it is generally based on business-as-usual activity.

26.6.8 Customer Outcomes

The Operating Expenditure – Other Operating Expenditure forecast is required in order to ensure that Ergon Energy is appropriately funded to deliver the following customer outcomes:

- Undertaking regulated meter reading services for Types 5, 6 and 7 metering installations across its distribution area;
- Undertaking a variety of regulated Customer Service activities for customers that are ancillary to the provision of Ergon Energy's broader network, connection and metering services; and
- The projects and programs that will be funded by the DMIA will be directly targeted at saving energy and reducing demand for large commercial and industrial customers, reducing residential peak demand, and building on existing non-network alternative trials for rural customers;
- Compliance with the Queensland Electricity Industry Code's requirements in relation to GSLs; and

There are no customer-specific outcomes arising from training costs.

26.7 KEY VARIABLES IN OPERATING EXPENDITURE FORECASTS

Clause S6.1.2(3) of the Rules requires that the Building Block Proposal contain information on the forecasts of key variables relied upon to derive the operating expenditure forecast and the method used for developing those forecasts of key variables.

26.7.1 Preventive Maintenance

The key variables for Ergon Energy's Preventive Maintenance program are:

- Growth rates of the opening asset population;
- Unit costs of Preventive Maintenance activity;
- Defect rates for different assets;
- Cycle times for undertaking Preventive Maintenance activity;
- The scope to bundling packages of work across asset classes; and
- Any need for new Preventive Maintenance programs.

The methods used to develop forecasts of these key variables differ by asset class and are described in Ergon Energy's Asset Equipment Plans and the documents entitled Preventive Maintenance Programs for 2010-11 to 2014-15.

26.7.2 Corrective Maintenance

The key variables for Ergon Energy's Corrective Maintenance program are:

- The frequency of events or asset failures that give rise to the need for Corrective Maintenance activity, involving repair, replacement or restoration work; and
- The inspection and remedial action undertaken as part of the vegetation management program and the track access program.

The Operating Expenditure - Corrective Maintenance forecasts are prepared at the aggregate level using a top-down/baseline-and-scope-change approach. The aggregate annual amount has been allocated between Ergon Energy's 26 asset equipment types only for the purposes of preparing this Regulatory Proposal. Ergon Energy does not use forecast information broken down in this manner for operational or budgeting purposes.

26.7.3 Forced Maintenance

The key variable for Ergon Energy's Forced Maintenance program is the frequency of unexpected events or asset failures that give rise to the need for Forced Maintenance activity, in order to bring the network to at least its minimum acceptable and safe operating condition.

The Operating Expenditure - Forced Maintenance forecasts are prepared at the aggregate level using a top-down/baseline-and-scope-change approach. The aggregate annual amount has been allocated between Ergon Energy's 26 asset equipment types only for the purposes of preparing this Regulatory Proposal. Ergon Energy does not use forecast information broken down in this manner for operational or budgeting purposes.

26.7.4 Other Operating Expenditure

The key variables for Ergon Energy's Other Operating Expenditure program are:

- The number of additional Type 5 and 6 meters that need to be manually read in the field;
- The frequency with which meters need to be read;
- The number of customers who need to receive Customer Care services; and
- The number of customers who become entitled to receive a Guaranteed Service Level payment.

26.8 VARIATIONS IN OPERATING EXPENDITURE

Section 2.2.4 of the AER's RIN requires Ergon Energy to identify and explain significant variations in its proposed forecast expenditure from historical expenditure for Standard Control Services. The AER has defined a significant variation as being a 10 per cent variation between the actual expenditure in 2007-08 and the average of the five years' forecast expenditure for 2010-11 to 2014-15.

26.8.1 Variations by Expense Category

Table 74 provides an extract from pro forma 2.2.4 of the completed RIN, which shows that there is a greater than 10 per cent variation between the actual operating expenditure in 2007-08 and the average of the five years' forecast operating expenditure for 2010-11 to 2014-15 for Preventive Maintenance, Corrective Maintenance and other operating costs. As a result of these items, there are also significant variations in the sub-totals for network maintenance and other costs and in the overall total operating expenditure program.

Clause S6.1.2(8) of the Rules requires an explanation of any significant variations in the forecast operating expenditure from historical operating expenditure. The remainder of this sub section explains the reasons for the variations in the Preventive Maintenance, Corrective Maintenance and other operating costs. The totals have not been separately explained because the same reasons apply to these variations as for the expense categories.

The variations in each expense category are caused by a combination of changes in direct costs, Shared Costs (Overheads) and cost escalations. The discussion below relates only to direct costs.

The changes in Shared Costs (Overheads) allocated to each expense category relate to changes in the relative share of total direct operating expenditure between the expense categories over the next regulatory control period. These allocations are made in accordance with Ergon Energy's approved Cost Allocation Method.

Some of the variations are also attributable to cost escalations. These cost escalations have been applied given that the consumer price index (CPI) does not accurately reflect movements in costs associated with Ergon Energy's expenditure programs. Ergon Energy engaged SKM to develop cost escalation factors for its 27 asset categories to be applied to its capital expenditure forecasts for the period 2004-05 to 2014-15. The nominal cost escalation factors are detailed in Table 90 in Chapter 33.

Table 74: *Variation between Actual 2007-08 and Forecast 2010-11 to 2014-15 Operating Expenditure by Expense Category ($M Real $2009-10)*

Expense category	Significant variance	2010-11 to 2014-15 Average	2007-08
Preventive Maintenance	Explain	118.71	101.52
Corrective Maintenance	Explain	117.96	75.30
Subtotal Network Maintenance	Explain	304.62	253.10
Other Operating Costs	Explain	42.74	19.75
Subtotal Other Operating Costs	Explain	75.07	57.07
Total	**Explain**	**379.69**	**310.17**

Source: Tables for Proposal 26.8.1

26.8.1.1 Preventive maintenance

Section 26.3.6 of this Regulatory Proposal discusses the key reasons for increases in the level of Preventive Maintenance expenditure between the current and next regulatory control periods. In particular, increased Preventive Maintenance work will be undertaken and increased direct costs will be incurred, in order to:

- Improve the pole top inspection program, by using a combination of mast-mounted cameras, aerial helicopter inspections and elevating platform vehicle inspections;
- Commence an overhead customer service inspection program on a 12-year cycle;
- Introduce a full program of internal inspection of underground pillars on an eight year cycle from 2010-11;
- Commence a new RMU inspection program on a 12 year cycle from 2010-11;
- Upgrade the vegetation management inspection program based on Ergon Energy's new Vegetation Strategy;
- Upgrade the existing access track maintenance program;
- Commence a new program for inspecting and testing automatic circuit recloser and sectionaliser protection systems every two year cycle from 2010-11;
- Introduce an additional communication maintenance programs and a new maintenance program following the rollout of UbiNet Stage 1;
- Introduce various new meter inspection programs; and
- Commence a new program for the SCADA Master Station and related equipment that was introduced through Project LINK.

26.8.1.1 Corrective maintenance

Section 26.4.6 of this Regulatory Proposal discusses the key reasons for increases in the level of Corrective Maintenance expenditure between the current and next regulatory control periods. In particular, increased Corrective Maintenance work will be undertaken, and increased direct costs will be incurred, on:

- Poles, pole tops, conductors and connectors, and distribution services following upgrades to the line patrol and pole top inspection programs that are to be undertaken as part of the Preventive Maintenance programs;
- Access track remediation following upgrades to the inspection program that is to be undertaken as part of the Preventive Maintenance program; and
- Vegetation management cutting and clearing program following upgrades to the inspection program that is to be undertaken as part of the Preventive Maintenance program.

It is therefore expected that, in relation to each of these expenditure categories, the increased inspection program that is to be undertaken as part of the Preventive Maintenance program will identify the need for more Corrective Maintenance work to be undertaken.

26.8.1.3 Other operating costs

Other operating costs include the costs of self insurance, training, the DMIA, demand management, GSLs and equity raising costs. Each of these components, other than training and GSLs, is a new item that has been included in the operating expenditure forecasts for the first time. For this reason, there is a variance between the actual operating expenditure in 2007-08 and the average of the five years' forecast operating expenditure for 2010-11 to 2014-15.

Section 26.6.1 of this Regulatory Proposal explains the nature of Ergon Energy's self insurance, demand management innovation allowance and equity raising costs. In addition, Chapter 28 provides further details in relation to self insurance and equity raising costs, Chapter 30 provides further details in relation to demand management and Chapter 45 provides further details about the demand management incentive scheme.

26.8.2 Variations by Cost Category

Table 75 provides an extract from pro forma 2.2.4 of the completed RIN, which shows that there is a greater than 10 per cent variation between the actual operating expenditure in 2007-08 and the average of the five years' forecast operating expenditure for 2010-11 to 2014-15 for the three cost categories – labour, contractors and other. As a result of these items, there is also a significant variation in the total operating expenditure program.

Table 75: *Variation between Actual 2007-08 and Forecast 2010-11 to 2014-15 Operating Expenditure by Cost Category ($M Real $2009-10)*

Expenditure Purpose	Significant variance	2010-11 to 2014-15 Average	2007-08
Labour	Explain	158.92	135.75
Materials	n/a	15.60	16.16
Contractors	Explain	172.76	152.05
Other	Explain	32.41	6.20
Total	Explain	379.69	310.17

Source: Tables for Proposal 26.8.2

The remainder of this subsection explains the reasons for the variations in each cost category for system-related capital expenditure between the current and next regulatory control periods. The total has not been separately explained because the same reasons apply to this variation as for the cost categories.

26.8.2.1 Labour

Labour costs are forecast to increase across the next regulatory control period as a result of more Ergon Energy labour being required to undertake more Preventive and Corrective Maintenance work.

A further cause of the labour cost increases is the higher wage escalation rates reflected in the new Ergon Energy Union Collective Agreement 2008.

The nature, and drivers, of the labour cost increases that were used to prepare the operating expenditure forecasts are discussed further in:

- Chapters 32 and 33 of this Regulatory Proposal, which deal with Ergon Energy's unit rates and escalations respectively; and
- The report that were prepared for Ergon Energy by SKM in 2008 entitled "Electricity Industry Labour, Commodity and Asset Price Cost Indices".

26.8.2.2 Contractors

Contractor costs are forecast to increase across the next regulatory control period as a result of Ergon Energy significantly increasing the amount of work being undertaken by contractors, particularly in relation to Preventive and Corrective Maintenance. Two other causes of the contractor cost increases are the expected higher prices resulting from a continuing tight contractor market and the higher wage escalation rates that have been reflected in the new Ergon Energy Union Collective Agreement 2008, which flow through to contractors.

The nature, and drivers, of the contractor cost increases that were used to prepare the capital expenditure forecasts are discussed further in:

- Chapters 32 and 33 of this Regulatory Proposal, which deal with Ergon Energy's unit rates and escalations respectively; and
- The report that were prepared for Ergon Energy by SKM in 2008 entitled "Electricity Industry Labour, Commodity and Asset Price Cost Indices".

26.8.2.3 Other costs

The other costs that are used to prepare the operating expenditure building blocks that result in variations between actual 2007-08 operating expenditure and the average of 2010-11 to 2014-15 operating expenditure are self insurance, the DMIA and equity raising costs.

As discussed above, each of these components is a new item that has been included in the operating expenditure forecasts for the first time. Section 26.6.1 of this Regulatory Proposal explains the nature of Ergon Energy's self insurance, DMIA and equity raising costs. In addition, Chapter 28 provides further details in relation to self insurance and equity raising costs and Chapter 45 provides further details about the demand management incentive scheme.

26.9 OPERATING EXPENDITURE ASSOCIATED WITH PLANNED MAINTENANCE PROGRAMS TO IMPROVE STPIS

Clause S6.1.2(4) of the Rules requires Ergon Energy to provide information on any method used for determining the cost associated with planned maintenance programs designed to improve the performance of its distribution system in the next regulatory control period for the purposes of the Service Target Performance Incentive Scheme (STPIS).

Ergon Energy has not included any planned maintenance program in its operating expenditure forecasts for the next regulatory control period that are specifically designed to improve the performance of its distribution system for the purposes of the STPIS. However, it is expected that the Preventive, Corrective and Forced Maintenance programs will all generally contribute to the improved performance of the distribution system in the next regulatory control period.

26. OPERATING EXPENDITURE – FORECAST AND JUSTIFICATION – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR406	Electrical Safety Regulation 2002 (Qld)

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR367c & 368c	AER Regulatory Information Notice
AR407 & 408	AER Final Decision DMIS, October 2008 & AER DMIS (Scheme), October 2008
AR417 & 418	AER Cost Allocation Guidelines, Final Decision and Guidelines, 26 June 2008

QCA Documents

Nil

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR158	"Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland" (EDSD Review), July 2004
AR209	Electrical Safety Act - Code of Practice for Works (Protective Earthing, Underground Cable Systems and Maintenance of Supporting Structures for Powerlines)
AR364	National Electricity Rules
AR404	Qld Govt "An Action Plan for Queensland Electricity Distribution" (EDSD Action Plan), 23 August 2004
AR439	Qld Govt_Report on Operational Review of Qld DNSPs_23Jun08

Ergon Energy Documents

AR022c	VEMCO Vegetation Maintenance Strategy, January 2009-June 2010
AR075	EE NA000900R102 Meter Asset Management Plan, V3, 1 February 2008
AR076	EE P55C06R01 Code of Practice Powerline Clearance (Vegetation) 2006, V2
AR078	EE Network Maintenance Defect Classification Manual
AR094	Ergon Energy Union Collective Agreement 2008
AR160	EE "The powerful new deal for regional Queensland customers – Ergon Energy's response to the Independent Review Panel Report Electricity Distribution and Service Delivery for the 21st Century – August 2004"
AR169	SKM Electricity Industry Labour, Commodity and Asset Price Indices, Model Outputs, 9 October 2008
AR226	EE Asset Equipment Plans 2009
AR227	EE Instrument Transformer Maintenance Strategy and Test Plan
AR228	EE Meter Asset Maintenance Strategy and Test Plan
AR236c	EE Network Operations Forecast Report (Works Planning)
AR272c	EE Customer Care Forecast Report including Meter Reading,
AR284	EE Capitalisation Accounting Policy Property Plant & Equipment, March 2009
AR285	EE Capitalisation Accounting Policy Intangible Assets, March 2009
AR314	EE Cost Allocation Method, AER Approved
AR318	EE EP51 Asset Management Defect Policy, V2, 1 May 2008
AR336	EE Network Performance Strategy 2010-15, 24 March 2009
AR355	EE Asset Maintenance Strategy, V8, April 2009
AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005
AR434c	EE Unit Rates Master List Spreadsheet, 5 May 2009
AR438	SKM Electricity Industry Labour, Commodity & Asset Price Cost Indices, St 2 (updated for GFC), 6 October 2008
AR446	EE Network Preventative Maintenance Programs for 2010-11 to 2014-15, V7, May 2009
AR448c	EE Vegetation Strategy 2010-15, 31 March 2009
AR449	EE Weed Management Strategy 2010-15, 2 April 2009
AR451	EE Strategic Plan for Asset Renewal, 3 April 2009
AR461	SKM Electricity Industry Labour, Commodity & Asset Price Cost Indices, St 2 (Jan09 Update of Escalators), 14 January 2009
AR539c	EE Regulatory Proposal Models, NARMCOS Model

C CONFIDENTIAL INFORMATION

27. OPERATING EXPENDITURE – OBJECTIVES, CRITERIA AND FACTORS

Rules – Clause 6.5.6

This chapter demonstrates how Ergon Energy's forecast operating expenditure for the next regulatory control period achieves the operating expenditure objectives, having regard for the operating expenditure criteria and operating expenditure factors. It also provides certain other information that is required in relation to its operating expenditure forecasts under the Rules.

27.1 JUSTIFICATION OF FORECASTS AGAINST OPERATING EXPENDITURE OBJECTIVES

Clause 6.5.6(a) of the Rules states that:

> *A building block proposal must include the total forecast operating expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the operating expenditure objectives:*
>
> 1. *meet or manage the expected demand for standard control services over that period;*
> 2. *comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
> 3. *maintain the quality, reliability and security of supply of standard control services;*
> 4. *maintain the reliability, safety and security of the distribution system through the supply of standard control services.*

27.1.1 Interpretation of Clause 6.5.6(a)

Ergon Energy interprets clause 6.5.6(a) of the Rules as requiring it to demonstrate that its forecast operating expenditure will enable it to achieve certain performance outcomes relating to its distribution system and its distribution services in the next regulatory control period. These performance outcomes become the 'objectives' that Ergon Energy's operating expenditure must achieve.

However, this clause, of itself, does not require Ergon Energy to justify the costs that have been used to develop its forecast operating expenditure. Rather, the nature and level of costs will be justified in addressing the requirements of clauses 6.5.6(c) and 6.5.6(e) of the Rules.

Therefore, this section focuses on how the activity to be undertaken through the operating expenditure programs will deliver the required performance outcomes required by clause 6.5.6(a) rather than whether the dollar value of the operating expenditure forecasts is 'the right number'.

The performance outcomes that clause 6.5.6(a) of the Rules requires Ergon Energy's forecast operating expenditure to deliver relate only to Standard Control Services. Ergon Energy proposes, in Chapter 14 of this Regulatory Proposal, that its Standard Control Services in the next regulatory control period should be network services, connection services and metering services.

Ergon Energy interprets clause 6.5.6(a)(1) of the Rules to mean that its forecast operating expenditure must be capable of resulting in operating and maintenance activity that meets or manages the demand for:

- Network services that are provided over the distribution network to all network users that are connected to that network. The demand for network services can be measured in terms of the levels of maximum demand and energy consumption from the distribution network and the number of customer connections to the distribution network;
- Connection services that are provided through connection assets, such as a padmount transformer or a service line for metered or unmetered connections. The demand for connection services can be measured in terms of the number of customer connections; and
- Metering services that are provided in relation to Type 5 to 7 metering installations. The demand for metering services can be measured in terms of the number of new meter installations, scheduled and unscheduled meter readings and metering investigations that are required.

Ergon Energy interprets clause 6.5.6(a)(2) of the Rules to mean that its forecast operating expenditure must be capable of resulting in operating and maintenance activity that ensures that it complies with the legislative and regulatory instruments relevant to the provision of Standard Control Services. Chapter 10 of this Regulatory Proposal identifies the key legislative and regulatory instruments that will apply to Ergon Energy in the (current and) next regulatory control period. These instruments include Queensland and national:

- Legislation and regulations;
- Contracts and agreements;
- Authorities and Codes; and
- Economic regulatory instruments.

Ergon Energy considers that clause 6.5.6(a)(3) of the Rules is framed problematically, because it requires the forecast operating expenditure to "maintain the quality, reliability and security of supply of standard control services". A problem arises because the terms "quality, reliability and security of supply" are typically used in the electricity distribution industry to refer to assets, not services. Indeed, of the five types of service standards referred to in Chapter 12 of this Regulatory Proposal – security of supply, reliability of supply, quality of supply, safety and customer service – only the last relates to standards that individual customers are entitled to receive. The other four relate to standards that Ergon Energy must meet across its distribution system generally.

This suggests that there is an overlap between this clause and clause 6.5.6(a)(4) of the Rules, which requires Ergon Energy to "maintain the reliability, safety and security of the distribution system through the supply of standard control services".

Taken together, Ergon Energy interprets clauses 6.5.6(a)(3) and 6.5.6(a)(4) of the Rules to mean that its forecast operating expenditure must be capable of:

- Resulting in operating and maintenance activity that ensures that its distribution system, that is used to provide its Standard Control Services, complies with the quality, reliability, safety and security of supply standards detailed in Chapter 12 of this Regulatory Proposal; and
- Funding the customer service standards that individual customers are entitled to receive through the Guaranteed Service Level (GSL) regime under the Electricity Industry Code.

27.1.2 Meeting the Requirements of Clause 6.5.6(a)

Ergon Energy considers that its forecast operating expenditure will enable it to deliver the performance outcomes in the next regulatory control period that are required by clause 6.5.6(a)(1) to (4) of the Rules. This means that its forecast operating expenditure will result in operating and maintenance activity so that Ergon Energy can:

- Meet or manage the demand for network, connection and metering services;
- Comply with regulatory obligations that apply to its network, connection and metering services;
- Have a distribution system that complies with quality, reliability, safety and security of supply standards that apply to its distribution system; and
- Fund the customer service standards that individual customers are entitled to receive under the Queensland GSL regime.

Ergon Energy believes its forecast operating expenditure will deliver these outcomes because of:

- The nature of the activities that it will undertake through its operating expenditure program;
- The nature of the plans, policies, procedures and strategies that it has in place to support the development and delivery of its operating expenditure program;
- The estimation processes that it has used to prepare its operating expenditure forecasts; and
- Its ability to physically deliver the operating expenditure program.

These justifications are discussed in turn.

27.1.2.1 Nature of activities

As discussed in Chapter 26 of this Regulatory Proposal, Ergon Energy's operating expenditure comprises:

- Network operations – this relates largely to operating support services, especially switching and outage co-ordination, managing energy flows by co-ordinating network configuration, co-ordinating with National Electricity Market Management Company (NEMMCO) for managing the network and ensuring appropriate procedures are in place to properly co-ordinate supply. There is also some activity associated with the reconfiguration of the distribution network.

  The activity delivered by this category of expenditure is therefore critical to ensuring that the distribution network is operated in a manner that meets customers' day-to-day demand and achieves Ergon Energy's operational service standard requirements, in particular in relation to the quality and reliability of supply.

- Preventive Maintenance – this involves scheduled inspection and maintenance activity that is carried out at predetermined intervals, or in accordance with prescribed criteria. This expenditure is necessary to minimise the probability of network failure, maintain the integrity of the distribution network, meet required operating conditions and performance standards, and keep staff and the public safe.

  The inspection and maintenance programs are tailored to address the specific risks associated with each class of distribution network asset. As discussed in section 26.6.1 of this Regulatory Proposal, the key variables for Ergon Energy's Preventive Maintenance program are:
  - Growth rates of the opening asset population;
  - Unit costs of Preventive Maintenance activity;
  - Defect rates for different assets;
  - Cycle times for undertaking Preventive Maintenance activity;
  - The scope to bundling packages of work across asset classes; and
  - Any need for new Preventive Maintenance programs.
- Corrective Maintenance – this involves planned and regular repair, replacement or restoration work after the occurrence of an event or failure in order to eliminate the source of the failure or to reduce the frequency of its future occurrence. The activity undertaken as part of this expenditure program is designed to:
  - Keep distribution network assets fit for purpose, and in a safe and environmentally sound condition, so as to minimise the risk of condition-based and age-related failures; and
  - Manage vegetation around powerlines, and provide access tracks, in order to promote public safety, reliable electricity supply and compliance with regulatory obligations.

  As discussed in section 26.6.1 of this Regulatory Proposal, the key variables for Ergon Energy's Corrective Maintenance program are:
  - The frequency of events or asset failures that give rise to the need for Corrective Maintenance activity, involving repair, replacement or restoration work; and
  - The inspection and remedial action undertaken as part of the vegetation management program and the access track program.
- Forced Maintenance – this involves unplanned repair, replacement or restoration activity that is carried out as quickly as possible after the occurrence of an unexpected event or failure in order to bring the network to at least its minimum acceptable and safe operating condition.

  Forced Maintenance activity is therefore generally required in response to, rather than in anticipation of, interruptions to supply. It can help to limit the extent of, but not to eliminate altogether, these interruptions.

  As discussed in section 26.6.1 of this Regulatory Proposal, the key variable for Ergon Energy's Forced Maintenance program is the frequency of unexpected events or asset failures that give rise to the need for Forced Maintenance activity, in order to bring the network to at least its minimum acceptable and safe operating condition.
- Other Operating Expenditure – this includes meter reading for Types 5, 6 and 7 metering installations and certain customer service activity, such as for meter maintenance, cold water reports, check inspections, revenue protection, customer support and managing compliance with electrical safety legislation.

  As discussed in section 26.6.1 of this Regulatory Proposal, the key variables for Ergon Energy's Other Operating Expenditure program are:
  - The number of additional Type 5 and 6 meters that need to be manually read in the field;
  - The frequency with which meters need to be read; and
  - The number of customers who need to receive Customer Services.

Ergon Energy therefore believes that the nature of the activities that it will undertake through its operating expenditure program will contribute directly to it achieving all four of the operating expenditure objectives in the next regulatory control period, provided for under clause 6.5.6(a) of the Rules.

27.1.2.2 Plans, policies, procedures and strategies

As discussed in Chapters 17 and 26 of this Regulatory Proposal, Ergon Energy has a large number of plans, policies, procedures and strategies that are used to develop and implement its operating expenditure program for the next regulatory control period.

Ergon Energy's policies provide concise, broad, formal statements that establish guiding principles or rules by which it will make its operating and maintenance decisions. Key policies relevant to its operating expenditure forecasts include its:

- Risk Management Policy;
- Asset Management Defect Policy; and
- Workplace Security and Access Policy.

Ergon Energy's strategies reflect approaches to issues that are designed to deliver particular operating and maintenance outcomes or goals. Key strategies relevant to its operating expenditure forecasts include its:

- Asset Maintenance Strategy;
- Weed Management Strategy;
- Vegetation Strategy; and
- Network Performance Strategy.

Ergon Energy's plans detail its planned activities, achievements and outcomes over time. They set out the action that Ergon Energy will take, and the outcomes that it will achieve:

- To deliver against the internal and external drivers and factors influencing strategic asset management;
- Having regard for the current state of the distribution network; and
- Based on its policies, strategies and procedures.

Ergon Energy's Asset Management Plan categorises plans into two types – 'Plans What' and 'Plans – How'.

'Plans What' are the plans that deal with 'what' needs to be done. These plans include:

- Asset Equipment Plans (AMP) – there is a plan for each asset equipment type;
- Meter Asset Management Plan;
- 20 Year Strategic Plan for Single Wire Earth Return (SWER); and
- Network Preventive Maintenance Programs for 2010-11 to 2014-15.

'Plans How' are the plans that deal with 'how' Ergon Energy will undertake its work.
These plans include:

- Network Defect Classification Manual;
- Climate Change Response Plan;
- Code of Practice Powerline Clearance (Vegetation) 2006;
- Strategic Workforce Plan 2008-18;
- Joint ICT Plan and Finances; and
- Security Standards and Guidelines.

There are also key focus plans that include:

- Network Management Plan (NMP);
- Summer Preparedness Plan;
- Disaster Management Plan; and
- Contingency Plans

Ergon Energy believes that, taken together, the collection of plans, policies, procedures and strategies that it uses to develop its operating expenditure program support the development of operating expenditure forecasts that will achieve all four of the operating expenditure objectives in the next regulatory control period. This is because these plans, policies, procedures and strategies ensure that Ergon Energy's operating expenditure forecasts have regard for:

- The number, age and condition of each class of distribution asset that is needed to deliver its Standard Control Services;
- The need to comply with relevant regulatory obligations; and
- The service standards that Ergon Energy must deliver.

27.1.2.3 Estimation process to prepare operating expenditure forecasts

Chapter 26 of this Regulatory Proposal details the estimation processes that Ergon Energy has used to prepare each subcategory of its operating expenditure forecasts. This Chapter illustrates and describes how Ergon Energy has applied its plans, policies, procedures and strategies to prepare its operating expenditure forecasts. It also explains why and how Ergon Energy has developed:

- The Network Operations expenditure forecasts based on historic baseline expenditure, with adjustments made for abnormalities and scope changes;
- The Preventive Maintenance forecast on a bottom up basis by multiplying an estimated unit rate by an estimated number of units for each of the 26 asset equipment types;
- The Corrective Maintenance forecasts at the aggregate level using a top-down/baseline-and-scope-change approach. The aggregate annual amount has been allocated between Ergon Energy's 26 asset equipment types only for the purposes of preparing this Regulatory Proposal;
- The Forced Maintenance forecasts at the aggregate level using a top-down/baseline-and-scope-change approach. The aggregate annual amount has been allocated between Ergon Energy's 26 asset equipment types only for the purposes of preparing this Regulatory Proposal; and
- The Other Operating Expenditure forecasts:
  - → Using a top-down/baseline-and-scope-change approach for Meter Reading and Customer Care services;
  - → Based on actuarial advice for self insurance; and
  - → Based on the AER's DMIS Guideline.

Ergon Energy believes that the expenditure estimation processes support the development of operating expenditure forecasts that will achieve all four of the operating expenditure objectives in the next regulatory control period. This is because:

- The forecasts are based on the plans, policies, procedures and strategies discussed above, which promote the achievement of the operating expenditure objectives; and
- Ergon Energy has used a combination of robust bottom-up or top-down approaches to translate the plans, policies, procedures and strategies into operating expenditure forecasts for the next regulatory control period.

27.1.2.4 Deliverability of expenditure program

Chapter 35 of this Regulatory Proposal explains that Ergon Energy has forecast that its proposed total capital and operating expenditure program for the 2010-15 regulatory control period will, on average, only require a 5 per cent annual increase in work to be performed, compared with its actual 2007-08 work levels.

Allowing for some annual productivity improvement, Ergon Energy has assessed that the successful delivery of this level of growth in work requires an average annual workforce increase of up to 332 full time equivalent employees and contractors. This is significantly less than the growth of 368 full time equivalent employees and contractors that Ergon Energy successfully achieved in 2006-07, during a period of strong economic activity and a tight labour market. The 2006-07 increase was needed in order to meet the sustained increase in demand for Distribution Services.

On this basis, and for the reasons that are further explained in Chapter 35 of this Regulatory Proposal, Ergon Energy considers that it can readily physically deliver the work program in the next regulatory control period associated with its forecast operating expenditure.

It follows, given the justifications of the forecast operating expenditure provided above, that Ergon Energy also believes that the physical delivery of its operating expenditure program will ensure that it achieves all four of the operating expenditure objectives detailed in clause 6.5.6(a) of the Rules in the next regulatory control period.

27.2 FORECAST OPERATING EXPENDITURE COMPLIANCE REQUIREMENTS

Ergon Energy confirms that its operating expenditure forecasts in Chapter 26 of this Regulatory Proposal:

- Comply with the requirements of the Regulatory Information Notice (RIN) issued by the Australian Energy Regulator (AER) to Ergon Energy on 22 April 2009, as is required by clause 6.5.6(b)(1) of the Rules. Ergon Energy has provided the Australian Energy Regulator (AER) with a completed version of the RIN pro formas at the same time as providing this Regulatory Proposal. In addition, the Skeleton provided with this Regulatory Proposal details where Ergon Energy's addresses the various regulatory requirements, including under the RIN;
- Are for expenditure that has been allocated to Standard Control Services in accordance with its CAM approved by the AER, as is required by clause 6.5.6(b)(2) of the Rules. Chapter 34 of this Regulatory Proposal describes how Shared Costs (Overheads) have been applied in developing Ergon Energy's operating and capital expenditure forecasts for its Standard Control Services;
- Include the total of the forecast operating expenditure for the next regulatory control period, 2010-15, as is required by clause 6.5.6(b)(3)(i) of the Rules; and
- Include the forecast operating expenditure for each year of the next regulatory control period, 2010-15, as is required by clause 6.5.6(b)(3)(ii) of the Rules.

27.3 OPERATING EXPENDITURE REFLECTS OPERATING EXPENDITURE CRITERIA HAVING REGARD FOR OPERATING EXPENDITURE FACTORS

Clause 6.5.6(c) of the Rules requires that:

> *The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects:*
>
> 1. *the efficient costs of achieving the operating expenditure objectives; and*
> 2. *the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives; and*
> 3. *a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.*
>
> *(the operating expenditure criteria).*

Clause 6.5.6(e) of the Rules requires that:

> *In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the following (the operating expenditure factors):*
>
> 1. *the information included in or accompanying the building block proposal;*
> 2. *submissions received in the course of consulting on the building block proposal;*
> 3. *analysis undertaken by or for the AER and published before the distribution determination is made in its final form;*
> 4. *benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period;*

5. *the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;*

6. *the relative prices of operating and capital inputs;*

7. *the substitution possibilities between operating and capital expenditure;*

8. *whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;*

9. *the extent the forecast of required operating expenditure of the Distribution Network Service Provider is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms;*

10. *the extent the Distribution Network Service Provider has considered, and made provision for, efficient non-network alternatives.*

27.3.1 Interpretation of Clauses 6.5.6(c) and 6.5.6(e)

27.3.1.1 Clause 6.5.6(c) of the Rules

Ergon Energy interprets clause 6.5.6(c) of the Rules as requiring the AER to accept Ergon Energy's operating expenditure forecasts for the next regulatory control period if they represent the efficient costs that a prudent operator would incur in Ergon Energy's circumstances, based on realistic demand forecasts and cost inputs, in order to achieve the operating expenditure objectives.

Ergon Energy's operating expenditure must therefore be efficient and must reflect the behaviour of a prudent operator. However, efficiency and prudency are not absolute concepts that can either be directly observed or objectively quantified. This is particularly the case when they are applied to expenditure forecasts, which are by their nature concerned with future, rather than historic, events.

In Ergon Energy's view, the AER's assessment of the efficiency of its operating expenditure forecasts needs to have regard for section 7A of the National Electricity Law (NEL), which provides that: "A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs". This means that clause 6.5.6(c)(1) of the Rules should not be interpreted as necessarily requiring a least cost outcome, such as what might in theory be achieved in a perfectly competitive market.

Rather, the AER's assessment should consider whether Ergon Energy is producing the 'right' outcomes (i.e. allocative efficiency) at the 'right' costs (i.e. productive efficiency) over time (i.e. dynamic efficiency). For the reasons set out in section 27.3.2, Ergon Energy considers that it will achieve the 'right' outcomes at the 'right' costs over time.

Unlike efficiency, prudency is not an economic concept. Rather, it concerns whether, in seeking to fulfil its obligations and requirements, Ergon Energy is:

- Acting in good faith;
- Exercising reasonable care; and
- Diligently applying knowledge, skill and foresight.

In Ergon Energy's view, the AER's assessment of Ergon Energy's operating expenditure for the purposes of clause 6.5.6(c)(2) of the Rules should be concerned with whether Ergon Energy is exhibiting these behavioural characteristics.

Both efficiency and prudency are dynamic concepts and therefore need to be considered over time, rather than at specific moments. Achieving efficient and prudent outcomes requires Ergon Energy constantly to exercise sound judgment and to make subjective assessments. As contemplated by clause 6.5.6(c)(2) of the Rules, this requires giving due consideration to the specific circumstances that impact on Ergon Energy's operating expenditure needs.

In addition to efficiency and prudency, clause 6.5.6(c)(3) of the Rules requires the AER to consider whether Ergon Energy's operating expenditure forecasts reflect a realistic demand forecast and realistic cost inputs.

Ergon Energy interprets clause 6.5.6(c)(3) of the Rules as requiring the AER to be satisfied that Ergon Energy's expenditure forecasts reflect realistic demand forecasts. As noted in section 27.1.1, Ergon Energy interprets the demand for:

- Network services to be concerned with the levels of maximum demand and energy consumption from the distribution network and the number of customer connections to the distribution network;
- Connection services to be concerned with the number of customer connections; and
- Metering services to be concerned with the number of new meter installations, scheduled and unscheduled meter readings and metering investigations that are required.

Ergon Energy also interprets clause 6.5.6(c)(3) of the Rules as requiring the AER to be satisfied that, where unit rates have been used to develop Ergon Energy's expenditure forecasts, they are reasonable and have been developed in a prudent and justifiable manner.

27.3.1.2 Clause 6.5.6(e) of the Rules

Clause 6.5.6(e) of the Rules details the factors that the AER must have regard for in deciding whether or not it is satisfied that Ergon Energy's operating expenditure forecasts for the next regulatory control period reasonably reflect the operating expenditure criteria under clause 6.5.6(c) of the Rules.

Clause 6.5.6(e)(1) of the Rules provides that one of the factors that the AER must have regard to is "the information included in or accompanying the building block proposal". Ergon Energy interprets this to mean that, in addition to the other matters detailed in clause 6.5.6(e)(2) to (10) of the Rules, the AER must consider everything that Ergon Energy includes in, or attaches to, this Building Block Proposal when assessing its operating expenditure forecasts.

Ergon Energy considers that clause 6.5.6(e)(6) of the Rules is framed problematically and considers that it is not clear what is meant by "the relative prices of operating and capital inputs". Ergon Energy has interpreted "prices" in this clause to mean the unit rates used in developing capital and operating expenditure forecasts. However, it is not possible for Ergon Energy to compare the unit rates that it has used to prepare its capital and operating expenditure forecasts. This is because the units are fundamentally different in nature and are specific to the capital or operating activities being undertaken. The different nature of, and approaches used to prepare, Ergon Energy's unit rates are discussed in Chapter 32 of this Regulatory Proposal. Ergon Energy considers that the unit rates that it has used to prepare its operating expenditure are efficient and have been developed in a prudent manner. This is a factor that the AER should consider in assessing Ergon Energy's operating expenditure forecasts against the operating expenditure criteria.

It is not clear to Ergon Energy what clause 6.5.6(e)(8) of the Rules is intended to address. This is because labour costs are only one element of Ergon Energy's capital and operating expenditure forecasts and Ergon Energy does not understand the relevance of demonstrating that these costs are consistent with the incentives under the Service Target Performance Incentive Scheme (STPIS). Ergon Energy has therefore not provided information to the AER to address this matter.

27.3.2 Meeting the Requirements of Clause 6.5.6(c) and clause 6.5.6(e)

Ergon Energy considers that its forecast operating expenditure is consistent with the efficient costs that a prudent operator would incur in Ergon Energy's circumstances to achieve the operating expenditure objectives, based on realistic demand forecasts and cost inputs.

Ergon Energy will demonstrate that its operating expenditure forecasts reflect the operating expenditure criteria by reference to:

- The circumstances in which Ergon Energy operates – this information is provided in accordance with clause 6.5.6(e)(1);
- The estimation processes that Ergon Energy uses to prepare its forecasts – this information is provided in accordance with clause 6.5.6(e)(1);
- The reasonableness of the assumptions used to prepare the operating expenditure forecasts – this information is provided in accordance with clause 6.5.6(e)(1);
- The efficiency of the unit rates used to prepare the operating expenditure forecasts – this information is provided in accordance with clause 6.5.6(e)(1);
- The efficiency of the escalators used to prepare the operating expenditure forecasts – this information is provided in accordance with clause 6.5.6(e)(1);
- A comparison of the forecast operating expenditure against actual and forecast operating expenditure in previous regulatory control periods – this information is provided in accordance with clause 6.5.6(e)(5);
- The substitution possibilities between capital and operating expenditure – this information is provided in accordance with clause 6.5.6(e)(7);
- The use of supply arrangements with related parties – this information is provided in accordance with clause 6.5.6(e)(9); and
- The consideration of non-network alternatives – this information is provided in accordance with clause 6.5.6(e)(10).

These justifications are discussed in turn in this section.

The following other operating expenditure factors are dealt with elsewhere in this Regulatory Proposal:

- Relative prices of operating and capital inputs – this is discussed in section 27.3.1;
- The substitution possibilities between capital and operating expenditure – this information is provided in accordance with clause 6.5.6(e)(7) and is dealt with in Chapter 29;
- Total labour costs being consistent with the incentives provided by the applicable STPIS in accordance with clause 6.5.6(e)(8) is discussed in section 24.3.1 and section 27.3.1;
- The use of supply arrangements with related parties – this information is provided in accordance with clause 6.5.6(e)(9) and is dealt with in Chapter 5; and
- The consideration of non-network alternatives – this information is provided in accordance with clause 6.5.6(e)(10) and is dealt with in Chapter 30.

27.3.2.1 Circumstances in which Ergon Energy operates

The circumstances in which Ergon Energy operates are a factor that the AER should consider under clause 6.5.6(e)(1) of the Rules in assessing whether Ergon Energy's operating expenditure forecasts meet the operating expenditure criteria under clause 6.5.6(c) of the Rules.

As discussed in section 4.19 of this Regulatory Proposal, the circumstances of Ergon Energy's operations are:

- A service area of 1,698,100 square kilometres, which covers 97 per cent of the Queensland land mass – an area approximately six times the size of the State of Victoria. Vast distances and low customer density result in significant geographic isolation in large parts of Ergon Energy's service area;
- Significant summer-winter and day-night temperature variations, which translate into large variability in seasonal and daily electricity demand;
- High rainfall, which can adversely affect asset condition, for example by causing pole top rot, and restrict access for operational purposes, for example in the Channel Country, which is prone to prolonged flooding coming from hundreds of kilometres away;
- Extreme winds, including cyclones, which can cause extensive damage to assets across vast areas. Cyclones are particularly prevalent along the northern coastal strip of Queensland;
- Lightning and summer storms, which require lightning arresters and additional earth protection to be installed. These events are particularly prevalent in the south west and south east of Ergon Energy's supply area;
- Vegetation whose types, density and growth rates adversely affect the operation of assets and limit access for operational purposes. This requires an extensive vegetation management program;
- Topography, which can affect the type of assets that need to be built as well as the approach to, and cost of, construction works;
- Soil conditions, including soil instability in areas such as the Darling Downs; and
- Wildlife, including termite infestations, which can adversely affect the condition and integrity of assets, such as wooden poles.

Ergon Energy's electricity distribution system is built to accommodate, as well as possible, these circumstances, and is characterised by:

- A large radial network, including approximately 65,000 kilometres of SWER lines, operating at three voltage levels (11, 12.7 and 19.1 kV) and servicing around 26,000 customers. Over 68 per cent of Ergon Energy's feeder powerlines are classified as non-urban;
- Connection to Powerlink's high voltage transmission network at 48 transmission network connection points and direct connection to, and supply from, a small number of embedded generators;
- Low load density and a high geographic spread of customers. Ergon Energy has the lowest customer density of any network in the western world for the 100,000 kilometres of line west of the Great Dividing Range;
- High numbers of new customer connections, due to strong population growth and high levels of investment in the industrial and mining sectors. This results in increased pressures to meet customer expectations regarding connection times and, for major customer loads, difficulties in predicting the timing and magnitude of the load to be serviced. Ergon Energy's forecast growth in customer numbers is discussed in Chapter 21 of this Regulatory Proposal;
- Shifts in end-usage patterns to include larger loads (e.g. air conditioning) and more sophisticated and complex electronic equipment. The standards and technologies upon which the network has been based may not be capable of meeting customer expectations as to the future reliability and quality of supply; and
- A sustained increase in maximum demand. Maximum demand for Ergon Energy's grid connected network is forecast to grow rapidly (at an average of 4.9 per cent) from the 2006-07 maximum demand level of 2,584 MW. Capital investment is required to ensure that network utilisation remains within appropriate bounds. Ergon Energy's forecast growth in maximum demand is discussed in Chapter 21 of this Regulatory Proposal.

These circumstances affect all aspects of the planning, management and operation of Ergon Energy's distribution system, including the nature and cycle times of the inspections that are undertaken of assets as part of the Preventive Maintenance program and the resultant Asset Replacement capital expenditure and Corrective and Forced Maintenance. The plans, policies, procedures and strategies referred to in Chapter 26 of this Regulatory Proposal provides further detail about how Ergon Energy's circumstances are reflected in its forecasts. It is noted that:

- Geographic isolation significantly impacts Ergon Energy's approach to asset maintenance, including the need to limit site visits through amalgamation of differing maintenance regimes; and
- Vegetation management is the largest component of the Corrective Maintenance program.

27.3.2.2 Ergon Energy's estimation processes

Ergon Energy's estimation processes are a factor that the AER should consider under clause 6.5.6(e)(1) of the Rules in assessing whether Ergon Energy's operating expenditure forecasts meet the operating expenditure criteria under clause 6.5.6(c) of the Rules.

Chapter 26 of this Regulatory Proposal details the estimation processes that Ergon Energy has used to prepare each sub-category of its operating expenditure forecasts. This chapter illustrates and describes how Ergon Energy has applied its plans, policies, procedures and strategies to prepare its operating expenditure forecasts. It also explains why and how Ergon Energy has developed:

- The Network Operations expenditure forecasts based on historic baseline expenditure, with adjustments made for abnormalities and scope changes;
- The Preventive Maintenance forecast on a bottom up basis by multiplying an estimated unit rate by an estimated number of units for each of the 26 asset equipment types;
- The Corrective Maintenance forecasts at the aggregate level using a top-down/baseline-and-scope-change approach. The aggregate annual amount has been allocated between Ergon Energy's 26 asset equipment types only for the purposes of preparing this Regulatory Proposal;
- The Forced Maintenance forecasts at the aggregate level using a top-down/baseline-and-scope-change approach. The aggregate annual amount has been allocated between Ergon Energy's 26 asset equipment types only for the purposes of preparing this Regulatory Proposal; and
- The Other Operating Expenditure forecasts:
    - → Using a top-down/baseline-and-scope-change approach for Meter Reading and Customer Care services;
    - → Based on actuarial advice for self insurance; and
    - → Based on the AER's Demand Management Incentive Scheme (DMIS) Guideline.

Ergon Energy believes that its expenditure estimation processes reflect the behaviour of a prudent operator in its circumstances and result in efficient costs. This is because:

- The forecasts are based on the plans, policies, procedures and strategies, which promote the achievement of the operating expenditure objectives; and
- Ergon Energy has used a combination of robust bottom-up or top-down approaches to translate the plans, policies, procedures and strategies into operating expenditure forecasts for the next regulatory control period.

27.3.2.3 Reasonableness of assumptions used to prepare operating expenditure forecasts

The assumptions that Ergon Energy has made are a factor that the AER should consider under clause 6.5.6(e)(1) of the Rules in assessing whether Ergon Energy's operating expenditure forecasts meet the operating expenditure criteria under clause 6.5.6(c) of the Rules.

Chapter 26 of this Regulatory Proposal details the assumptions that Ergon Energy has made in preparing each subcategory of its operating expenditure forecasts. Ergon Energy has used assumptions as substitutes for facts or inputs in order to prepare its operating expenditure forecasts, where facts or inputs are not known with certainty or cannot reasonably be derived from other data. Ergon Energy has therefore developed assumptions where it has not otherwise had an objectively verifiable factual basis on which to prepare its operating expenditure forecasts.

Different assumptions have been used in relation to each category of operating expenditure. The assumptions principally relate to:

- The nature of the activity that needs to be undertaken for particular categories of operating expenditure;
- The workloads associated with particular categories of operating expenditure;
- The regulatory obligations and other requirements that will apply, and the plans, policies, strategies and procedures that will be used, as the basis for preparing particular categories of operating expenditure; and
- The nature, and use, of different approaches to preparing particular categories of expenditure within the overall operating expenditure program.

The assumptions in Chapter 26 of this Regulatory Proposal build on, and complement, the Key Assumptions that are detailed in Chapter 15 of this Regulatory Proposal.

Ergon Energy believes that its assumptions are consistent with a prudent operator in its circumstances. This is because the assumptions are:

- Necessary for Ergon Energy to make its operating expenditure forecasts;
- Consistent with Ergon Energy acting in good faith and with reasonable care in preparing its operating expenditure forecasts; and
- Reasonable in the circumstances of Ergon Energy's operations.

27.3.2.4 The efficiency of unit rates

Ergon Energy's unit rates used to prepare its operating expenditure forecasts are a factor that the AER should consider under clause 6.5.6(e)(1) of the Rules in assessing whether Ergon Energy's operating expenditure forecasts meet the operating expenditure criteria under clause 6.5.6(c) of the Rules.

Chapter 32 of this Regulatory Proposal details the way in which Ergon Energy developed and applied its unit rates for the purposes forecasting its operating expenditure.

As discussed in detail in Chapter 32 of this Regulatory Proposal, Ergon Energy believes that the unit rates that it applied in developing its operating expenditure program are efficient because:

- Ergon Energy has well established technical standards for undertaking the design and construction of works, as well as to maintain its assets;
- Ergon Energy has robust and well tested procurement processes that are applied when labour and materials are purchased from the market. The outcomes are efficient because of this market competition;
- A significant proportion of the key cost components on which the unit rates (and capital and operating expenditure forecasts are based) are market tested;
- The key cost components are consistently applied in Ergon Energy's internal estimating tools to produce both the unit rates used for forecasting capital and operating expenditure and the cost estimates of projects; and
- There is a feedback loop between historic and market costs that is reflected into the unit rates that have been used to develop the capital and operating expenditure forecasts. This means that the unit rates reflect current market conditions.

27.3.2.5 The efficiency of real escalators

Ergon Energy's escalators used to prepare its operating expenditure forecasts are a factor that the AER should consider under clause 6.5.6(e)(1) of the Rules in assessing whether Ergon Energy's operating expenditure forecasts meet the operating expenditure criteria under clause 6.5.6(c) of the Rules.

Section 33.3.2 of this Regulatory Proposal details the way in which Ergon Energy developed and applied its escalators for the purposes of forecasting its operating expenditure. Section 41.5.2 details Ergon Energy's approach to inflation forecasting.

Common operating expenditure escalators have been applied to all of Ergon Energy's operating expenditure, albeit that annual escalators have been developed for materials, contractors, labour and other inputs. Individual escalators have not been developed for different operating expenditure programs.

Ergon Energy's escalators are considered efficient because:

- Ergon Energy's Union Collective Agreement 2008 has been used as the basis for escalating all labour costs related to both capital and operating expenditure. Ergon Energy believes that the actual Ergon Energy Union Collective Agreement 2008 rate is the most realistic expectation of actual labour cost growth in the next regulatory control period. Ergon Energy notes the AER has recently rejected the use of such rates beyond the current regulatory control period because it believes it would move distribution entities from an incentive based framework to a cost of service recovery framework[44]. Ergon Energy is unclear how this approach reconciles with the requirement in clause 6.5.6(c)(3) of the Rules to provide a realistic expectation of cost inputs required to achieve the operating expenditure objectives. Ergon Energy believes that the most realistic expectation of future labour cost growth is the labour cost growth prescribed in the Ergon Energy Union Collective Agreement 2008. Ergon Energy also understands cost of service regulation requires the recovery of costs actually incurred by the firm. Ergon Energy notes that the actual cost of its labour force will be heavily influenced by actual changes in employee numbers over time. Actual employee numbers could diverge from the forecasts provided in this Regulatory Proposal.
- Ergon Energy's Union Collective Agreement 2008 has been used as the basis for escalating all labour costs (including contractors) related to operating expenditure. Ergon Energy believes that the actual EBA rate is the most realistic expectation of actual labour cost growth in the next regulatory period for the reasons described above.
- Ergon Energy has, through the engagement of independent engineering consultant SKM, utilised recent, publicly available data and forecasts to derive a materials escalator. Ergon Energy believes that, since there is no futures market for goods included in this category of operating expenditure, the SKM approach would yield an efficient escalator to forecast expenditure on 'materials'.
- The application of zero real growth to 'other' direct inputs reflects the belief that the growth in nominal prices of a grouping of miscellaneous goods and services - ranging from training costs to freight charges - is best measured by the expected growth in consumer price index (which measures the growth in prices of a basket of goods and services). The CPI forecast applied is that used in Ergon Energy's budget.

27.3.2.6 Comparison of actual and expected operating expenditure

Clause 6.5.6(e)(5) of the Rules requires the AER to have regard for Ergon Energy's actual and expected operating expenditure during any preceding regulatory control period in assessing whether Ergon Energy's operating expenditure forecasts meet the operating expenditure criteria under clause 6.5.6(c) of the Rules.

Table 76 details the differences between the Queensland Competition Authority's (QCA) operating expenditure building blocks and Ergon Energy's actual (and forecast) operating expenditure in the current regulatory control period.

[44] AER, NSW final decision, page 493

***Table 76:** Comparison of QCA's Operating Expenditure Building Blocks and Actual/Forecast Operating Expenditure for 2005-10 ($M Nominal)*

		2005-06	2006-07	2007-08	2008-09 Estimate	2009-10 Estimate	5 Year Total
1.	QCA Operating Expenditure Building Block (CAMP)	266.70	279.60	286.50	262.70	271.90	1,367.40
2.	Less estimated Street Lighting and Excluded Distribution Services (CAMP)	8.36	9.00	13.75	15.84	18.15	65.10
3.	QCA Operating Expenditure Building Block - net of Street Lighting and Excluded Distribution Services (CAMP)	258.34	270.60	272.75	246.86	253.75	1,302.30
4.	Total Actual/Forecast Operating Expenditure - excluding Street Lighting and Excluded Distribution Services (CAM)	256.73	264.81	290.57	313.94	317.02	1,443.08
5.	Variance QCA Building Block (CAMP) to Total Actual/Forecast Operating Expenditure (CAM) - excluding Street Lighting and Excluded Distribution Services	1.62	5.78	-17.82	-67.08	-63.27	-140.78
6.	Change in Actual/Forecast Operating Expenditure by moving from CAM to CAMP (negative value equates to reduction in Operating Expenditure)	-21.44	-21.37	-13.74	-82.38	-80.17	-219.10
7.	**Variance QCA Building Block (CAMP) to Total Actual/Forecast Operating Expenditure (CAMP) - excluding Street Lighting and Excluded Distribution Services (negative value equates to overspend against QCA building block)**	**-19.83**	**-15.59**	**-31.56**	**-149.47**	**-143.44**	**-359.88**

Source: Tables for Proposal 27.3.2

There are several matters that are important to understand in analysing Table 76:

- The QCA's operating expenditure building blocks (detailed in Row 1) that were approved in its 2005 Final Determination were based on Ergon Energy's Cost Allocation Methods and Procedures (CAMP), which was approved by the QCA. These building blocks included allowances for street lighting and excluded distribution services given that they were both originally classified as prescribed distribution services in the Final Determination;
- The QCA's Final Determination did not make explicit what amount of the operating expenditure building blocks related to street lighting and excluded distribution services. In order to compare Ergon Energy's actual (and forecast) operating expenditure on Standard Control Services for 2005-06 to 2009-10 with the QCA's operating expenditure building blocks it is necessary to exclude from the building blocks an estimate of the amount that relates to street lighting and excluded distribution services. Ergon Energy has estimated the share of the operating expenditure building block attributable to:
  - → Street lighting by applying the proportion of actual (and forecast) annual street lighting expenditure of the actual (and forecast) total annual operating expenditure to the annual operating expenditure building blocks; and

- → Excluded distribution services based on the amounts that the QCA removed from the total operating expenditure building blocks (and thereby reduced Ergon Energy's aggregate annual revenue requirements) when it reclassified certain services as excluded distribution services.

Ergon Energy has therefore deducted these amounts (detailed in Row 2) from the QCA's operating expenditure building blocks (in Row 1) in order to determine revised building block amounts (detailed in Row 3) that relate only to Standard Control Services. These revised amounts are based on the application of Ergon Energy's CAMP.

- The AER's RIN requires Ergon Energy to backcast its total actual (and forecast) operating expenditure for 2005-06 to 2009-10 by applying its Cost Allocation Method (CAM), which has been approved by the AER (i.e. not the QCA-approved CAMP). These backcast total actual (and forecast) amounts, excluding expenditure on street lighting and excluded distribution services, relate only to Standard Control Services and are detailed in Row 4;
- Row 5 details an expected overspend of $140.78 million for 2005-06 to 2009-10 between the total actual (and forecast) operating expenditure (in Row 4) for Standard Control Services and the revised QCA operating expenditure building blocks (in Row 3). However, the values in Row 3 are based on the application of the QCA-approved CAMP, whereas the values in Row 4 (which have been prepared in accordance with the AER's RIN) are based on the application of the AER-approved CAM. Ergon Energy therefore considers that this is not the amount that requires explanation for the purposes of clause 6.5.6(e)(5) of the Rules;
- Row 6 details the amounts of additional overheads that would be included in Ergon Energy's total actual (and forecast) operating expenditure amounts if the QCA-approved CAMP, rather than the AER-approved CAM, was applied. It shows that an expected $219.10 million would be added to Ergon Energy's total actual (and forecast) operating expenditure for 2005-06 to 2009-10 by applying the CAMP; and
- Row 7 details an expected overspend of $359.88 million for 2005-06 to 2009-10 between the total actual (and forecast) operating expenditure for 2005-06 to 2009-10 for Standard Control Services and the revised QCA operating expenditure building blocks, if both sets of values are based on the QCA-approved CAMP. Ergon Energy considers that this is the amount that requires explanation for the purposes of clause 6.5.6(e)(5) of the Rules, because all values are based on the QCA-approved CAMP and relate only to expenditure on Standard Control Services.
- Ergon Energy can only compare actual (and forecast) expenditure against the QCA's operating expenditure building block allowances on the basis of the QCA's CAMP, not the CAM, because it cannot present the QCA's operating expenditure building block allowances on the basis of the CAM, only the CAMP.

The causes of the $359.88 million overspend detailed in Row 7 of Table 76 can be explained as follows:

- Labour, materials, contractors and other costs:
  - → Labour costs have increased across the current regulatory control period as a result of more labour being required to undertake more work, particularly in relation to corrective and Forced Maintenance;
  - → Contractor costs have increased across the current regulatory control period as a result of Ergon Energy significantly increasing the amount of work being undertaken by contractors, particularly in relation to Preventive Maintenance inspections; and
  - → Other costs increasing, particularly as a result of being required to treat all training costs as operating expenditure, rather than as a Shared Costs (Overheads) which is spread over the capital and operating expenditure programs.
- Direct and shared costs:
  - → Direct costs have increased across the current regulatory control period, as a result of more maintenance work being undertaken than was assumed in preparing the operating expenditure building blocks. This has particularly related to more Corrective Maintenance work being undertaken by Ergon Energy staff and more preventive and Corrective Maintenance work being undertaken by contractors; and
  - → Shared Costs (Overheads) being higher than were forecast in preparing the operating expenditure building blocks, especially as a result of Ergon Energy employee numbers increasing from 3,652 in June 2005 to 4,489 in June 2008 (on the basis of headcount). It should be noted that for the same period external fixed term resource numbers fell from 768 to 320 (on the basis of headcount).
- Quantities and unit rates:
  - → There has been more work undertaken during the current regulatory control period than was assumed in preparing the operating expenditure building blocks. This has particularly related to more pole and pole top inspection and maintenance activity and vegetation management; and

- Certain unit rates have been higher than were forecast in preparing the operating expenditure building blocks, such as labour and contractor costs which arise in applying the new Ergon Energy Union Collective Agreement 2008.

- Expenditure programs:
  - The Network Operations, and preventive and Corrective Maintenance, programs have increased significantly over the current regulatory control period;
  - The Network Operations program has increased during the current period following a move to 24-hour control rooms monitoring all of Ergon Energy. This occurred as part of Project LINK;
  - Only three of Ergon Energy's 26 asset equipment types individually account for more than 5 per cent of its total direct maintenance costs. These are:
    - Vegetation management that accounts for around 35 per cent of total direct maintenance costs – these costs have increased significantly above the forecasts that were used to prepare the operating expenditure building block in order to meet increased work requirements;
    - Poles that account for around 18 per cent of total direct maintenance costs – these costs have increased significantly above the forecasts that were used to prepare the operating expenditure building block because the original forecasts underestimated the number of poles. More pole inspections have resulted in more maintenance work being required; and
    - Access track maintenance that account for around 6 per cent of total direct maintenance costs – this was formalised as a specific program of work for the first time in the current regulatory control period.
  - There are 23 other asset equipment types that account for the remaining approximately 41 per cent of total direct maintenance costs, but which individually account for between less than one and around 4 per cent of total direct maintenance costs; and
  - 14 of the 26 asset equipment types relate to lines, which account for around 80 per cent of total direct maintenance expenditure.

- Abnormalities and one-off events:

  There have been several significant one-off events that have increased the actual (and forecast) operating expenditure during the current regulatory control period above the operating expenditure building blocks, including:
  - Severe Tropical Cyclone Larry, which resulted in increased operating expenditure of $15.8 million in 2005-06 and $0.1 million in 2006-07;
  - An increase in labour and contractor costs arising from a 0.5 percentage point annual increase under the new Ergon Energy Union Collective Agreement 2008 from 4.0 per cent to 4.5 per cent from 2008;
  - Changes in the treatment of Information Communication and Telecommunications (ICT) costs, which were previously included as capital expenditure and depreciated, whereas ICT costs are now treated as Shared Costs (Overheads) and spread across capital and operating expenditure. This means that some costs are expensed that were previously capitalised; and
  - A change in the charging methodology for fees from the Electrical Safety Office and the Queensland Competition Authority, which increased Ergon Energy's operating expenditure by about $1.5 million per annum.

Preparing for the introduction of Full Retail Competition (FRC) from 1 July 2007 and then providing the additional capability required to service retailers and customers in a new competitive environment. As discussed in section 7.4, Ergon Energy acquired some new, and modified some existing, systems and processes, and recruited and re-trained personnel, to meet its new regulatory obligations. Ergon Energy incurred operating expenditure costs of approximately $18.5 million in operating expenditure during 2005-06 and 2006-07.

27.3.2.7 Capital and operating expenditure substitution possibilities

Clause 6.5.6(e)(7) of the Rules requires the AER to have regard for the substitution possibilities between Ergon Energy's capital and operating expenditure in assessing whether Ergon Energy's operating expenditure forecasts meet the operating expenditure criteria under clause 6.5.6(c) of the Rules.

Chapter 29 of this Regulatory Proposal highlights the strong interactions between various categories of Ergon Energy's capital and operating expenditure forecasts. In particular, Ergon Energy's:

- Capital Expenditure – Asset Replacement forecast has strong interactions with:
  - The Preventive Maintenance program, as the asset inspection program identifies where there are defective assets that need to be replaced by undertaking capital works or alternatively the subject of Corrective Maintenance; and

- → The Corrective and Forced Maintenance expenditure program because the Capital Expenditure – Asset Replacement program will result in defective assets being replaced with new assets. This will reduce the need for future Corrective and Forced Maintenance as new assets are less likely to fail in service.
- Corporation Initiated Augmentation (CIA) capital expenditure has strong interactions with its operating expenditure programs because:
  - → If inadequate augmentation expenditure is undertaken then there is a greater likelihood of Ergon Energy's distribution system failing to comply with its Network Planning Criteria NP02 and Security Criteria NPD05, which may in turn increase the need for Forced Maintenance expenditure; and
  - → As the distribution system is augmented, the new assets that are installed all need to be operated and maintained in accordance with Ergon Energy's asset management policies and procedures.
- Reliability and Quality Improvements capital expenditure forecast will reduce the need for Corrective and Forced Maintenance, while each of the maintenance programs will themselves positively contribute to improved reliability performance of the distribution system thus potentially deferring the need for additional capital expenditure;
- Tools and equipment capital expenditure and its operating expenditure program because tools and equipment are necessary enablers of the broader system capital and operating expenditure programs that are required to support the safe and efficient delivery of Distribution Services;
- Fleet capital expenditure and its operating expenditure program because once an item of fleet has been purchased, it will incur a range of operating costs; and
- Property capital expenditure and its operating expenditure program because all property, whether existing or new, requires maintenance, albeit that assets will require different maintenance works depending on the point they are at in their maintenance cycle; and

There are therefore strong interactions, and substitution possibilities, between Ergon Energy's capital and operating expenditure programs. Ergon Energy considers that it has struck a reasonable balance between the two categories of expenditure on the basis of:

- Risk management framework discussed in Chapter 16 of this Regulatory Proposal;
- Plans, policies, procedures and strategies discussed in Chapter 17 of this Regulatory Proposal; and
- Approach to network planning and management, discussed in Chapter 20 of this Regulatory Proposal.

Where there is the potential to substitute between capital and operating expenditure, Ergon Energy has not sought an allowance for both types of expenditure from the AER.

27.3.2.8 Supply arrangements with related parties

Clause 6.5.6(e)(9) of the Rules requires the AER to have regard, in assessing the operating expenditure criteria under clause 6.5.6(c) of the Rules, for whether Ergon Energy's operating expenditure forecasts are referrable to a person not at arm's length from Ergon Energy.

Chapter 5 of this Regulatory Proposal details Ergon Energy's relationships with other entities. SPARQ is the only entity that is controlled by Ergon Energy that provides services to Ergon Energy that are relevant to its Standard Control Services.

SPARQ was formed as a joint venture company by Ergon Energy and ENERGEX to provide ICT services to both companies. Ergon Energy and ENERGEX each own a 50 per cent share in SPARQ. Ergon Energy and ENERGEX are SPARQ's only clients. SPARQ is not able under its Constitution to provide services to other clients.

SPARQ provides ICT services to Ergon Energy under a Service Level Agreement, which is re-negotiated annually. Ergon Energy treats SPARQ's charges under this Agreement as shared costs and allocates them between its services in accordance with its CAM.

Chapter 34 of this Regulatory Proposal provides further details about the nature of SPARQ's costs and the way in which they are allocated as Shared Costs (Overheads) in the build up of Ergon Energy's capital and operating expenditure programs. This chapter also details why Ergon Energy considers SPARQ's forecast costs for the next regulatory control period, which are set out in Table 92, to be efficient.

27.3.2.9 Consideration of, and provision for, Non-Network alternatives

Clause 6.5.6(e)(10) of the Rules requires the AER to have regard, in assessing the operating expenditure criteria under clause 6.5.6(c) of the Rules, for the extent Ergon Energy has considered, and made provision for, efficient non-network alternatives.

Chapter 30 of this Regulatory Proposal details and explains Ergon Energy's proposed non-network alternatives program for the next regulatory control period. All of the proposed $61.248 million non-network alternative expenditure forecast is operating expenditure. The chapter also details Ergon Energy's processes, procedures and policies for identifying efficient non-network alternatives.

Ergon Energy has forecast modest non-network alternative expenditure given that, these types of programs are in their infancy, and continue to be the subject of trials to demonstrate their viability to deliver Standard Control Services. Therefore, Ergon Energy has, for the most part, prepared its Standard Control Service forecasts based on it delivering network solutions. However, Ergon Energy will continuously examine the potential during the next regulatory control period to substitute network solutions with non-network alternatives where the business cases dictate that these alternatives are the most prudent and efficient means of providing Standard Control Services.

27. OPERATING EXPENDITURE – OBJECTIVES, CRITERIA AND FACTORS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR024c	EE Asset Management Plan for 2009-10 to 2014-15
AR064	EE Network Planning Criteria -NP02, V2.03, 30 May 2000
AR075	EE NA000900R102 Meter Asset Management Plan, V3, 1 February 2008
AR076	EE P55C06R01 Code of Practice Powerline Clearance (Vegetation) 2006, V2
AR077	EE EP26 Risk Management Policy, V2, 8 May 2007
AR078	EE Network Maintenance Defect Classification Manual
AR094	Ergon Energy Union Collective Agreement 2008
AR135	EE Summer Preparedness Plan 2008-09
AR172c	EE ED000401R100 Disaster Management Plan, 20 October 2008
AR175	EE Security Criteria - NPD05, 12 April 2005
AR226	EE Asset Equipment Plans 2009
AR236c	EE Network Operations Forecast Report (Works Planning)
AR268c	EE Strategic Workforce Plan 2008-18, May 2008
AR272c	EE Customer Care Forecast Report including Meter Reading
AR307c	EE Joint ICT Plan, Sep08 baseline, V1.2, 19 January 2009
AR308c	EE Joint ICT Finances Sep08 Baseline, V1.4, 2 February 2009
AR310c	KPMG IT Service Delivery Efficiency Assessment – ENERGEX, Ergon Energy and SPARQ Solutions
AR311c	KPMG IT Expenditure Forecast Prudency Assessment – ENERGEX, Ergon Energy and SPARQ Solutions, 12 March 2009
AR312	KPMG ENERGEX and Ergon IT Efficiency and Prudency Summary Report
AR314	EE Cost Allocation Method, AER Approved
AR318	EE EP51 Asset Management Defect Policy, 1 May 2008
AR332	EE Climate Change Response Plan 2008-10, Horizon One, July 2008
AR336	EE Network Performance Strategy 2010-15, 24 March 2009
AR355	EE Asset Maintenance Strategy, V8, April 2009
AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005
AR391	EE Cost Allocation Methods and Procedures approved by QCA, 2 May 2006
AR401	EE Network Management Plan, Summary, 2008-13
AR402	EE Network Management Plan, Part A 2008-09 to 2012-13
AR408	AER DMIS Qld & SA Scheme, 17 October 2008
AR417	AER Cost Allocation Guidelines Final Decision, 26 June 2008
AR444	EE 20 Year Strategic Plan for Single Wire Earth Return, V1.0.7, 30 November 2007
AR445	EE Network Management Plan, Part B 2008-09 to 2012-13
AR446	EE Preventive Maintenance Programs for 2010-11 to 2014-15, V7, May 2009
AR448c	EE Vegetation Strategy, 31 March 2009
AR449	EE Weed Management Strategy 2010-15, 2 April 2009
AR458	EE P89Y09R02 Security Standards & Guidelines, V2, 3 September 2006
AR459	EE EP28 Workplace Security and Access Policy, 26 April 2002
AR467c	EE Regulatory Proposal Skeleton, June 2009
AR509	SKM Cover Letter, Opex Materials Cost Ecalators, 9 April 2009

C CONFIDENTIAL INFORMATION

28. SELF INSURANCE AND DEBT AND EQUITY RAISING COSTS

RIN – Section 2.3.11

28.1 SELF INSURANCE

Self insurance is not specifically addressed in the Rules. However, the Australian Energy Regulator (AER) has previously accepted self insurance claims from both Transmission Network Service Provisers (TNSPs)[45] and Distribution Network Service Providers (DNSPs)[46] and has set out requirements for self insurance in its Regulatory Information Notice (RIN) for Ergon Energy:

- Section 2.3.11 of the RIN identifies self insurance as an alternative means of insuring against the losses from certain exogenous events. The onus is on the DNSP to determine the most efficient means of addressing those events; and
- Section 2.3.11 of the RIN sets out the requirements for the self insurance application in Ergon Energy's Regulatory Proposal. This includes a requirement for Ergon Energy's operating expenditure forecasts to specify the values that Ergon Energy proposes to attribute to self insurance for each year of the next regulatory control period. In addition, Ergon Energy is required to provide:
  - Details of all amounts, values and other inputs used by Ergon Energy to calculate its proposed self insurance costs;
  - An explanation of Ergon Energy's calculation of these amounts, values and inputs;
  - A Board resolution to self insure (i.e. a copy of the signed minutes recording the resolution made by the Board) – this document is included with this Regulatory Proposal;
  - Confirmation that Ergon Energy is in a position to undertake credible self insurance;
  - Details of the specific risks that Ergon Energy has resolved to self insure; and
  - A report from an appropriately qualified actuary verifying the calculation of risks and corresponding insurance premiums – this document is included with this Regulatory Proposal.

This self insurance application relates to Ergon Energy's Standard Control Services only.

28.1.1 Ergon Energy's Current Approach to Managing Risk

There are a number of risks borne by Ergon Energy in providing its Standard Control Services, which are not compensated through the weighted average cost of capital (WACC). These risks relate to adverse exogenous events such as cyclones, major storms, bushfires and third party damage to Ergon Energy's assets. Such risks are typically beyond Ergon Energy's ability to control and forecasting their probability of occurring, their severity and associated costs is difficult. Because of the uncertainties associated with these events, it is difficult for Ergon Energy to prepare an accurate forecast for inclusion in the 'baseline' operating expenditure building block to be provided as part of its Regulatory Proposal.

During the current regulatory control period, Ergon Energy employed a number of strategies in dealing with adverse exogenous events. Specifically it:

- Incorporated storm-related emergency expenditure in its baseline operating expenditure;
- Utilised external insurance against a range of events (with the insurance premium incorporated in the revenue allowance approved by the Queensland Competition Authority (QCA));
- Accessed the QCA's general pass through mechanism for 'catastrophic' events; and
- Self insured losses that were not covered under the above categories (although, as discussed below, no formal self insurance allowance was provided for by the QCA for the current regulatory control period).

Ergon Energy sought to have a self insurance allowance of $17 million included in its operating expenditure building block for the current regulatory control period in order to account for asymmetric risks not recompensed through the approved WACC[47].

In its 2005 Final Determination, the QCA accepted the concept of self insurance but did not consider that Ergon Energy (or ENERGEX) had provided the QCA with the supporting evidence that it considered was necessary to approve the claim[48]. The QCA required an actuarial assessment of the expected incidence and costs of

[45] See for example, the Australian Energy Regulator, *SP AusNet transmission determination 2008-09 to 2013-14 - Final decision, January 2008*
[46] See for example, the Australian Energy Regulator, *New South Wales Final Dstribution Determination 2009–10 to 2013–14, April 2009.*
[47] Queensland Competition Authority, *Regulation of Electricity Distribution - Final Determination, April 2005.*
[48] Ibid.

relevant risks and a comparison between the proposed premium and any actuarial assessment that has been undertaken. In the absence of this information, the QCA rejected Ergon Energy's claim for self insurance.

While Ergon Energy has been able to utilise the QCA's pass through mechanism to address catastrophic events such as severe cyclones or earthquakes that occur during the period, revenue from network charges does not reimburse any costs below the materiality threshold imposed on pass through events or events that are not eligible for pass through. During the current regulatory control period, Ergon Energy has therefore funded costs associated with these self insurance events without being able to recover them from its customers.

28.1.2 Treatment of Self Insurance in the 2010-15 Regulatory Control Period

Ergon Energy has engaged Synergies Economic Consulting (Synergies) in partnership with Finity Consulting (Finity), a firm of actuarial and insurance consultants, to assess the potential for self insurance to be included in their respective Regulatory Proposals for the next regulatory control period. As part of this engagement, Finity prepared an actuarial report which analysed the key losses that fall outside of Ergon Energy's external insurance program, either because Ergon Energy has elected or been forced to self insure the risk, or because the losses fall under the relevant external insurance policy deductible. The Finity report is provided with this Regulatory Proposal.

Finity's actuarial report quantified Ergon Energy's self insured losses to be incorporated in a potential self insurance program for the 2010-15 regulatory control period. In developing the self insurance forecasts, Finity ensured that the costs only relate to losses that:

- Are not covered by any of Ergon Energy's market insurance policies;
- Are not included in Ergon Energy's baseline operating expenditure forecasts for the next regulatory control period; and
- Do not include losses relating to structural failure from poor construction or maintenance as it is considered that these losses do not meet the AER's criteria for self insurance funding, whereby cost estimates are required to be on an 'efficient' basis.

Ergon Energy considers that a self insurance allowance is only applicable to its Standard Control Services. While Alternative Control Services are subject to similar risks as Standard Control Services, the level of exposure is lower due to the limited assets associated with these services. In addition, given the nature of Alternative Control Services, customer specific risks can be more readily accommodated on an individual customer basis rather than through a self insurance allowance.

28.1.3 Proposed Self Insurance Risks and Associated Costs for the 2010-15 Regulatory Control Period

Based on the Finity actuarial report, Ergon Energy's Board has resolved to self insure against the following specific risks:

- Catastrophic storm loss. This covers catastrophic storms with potential damage to Ergon Energy's assets exceeding $2.2 million of direct costs (i.e. excluding overheads) but below the expected pass through threshold of $10 million of direct costs (i.e. excluding overheads). Ergon Energy made a policy decision to include attritional storm losses (i.e. those losses below $2.2 million of direct costs) in the maintenance component of its forecast operating expenditure. This approach is the same as that used for the 2005-10 regulatory control period. Hence, losses below $2.2 million of direct costs are not included in the self insurance claim.

This item therefore relates to an otherwise uninsured risk.

- Losses associated with public liability claims. [redacted] Ergon Energy therefore self insures:
  - → Small (attritional) public liability claims. [redacted]
  - → Large public liability claims. [redacted] and
  - → Public liability claims associated with bushfires started by Ergon Energy's distribution network. [redacted]

Each of these items therefore relate to below deductible amounts on risks that are insured and where Ergon Energy holds material levels of risk in respect of the self insurance retention. These risks primarily relate to property and public liability risks.

Table 77 provides details of the proposed self insurance risks against the requirements of section 2.3.11 of the AER's RIN.

Table 77: *Details of proposed self insurance risks for 2010-2015 ($M)*

Event name	Property damage	Public liability		
	Storm catastrophe	Attritional	Large	Bushfire
Description of the specific risks that Ergon Energy has resolved to self insure.	Risk of major loss as a result of damage to Ergon Energy's distribution assets due to a catastrophic storm. Catastrophic storms are defined as storms with a wind speed exceeding 120 km/h with potential damage to Ergon Energy's assets	Public liability claims below the market insurance deductible.	Public liability claims in excess of the market insurance deductible.	Public liability claims associated with bushfires started by Ergon Energy's distribution network.
The value of the annual self insurance premium for the event.	$1.0 million per annum.*	$2.1 – 2.3 million per annum.*	$0.7 – 0.8 million per annum.*	$0.1 million per annum.*
Date of Board decision to self insure (signed minutes of the Board resolution is provided with this Regulatory Proposal).	27 March 2009.			
Confirmation that Ergon Energy is in a position to undertake credible self insurance.	Ergon Energy confirms it is able to undertake credible self insurance.			
A report from an appropriately qualified actuary.	Finity has provided a report entitled 'Review of Self Insurance Program' (March 2009). Finity's report is provided with this Regulatory Proposal.			
Details of all amounts, values and other inputs used by Ergon Energy to calculate its proposed self insurance costs.	This is detailed in Finity's 'Review of Self Insurance Program' (March 2009). Finity's report is provided with this Regulatory Proposal. This report provides full details of all amounts, values and other inputs used by Ergon Energy to calculate its proposed self insurance costs. In particular, refer to: • Catastrophic storm loss are addressed in section 5 of Finity's report; and • Losses associated with public liability claims are addressed in section 6 of Finity's report.			
An explanation of Ergon Energy's calculation of the self insurance amounts, values and inputs.	This is explained in Finity's 'Review of Self Insurance Program' (March 2009). Finity's report is provided with this Regulatory Proposal. This report provides a detailed explanation of the calculation of all of Ergon Energy's self insurance, amounts, values and inputs.			

* Annual average – incorporates projected growth in Ergon Energy's assets, as well as price inflation of 3 per cent and customer connections growth.

The profile of Ergon Energy's annual self insurance costs associated with the identified risks for the next regulatory control period, as determined by Finity, is provided in Table 78.

Table 78: *Self Insured Losses to be Incorporated in Self Insurance Program for 2010-2015 [49] ($M Real $2009-10)*

Year	Property damage	Public liability			TOTAL
	Storm catastrophe	Attritional	Large	Bushfires	
2010-11	1.0	2.1	0.7	0.1	3.9
2011-12	1.0	2.1	0.7	0.1	3.9
2012-13	1.0	2.2	0.7	0.1	4.0
2013-14	1.0	2.2	0.8	0.1	4.1
2014-15	1.0	2.3	0.8	0.1	4.2
Total	**4.9**	**10.8**	**3.7**	**0.6**	**20.1**

Source: Finity Consulting Pty Ltd – Review of Self Insurance Program (March 2009)

28.2 DEBT AND EQUITY RAISING COSTS

Debt and equity raising costs are not specifically addressed in the Rules. However, the AER has previously accepted debt and equity raising cost claims from DNSPs[50].

Ergon Energy has engaged Synergies Economic Consulting (Synergies) to advise it on the appropriate forecast for the transaction costs expected to be incurred by the benchmark firm when raising debt and equity capital. Synergies' confidential expert report is provided with this Regulatory Proposal.

Ergon Energy's debt and equity raising cost proposals relate to Ergon Energy's Standard Control Services only.

28.2.1 Debt Raising Costs

The debt raising cost forecasts proposed by Ergon Energy represent the transaction cost of re-financing fixed rate bonds to maintain gearing of 60 per cent of the value of Ergon Energy's Regulatory Asset Base (RAB). Debt raising costs include both the direct fee charged by an underwriter and the indirect costs associated with issuing capital at a discount in the market to sell it.

Table 79 details the most recent regulatory precedent on the transaction costs associated with debt financing.

Table 79: *Debt Raising Transaction Costs – 2009-10 NSW Distribution Determination*

	Debt Raising Costs (Basis Points Per Annum)		
	Direct	Indirect	Total
NSW Revised Regulatory Proposal	12.5	3.0	15.5
AER NSW Final Decision	8.1*	0	8.1

*Dependent upon bond issues required. 8.1 bppa was adopted for Country Energy and is based on 11 issues of $200 million each.

[49] The growth in estimates over the regulatory control period reflects the projected growth in Ergon Energy's assets, as well as price inflation of 3% and customer connections growth.

[50] See for example, the Australian Energy Regulator, *New South Wales final distribution determination 2009–10 to 2013–14, April 2009.*

An analysis of firms undertaken by Synergies on behalf of Ergon Energy shows that there are a variety of debt financing options and considers that a conservative direct debt raising cost estimate of 12.5 basis points is appropriate as it is consistent with information available to the market. The Synergies report concludes that three basis points per annum is considered a reasonable estimate for indirect debt raising costs.

Therefore Ergon Energy proposes the application of a margin of 15.5 basis points to the notional value of debt in the RAB to forecast debt raising costs. The application of this margin in the Post Tax Revenue Model (PTRM) results in the debt raising cost forecast detailed in Table 80.

***Table 80:** Debt Raising Cost Forecast for Standard Control Services for 2010-15 ($M Real $2009-10)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Debt Raising Cost Forecast	11.85	16.34	22.02	22.76	21.11	94.08	18.82

Source: Tables for Proposal 28.2.1

28.2.1.1 Cost of a hedging strategy

It would be considered prudent for a benchmark efficient network service provider to manage interest rate risk. This would include a requirement to hedge a portion of its interest rate risk on forward borrowings. Based on the magnitude of Ergon Energy's forecast debt funding requirements, the cost of implementing a hedging strategy would be material. The factors driving the cost of a hedging strategy are the slope of the yield curve, the settlement profile of forward rate agreements and the liquidity in debt capital markets (which can affect transaction costs). Given the potential for large market movements between 1 July 2009 and when the hedging program is likely to be implemented, a forecast of these costs is not proposed in this Regulatory Proposal. Ergon Energy will continue to review the costs of a prudent hedging program and may later seek to propose these costs in its expenditure forecasts.

28.2.2 Equity Raising Costs

Equity raising costs represent the transaction costs associated with raising equity capital. These costs include direct accounting, legal and broker fees, as well as indirect costs in the form of underpricing. Ergon Energy has engaged Synergies to provide a forecast of these transaction costs in the form of a unit cost as a percentage that should be applied to the equity requirement over the next regulatory period. Synergies has also analysed preferred mechanisms for secondary raisings in Australia.

Table 81 details the most recent regulatory precedent on the unit transactions costs associated with debt and equity financing.

***Table 81:** Equity Raising Transaction Costs – 2009-10 NSW Distribution Determination*

	Equity Raising Cost (% of equity to be raised)		
	Retained Earnings	DRP	SEO (Direct & Indirect)
NSW Revised Regulatory Proposal	3.8	N/A[51]	7.6
AER NSW Final Decision	0.0	1.0	2.75

[51] The NSW distributors argued that a placement is the preferred method of secondary raising. Therefore a unit cost (direct and/or indirect) was not proposed for a DRP.

28.2.2.1 Real Unit Cost of Retained Earnings

Ergon Energy believes that there is a transactions cost associated with the use of retained earnings for capital financing. Reinvesting earnings at the expense of dividend payouts:

- Imposes an investment decision on existing shareholders;
- Exposes returns to interest rate risk, as the firm is essentially deciding that it will forgo immediate returns for relatively larger returns in the future;
- Reduces the firm's ability to distribute imputation credits; and
- Results in potential signalling problems from the perspective of investors if the firm changes its dividend payout.

Whilst Ergon Energy believes that there are strong grounds for inclusion of an estimate of this cost, Ergon Energy notes that establishing a reasonable estimate of this cost is difficult. Ergon Energy therefore does not, at this time, propose a transactions cost for the use of retained earnings to fund future capital expenditure.

28.2.2.2 Mechanism for a Secondary Raising

Synergies' report details the preferred methods to raise external equity for firms listed on the Australian Securities Exchange (ASX). This research concludes that placements are the preferred option for secondary raisings by such firms, although it agrees that the rights issues and Dividend Reinvestment Plans (DRPs) are also commonly used methods of raising equity capital in Australia. Synergies' analysis therefore examines the costs of all these methods.

It is noted that the AER has undertaken its own research into the preferences of a number of firms it believes are 'comparable' to the benchmark firm. The research was undertaken to inform the AER's 2009 Final Decisions for NSW distributors.

Synergies estimated the proportion of equity funding raised from placements, rights issues and DRPs based on ASX data. It comes up with different estimates to the AER (although a similar estimate for DRPs), noting that the data relied upon by the AER's consultant has not been published (although the sources have been referenced). The ASX data is considered a more transparent and reliable source and hence Ergon Energy proposes to use Synergies' estimates.

28.2.2.3 Real unit cost of a Seasoned Equity Offering (SEO)

Ergon Energy proposes a unit transaction cost for a SEO of 7.8 per cent. This comprises a direct cost of 4.5 per cent and an indirect cost of 3.3 per cent. Details of this proposal are provided in the Synergies report.

28.2.2.4 Real Unit Cost of a DRP

Ergon Energy proposes a unit transaction cost for a DRP of 2 per cent. Details of this proposal are provided in the Synergies report.

Ergon Energy reiterates that the AER's research into the behaviour of 'comparable' firms seeking to raise equity from external sources should be reviewed independently. It is noted that the underlying data supporting the AER's preferred estimate (of 1 per cent) is not transparent. The AER should therefore make its underlying data sources available if it seeks to rely on this data to support its position that DRPs are preferred mechanism for secondary raisings by comparable firms.

28.2.2.5 Equity Raised Through a DRP

Ergon Energy proposes that, consistent with the AER's Final Decisions for NSW distributors, 30 per cent of dividends distributed should be assumed to return to the business through a DRP.

Ergon Energy reiterates that the AER's research into the behaviour of 'comparable' firms seeking to raise equity from external sources should be reviewed independently. The AER should also address the data issues identified by Synergies if it seeks to rely on this data to support its position that DRPs are a preferred mechanism for secondary raisings by comparable firms.

28.2.2.6 Total Equity Raising Cost

Ergon Energy has applied the cash flow model provided by the AER on 22 May 2009 to calculate its equity raising cost proposal for the 2010-15 regulatory control period.

In applying the cash flow model Ergon Energy has adjusted the revenue input to remove the contributed assets and capital contributions forecast which represent the Net Present Value (NPV) of contributed assets and capital contributions in the forecast of Customer Initiated Capital Works (CICW).

Transitional Rule 11.16.3 of the National Electricity Rules permits Ergon Energy to recognise the full value of the gifted and contributed assets in its RAB by making an adjustment to its revenue to ensure that Ergon Energy does not receive revenue twice for the same assets. This is consistent with the method approved by the QCA in the current regulatory control period.

Ergon Energy's Capital Contribution Methodology explains that the calculation of the contributions is based on the incremental costs, less an amount for the incremental revenue requirement over 20 years and includes recognition of incremental revenue for a portion of shared network costs. The incremental revenue is in turn based on the network price book rates for the assets which reflect the building blocks of the revenue i.e. return on assets, return of assets, depreciation and operating costs.

28.2.2.7 Treatment in the PTRM

Ergon Energy notes that the AER has stated its preference for treating equity raising costs as capital expenditure to be depreciated over the life of new assets[52]. In the context of the NSW regulatory review, the AER argued that this approach was superior to treating it as operating expenditure because it:

- Would improve transparency, given that the nature of the allowance is associated with Capital Expenditure;
- Ensures that future regulatory resets for the DNSPs would be administratively simpler in the provision for such an allowance; and
- Is consistent with regulatory precedent, as the AER treated the allowance as capital expenditure for Powerlink, based on a recommendation made by Allen's Consulting Group (ACG).

The NSW DNSPs accepted this approach in their January 2009 Revised Regulatory Proposals. Ergon Energy notes that ActewAGL Distribution's Revised Regulatory Proposal submitted that its equity raising cost forecast be treated as operating expenditure.

Ergon Energy notes the following in response to the AER's approach in the NSW-ACT Regulatory Reset:

- Treating equity raising costs as capital expenditure is equally as transparent as treating the allowance as operating expenditure as both approaches result in the forecast being recognised in the Regulatory Information Notice (RIN) and the PTRM in the forecast expenditure items;
- Debt raising costs, which are also associated with capital expenditure, are treated by the AER's PTRM as operating expenditure;
- The current regulatory reset would be more administratively simple if the equity raising cost allowance was treated as operating expenditure. If it were to be treated as capital expenditure, it would create an obligation under the Rules for Ergon Energy to provide economic and tax depreciation schedules for this asset class. This would involve the construction and justification of proposed economic and tax lives for this unique financial asset. These schedules and lives would also need to be remodelled each time a substitution or adjustment is made by either the AER or Ergon Energy to Ergon Energy's opening RAB or capital expenditure proposal. This process is less administratively simple than treating the forecast as operating expenditure, where depreciation schedules, justifications and subsequent recasting would not be required;
- Future regulatory resets would be more administratively simple if the equity raising cost allowance was treated as operating expenditure. Under this treatment, an expenditure allowance may be proposed by the business, in much same way as debt raising costs are proposed. If the allowance were to be treated as capital expenditure, any proposed allowance at subsequent regulatory resets would require an additional asset category to be added to the PTRM, to ensure that the requirements of clause 6.5.5(b) of the Rules are met; and
- In its decision for Powerlink, the Australian Competition and Consumer Commission (ACCC) treated equity raising costs as capital expenditure, consistent with a recommendation in a 2004 report by ACG:

  > If the regulator has determined that an allowance for the SEO cost of raising equity for ongoing capital expenditure should be provided for, we recommend that this amount be added to the RAB (i.e. included as part of the capital expenditure cost) and depreciated over the life of the assets. This follows the approach recommended for the treatment of the transaction cost for the initial equity[53].

ACG does not appear to provide further substantiation for its recommendation to incorporate the transaction costs associated with equity raising costs in the RAB. In fact, in a subsequent memorandum produced for ElectraNet in May 2007, ACG noted that treating the allowance as operating expenditure was also a viable option available to the AER:

> *The next issue to be considered by the AER is how to compensate ElectraNet for this notional benchmark expenditure requirement. There are two equivalent approaches that could be adopted:*
>
> 1. *In our [2004] report to the ACCC, our recommendation was as follows: If the regulator has determined that an allowance for the SEO cost of raising equity for ongoing capital expenditure should be provided for, we recommend that this amount be added to the RAV (i.e. included as part of the capital expenditure cost) and depreciated over the life of the relevant assets.*
> 2. *An alternative approach would be to convert the transaction cost of $6.5 million into an annuity-equivalent stream and to include it in operating expenses[54].*

Consistent with ACG's option 2, Ergon Energy proposes that its annual equity raising cost forecast be treated as operating expenditure. Ergon Energy believes this proposal is more administratively simple than treating the forecast as capital expenditure and is therefore the lowest cost solution.

[52] See for example, the Australian Energy Regulator, *New South Wales final distribution determination 2009–10 to 2013–14, April 2009.*

[53] ACG, Debt and equity raising transaction costs: final report to the ACCC, December 2004, p. xiii.

[54] ACG, Memorandum: Estimation of ElectraNet's equity raising transaction cost allowance, 29 May 2007, p8.

28. SELF INSURANCE & DEBT & EQUITY RAISING COSTS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c AER Regulatory Information Notice

Codes and Rules

AR364 National Electricity Rules

Ergon Energy Documents

AR047	EE Capital Contribution Methodology (QCA Approved), 20 April 2005
AR313c	Finity EE Self Insurance Arrangements for 2010-15, V2, March 2009
AR317c	Synergies EE Self Insurance Arrangements for 2010-15, 19 March 2009
AR347c	EE Self Insurance 27 March 2009 Board Resolution, signed 30 March 2009
AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005
AR534c	Synergies, Debt and Equity Raising Costs, 28 May 2009

C CONFIDENTIAL INFORMATION

29. CAPITAL EXPENDITURE – OPERATING EXPENDITURE INTERACTIONS

Rules – Clauses 6.5.6(e)(7), 6.5.7(e)(7) and S6.1.3(1)

Clauses 6.5.6(e)(7) and 6.5.7(e)(7) of the Rules require the Australian Energy Regulator (AER) to have regard for the substitution possibilities between operating and capital expenditure when assessing whether Ergon Energy's expenditure proposals satisfy the operating and capital expenditure criteria in clauses 6.5.6(c) and 6.5.7(c) respectively of the Rules.

Clause S6.1.3(1) of the Rules requires Ergon Energy's building block proposal to identify and explain any significant interactions between its operating and capital expenditure forecasts.

There are strong interactions between various categories of Ergon Energy's capital and operating expenditure forecasts.

Ergon Energy's Capital Expenditure – Asset Replacement forecast has strong interactions with:

- The Preventive Maintenance program, as the asset inspection program identifies where there are defective assets that need to be replaced by undertaking capital (and Corrective Maintenance) works. The capital works program is therefore informed by the operating expenditure inspection program.

  If operating expenditure is increased and more inspections are undertaken, it is likely that more defects will be identified, which may require greater capital expenditure in order to rectify them. The converse is also true if operating expenditure is reduced and fewer inspections are undertaken; and

- The Corrective and Forced Maintenance expenditure program. The Capital Expenditure – Asset Replacement program will result in defective assets being replaced with new assets. This will reduce the need for future Corrective and Forced Maintenance as new assets are less likely to fail in service.

  Increasing capital expenditure will reduce the need for Corrective and Forced Maintenance because more defective assets will be identified, and replaced, before they fail. It will also decrease the likelihood of dangerous electrical events and hazards to staff and the public and increase Ergon Energy's service performance. The converse is also true if Capital Expenditure – Asset Replacement was to be reduced and more defective assets failed before being replaced.

There are also strong interactions between Ergon Energy's Corporation Initiated Augmentation (CIA) capital expenditure and operating expenditure programs:

- If inadequate augmentation work is undertaken then there is a greater likelihood of Ergon Energy's distribution system failing to comply with its Network Planning Criteria NP02 and Security Criteria NPD05. The failure of assets may result in outages to significant numbers of customers until repairs can be made. These interruptions may last several weeks and require rotational load shedding. Additional Forced Maintenance expenditure would be required to manage these contingencies and limit customer inconvenience; and
- As the distribution system is augmented, the new assets that are installed would all need to be operated and maintained in accordance with Ergon Energy's asset management policies and procedures. There is therefore a direct relationship between growth in CIA capital expenditure and the need for greater operating expenditure. This is equally true of new assets that are installed on the distribution system through Customer Initiated Capital Works (CICW).

The key interactions between Ergon Energy's Capital Expenditure – Reliability and Quality Improvements forecast and its operating programs are that:

- Expanded remote control and restoration capability will reduce the need for Corrective and Forced Maintenance and the amount of down time that customers experience; and

- Each of the Preventive, Corrective and Forced Maintenance programs will themselves positively contribute to improved reliability performance of the distribution system.

The capital and operating expenditure projects and programs are therefore designed to complement each other to ensure Ergon Energy meets its minimum service standard requirements under the Queensland Electricity Industry Code.

There are also some specific interactions between Ergon Energy's Capital Expenditure – Other System forecast and its operating expenditure programs. In particular, capital expenditure on:

- Undergrounding assets will reduce operating expenditure, although it does not necessarily result in a lower life cycle cost, as the operating expenditure associated with underground assets is still significant;
- Communication infrastructure will reduce operational communication costs and improve operational response times, thereby reducing Forced Maintenance costs;
- Autoreclosers will reduce outages and thereby reduce Forced Maintenance costs;
- Improved substation security will reduce theft and vandalism;
- Substation bunding will reduce environmental cleanup costs; and
- Low voltage spreaders will reduce conductor clashing, supply interruptions and Forced Maintenance expenditure.

There is also a close relationship between Ergon Energy's capital expenditure on:

- Tools and equipment and its operating expenditure program. This is because tools and equipment are necessary enablers of the broader system capital and operating expenditure programs that are required to support the safe and efficient delivery of standard, alternative and unclassified works;
- Fleet and its operating expenditure program. This is because once an item of fleet has been purchased, it will incur some or all of the following operating costs: depreciation, management support, fuel, scheduled and unscheduled maintenance, tyres, accident costs and registration; and
- Property and its operating expenditure program. This is because all property, whether existing or new, requires maintenance, albeit those assets will require different maintenance works depending on the point they are at in their maintenance cycle.

There is a strong relationship between Ergon Energy's operating expenditure on Network Operations and its capital expenditure program. This is because network operations activity will generally increase as capital expenditure increases in order to accommodate greater outage co-ordination, switching and access, fault management and network contingency planning.

In addition to these interactions between capital and operating expenditure projects and programs, there is a strong relationship between certain operating expenditure programs. In particular:

- The Preventive Maintenance program identifies where there are defective assets that need to be maintained through specific Corrective Maintenance (as well as Capital Expenditure – Asset Replacement) activity;
- If the Preventive Maintenance program does not identify assets that need to be replaced or otherwise maintained, then there may be a need for greater Forced Maintenance as and when assets fail; and
- Self insurance is intended to manage the cost of residual risks of providing Distribution Services that are not otherwise compensated through the Weighted Average Cost of Capital (WACC), Corrective and Forced Maintenance expenditure, cost pass throughs or market-based insurance.

29. CAPITAL EXPENDITURE-OPERATING EXPENDITURE INTERACTIONS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

Nil

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR364	National Electricity Rules

Ergon Energy Documents

AR064	EE Network Planning Criteria – NP02, V2.03, 30 May 2000
AR175	EE Security Criteria Network Planning NPD05, 12 April 2005

30. NON-NETWORK ALTERNATIVES

Rules – Clauses 6.5.6(e)(10) and 6.5.7(e)(10)
RIN – Section 2.3.9

30.1 CONSIDERATION OF, AND PROVISION FOR, EFFICIENT NON-NETWORK ALTERNATIVES IN DEVELOPING CAPITAL EXPENDITURE AND OPERATING EXPENDITURE FOR 2010-15

Clause 6.5.6(e)(10) of the Rules requires that, in assessing Ergon Energy's operating expenditure forecasts for the next regulatory control period, the Australian Energy Regulator (AER) is to have regard for the extent Ergon Energy has considered, and made provision for, efficient Non-Network Alternatives.

Clause 6.5.7(e)(10) of the Rules requires that, in assessing Ergon Energy's capital expenditure forecasts for the next regulatory control period, the AER is to have regard for the extent Ergon Energy has considered, and made provision for, efficient Non-Network Alternatives.

30.1.1 Non-Network Alternatives Expenditure Forecast for 2010-15

Section 2.3.9(a)(1) of the AER's Regulatory Information Notice (RIN) requires Ergon Energy to provide information regarding the extent to which it has considered, and made provision for, efficient Non-Network Alternatives in developing its forecast operating and capital expenditures for the next regulatory control period.

Ergon Energy's non-network alternatives program for the next regulatory control period is $61.248 million, all of which is operating expenditure. Table 82 provides an annual breakdown of this amount by expenditure program.

Ergon Energy's non-network alternatives program consists of a number of broad based programs combined with projects that provide specific deferral of network augmentation projects identified through the Regulatory Test process. Forecast non-network alternatives expenditure in this Regulatory Proposal is targeted at the broad based programs, whereas projects that provide specific deferral of network augmentation projects are expected to be funded from capital expenditure that will occur following the Regulatory Test process.

30.1.1.1 Program Management

The program management costs of Ergon Energy's Non-Network Alternatives program are, unlike other types of programs, not included in Shared Costs (Overheads). They are therefore forecast and included specifically in the forecast for operating expenditure for Non-Network Alternatives.

30.1.1.2 Large Customers

Commercial and Industrial Customer Program

This program is a continuation of the Townsville commercial and industrial pilot project that received funding approval in July 2008.

There has been no additional specific allowance for commercial and industrial customers in the next regulatory control period. Rather, Ergon Energy will assess the merits of Non-Network Alternatives on a case-by-case basis and will substitute funding from its network expenditure forecasts where a non-network solution is assessed to be the most appropriate.

Table 82: *Non-Network Alternatives Operational Expenditure ($'000 Real $2009-10)*

Activity	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Program management	3,086	3,086	3,086	3,086	3,086	15,432
Large customers	640	1,240	1,240	1,240	1,240	5,600
Residential customers	6,195	6,266	6,340	6,418	6,497	31,716
Rural customers	1,050	1,050	1,050	1,050	1,050	5,250
Energy information one-stop shop	650	650	650	650	650	3,250
Total	**11,621**	**12,292**	**12,366**	**12,444**	**12,523**	**61,248**

Source: Non-Network Alternatives_Revised Forecasts M Muir 6Mar09_Revised by SCtee 17Mar09

A breakdown of the annual forecast for commercial and industrial customers is therefore detailed in Table 83.

Table 83: *Commercial and Industry Customer Program Forecast ($'000 Real $2009-10)*

Activity	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Commercial and industrial program	640	1,240	1,240	1,240	1,240	5,600

Embedded Generation Program

Embedded generation will be a focus as it has the potential to defer augmentation of parts of the distribution network.

This program will be linked to the Regulatory Test process and as such, specific operational expenditure has not been included in the overall Non-Network Alternatives program.

30.1.1.3 Residential Customers

Air Conditioning Direct Load Control

This program involves the expansion of the Townsville and Magnetic Island Residential direct load control (DLC) air conditioning pilot project, with particular focus on the deployment of new technology, channels to market and creating the necessary customer incentives to uptake this product.

As discussed, a significant contributor to the growth in peak-load demand over and above 'base load' growth is the increased installation of more affordable air conditioning units – both in new and existing residential areas. Air conditioning is no longer considered a luxury appliance as the market has been flooded with low cost generically branded units.

Within existing residential properties, the falling cost of air conditioning units has enabled increasing numbers of householders to install large enough systems to air condition their living areas. This is a lifestyle choice made by customers and is placing a significant additional demand on Ergon Energy's distribution system.

Within new residential properties, the change in style and design of buildings, and the construction materials being used have been increasingly less appropriate for the climatic conditions in Ergon Energy's distribution area. Installing air conditioning with significant load potential has become a necessity to make houses liveable at times of climatic extremes.

The air conditioning in living spaces is primarily being used during the late afternoon and evening hours. This directly impacts the times of daily peak demand.

The total cost of the air conditioning program is estimated at $17.22 million over the five years of the next regulatory control period, as detailed in Table 84 below.

Table 84: *Air Conditioning DLC Program Forecast ($'000 Real $2009-10)*

Activity	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Air Conditioning DLC	3,294	3,366	3,440	3,517	3,597	17,216

Pool Pump and Filtration DLC

On successful completion of the pool pump trials, a product will be launched to promote the use of controlled load tariffs for pool pumps and filtration to customers. The product will be primarily targeted at new pool installations, however, it is also expected that the promotion will also target a certain level of retrofitting of DLC devices to existing pool pump installations.

The cost of the pool pump and filtration program is provided in Table 85.

Table 85: *Pool Pump and Filtration DLC Program Forecast ($'000 Real $2009-10)*

Activity	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Pool Pump and Filtration DLC	700	700	700	700	700	3,500

Customer Appliance and Energy End Use Information

In order to allow residential customer non-network alternative initiatives to be properly targeted, it is essential to gather information on appliances that customers have installed and their energy end uses. As this information varies from region to region across Ergon Energy's distribution area, an allowance has been made to collect this information from a representative customer sample on an ongoing basis.

The data collection will be conducted at customer premises by trained energy assessors who will also offer the customer advice as to the best means of energy conservation and energy efficiency tailored for each customer's circumstances.

The forecast cost for this initiative is estimated at $2.5 million, split evenly in amounts of $0.5 million over the five years of the next regulatory control period.

Promotion of Existing Load Control Tariffs

This activity continues the approach of managing appropriate appliance loads via existing controlled load tariffs. A controlled load tariff rewards customers with a permanently discounted kWh rate compared to the general use tariff. The discount is in lieu of customer control over when the connected appliance(s) can operate.

At present over 70 per cent of Ergon Energy's residential customers utilise controlled load tariffs. These tariffs are primarily suited to DLC or hot water systems of a minimum 140 litres storage capacity. It also has the capacity to be used for other appliances (at the customer's request) such as pool and spa pumps and air conditioning, though these tariffs are not always a suitable 'fit' for these appliances.

Continued access to control over these appliances through controlled load tariffs is vital to Ergon Energy's ongoing Non-Network Alternatives program. The primary activity under this work area consists of promoting these tariffs to new and existing customers.

The forecast cost for this initiative is estimated at $2.5 million, split evenly in amounts of $0.5 million over the five years of the next regulatory control period.

Maintenance of Existing Load Control Relays

Ergon Energy's load control system has been growing for more than 20 years and, as such, a proportion of its signal receivers now have either been tampered with, are broken or are in some other state of disrepair. The nature of Ergon Energy's load control system is such that identifying failed receivers is a difficult task.

A comprehensive approach will be undertaken to understand how Ergon Energy can readily identify receivers in a non-working state and repair or replace them. Ergon Energy will then undertake a rolling program of device management and maintenance to maximise the load under control.

The forecast cost for this initiative is estimated at $3.0 million, split evenly in amounts of $0.6 million over the five years of the next regulatory control period.

Hot Water DLC

Penetration of residential controlled load tariffs is considered to be high and further inroads to migrating suitable load to these are limited because:

- There is significant penetration of alternative hot water generation to electric hot water systems – solar and gas (instantaneous and storage through bottled or reticulated systems);
- Small hot water units (<140 litres) are not suitable for load control under existing controlled load tariffs as they do not have sufficient capacity to sustain hot water supply at any time for general daily use; and
- The growth of high-density, smaller occupancy dwellings generally means there is little opportunity to give customers existing controlled load tariffs due to the wiring configuration of their communal building.

Efforts will continue to identify those customers with suitable hot water systems for migration to controlled load tariffs in a retrofit environment. Effort will also be placed in ensuring appropriate connection to controlled load tariffs in all new residential build situations.

The forecast cost for this initiative is estimated at $3.0 million, split evenly in amounts of $0.6 million over the five years of the next regulatory control period.

30.1.1.4 Rural Customers

Energy Audits

It is expected that activities in rural communities will be based on information provided from energy audits of customers supplied through Single Wire Earth Return (SWER) networks. This will allow Ergon Energy to identify heavy load appliances in these communities.

The forecast cost for this initiative is estimated at $2.25 million, split evenly in amounts of $0.45 million over the five years of the next regulatory control period.

Off Peak Pumping / Storage

Off peak pumping represents an opportunity to even out the daily generating load by pumping water into a high storage reservoir at off peak times.

The forecast cost for this initiative is estimated at $0.75 million, split evenly in amounts of $0.15 million over the five years of the next regulatory control period.

Hot Water Promotion

Also proposed for this customer segment is the promotion of the following hot water opportunities:

- DLC for hot water systems; and
- Replacement of electric element hot water systems with solar hot water, gas or heat pump hot water systems.

The forecast cost for this initiative is estimated at $2.25 million, split evenly in amounts of $0.45 million over the five years of the next regulatory control period.

30.1.1.5 Energy Education One-Stop Shop

The need for accurate, reliable information on energy efficiency and energy conservation is growing stronger in regional Queensland as the public become more aware and concerned with the impact of climate change.

In regional Queensland there is no single reference point for energy conservation information with regards to issues including, but not limited to:

- Customer education programs;
- Climate control and air conditioning issues;
- Energy efficient lighting;
- Hot water systems;
- Energy efficient house wiring; and
- Solar PV purchase and connection.

Funding for an Energy Education One-Stop Shop involves creating a centre of excellence in the field of energy conservation, energy efficiency and demand management for use by regional Queensland energy users and stakeholders.

The forecast cost for this initiative is estimated at $3.25 million, split evenly in amounts of $0.65 million over the five years of the next regulatory control period.

30.2 PROCESSES, PROCEDURES AND POLICIES FOR IDENTIFYING EFFICIENT NON-NETWORK ALTERNATIVES

Section 2.3.9(a)(2) of the AER's RIN requires Ergon Energy to provide information regarding the processes, procedures or policies that it has in place to ensure efficient non-network solutions are identified and, where appropriate, selected.

The focus of Ergon Energy's current Non-Network Alternatives program is conducting trials and pilot projects in 2008-09 and 2009-10 to develop the necessary skills and expertise before the commencement of the next regulatory control period.

The trials and pilot project programs will establish an evidence base for the future deployment of Non-Network Alternatives as appropriate in regional Queensland whilst not comprising service standards, safety or security. Ergon Energy will continue to work closely with customers in undertaking these activities, as they will need to choose to participate in the programs. The end goal of the Non-Network Alternatives program is to deliver to customers the reliability and security of supply they expect at the lowest cost, by enabling customers to participate in non-network alternative solutions. It will seek to do this by providing a low cost, reduced risk solution to traditional supply side solutions.

Embedded generation projects are a key component of Ergon Energy's Non-Network Alternatives program and will be linked to the Regulatory Test Process. No specific operational expenditure has been identified for embedded generation projects in this Regulatory Proposal.

Ergon Energy has developed a three-stage process to support the requirements of clause 5.6.5A of the Rules to apply the Regulatory Test. This process will be undertaken in conjunction with existing capital planning and investment approval processes to assess whether a suitable non-network alternative is more prudent than a network augmentation. The three stages of this process involve undertaking a screening test, a feasibility investigation and a business case:

- Screening test – this is a high level assessment to determine whether undertaking a Non-Network Alternative could be viable and whether further investigations are warranted;
- Feasibility investigation – if a screening test identifies that one or more Non-Network Alternatives may be viable then a feasibility investigation is undertaken. The feasibility investigation is a detailed investigation that details the prospective Non-Network Alternatives' technical requirements and risks, customer agreement terms and supplier quotations.

  The feasibility investigation also sets out discounted cash flow and Net Present Value (NPV) calculations of the prospective options to provide an understanding of whether a Non-Network Alternative may be financially viable when compared with feasible network options. If a non-network alternative is determined to be viable a full business case will be undertaken; and
- Business Case - a business case involves a detailed investigation of the identified non-network alternative option which is incorporated with detailed investigations of the network options and discounted cash flow analysis.

  As with the feasibility investigation, the business case sets out technical requirements and risks, detailed customer agreements and firm quotations from suppliers. The business case is submitted for approval through Ergon Energy's internal investment review and approval processes. Once approved, the Non-Network Alternative is progressed and implemented.

30.3 DESCRIPTION OF TYPES OF NON-NETWORK ALTERNATIVES DNSP NORMALLY CONSIDERS

Section 2.3.9(a)(3) of the AER's RIN requires Ergon Energy to describe the types of Non-Network Alternatives that Ergon Energy normally considers.

Ergon Energy's Non-Network Alternatives program has historically focused on demand management through the delivery of price signals through off-peak tariffs, controlled tariffs and direct load management through audio frequency load control (ripple control) systems. Ergon Energy has identified opportunities for further Non-Network Alternatives, which include:

- Network Demand Management – this focuses on working with customers on behind the meter solutions to deliver peak demand reductions and to defer or avoid network augmentation. Customer-based interventions of this kind to reduce peak demand include, but are not limited to:
  - → Load shifting;
  - → Replacing old, inefficient equipment and appliances with energy efficient equipment and appliances;
  - → Fuel/energy source substitution; and
  - → Peak lopping through use of customer embedded generation or curtailable load.
- Embedded Generation – this focuses on the use of standby, peaking or renewable generators, directly connected to Ergon Energy's network to reduce peak loads (as opposed to being connected beyond the customer's connection point). The embedded generation plant can be owned either by:
  - → Ergon Energy – this involves a capital cost and associated operating costs for Ergon Energy; or
  - → A third party – this involves Ergon Energy making network support payments to the third party.

The Non-Network Alternatives program is focussed on three key customer segments:

- Large commercial and industrial customers – projects for these customers represent a comparatively inexpensive alternative to distribution network augmentation that can be delivered quickly. The opportunities for saving energy and reducing demand are most significant in this sector given their size.

  Unlike residential initiatives that are generally rolled out in a widespread, broad-based manner, commercial and industrial projects require targeted, customised solutions for individual customers or industries that encompass specific technologies, organisational changes and delivery models to fund them.

- Residential customers - non-network alternative initiatives targeted at residential customers focus on reducing peak demand through the installation of DLC devices and extended load control availability for off-peak tariffs. These initiatives contribute to Ergon Energy's capacity to drive the mass-adoption of the next-generation, multiple-appliance DLC. Ergon Energy considers that the long term viability of distributor-led mass market residential DLC depends on an ability to:
  - → Maximise customer uptake;
  - → Motivate customers to take advantage of control options for multiple appliances; and
  - → Secure customers long-term participation and support for the program.
- Rural customers - customers serviced from the SWER system represent a growing issue for Ergon Energy. SWER systems were originally built to provide supply for rural loads such as lighting, refrigeration and water pumping. Today, customers are adding more loads upon these distribution lines, such as air conditioning, so there is a requirement to promote better use of the network to maximise its utility.

  Proposed activity within this customer segment will be developed from Non-Network Alternatives trials currently being conducted on the Cloncurry North SWER network.

30.4 LIST OF NON-NETWORK PROJECTS SELECTED DURING 2005-10

Section 2.3.9(a)(4) of the AER's RIN requires Ergon Energy to provide a list of those Non-Network Alternative projects that have been selected during the current regulatory control period.

The current Non-Network Alternatives program focuses on the following five projects:

- Townsville Network Demand Management (NDM) commercial and industrial pilot project;
- Townsville: Queensland Solar City;
- Townsville and Magnetic Island Residential Air Conditioning DLC;
- Pool Pump and Filtration DLC Trials; and
- Cloncurry North SWER NDM trials.

30.4.1 Townsville Commercial and Industrial NDM Pilot Project

The commercial and industrial NDM pilot project initiative involves entering into contracts with commercial and industrial customers in Townsville. Ergon Energy makes financial contributions to each customer's capital works programs in order to implement various technical and commercial NDM arrangements.

Ergon Energy will not be the owner of each of the customers' capital works programs but will make a financial contribution once the target reduction in demand has been measured and verified. Generally, payments will be made annually in arrears to customers once measurement and verification reports have been prepared by an independent expert – these reports are paid for by the customer. This will avoid the possibility of paying for benefits that cannot be realised.

In addition, Ergon Energy will facilitate third party providers working with targeted customers to assist the customers to undertake capital works. Over time this is expected to increase the depth of third party service providers and may assist customers with obligations under legislation such as the Clean Energy Act 2008.

The Townsville pilot project will enable Ergon Energy to develop the tools and expertise to proactively implement NDM solutions with commercial and industrial customers, which could be applied more broadly across Ergon Energy's distribution system.

The methodology for the Townsville commercial and industrial NDM pilot project is as follows:

- Choose a typical business centre to conduct a detailed analysis;
- Target a representative cross-section of suitable customers within that centre;
- Match those customers with appropriate commercial delivery models; and
- Identify the most cost effective technology solutions for each customer.

A wide range of customers, technical solutions and commercial delivery models were selected in the pilot project to understand the challenges and develop the tools and capability to implement various NDM arrangements with commercial and industrial customers.

The businesses were chosen on the basis of providing a mixture of large and small commercial businesses, a not-for-profit organisation plus local, State and Federal government sites. The variety of technical solutions and commercial models required by this portfolio is considered to be representative of what could be expected from a wider rollout of NDM programs with larger and more diverse customers across Queensland.

30.4.2 Townsville - Queensland Solar City

The Townsville - Queensland Solar City (Solar Cities) project is a Federal Government initiative to trial a sustainable business model for the concentrated deployment of distributed generation (solar photovoltaics) and demand management through energy efficiency, load management, smart meters and innovative tariffs.

The Solar City trial is expected to:

- Demonstrate future replication opportunities in the area of network driven demand management with specific focus on options to address the marginal cost of electricity in system peak; and
- Further develop Ergon Energy's capability in deploying demand management techniques.

30.4.3 Townsville and Magnetic Island Residential DLC Air Conditioning Pilot Project

Ergon Energy has been undertaking a pilot of controlling air conditioning compressors in up to 70 volunteer residential customer premises across Townsville/ Magnetic Island.

The purpose of the project is to test offers to understand optimal customer purchasing and to demonstrate peak load reduction in a defined area by controlling residential air conditioning units in a manner that has negligible impact on customer comfort perceptions.

The project is a demonstration of demand management at the residential level that is not directly aimed at deferring or avoiding specific network augmentations. The project is a strategic investment decision that will inform the business case being developed for the potential long-term rollout of a broad-based residential DLC product. If satisfactory results are achieved in the Townsville and Magnetic Island air conditioning DLC trials, further trials will be conducted with a view to developing a product offering that will become business as usual and made operational as part of the rollout of the long-term strategy.

It is recognised that in the residential market, a critical mass uptake of demand management opportunities is required before cumulative benefits to the network can be seen. Given the expected customer take-up rate this is expected to fall outside the 2010 to 2015 regulatory control period for the residential DLC products.

30.4.4 Pool Pump and Filtration DLC Trials

Currently, there is little opportunity to exercise DLC on pool pumps. The pool construction and pool servicing industries, who have direct contact with customers and are key channels to the market, have little if any incentive to promote energy efficiency and in some cases actively advise against customers having their pool pumps controlled through a controlled load tariff. The reasons for this are:

- Pool construction companies do not consider the effect of the pool pump use on the distribution system. Engaging with customers to encourage connection to a controlled load tariff is not a consideration at the time of building the pool. Once a pool is in place, the cost to retrofit a controlled load connection can be prohibitive; and
- Pool service/maintenance companies can be opposed to installing pool pumps on controlled load tariffs because:
  - → Connection to a controlled load tariff requires hardwiring of the appliance – this can make maintenance and pump replacement a time consuming and costly affair; and
  - → Advice for pool sanitation is that the pool pump should be running during use – a controlled load tariff connection can conflict with times when the pool is in use.

In order to address these potential barriers, a technological solution is being developed to allow connection to existing controlled load tariffs without the shortcomings associated with them. Trials and prototype testing anticipate having supplied a solution before the next regulatory control period.

The trials will target new pool builds, as connection to controlled load tariffs for existing pools can still be costly. Notwithstanding this, the trial will include incentives for retrofitting a DLC device and partially covering the cost of any additional work required to allow a controlled load tariff connection.

30.4.5 Cloncurry North SWER NDM Trials

Rural customers are a separate customer segment due to the particular network and energy use issues that they face. Customers on SWER systems are a particular focus as the demand being placed on SWER systems far exceeds what they were originally designed to support.

A trial is underway with a small number of customers on the Cloncurry North SWER system that involves demand reduction through the installation of timers on hot water, pumps and air conditioning loads as well as the installation of ceiling insulation and installation of solar hot water systems.

The various interventions have been installed and the project is now moving into the data gathering and analysis phase to determine which interventions have been successful. Beyond this phase, the successful interventions will be incorporated into a broader program of initiatives for the rural customer segment.

30. NON-NETWORK ALTERNATIVES – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR522	Clean Energy Act 2008

AER Documents

AR367c & 368c	AER Regulatory Information Notice

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

Nil

31. MATERIAL PROJECTS (CAPITAL EXPENDITURE) AND PROGRAMS (OPERATING EXPENDITURE AND CAPITAL EXPENDITURE)

Rules – Clauses S6.1.1(1)(iii)-(v), S6.1.1(7), S6.1.2(1)(i)-(iv), and S6.1.2(8)
RIN – Section 2.2.3

This chapter addresses the requirements of the Rules and the Australian Energy Regulator's (AER) Regulatory Information Notice (RIN) in relation to the material projects that are included in Ergon Energy's capital expenditure forecasts, and material programs that are included in its capital and operating expenditure forecasts, for the next regulatory control period.

Clause S6.1.1(1) of the Rules requires Ergon Energy to provide certain information in relation to proposed material assets that are expected to be built based on the forecast capital expenditure. Clause S6.1.2 of the Rules requires Ergon Energy to provide certain information in relation to its forecast operating expenditure programs.

Section 2.2.3(a) of the RIN requires Ergon Energy to provide certain information on material projects that are included in Ergon Energy's capital expenditure forecasts, and material programs that are included in its capital and operating expenditure forecasts, for:

- The current regulatory control period; and
- The next regulatory control period.

Section 2.2.3(c) of the RIN provides that material projects and programs are those that have a total cumulative expenditure of greater than 2 per cent of Ergon Energy's Annual Revenue Requirement for the current regulatory control period. Ergon Energy's forecast Annual Revenue Requirement for 2009-10 is $860.4 million. On this basis, Ergon Energy's materiality threshold for its projects and programs is $17.2 million.

Clauses S6.1.1(7) and S6.1.2(8) of the Rules, and section 2.2.4 of the RIN, require Ergon Energy to identify and explain significant variations in its forecast and historic capital and operating expenditure. Ergon Energy has provided these explanations in section 23.12 for capital expenditure and section 26.8 for operating expenditure.

Section 2.3.1(a)(9) of the AER's RIN requires Ergon Energy to provide a recent high level map of the network showing major network features including key forecast augmentations.

Ergon Energy has prepared four maps of its distribution service area:

- Map 1 shows the key features of the existing distribution network;
- Map 2 shows the maintenance areas into which Ergon Energy packages its maintenance work;
- Map 3 shows the depot zones and the number of customer and connections points serviced by each depot zone; and
- Map 4 shows the key forecast augmentations to Ergon Energy's distribution network in the next regulatory control period based on the material projects from Artemis 7 (A7) and the Sub-transmission Network Augmentation Plans (SNAPs).

31.1 ERGON ENERGY'S METHOD FOR DATA CAPTURE AND EXPLANATIONS

Ergon Energy's Enterprise Resource Planning (ERP) system is Ellipse. Ellipse was commissioned during 2006. Linked to Ellipse is Ergon Energy's portfolio management tool, A7. It has not been possible to capture data relating to material projects and programs electronically prior to the commissioning and successful integration of A7 with Ellipse.

This means that, for the current regulatory control period, Ergon Energy's historical records have been manually kept in various parts of the business. However, projects that are underway in the current regulatory control period are progressively being entered into A7. Similarly, projects planned for the next regulatory control period are progressively being entered into A7.

Ergon Energy's ability to report material projects and programs for the current regulatory control period and the next regulatory control period has therefore been restricted to the information that is available from A7 and from the SNAPs.

The RIN pro forma 2.2.3 has been populated on the following basis:

- Projects completed prior to 2006-07 – have not been entered into A7 and details are therefore not available;
- Projects underway at 2006-07 and due to be completed by the end of the current regulatory control period:
    - Have had costs prior to 2006-07 accumulated into the 2007-08 year; and
    - The balance of costs are shown in the year they are expected to be incurred;
- Projects underway or commencing after 2006-07 and due to be completed in the next regulatory control period – have had the current regulatory control period's costs accumulated into the 2010-11 year;
- Projects that are expected to commence in the next regulatory control period:
    - Are shown in the year(s) that costs are expected to be incurred; and
    - Can only be described up until the 2012-13 year, although the total costs are included in the total column in pro forma 2.2.3. This is because A7 only 'reports' for a five year period. Where possible, information has also been drawn from the SNAPs, not all of which have yet been loaded into A7.

31.2 MATERIAL PROJECTS AND PROGRAMS FOR 2005-10

Ergon Energy has completed pro forma 2.2.3 of the RIN in order to provide the following information about Ergon Energy's material projects and programs for the current regulatory control period, 2005-10, in order to meet the requirements of section 2.2.3(a) of the RIN:

- Project/program unique identifier;
- Project/program name;
- Brief description;
- Reason for project/program per pro forma categories;
- Proposed start date;
- Proposed commissioning date;
- Relevant categories of Distribution Services;
- Location of project/program;
- Indication of business case/board approval for project/program;
- Indication of whether Capital Expenditure has satisfied regulatory test; and
- Cost of project/program.

31.3 MATERIAL PROJECTS AND PROGRAMS FOR 2010-15

Ergon Energy has completed pro forma 2.2.3 of the RIN in order to provide the following information about Ergon Energy's material projects and programs for the next regulatory control period, 2010-15, in order to meet the requirements of section 2.2.3(a) of the RIN:

- Project/program unique identifier;
- Project/program name;
- Brief description;
- Reason for project/program per pro forma categories;
- Proposed start date;
- Proposed commissioning date;
- Relevant categories of Distribution Services;
- Location of project/program;
- Indication of business case approval for project/program;
- Indication of whether forecast Capital Expenditure has satisfied regulatory test; and
- Anticipated or known cost of project/program.

31. MATERIAL PROJECTS (CAPITAL EXPENDITURE) AND PROGRAMS (OPERATING EXPENDITURE AND CAPITAL EXPENDITURE) – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR375c	EE Sub-transmission Network Augmentation Plans 2007
AR376c	EE Sub-transmission Network Augmentation Plans 2008
AR377	EE Map 2 Maintenance Areas, 23 February 2009
AR378	EE Map 4 Reg Proposal Material Projects from SNAPs, 23 February 2009
AR379	EE Map 3 Depots & Customer Nos & CPts, 23 February 2009
AR380	EE Map 1 Distribution Network, 23 February 2009

32. UNIT RATES

Rules – Clauses 6.5.6(e)(6), 6.5.7(e)(6) and S6.1.2(4)
RIN – Sections 2.3.10(b)(1) and 2.3.10(c)

This chapter details and explains the unit rates that Ergon Energy has applied to its capital and operating expenditure forecasts for the next regulatory control period.

Ergon Energy interprets unit rates to be the cost to deliver one unit of the building blocks it has used in developing a forecast of its regulatory expenditure forecast. As such, unit rates represent an aggregation of asset units and other costs required to complete a task or activity, and are aligned to building blocks Ergon Energy uses for operational planning and delivery of its system work programs.

The unit rate values are not directly comparable to asset valuation unit rates. Asset valuation unit rates are not generally used by Ergon Energy in its operational activities.

Details of unit rates provided in this chapter exclude overhead allocations and price escalations. Unit rates represent the direct costs of doing work in 2007-08 dollars. This was done to make visible the underlying cost of delivering various tasks and activities in current dollar terms and without any financial distortions.

Overheads and escalators are applied separately in the aggregated forecasting models Ergon Energy has used to prepare its regulatory expenditure forecast. This was done to ensure consistent application of overheads and escalators across the entire regulatory expenditure forecast.

A full list of units and, where applicable, unit rates, is provided to the Australian Energy Regulator (AER) which accompanies this Regulatory Proposal, in Ergon Energy's Unit Rates Master List Spreadsheet. There are approximately 540 different units included in Ergon Energy's Unit Rates Master List Spreadsheet:

- In cases where total regulatory expenditure for a building block is determined by multiplying a volume of building blocks by a unit rate for the building block, the unit rate value is provided in the Unit Rate Master List Spreadsheet and is the cost to complete a single unit (e.g. replace one pole). Around 430 units have their expenditure forecasts prepared based on unit rates; and
- In cases where regulatory expenditure for a particular building block is determined using a baseline and scope change approach, the unit is listed but no unit rate is provided (e.g. Forced Maintenance is an allocation of funds prepared using a historical baseline rather than based on a volume of units).

32.1 UNIT RATES FOR KEY ITEMS OF PLANT AND EQUIPMENT

Subsection 2.3.10(b)(1) of the Regulatory Information Notice (RIN) requires Ergon Energy to detail the unit rates that it has adopted for key items of plant and equipment. As noted above, Ergon Energy has interpreted unit rates to be the cost to deliver one unit of the building blocks it has used in developing a forecast of its regulatory expenditure forecast for system works.

Ergon Energy has interpreted "unit rates for key items of plant and equipment" to mean the list of top 10 capital expenditure unit rates and top 10 operating expenditure unit rates that contribute the greatest overall value to the regulatory expenditure forecasts on a volume-weighted basis.

This list of 20 includes only those units for which total expenditure is forecast by multiplying a volume by a unit rate.

The 10 largest capital expenditure units on a volume-weighted basis, that are estimated using unit rates, account for approximately 30 per cent of Ergon Energy's total system capital expenditure forecast. Table 86 shows the unit rates estimated for these items, as well as the share of the system capital expenditure forecast attributable to these top 10 items in the next regulatory control period. These unit rates exclude overheads and are in 2007-08 dollars (i.e. unescalated).

Table 86: *Top 10 System Capital Expenditure Units by Total 5-Year Expenditure*

Unit	Program	Unit rate ($)	Total Expenditure ($)	Share of System Capital Expenditure (%)

Source: Unit Rates Master List.xls

The 10 largest operating expenditure units on a volume-weighted basis, that are estimated using unit rates account for approximately 11 per cent of Ergon Energy's forecast system operating expenditure. Table 87 shows the unit rates estimated for these items, as well as the share of the system operating expenditure forecast attributable to these top 10 items in the next regulatory control period. These unit rates exclude overheads and are in 2007-08 dollars (i.e. unescalated).

Table 87: *Top 10 System Operating Expenditure Units by Total 5-Year Expenditure*

Unit	Program	Unit rate ($)	Total Expenditure ($)	Share of System Capital Expenditure (%)

Source: Unit Rates Master List.xls

32.2 HOW UNIT RATES HAVE BEEN DEVELOPED, INCLUDING SOURCE MATERIAL AND DATE ON WHICH DEVELOPED

Subsection 2.3.10(b)(1) of the RIN requires Ergon Energy to explain how the unit rates that it has adopted for key items of plant and equipment have been developed, including the source material and date when they were developed.

Ergon Energy applies two broad approaches to developing its system capital and operating expenditure forecasts:

- Specified work: The first approach is used where individual units of work can be specified (e.g. build a new zone substation). It involves a bottom-up process of multiplying quantities of specified work by the relevant unit rates for the specified work; and
- Unspecified work: The second approach is used where it is difficult to specify what units of work will be required in advance, but there is a high probability that it will occur (e.g. Forced Maintenance). It involves a top-down approach through which the forecasts for such unspecified expenditure are based on historic expenditure in one of the following ways:
  - Retaining the same dollar value of historic expenditure without escalation;
  - Increasing historic expenditure using an appropriate escalator;
  - Developing a baseline of historic expenditure and identifying scope changes from that baseline. These scope changes may be either positive or negative;
  - Maintaining a fixed pro-rata percentage of total expenditure programs for each element of the program as in previous years; and
  - Where there are new programs of work, an initial estimate is prepared by subject mater experts, which can then be refined once actual results are available.

This chapter of the Regulatory Proposal explains how Ergon Energy has used a combination of these two broad approaches in developing its capital and operating expenditure forecasts. This is intended to make clear to the AER when, why and how Ergon Energy has applied unit rates in developing certain parts of its capital and operating expenditure forecasts and when, why and how it has applied a different approach for other parts of its forecasts.

32.2.1 Capital Expenditure

As discussed in Chapters 22 to 23.12 of this Regulatory Proposal, Ergon Energy has two types of capital expenditure – system and non-system capital expenditure.

System capital expenditure comprises: Asset Replacement, Corporation Initiated Augmentation (CIA), Customer Initiated Capital Works (CICW), Reliability and Quality Improvement and Other System.

As discussed in section 32.2 of this Regulatory Proposal, Ergon Energy's capital program comprises certain components where specified works have been identified and other components where specified projects are not able to be identified in advance:

- Where specified works have been identified, that part of the capital program is developed by multiplying quantities of work by unit rates; and
- Where the works are not able to be identified in advance, and quantities of work cannot therefore be reliably forecast, programs of unspecified expenditure are established based on an extrapolation of historic expenditure.

The use of these two approaches in developing the capital expenditure forecasts is discussed below.

32.2.1.1 Unit Rates (Specified Works)

Approximately 64 per cent of Ergon Energy's system capital expenditure for Standard Control Services is specified works, the forecasts for which are developed using unit rates.

The unit rates that Ergon Energy applies in developing its system capital expenditure for Standard Control Services are detailed in its Unit Rates Master List Spreadsheet.

The reasons why unit rates, rather than a top-down approach, have been used to prepare the forecasts for certain components of the capital expenditure program are that:

- They relate to specified works that can be readily identified and broken down into smaller components, the costs of which components can be individually estimated;
- They tend to relate to low volume, high value types of works;
- The more lumpy nature of these works means that there is likely to be greater variability from year to year, such that it would not necessarily be appropriate to use historic expenditure as the basis for forecasting expenditure;
- The quantity of units of work that needs to be undertaken can be forecast with reasonable certainty and accuracy; and
- The unit rates of undertaking each unit of work for each component of work can also be forecast with reasonable certainty and accuracy.

Of the total specified capital expenditure above, approximately 85 per cent is based on unit rates produced by the TaDS estimating tool.

The TaDS estimating tool is an internally developed database that was built in early 2008, and uses a bottom-up approach to preparing estimates by drawing on a catalogue of equipment units. Unit rates for particular works can be prepared by drawing on the standard equipment units and making modifications where necessary to meet specific project requirements. This method of costing works provides significant consistency, transparency and robustness to the estimates.

The library of equipment units in the TaDS estimating tool was developed by creating estimates of individual items required in the equipment unit, having regard for matters such as labour hours by skill type, materials, and contractor costs.

During April and May 2008 a set of standard unit rates were added to the TaDS estimating tool library of equipment units for the purposes of estimating the items in the capital works program.

The unit rates were developed in the TaDS estimating tool using the following key elements:

- Materials prices – these were obtained from a combination of Ergon Energy's supply system, period contract rates (where available), subject matter experts, suppliers and other third party organisations;
- Labour estimates – these quantity estimates were prepared for each skill type by subject matter experts within Ergon Energy;
- Price escalators – these were set to zero so they could be separately applied in Ergon Energy's AER financial model;
- Labour and vehicle rates – these were determined based on the new Ergon Energy Union Collective Agreement 2008 rates for labour and standard vehicle rates. All labour is costed at normal time, and no allowance has been made for overtime rates or other living away from home allowances. This represents an effective efficiency gain of around $20 million in total over the next regulatory control period, as Ergon Energy typically does an average of around 15 per cent overtime for the types of major capital works for which the TaDS estimating tool has been used to develop unit rates. (Note that Ergon Energy does not necessarily intend to reduce or eliminate overtime, and some or all of these savings may be achieved through other mechanisms.);
- Specific risks and contingencies – these were set at zero because it has been assumed that these can be managed within the broader capital expenditure program;

- Travel and accommodation costs – these were based on the actual historical average direct costs for travel and accommodation for capital expenditure for 2007-08, plus an allowance of 10 per cent of total labour hours for travel. An average 4.3 per cent was added to unit rates to allow for travel and accommodation costs; and
- Outsourcing costs – unit rates applied to works that will be outsourced are the same as those used for internally developed works, despite some evidence that Ergon Energy has incurred a premium where works have been outsourced in previous years.

In December 2008, Ergon Energy engaged Sinclair Knight Mertz (SKM) to review Ergon Energy's Unit Rates. SKM found in its review that the unit rates were within an acceptable range of +/-15 per cent estimates of their nature. That is Ergon Energy's unit rates, while being consistently higher than the unit rates from SKM for the same work, were considered within the acceptable tolerance of +/-15 per cent. SKM's report "Review of Estimates for AER Regulatory Proposal" is provided with this Regulatory Proposal.

32.2.1.2 Unspecified Works

Ergon Energy has applied a top-down approach to forecasting system capital expenditure for Standard Control Services in the next regulatory control period, where it has not been possible to accurately forecast specified work in advance and apply unit rates.

These unspecified components represent approximately 36 per cent of the total value of Ergon Energy's system capital expenditure program.

Ergon Energy has forecast its unspecified system capital expenditure program by using one or more of the following approaches:

- Retaining the same dollar value of historic expenditure without escalation;
- Increasing historic expenditure using an appropriate escalator;
- Developing a baseline of historic expenditure and identifying scope changes from that baseline. These scope changes may be either positive or negative;
- Maintaining a fixed pro-rata percentage of total expenditure program for each element of the program as in previous years; and
- Where there are new programs of work, an initial estimate is prepared by subject matter experts, which can then be refined once actual results are available.

32.2.2 Operating Expenditure

As discussed in Chapters 25 to 27 of this Regulatory Proposal, Ergon Energy has five categories of system operating expenditure: Preventive Maintenance, Corrective Maintenance, Forced Maintenance, Network Operations and Other Operating Expenditure.

Unit rates for operating expenditure are not required under the RIN, which refers to unit rates for plant and equipment. However, Ergon Energy has provided operating expenditure units and unit rates as they form part of the building blocks used to prepare the regulatory expenditure forecasts.

32.2.2.1 Preventive Maintenance

The Preventive Maintenance expenditure forecasts have been developed in the NARMCOS model using the same approach for all 26 classes of system assets by:

- Identifying the different types of Preventive Maintenance work that need to be undertaken for each asset equipment type;
- Identifying the amount of Preventive Maintenance work (i.e. in units) that needs to be undertaken for each asset equipment type for each of the five years;
- Identifying the total cost of undertaking a single unit of work for the different types of work required for each type of Preventive Maintenance;
- Calculating the total cost of each type of Preventive Maintenance work for each of the 26 classes of system assets for each of the five years; and
- Aggregating the total Preventive Maintenance work required for each of the 26 classes of system assets for each of the five years.

Ergon Energy's Asset Equipment Plans and Network Preventive Maintenance Programs for 2010-11 to 2014-15 explain how Ergon Energy has developed unit rates for all 26 classes of system assets. These documents accompany this Regulatory Proposal. Different approaches have been used to develop unit rates for different system assets, involving one, or a combination of, the following components:

- The time to perform the standard job in the field plus travel costs;
- The average current contract rates;
- The average current cost of materials; and
- The historical cost of undertaking specific activities.

Individual unit rates are reflected in the Unit Rates Master List Spreadsheet.

As a result, all Preventive Maintenance expenditure forecasts have been developed by multiplying an estimated unit rate by an estimated number of units. None of the forecasts have been developed using historic expenditure.

32.2.2.2 Corrective Maintenance

The Corrective Maintenance expenditure forecasts have been developed in the Network Assets Replacement Maintenance Capex Opex Summary (NARMCOS) model using a mixture of the following different approaches for the 26 classes of system assets:

- Specified works: Multiplying quantities of work by unit rates;
- Unspecified works:
  - → Increasing the historic expenditure for the asset class using an appropriate escalator;
  - → Retaining the same dollar value of historic expenditure for the asset class without escalation;
  - → Maintaining a fixed pro-rata percentage of total Corrective Maintenance expenditure for the asset class as in the previous year.

Ergon Energy's Asset Equipment Plans explain how Ergon Energy has developed unit rates for all 26 classes of system assets. These documents accompany this Regulatory Proposal.

The three alternative approaches to extrapolating historic expenditure for unspecified works have been applied to those asset classes where either the quantity of units or the level of the unit rates could not be forecast with sufficient certainty or accuracy to be used as a basis for developing the expenditure forecast. As a result, for these asset classes it was considered more prudent to base the forecast on known historical expenditure trends.

However, unit rates have been applied to those asset classes where the quantity of units and the level of the unit rates could be accurately forecast for individual equipment components. The asset classes where unit rates have been used include distribution transformers, distribution enclosed switches, distribution air break switches, lightning arrestors, public lighting, distribution earths, distribution reactors and regulators, access tracks (corridors) and equipment sites, vegetation management, transformers, current transformers and voltage transformers, and control systems.

As with Preventive Maintenance, different approaches have been used to develop unit rates for different system assets, involving one, or a combination of, the following components:

- The time to perform the standard job in the field plus travel costs;
- The average current contract rates;
- The average current cost of materials; and
- The historical cost of undertaking specific activities.

Individual unit rates are reflected in the Unit Rates Master List Spreadsheet.

As a result, only some Corrective Maintenance expenditure forecasts have been developed by multiplying an estimated unit rate by an estimated number of units. The remaining forecasts have been developed based on one of several approaches to extrapolating historic expenditure.

32.2.2.3 Forced Maintenance

The Forced Maintenance expenditure forecasts have been developed in the NARMCOS model using two different approaches for the 26 classes of system assets:

- Maintaining a fixed pro-rata percentage of total Forced Maintenance expenditure for the asset class as in the previous year; and
- Multiplying quantities of work by unit rates.

Ergon Energy's Asset Equipment Plans explain how Ergon Energy has developed unit rates for all 26 classes of system assets. These documents accompany this Regulatory Proposal.

The approach of maintaining the same fixed pro-rata percentage of total Corrective Maintenance expenditure for the asset class as in the previous year has been used for those asset classes where either the quantity of units or the level of the unit rates could not be forecast with sufficient certainty or accuracy to be used as a basis for developing the expenditure forecast. This reflects the fact that Forced Maintenance involves unplanned repair, replacement or restoration work. As a result, Ergon Energy has provided top-down forecasts of expenditure for these asset classes, with no breakdown into sub-components of work that are required within the individual asset class.

However, unit rates have been applied to those asset classes where the quantity of units and the level of the unit rates could reasonably be forecast for individual equipment components based on Ergon Energy's knowledge and experience. The asset classes where unit rates have been used include meters, underground cables and joints, fuses, lightning arrestors, distribution services, access tracks (corridors) and equipment sites, zone substation transformers, zone substation circuit breakers, zone substation CT and VT, zone substation outdoor switchyards, zone substation capacitor banks, zone substation AC and DC Systems, zone substation civils, communications and protection.

As with Preventive and Corrective Maintenance, different approaches have been used to develop unit rates for different system assets, involving one, or a combination of, the following components:

- The time to perform the standard job in the field plus travel costs;
- The average current contract rates;
- The average current cost of materials; and
- The historical cost of undertaking specific activities.

Individual unit rates are reflected in the Unit Rates Master List Spreadsheet.

As a result, only some Forced Maintenance expenditure forecasts have been developed by multiplying an estimated unit rate by an estimated number of units. The remaining forecasts have been developed based on extrapolating historic expenditure trends.

32.2.2.4 Network Operations

Network Operations relates largely to the operation and control of the network through Ergon Energy's control centres as well as some activity associated with reconfiguration of the network.

As noted in Section 26.2 of this Regulatory Proposal, the Network Operations expenditure forecasts have been developed based on historic baseline expenditure, with adjustments made for identified scope changes and work load growth.

Therefore, there are no Unit Rates applied in developing the Network Operations expenditure forecasts.

32.2.2.5 Other Operating Expenditure

The Other Operating Expenditure relates to Ergon Energy's self insurance program, Demand Management Innovation Allowance (DMIA), meter reading in Ergon Energy's capacity as a Metering Data Provider for Type 5, 6 and 7 metering installations, and customer service activity only in Ergon Energy's capacity as a Distribution Network Service Provider (DNSP).

As noted in section 26.6.3 of this Regulatory Proposal:

- The meter reading and customer services expenditure forecasts have both been developed based on historic baseline expenditure, with adjustments made for identified scope changes and workload growth;
- The self insurance forecast is based on a review conducted by Synergies Economic Consulting in partnership with Finity Consulting (this is discussed in section 28.1 of this Regulatory Proposal); and
- The DMIA allowance of $1 million per annum (Nominal) is based on the notional amount provided for in the AER's F&A Stage 2.

Therefore, there are no Unit Rates applied in developing the Other Operating Expenditure expenditure forecasts.

32.3 EVIDENCE THAT UNIT RATES ARE EFFICIENT

Subsection 2.3.10(b)(1) of the RIN requires Ergon Energy to demonstrate that the unit rates that it has adopted for key items of plant and equipment reflect efficient costs.

Ergon Energy believes that the unit rates applied in developing its capital and operating expenditure program are efficient because:

- An independent review of a statistically relevant sample of Ergon Energy's capital unit rates by Sinclair Knight Merz (SKM) suggests that the value of total system capital expenditure generated from unit rates is within 6.5 per cent of the rates suggested by SKM. This is well within the acceptable range of +/-15 per cent nominated by SKM;
- A significant proportion of the key cost components on which the unit rates (and capital and operating expenditure forecasts) are based, are externally procured and, hence, are market tested. Externally procured materials and labour account for around 80 per cent of capital expenditure and 60 per cent of operating expenditure;
- Ergon Energy has robust and well tested procurement processes that are applied when labour and materials are purchased from the market. This helps ensure that efficient market prices are obtained;
- Ergon Energy has well established technical standards for undertaking the design and construction of works, as well as to maintain its assets;
- The key cost components are consistently applied in Ergon Energy's internal estimating tools to produce both the unit rates used for forecasting capital and operating expenditure and the cost estimates of projects; and
- There is a feedback loop between historic and market costs and unit rates used to develop the capital and operating expenditure forecasts.

Each of these matters is discussed further below.

32.3.1 Independent Review by SKM

Ergon Energy engaged SKM to undertake a review of major capital expenditure unit rates against a set of 'efficient' unit rates prepared by SKM. SKM reviewed Ergon Energy's unit rates which collectively represented 29 per cent or $1.09 billion of the five-year forecast system capital expenditure. The total difference in forecast expenditure was around 6.4 per cent, and is well within SKM's recommended overall tolerance of +/-15 per cent. SKM indicated it believed the sample of unit rates it reviewed was statistically significant in representing the overall efficiency of Ergon Energy unit rates.

32.3.2 Expenditure that is Market Tested Using the Procurement Process

Around 81 per cent of Ergon Energy system capital expenditure is procured externally and therefore is market tested.

Table 88 and Table 89 provide percentage breakdowns of the total system capital and operating expenditure (excluding overheads and escalations) between:

- Internal Ergon Energy labour;
- Materials that are acquired by Ergon Energy for use by itself and contractors in undertaking capital works;
- External contractors who undertake works for Ergon Energy. This relates mainly to labour costs, as Ergon Energy provides most of the materials that contractors require to undertake capital and operating expenditure; and
- Other costs related to the delivery of capital and operating expenditure projects, such as transportation, travel and accommodation and other direct costs associated with the delivery of projects.

Table 88: *Breakdown of Total Capital Expenditure*

Category	2010-11	2011-12	2012-13	2013-14	2014-15
Labour	26.24%	24.76%	24.09%	23.49%	22.38%
Materials	22.77%	21.99%	22.23%	23.22%	23.22%
Contractors	16.07%	15.56%	15.23%	14.93%	14.56%
Other	34.93%	37.69%	38.45%	38.37%	39.84%
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Source: Tables for Proposal 32.3.2

Table 89: *Breakdown of Total Operating Expenditure*

Category	2010-11	2011-12	2012-13	2013-14	2014-15
Labour	41.86%	41.24%	40.89%	41.80%	43.53%
Materials	4.18%	4.05%	4.08%	4.07%	4.16%
Contractors	45.54%	46.18%	46.58%	45.65%	43.52%
Other	8.42%	8.53%	8.45%	8.48%	8.79%
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Source: Tables for Proposal 32.3.2

It can be seen from Table 88 that:

- Just over 80 per cent of total system capital expenditure is market tested because materials, contractors and other costs are generally procured from third party providers using Ergon Energy's competitive tender process; and
- The near 20 per cent attributable to internal labour is based on Ergon Energy's labour rates in its Ergon Energy Union Collective Agreement 2008.

It can be seen from Table 89 that:

- Up to 59 per cent of total system operating expenditure is market tested because materials, contractors and other costs are all procured from third party providers using Ergon Energy's competitive tender process; and
- The 41 per cent attributable to internal labour is based on Ergon Energy's labour rates in its Ergon Energy Union Collective Agreement 2008.

It is noted that many of the internally completed operating expenditure works are estimated based on average historical costs based on standard jobs.

32.3.3 Robust and Well Tested Procurement Processes

Ergon Energy has robust and well tested procurement processes in place, which support and encourage the achievement of competitive prices for the procurement of goods and services. These processes include the application of:

- Queensland Government State Purchasing Policy;
- Procurement policy business rules;
- Guidelines to establish and manage contracts for goods and services;
- Work instructions to manage, extend, re-invite and complete contracts;
- Work instructions to request prepare and advertise tenders for goods or services;
- Work instructions to evaluate, recommend, obtain approval and award contract; and
- Work instructions to issue tender packs, receive and open tenders.

In early 2006, DecisionMAX (an external procurement advisory company) facilitated their Health Check Program to review Ergon Energy procurement processes. Their reported indicated that:

> *.....Ergon Energy has already developed an array of best practice drivers, showcasing how procurement can be used to underpin corporate profitability and also assist an organisation in meeting their corporate governance roles and community obligations. In the Health Check Reviews considering Diversity, Partnering, Policy and Procedures, Risk Management, Centre of Excellence, Business Case Development, Strategy Development and Purchasing Skills, Ergon achieved a Health Check Review of 8,293 out of a possible 10,000 points. The highest ranked score for any government of private organisation benchmarked by the DecisionMAX Health Check Program since its inception in 1999 in the UK and Australia.*

This procurement process helps to ensure that Ergon Energy acquires its goods and services in a competitive, transparent and efficient manner. This is a key contributor to ensuring that Ergon Energy's unit rates reflect efficient market based costs, particularly for higher value or volume purchases. This is because Ergon Energy procures the majority of its materials from external sources and also outsources a significant amount of work to contractors.

32.3.4 Well Established Technical Standards

Ergon Energy requires all works to be undertaken in accordance with its technical standards and specifications. This ensures that there is consistency of application of approved design and construction standards regardless of whether the works are undertaken by Ergon Energy or a third party. These technical standards are discussed in Chapters 17, 23 and 26 of this Regulatory Proposal.

The application of these technical standards and specifications supports the prudency and efficiency of Ergon Energy's work program.

32.3.5 Application of Internal Cost Estimating Tools

As discussed in section 32.2, Ergon Energy uses the TaDS estimating tool to produce the majority of the unit rates that have been used to prepare the specified capital expenditure forecasts for the 2010-15 regulatory control period.

The TaDS estimating tool uses a bottom-up approach to prepare project estimates by drawing on a catalogue of equipment units. It has been used to prepare unit rates for particular works for this Regulatory Proposal by drawing on standard equipment units and making modifications where necessary to meet specific project requirements.

The application of the TaDS estimating tool provides significant consistency, transparency and robustness to the estimates of unit rates.

Where Ergon Energy uses unit rates to prepare specified operating expenditure forecasts, it generally applies either:

- Contractors' schedule of rates obtained through a tender process; or
- Average historical costs for standard jobs, which is sourced from the Ergon Energy Enterprise Resource Planning system.

32.3.6 Relationship between Market and Historic Cost and Unit Rates

There is feedback loop between the market and historic costs of work completed by Ergon Energy and its unit rates.

- The TaDS estimating tool was developed in 2008 and is being continually refined and updated based on market and historic information in order to align actual and estimated costs. As better estimates of costs become available they are reflected into the TaDS estimating tool so that future estimates of costs are increasingly accurate;
- Schedules of rates are periodically updated to reflect the current rates for labour and materials that result from tender processes; and
- Average historical costs for standard jobs are periodically updated to reflect the costs incurred by Ergon Energy in undertaking works in previous years.

These progressive refinements to Ergon Energy's unit rates contribute to ensuring that they are reflective of actual costs and provide an appropriate basis for forecasting capital and operating expenditure for the next regulatory control period.

32.4 LIST UNIT RATES FOR KEY ITEMS OF PLANT APPLIED IN PREVIOUS DISTRIBUTION DETERMINATION AND PROVIDE REASONS FOR MATERIAL DIFFERENCES BETWEEN 2005-10 AND 2010-15

Section 2.3.10(c) of the AER's RIN requires Ergon Energy to list the unit rates for key items of plant and equipment applied in the QCA's Final Determination for the current regulatory control period and their value. This section also requires Ergon Energy to detail the reasons for material differences between unit rates applied in the current regulatory control period and those proposed for the next regulatory control period.

Ergon Energy has provided the list of unit rates applied in the QCA's Final Determination separately to this regulatory proposal.

These QCA approved unit rates are not directly comparable to the unit rates used in the regulatory proposal for the AER because:

- The QCA unit rates used in the Final Determination for the current regulatory control period were developed for the purposes of valuing of Ergon Energy's asset base; and
- The unit rates Ergon Energy has described for the next regulatory control period have been developed for the purpose of forecasting system capital expenditure.

The difference between the unit rates is due to the fact that they are not equivalent (i.e. not comparing 'like with like').

32. UNIT RATES – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice

Codes and Rules

AR094	Ergon Energy Union Collective Agreement 2008
AR364	National Electricity Rules
AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005

Ergon Energy Documents

AR094	Ergon Energy Union Collective Agreement 2008
AR226	EE Asset Equipment Plans 2009
AR313c	Finity EE Self Insurance Arrangements for 2010-15, V2, March 2009
AR317c	Synergies EE Self Insurance Arrangements for 2010-15, 19 March 2009
AR434c	EE Unit Rates Master List Spreadsheet, 5 May 2009
AR446	EE Preventive Maintenance Programs for 2010-11 to 2014-15, V7, May 2009
AR510c	SKM Review of Estimates for Regulatory Proposal, 28 May 2009
AR514c	EE Establish & Manage Contracts for Goods and Services Guidelines, MP000901R100, V2
AR515c	EE Manage Extend Reinvite and Complete Contracts, MP000902W101, V1
AR516c	EE Issue Tender Packs, Receive and Open Tenders Works Instruction, MP000901W101, V2
AR517c	EE Procurement Policy Business Rules, MP000200R100, V8
AR518c	EE Request, Prepare and Advertise Tenders for Goods or Services Work Instructions, MP000901W100, V2
AR519	EE EP19 Procurement Policy, V1
AR535c	EE Evaluate, Recommend, Obtain Approval and Award Contract, MP000902W101, V2
AR539c	EE Regulatory Proposal Models, NARMCOS Model

33. ESCALATIONS

RIN – Section 2.3.10(b)(2)-(4) and 2.3.10(c)
[Note: RIN section 2.3.10(b)(5) is addressed in Chapter 20]

This chapter details and explains the cost escalation factors that Ergon Energy has applied to its capital and operating expenditure forecasts.

33.1 IDENTIFY SPECIFIC EXPENDITURE ESCALATORS USED IN DEVELOPING EXPENDITURE FORECASTS IN EACH YEAR 2010-15

Subsection 2.3.10(b)(2)(i) of the Regulatory Information Notice (RIN) requires Ergon Energy to identify specific expenditure escalators used in developing expenditure forecasts in each year 2010-15.

Ergon Energy has developed separate cost escalation factors to be applied to its capital and operating expenditure forecasts for the next regulatory control period on the basis that the consumer price index (CPI) does not accurately reflect movements in nominal costs associated with Ergon Energy's expenditure programs.

Ergon Energy engaged Sinclair Knight Mertz (SKM) to develop cost escalation factors for its 27 asset categories to be applied to its capital expenditure forecasts for the period 2008-09 to 2014-15. These cost escalation factors are detailed in Table 90. SKM's report is provided together with this Regulatory Proposal.

Table 90: *SKM's Real Escalators for Capital Expenditure 2004-05 to 2014-15 adjusted with Ergon Energy's CPI to be Nominal and Rebased to 2007-08*

	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Overhead Sub-transmission Lines	0.919	0.944	1.006	1.000	0.967	0.996	1.095	1.127	1.146	1.175	1.211
Underground Sub-transmission Cables	0.911	0.951	1.028	1.000	1.017	0.991	1.073	1.107	1.128	1.152	1.189
Overhead Distribution Lines	0.928	0.961	1.014	1.000	1.046	0.984	1.096	1.138	1.162	1.188	1.225
Underground Distribution Cables	0.934	0.979	1.033	1.000	1.071	1.008	1.102	1.138	1.162	1.186	1.222
Distribution Equipment	0.950	0.983	1.029	1.000	1.066	0.986	1.114	1.158	1.184	1.210	1.247
Substation Bays	0.945	0.981	1.034	1.000	1.059	1.001	1.110	1.149	1.172	1.195	1.232
Substation Establishment	0.920	0.957	1.060	1.000	1.028	1.047	1.093	1.113	1.121	1.136	1.177
Distribution Substation Switchgear	0.971	1.007	1.049	1.000	1.078	0.930	1.131	1.189	1.214	1.2436	1.276
Zone Transformers	0.926	0.971	1.039	1.000	1.028	0.806	1.081	1.158	1.177	1.194	1.237
Distribution Transformers	0.923	0.961	1.023	1.000	1.033	0.933	1.085	1.135	1.156	1.179	1.217
Low Voltage Services	0.905	0.935	1.012	1.000	0.961	0.879	1.059	1.120	1.147	1.176	1.215
Metering	0.950	0.989	1.024	1.000	1.073	1.026	1.114	1.150	1.178	1.205	1.239

	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Communications - Pilot Wires	0.919	0.944	0.977	1.000	1.018	1.045	1.071	1.097	1.124	1.152	1.180
Generation Assets	0.962	0.998	1.036	1.000	1.086	0.952	1.131	1.184	1.206	1.227	1.266
Street Lighting	0.927	0.954	0.995	1.000	1.042	1.030	1.094	1.127	1.149	1.176	1.210
Other Equipment	0.919	0.944	0.977	1.000	1.018	1.045	1.071	1.097	1.124	1.152	1.180
Control Centre - SCADA	0.919	0.944	0.977	1.000	1.018	1.045	1.071	1.097	1.124	1.152	1.180
Land & Easements											
RESIDENTIAL	0.852	1.034	0.961	1.000	1.025	1.066	1.091	1.113	1.141	1.173	1.207
COMMERCIAL	0.889	1.308	0.971	1.000	1.025	1.066	1.091	1.113	1.141	1.173	1.207
RURAL	0.867	1.370	0.948	1.000	1.025	1.066	1.091	1.113	1.141	1.173	1.207
OTHER	0.893	0.989	1.040	1.000	1.025	1.066	1.091	1.113	1.141	1.173	1.207
Communications	0.919	0.944	0.977	1.000	1.018	1.045	1.071	1.097	1.124	1.152	1.180
IT Systems	0.919	0.944	0.977	1.000	1.018	1.045	1.071	1.097	1.124	1.152	1.180
Office Equipment & Furniture	0.919	0.944	0.977	1.000	1.018	1.045	1.071	1.097	1.124	1.152	1.180
Motor Vehicles	0.919	0.944	0.977	1.000	1.018	1.045	1.071	1.097	1.124	1.152	1.180
Plant & Equipment	0.919	0.944	0.977	1.000	1.018	1.045	1.071	1.097	1.124	1.152	1.180
Buildings	0.920	0.957	1.060	1.000	1.028	1.047	1.093	1.113	1.121	1.136	1.177

Source:

Tables for proposal 33.1, SC Opex and Capex Model, AR438 SKM_Electricity Industry Labour, Commodity & Asset Price Cost Indices_St 2 (updated for GFC)_6Oct08 and AR461 SKM_Electricity Industry Labour, Commodity & Asset Price Cost Indices_St 2 (Jan09 Update of Escalators)_14Jan09

Ergon Energy has developed cost escalation factors to be applied to materials, contractors, labour and all other cost inputs to be applied to its operating expenditure forecasts for the period 2008-09 to 2014-15. These cost escalation factors are detailed in Table 91.

Table 91: *Ergon Energy's Nominal Escalators for Operating Expenditure 2008-09 to 2014-15*

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Materials	1.036	0.949	1.051	1.037	1.041	1.036	1.032
Contractors	1.051	1.051	1.044	1.045	1.045	1.045	1.045
Labour	1.051	1.051	1.044	1.045	1.045	1.045	1.045
Other	1.027	1.029	1.028	1.028	1.028	1.028	1.028

Source: Tables for Proposal 33.1 and AR509 SKM Cover Letter Opex Materials Cost Esc_9Apr2009

It is noted that:

- 'Materials' refers to the cost of items used in undertaking repairs and maintenance, such as meters, poles, conductors and connectors, underground cables and joints, lines and fuses; and
- 'Other' refers to direct costs associated with the operating expenditure program, such as travel, freight, transport, training and consultant's fees. Importantly, these costs exclude overheads, which are separately incorporated into the operating expenditure forecasts, as discussed in Chapter 34 of this Regulatory Proposal.

33.2 STATE WHETHER EXPENDITURE ESCALATORS ARE IN REAL OR NOMINAL TERMS

Sub-section 2.3.10(b)(2)(ii) of the RIN requires Ergon Energy to state whether the expenditure escalators are expressed in real or nominal terms.

Ergon Energy confirms that all of the escalators detailed in Table 90 and Table 91 in section 33.1 are expressed in nominal terms (i.e. with inflation applied).

33.3 EXPLAIN METHODOLOGY FOR CALCULATING ESCALATOR, INCLUDING SOURCES, DATA CONVERSIONS AND USE OF ASSUMPTIONS, INCLUDING LAGS

Subsection 2.3.10(b)(2)(iii) of the RIN requires Ergon Energy to explain how its escalators have been developed and to provide associated source information including sources, data conversions and the use of any assumptions, including lags. Different approaches have been applied to developing escalators for capital and operating expenditure.

33.3.1 Escalators for Capital Expenditure

Ergon Energy engaged Sinclair Knight Mertz (SKM) to develop suitable cost escalation factors for its capital expenditure forecasts for the next regulatory control period. As a result, SKM prepared a report entitled 'Electricity Industry Labour, Commodity and Asset Price Cost Indices' (SKM Report) in October 2008. As a result of the ongoing global financial crisis, Ergon Energy requested that SKM provide, where relevant, updated escalation factors in January 2009.

The following process describes the approach taken by SKM to prepare its cost escalators and by Ergon Energy to apply these escalators to its capital expenditure forecasts for the next regulatory control period.

Step 1 – SKM assessed the key factors influencing costs of inputs

SKM assessed the key factors influencing the costs of inputs for network projects by conducting a strategic procurement study involving nine Australian electricity network businesses, including Ergon Energy. This study examined confidential contract information for the purchase of the businesses' main items of plant, equipment and materials, such as power transformers, switchgear, cables and conductors over the period 2002 to 2006. A detailed description of the process of this study is provided in section 4 of the SKM Report.

SKM found the key factors influencing cost movements to be:

> *...changes in the market pricing position for:*
>
> - *Oil;*
> - *Labour;*
> - *Construction costs;*
> - *Foreign exchange rates;*
> - *The Trade Weighted index;*
> - *Materials such as copper, aluminium and steel;*
> - *Wood poles; and*
> - *Other Cost Components (which include e.g. Supplier's Transport costs and profit margin sought in the supply chain, to which CPI is assigned as an appropriate escalator).*[55]

SKM's study also found "that for certain items of plant and equipment, specifically those with more rapidly evolving technology; long-term average price movements displayed notably lower growth rates"[56]. It found that "the extent of this factor tends to produce an effective 1 per cent cost reduction for these items per annum"[57]. This information is provided to satisfy the requirements of section 2.3.10(b)(2)(iv) of the RIN.

Step 2 - SKM assigned individual cost component weightings to each project component

SKM then determined the contribution, or weighting, of the key cost drivers to the total price of the main items of plant, equipment and materials that comprise network assets. This is described in section 4.8 of the SKM Report.

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[55] SKM, Electricity Industry Labour, Commodity and Asset Price Cost Indices, October 2008, pages 10-11

[56] Ibid, page 11

[57] Ibid, page 11

Step 3 – SKM applied standard project building blocks for plant, equipment and materials

SKM then mapped movements of individual plant, equipment and materials to movements in the cost of network infrastructure projects and asset classes through the application of established project 'building blocks'. These 'building blocks' represent the proportions of labour and materials based on standard unit rates for asset valuation and capital asset comparisons. This is described in section 4.9 of the SKM Report.

Step 4 – SKM updated movements in key cost drivers for plant, equipment and materials

SKM developed forecast positions of the key cost drivers for the period 2004-05 to 2014-15. Section 5 of the SKM Report describes the methodology for updating these movements in the key cost drivers from year to year. This methodology involves:

- Foreign exchange – applying the long-term forecast for the Australian dollar from the December 2007 publication entitled 'Australian National State and Industry Outlook' prepared by Econtech;
- Trade weighted index (TWI) – applying "a TWI of 71 post actual historical data, which was...(used) in developing an economic outlook for the 2008-9 Australian budget";
- Manufacturing costs – applying the Consumer Price Index (CPI) for locally manufactured equipment and, for imported equipment, "a proxy escalator by adding the TWI (to account for A$ movements) and CPI (based on a simplifying assumption that average manufacturing costs in other countries would change at the same rate as Australia)"[58];
- Site labour costs – applying the new Ergon Energy Union Collective Agreement 2008 between June 2005 and June 2011 and a utility sector labour price forecast prepared by Econtech for the period June 2012 to June 2015 inclusive;
- General labour costs – applying Econtech's National Forecasts for Wages Growth for its Australian 'All Industries' sector;
- Construction costs – applying the Australian National 'Engineering' cost forecasts (which cover electricity and pipeline construction) prepared by the Construction Forecasting Council of the Australian Construction Industry Forum;
- Aluminium, copper, oil and steel – employing "various combinations of futures contract prices and a range of views from credible forecasting professionals" as described in sections 5.6 to 5.8 of the SKM Report; and
- Wood poles – applying the CPI to all forecasts.

Chapter 6 of the SKM Report details the values of the forecast movements in each of these key cost drivers for the period 2004-05 to 2014-15.

Step 5 – SKM developed cost escalation factors for non-network equipment assets

SKM developed cost escalation factors for non-network equipment assets in section 7 of the SKM Report. This involved:

- Land and easements – employing an annual average growth rate based on long-term land value growth rates in Queensland as presented by the Australian Bureau of Statistics (ABS);
- IT systems – applying the CPI to all forecasts;
- Office equipment and furniture – applying the CPI to all forecasts;
- Motor vehicles – applying the CPI to all forecasts;
- Plant and equipment – applying the CPI to all forecasts; and
- Buildings – applying construction cost escalation rates.

Step 6 – SKM developed long-term forecasts of escalators for Ergon Energy's 27 asset categories

SKM developed long term forecasts, for the period 2004-05 to 2014-15, of the escalators to be applied to Ergon Energy's 27 asset categories by extrapolating the 'building blocks' approach described in step 3 using the cost escalation factors described in steps 4 and 5.

SKM's forecasts were developed in real terms, using 2004-05 as the base year.

Step 7 – Ergon Energy rebased the SKM real forecast escalators from 2004-05 to 2010-11

Ergon Energy rebased the SKM real forecast escalators so that 2007-08 became the base year – this resulted in the index for 30 June 2008 equalling 1.000.

The escalators for all years were then re-expressed as cumulative escalators, such that the 2010-11 escalator is the factor by which the cost as at 30 June 2008 needs to be increased in order for that cost to be expressed in 2010-11, but still in real dollars as at 30 June 2008.

Step 8 – Ergon Energy applied inflation to derive nominal forecasts

Ergon Energy then escalated the real SKM escalators by Ergon Energy's forecasts of inflation for the next regulatory control period in order to convert the real escalators into nominal terms. These are the same inflation forecasts that are used in the AER's Post Tax Revenue Model (PTRM) and the Roll Forward Model (RFM).

[58] Ibid, page 16

The inflation forecasts have been rebased such that 30 June 2008 equals 1.000, and the year-on-year 30 June 2008 dollar forecasts are escalated using a cumulative inflation factor.

This cumulative inflator works such that the 2010-11 escalator is the factor by which the real 30 June 2008 cost for 2010-11 (or other year) derived in step 7 needs to be increased, in order for that cost to be expressed in 2010-11 dollars (or other year).

At the end of step 8, the forecasts are nominal for each year for each of Ergon Energy's 27 asset categories.

Step 9 – Ergon Energy applied nominal inflators to capital expenditure forecasts

The PTRM requires inputs to be expressed as at 30 June 2010 (i.e. in 2009-10 dollars). This requires the nominal forecasts derived in step 8 to be deflated to 30 June 2010 dollars.

This has been done by re-basing an inflation factor such that 30 June 2010 equals 1.000 and expressing all past and future years as cumulative indices from that date.

The nominal forecasts for each year were then divided by these cumulative factors in order to express the forecasts in 2009-10 dollars.

At the end of this step 9, the forecasts include cost escalator increases as derived by SKM, which are expressed in 2009-10 dollars. These then form the inputs to the PTRM, which delivers the Annual Revenue Requirement.

Step 10 – SKM review of application of cost escalation factors

SKM reviewed Ergon Energy's application of the cost escalation factors and warranted that Ergon Energy had applied the cost escalation factors in its internal models in the manner that SKM intended them to be applied.

33.3.2 Escalators for Operating Expenditure

There are four input cost escalators that are relevant to Ergon Energy's proposed operating expenditure program:

- Materials and contractors – a constant nominal increase of 6 per cent per annum has been applied to all materials and contractors used in undertaking repairs and maintenance. This value has been determined based on advice received from SKM;
- Contractors – all contractor rates have ben escalted by an increment based on the new Ergon Energy Union Collective Agreement 2008. It is a requirement of the Union Collective Agreement that contractor staff rates are indexed to Ergon Energy's staff rates.
- Labour – all productive Ergon Energy labour costs have been escalated by an increment based on the new Ergon Energy Union Collective Agreement 2008 increase of 4.5 per cent per annum, plus an additional Electricity Distribution and Service Delivery (EDSD) Review technical or professional allowance increment that is payable to Ergon Energy staff, which ceases in 2010-11; and
- Other – it has been assumed that the cost of all other direct inputs will increase in real terms in line with previous years' budget escalations.

Further details relating to the efficiency of these proposed escalators is provided in section 27.3.2 of this Regulatory Proposal.

Unlike for capital expenditure, where escalators have been developed for individual assets, the four cost escalators are applied in the same manner across Ergon Energy's entire operating expenditure program, albeit different components of the program have different input costs.

33.4 WEIGHTINGS GIVEN TO ESCALATOR, HOW DEVELOPED, INCLUDING ASSUMPTIONS

The RIN section 2.3.10(b)(2)(iv) requires that escalators indicate the weightings given to each escalator and how these weightings have been developed, including assumptions.

None of the escalators Ergon Energy has applied to capital or operating expenditure involves the application of weightings.

The capital expenditure escalators are all inclusive escalators for each asset category. The escalators are applied to actual and forecast expenditure for each of Ergon Energy's 27 asset categories. There is therefore no need for weightings to be applied with these escalators.

Ergon Energy's unescalated operating expenditure programs have been built up based on four cost categories – labour, materials, contractors and other. Escalators have been developed for each of these cost categories. These escalators have been applied to the unescalated costs for each operating expenditure program. There is therefore no need for weightings to be applied with these escalators.

33.5 COPY OF MODELS USED TO DERIVE AND APPLY ESCALATORS

The RIN section 2.3.10(b)(2)(v) requires that Ergon Energy identify any model(s) it has used to apply escalators.

Ergon Energy:

- Cannot provide the AER with SKM's model that has been used to derive the capital expenditure escalators. This model is proprietary to SKM, however their methodology for preparing the cost escalators is fully explained in their report to Ergon Energy, which has been provided to the AER with this Regulatory Proposal;
- Did not use a model to derive the operating expenditure escalators; and
- Developed a model to apply the capital and operating expenditure escalators, which has been provided to the AER with this Regulatory Proposal.

33.6 EXPLAIN WHETHER SAME EXPENDITURE ESCALATORS HAVE BEEN DEVELOPED FOR CAPITAL EXPENDITURE AND OPERATING EXPENDITURE FOR 2010-15

Subsection 2.3.10(b)(3) of the RIN requires Ergon Energy to explain whether the same expenditure escalators have been used in developing proposed capital and operating expenditures.

Ergon Energy confirms that, as detailed above, it has applied different escalators to its capital and operating expenditure forecasts for the next regulatory control period.

33.7 IF NOT, JUSTIFY AND PROVIDE SUPPORTING EVIDENCE FOR DIFFERENT ESCALATORS

Subsection 2.3.10(b)(3) of the RIN requires Ergon Energy to provide a justification and supporting evidence as to why different expenditure escalators have been applied to its capital and operating expenditure forecasts.

Ergon Energy has applied different escalators to capital and operating expenditure because they relate to fundamentally different programs of work and involve the use of fundamentally different inputs.

The capital expenditure escalators have been developed to take into account movements in the costs of labour, oil, construction, materials such as copper, aluminium, and steel, wood poles as well as foreign exchange rates and the TWI. Specific escalators have then been developed by SKM for each individual asset class.

Common operating expenditure escalators have been applied to all of Ergon Energy's operating expenditure, albeit that annual escalators have been developed for materials, contractors, labour and other inputs. Individual escalators have not been developed for different operating expenditure programs.

Importantly, the Ergon Energy Union Collective Agreement 2008 has been used as the basis for escalating all productive labour costs related to both capital and operating expenditure. However, different escalators have been used for other input costs because of differences in the nature of the materials and other inputs used in undertaking the capital and operating expenditure programs.

33.8 CONTINGENCY FACTORS

Subsection 2.3.10(b)(4) of the RIN requires Ergon Energy to provide information about whether its capital and operating expenditure estimation process involves the application of contingency factors, what risks they account for and how they have been calculated.

Ergon Energy confirms that its capital and operating expenditure forecasts for the next regulatory control period do not include any contingency factors.

33.9 LIST ESCALATORS FOR KEY ITEMS OF PLANT APPLIED IN PREVIOUS DISTRIBUTION DETERMINATION AND PROVIDE REASONS FOR MATERIAL DIFFERENCES BETWEEN 2005-10 AND 2010-15

Section 2.3.10(c) of the RIN requires Ergon Energy to list the expenditure escalators and unit rates for key items of plant and equipment applied in the previous distribution determination and their value. Ergon Energy must also set out the reasons for any differences between the historical escalators and units rates and those proposed to be applied in the current regulatory control period.

Ergon Energy notes that it does not possess the individual expenditure escalators and unit rates for key items of plant and equipment applied in the Queensland Competition Authority (QCA) Final Determination for the 2005-10 regulatory control period. Ergon Energy is therefore unable to directly comment on these unit rates and escalators.

Ergon Energy does note however, any difference between the historical and proposed unit rates would likely be due, to a large extent, to the differences in economic conditions experienced (and expected to be experienced) in the current regulatory control period, and economic conditions expected to be experienced during the next regulatory control period. The relatively recent rapid change in economic outlook is closely linked to the global financial crisis, which manifested in the second half of 2008.

33. ESCALATIONS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice
AR524	AER Post Tax Revenue Model Handbook
AR526	AER Roll Forward Model Handbook

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005

Codes and Rules

Nil

Ergon Energy Documents

AR094	Ergon Energy Union Collective Agreement 2008
AR169	SKM Electricity Industry Labour, Commodity and Asset Price Indices, Model Outputs, 9 October 2008
AR438	SKM Electricity Industry Labour, Commodity & Asset Price Cost Indices, St 2 (updated for GFC), 6 October 2008
AR461	SKM Electricity Industry Labour, Commodity & Asset Price Cost Indices, St 2 (Jan09 Update of Escalators), 14 January 2009
AR539c	EE Regulatory Proposal Models, Roll Forward Model
AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

C CONFIDENTIAL INFORMATION

34. SHARED COSTS (OVERHEADS)

Rules – Clauses 6.5.6(b)(2) and 6.5.7(b)(2)
RIN – Sections 2.2.1(b) and 2.2.2(b)
CAG – Sections 5.1(b)(1) and (2)
[Note: CAG clause 5.1(b)(5) is addressed in Chapter 40]
RIN Pro formas - 2.2.1, 2.2.2, and 2.2.4

Sections 5.1(b)(1) and (2) of the Cost Allocation Guidelines require Ergon Energy to apply its approved Cost Allocation Method (CAM) in preparing its operating and capital expenditure forecasts that are to be submitted to the Australian Energy Regulator (AER) in accordance with clauses 6.5.6 and 6.5.7 of the Rules.

Sections 2.2.1(b) and 2.2.2(b) of the Regulatory Information Notice (RIN) require Ergon Energy's historical and forecast capital and operating expenditure to be prepared consistent with its CAM.

Clauses 6.5.6(b)(2) and 6.5.7(b)(2) of the Rules require the operating and capital expenditure forecasts that are included in this Building Block Proposal to relate to expenditure that has been properly allocated in accordance with Ergon Energy's approved CAM.

This chapter describes how Shared Costs (Overheads) have been applied in developing Ergon Energy's operating and capital expenditure forecasts for its Standard Control Services.

34.1 DISTINCTION BETWEEN DIRECT COSTS AND SHARED COSTS

Ergon Energy has two types of costs – direct costs and Shared Costs (Overheads).

Ergon Energy's CAM describes the process for the attribution of direct costs and for the allocation of shared costs using causal allocations.

The following nine-step method is used for determining and allocating Shared Costs (Overheads):

- Step 1 – Ergon Energy determines the total Shared Costs (Overheads) pool to be allocated based on the 2008-09 annual forecast budget and Statement of Corporate Intent (SCI), adjusted for known material changes since the preparation of the budget.

  This pool represents the total Shared Costs (Overheads) that are to be allocated between total 'regulated' and total 'unregulated' operating and capital expenditure. Ergon Energy's 'regulated' expenditure is included in this Regulatory Proposal, whereas its 'unregulated' expenditure is not.

- Step 2 – Ergon Energy then determines for operating expenditure:
  a. The direct 'unregulated' operating expenditure that is to attract a percentage of Shared Costs (Overheads);
  b. The direct 'regulated' operating expenditure that is to attract a percentage of Shared Costs (Overheads); and
  c. The total direct operating expenditure that is to attract a percentage of Shared Costs (Overheads), being the sum of (a) and (b) above.

- Step 3 – Ergon Energy then determines for capital expenditure:
  a. The direct 'unregulated' capital expenditure that is to attract a percentage of Shared Costs (Overheads);
  b. The direct 'regulated' capital expenditure that is to attract a percentage of Shared Costs (Overheads); and
  c. The total direct capital expenditure that is to attract a percentage of Shared Costs (Overheads), being the sum of (a) and (b) above.

- Step 4 – Ergon Energy then determines the total direct expenditure that is to attract Shared Costs (Overheads) by adding the total direct operating expenditure from step 2(c) to the total direct capital expenditure from step 3(c);

- Step 5 – Ergon Energy then determines the total Shared Costs (Overheads) to be allocated to operating expenditure.

  This is calculated by dividing the total direct operating expenditure attracting Shared Costs (Overheads) by the total direct expenditure attracting Shared Costs (Overheads) and multiplying the product by the total Shared Costs (Overheads).

  Total Shared Costs (Overheads) to be allocated to operating expenditure =

  [Step 2(c) ÷ Step 4] x Step 1

- Step 6 – Ergon Energy then determines the total Shared Costs (Overheads) to be allocated to 'regulated' direct operating expenditure.

  This is determined by dividing 'regulated' direct operating expenditure attracting Shared Costs (Overheads) by the total direct operating expenditure attracting Shared Costs (Overheads) and multiplying the product by the total Shared Costs (Overheads) to be allocated to operating expenditure.

  Total Shared Costs (Overheads) to be allocated to 'regulated' operating expenditure =

  [Step 2(b) ÷ Step 2(c)] x Step 5

  The same method is used to determine the total Shared Costs (Overheads) to be allocated to:

  - 'Unregulated' direct operating expenditure;
  - 'Regulated' direct capital expenditure; and
  - 'Unregulated' direct capital expenditure.

  As a result, Ergon Energy determines the Shared Costs (Overheads) to be allocated to 'regulated' and 'unregulated' direct operating and capital expenditure.

- Step 7 – Ergon Energy then spreads the Shared Costs (Overheads) to be allocated to 'regulated' direct operating expenditure across the various programs of operating expenditure used in this Regulatory Proposal. This is done by determining the proportion of the direct operating expenditure costs for each program to the total direct operating expenditure costs multiplied by the total Shared Costs (Overheads) to be allocated to 'regulated' operating expenditure. It is noted that there are some operating expenditure categories, such as training, that do not attract a Shared Costs (Overhead) charge as they represent Shared Costs (Overhead) in their own right.

  This method is also undertaken in order to allocate the Shared Costs (Overheads) to be allocated to 'regulated' direct capital expenditure between the various category drivers of capital expenditure.

  As a result, Ergon Energy quantifies the Shared Costs (Overheads) to be allocated to each program of direct operating expenditure and category driver of direct capital expenditure.

- Step 8 – Ergon Energy then determines the total costs for each program of operating expenditure by adding the direct operating expenditure costs to the Shared Costs (Overheads) for each program of operating expenditure. This is also undertaken for each category driver of capital expenditure.

  Because the programs of operating expenditure and category drivers of capital expenditure are categorised as either Standard Control Services or Alternative Control Services, it can clearly be demonstrated that Shared Costs (Overheads) have been correctly applied to Standard Control Services and Alternative Control Services.

- Step 9 – Ergon Energy also allocates the Shared Costs (Overheads) to be allocated to 'regulated' direct capital expenditure between its 27 asset categories. This is necessary because Ergon Energy is required to present its five year capital expenditure forecast for the next regulatory control period both by category driver and asset class.

  Shared Costs (Overheads) by asset class are calculated by determining the proportion of the direct capital expenditure costs for each asset class in proportion to the total direct capital expenditure costs multiplied by the total Shared Costs (Overheads) to be allocated to 'regulated' capital expenditure.

  As a result, the Shared Costs (Overheads) to be allocated to each of the 27 asset categories are also quantified.

34.2 FORECASTS CONSISTENT WITH CAM

Ergon Energy's operating and capital expenditure forecasts that are included in this Building Block Proposal relate to expenditure that has been properly allocated in accordance with its approved CAM. This is because Ergon Energy has:

- Distinguished between direct costs and Shared Costs (Overheads) on the basis provided for in the CAM;
- Proposed the same classification of Distribution Services in this Regulatory Proposal as is detailed in its CAM;
- Attributed its direct costs directly to the relevant categories of operating and capital expenditure, including by distinguishing between 'regulated' and 'unregulated' expenditure; and
- Ergon Energy has allocated its Shared Costs (Overheads) on the basis of total labour and materials costs as is provided for in the CAM.

Importantly, Ergon Energy interprets Chapter 6 of the Rules and the AER's Cost Allocation Guidelines to mean that it does not need to apply the principles and policies detailed in section 11 of its CAM in determining the operating and capital expenditure forecasts in this Regulatory Proposal. This is because these principles and policies are only relevant to allocating Shared Costs (Overheads) into Ergon Energy's Chart of Accounts as they are actually incurred. This involves allocating Shared Costs (Overheads) firstly to districts and then between responsibility centre, activity, product code and expense element segments.

The Chart of Account categories are not used to prepare the operating and capital expenditure forecasts for this Regulatory Proposal. Instead, the forecasts have specifically been prepared on the basis of category drivers and asset classes for capital expenditure, and program types for operating expenditure, as is required by clauses S6.1.1(1)(i) and (ii) and S6.1.2(1)(i) and (ii) of the Rules.

34.3 JUSTIFICATION OF SPARQ COSTS

Distribution Network Service Providers (DNSPs) require a significant Information and Communications Technology (ICT) capability. They can either develop this capability internally or acquire it from another party. When developed internally, the associated costs are typically incorporated into a DNSP's capital and operating expenditure forecasts.

However, Ergon Energy and ENERGEX established SPARQ Solutions Pty Ltd (SPARQ) to provide them with ICT services from 1 July 2004. As discussed in Chapter 5 of this Regulatory Proposal, SPARQ is a related party that is jointly controlled by Ergon Energy and ENERGEX and is only able to provide services to its owners.

Because SPARQ's costs make up a large proportion of Ergon Energy's Shared Costs (Overheads) and therefore are a significant contributor to the capital and operating expenditure forecasts, Ergon Energy considers it appropriate to explain and justify SPARQ's forecasts costs in this Regulatory Proposal.

34.3.1 Nature of Ergon Energy's Relationship with SPARQ

SPARQ is jointly owned 50/50 by Ergon Energy and ENERGEX. SPARQ operates under its own Constitution and provides ICT services under various contractual arrangements to its owners. SPARQ holds the majority of the ICT assets that are used by Ergon Energy on its books. The remaining ICT assets are owned by Ergon Energy and the capital expenditure forecasts for the next regulatory control for these assets are detailed in Chapter 23 of this Regulatory Proposal.

Importantly for this Regulatory Proposal:

- SPARQ only provides services to Ergon Energy and ENERGEX (not to external parties);
- SPARQ's Constitution requires that it operate on a not-for-profit basis so that it 'breaks even' each year; and
- SPARQ owns the ICT assets that it purchases (whilst Ergon Energy and ENERGEX also own a small amount of other ICT assets).

SPARQ incurs asset-related and non-asset-related costs. The asset-related costs are for the return on, and of, the assets in its asset base that it uses to provide its ICT services to Ergon Energy. The non-asset-related costs include SPARQ's operating expenditure that is required to provide its ICT services to Ergon Energy.

SPARQ levies a charge on Ergon Energy in order to recover its asset-related and non-asset-related costs.

SPARQ's costs are treated as a Shared Cost (Overhead) by Ergon Energy because they cannot be directly attributed to Business Units and services that are provided by Ergon Energy. SPARQ's costs are therefore allocated in accordance with Ergon Energy's approved CAM. It is this Shared Cost (Overhead) that is dealt with and justified in this section 34.3 of the Regulatory Proposal.

34.3.2 Ownership of ICT Assets

Ergon Energy owns certain ICT assets that are:

- System-related, which are necessary for the operation of the distribution network, such as Supervisory Control and Data Acquisition (SCADA), communications equipment, other system control equipment, broadband infrastructure and associated software; and
- Non-system related, but support the provision of its Distribution Services, such as:
  - Desktop and laptop personal computers and smaller ICT devices, such as printers and multi-function devices; and
  - Legacy assets where the original application asset was held by Ergon Energy prior to the formation of SPARQ and it is not cost effective to perform an asset transfer from Ergon Energy to SPARQ.

All other ICT assets used to provide Ergon Energy's Distribution Services are owned, operated and managed by SPARQ in order for it to provide ICT services to Ergon Energy and ENERGEX. These ICT assets are held on SPARQ's balance sheet.

It is expected that this asset ownership arrangement will continue in the next regulatory control period, although Ergon Energy's legacy assets will likely migrate into SPARQ as they are replaced.

34.3.3 Nature of Services Provided by SPARQ to Ergon Energy

SPARQ provides services to Ergon Energy under a Service Level Agreement (SLA). The services covered under the 2008-09 SLA are:

- End user services – this refers to Service Desk Services and Desktop Services. Subcategories of these services include:
  - Corporate ICT services, including help desk support;
  - ICT procurement of hardware and software;
  - Voice and data telecommunication; and
  - Infrastructure services, including Mainframe, Corporate Data, Storage Area Network, Unix, Windows and e-mail servers.

- Business application services – this refers to applications that are specific to Ergon Energy in order to assist in the management of its business processes and the provision of its Distribution Services. SPARQ provides different levels of service-based on the assessed criticality of the system to Ergon Energy's operations.
- ICT service continuity – this refers to the continuity of the provision of ICT services, including disaster recovery requirements; and
- Project services – this refers to services provided in response to specific work requests from Ergon Energy, as required.

All of these SPARQ services are relevant to the provision of Ergon Energy's Distribution Services.

34.3.4 Basis on Which SPARQ Incurs Costs and then Charges Ergon Energy

SPARQ's charges to Ergon Energy can be broken down as follows:

- SPARQ Operational Support Costs:
  - → An SLA charge;
  - → Pass through charges – this relates to a pass through of software licensing and maintenance costs and the costs of mobile and satellite phones and corporate telecommunications.
- ICT Asset Costs for Existing Capitalised Investments – this includes an asset charge and a finance charge; and
- Project Costs for new investments – this relates to:
  - → Upgrades and replacements in order to maintain existing ICT capability; and
  - → Enhancements and new capability.

Project services are provided on an 'as required' basis and SPARQ's charges are agreed with Ergon Energy in advance. These charges are therefore not detailed in the SLA.

Importantly, SPARQ structures these charges in order to recover the costs of its operations. This means that it neither makes profits nor losses each year.

34.3.5 Forecast 2010-15

Ergon Energy's Shared Costs (Overheads) – SPARQ forecast for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 92.

***Table 92:** Shared Costs (Overheads) - SPARQ – 2010-15 ($M Nominal)*

2007-08 AER BASE YEAR	2008-09 Estimate	2009-10 Estimate	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
41.41	57.74	59.52	69.10	80.56	90.39	93.35	90.37	423.76	84.75

Source: Tables for Proposal

34.3.6 Estimation Process

Table 93 provides a breakdown of the forecasts of SPARQ's charges to Ergon Energy for the next regulatory control period.

Table 93: *SPARQ Charges - Forecast 2010-15 ($M Nominal)*

		2010-11	2011-12	2012-13	2013-14	2014-15

Source: AR308c EE_Joint ICT Finances_Sep08 baseline_V1.4_2Feb09

The SPARQ ICT forecasts are developed as part of the Joint ICT Plan, which is Ergon Energy's seven year ICT plan that is developed in conjunction with SPARQ and ENERGEX. Ergon Energy has provided this Joint ICT Plan to the AER as part of this Regulatory Proposal.

The role of the Joint ICT Plan is to guide ICT investment decision making for the near to medium term. Specifically, this Plan provides direct input into the Annual Consolidated Program of Work planning process, which determines the ICT operating budget attributable to Ergon Energy and is recovered through SPARQ's charges. The Joint ICT Plan identifies the following 10 investment streams in which SPARQ will undertake its work:

- Governance, risk and compliance;
- Knowledge management;
- Market systems;
- Customer systems;
- Energy systems;
- Workforce automation;
- Enterprise resource planning;
- Network planning and design;
- Network operations; and
- Infrastructure and communications.

The Joint ICT Plan explains and justifies SPARQ's capital and operating expenditure programs in relation to each of these investment streams in order to enable it to provide its services to Ergon Energy and ENERGEX. It does this by addressing the following matters for each investment stream: general, current state, strategic drivers, investment intent, assumptions, dependencies, benefits and investment roadmap.

SPARQ recovers the costs of its capital and operating expenditure from Ergon Energy (and ENERGEX) through the charges discussed in section 34.3.4. The forecasts of these charges are detailed in the document entitled Joint ICT Plan – ICT Financial Forecast – Ergon Energy. The forecasts of SPARQ's asset charges include investment for four new areas of capability for Ergon Energy in the next regulatory control period:

- Distribution Management System at a cost of ;
- Field Force Automation at a cost of ;
- Data Centres at a cost of ; and
- ICT infrastructure at a cost of .

Governance of the Joint ICT Plan is overseen by a committee comprising executive management from Ergon Energy and ENERGEX and SPARQ. Initiatives within the Joint ICT Plan have been estimated using a project estimation model.

34.3.7 Assumptions

In addition to the Key Assumptions described in Chapter 15 of this Regulatory Proposal, the Joint ICT Plan details the assumptions that have been made for each of the 10 investment streams referred to in section 34.3.6.

34.3.8 Justification of the Forecasts

The Joint ICT Plan details the investment intent and benefits of investments for each of the 10 investment streams referred to in section 34.3.6.

In addition, Ergon Energy and ENERGEX jointly engaged Klynveld Peat Marwick Goerdeler (KPMG) to review the prudency and efficiency of SPARQ's capital and operating expenditure, which is recovered through charges to Ergon Energy and ENERGEX.

KPMG reviewed the Joint ICT Plan and the Joint ICT Plan – ICT Financial Forecast – Ergon Energy and prepared three reports:

- Report on efficiency of IT services and prudency of IT forecasts – ENERGEX, Ergon Energy and SPARQ Solutions;
- IT Service Delivery Efficiency Assessment – ENERGEX, Ergon Energy and SPARQ Solutions; and
- IT Expenditure Forecast Prudency Assessment – ENERGEX, Ergon Energy and SPARQ Solutions.

Ergon Energy has provided each of these reports to the AER as part of this Regulatory Proposal.

The three KPMG reports confirm that SPARQ's expenditure forecasts are reasonable and can be relied upon for the purposes of forecasting Ergon Energy's Shared Costs (Overheads) attributable to ICT services received from SPARQ.

34.3.9 Risk Considerations

The Joint ICT Plan details the current state, including the current gaps and weaknesses, for each of the 10 investment streams referred to in section 34.3.6. The expenditure program is designed to address these gaps and weaknesses. This will ensure that Ergon Energy has access to ICT systems that support its critical business operations to enable it to provide its Distribution Services to customers in accordance with its regulatory obligations.

34.3.10 Customer Outcomes

The Joint ICT Plan details the benefits that are expected to result from investment in each of the 10 investment streams referred to in section 34.3.6. Whilst these benefits will initially accrue to Ergon Energy, they will also result in improved service performance to customers.

34. SHARED COSTS (OVERHEADS) – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice
AR417 & 418	AER Cost Allocation Guidelines, Final Decision and Guidelines, 26 June 2008

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR173c	EE Statement of Corporate Intent 2008-09, 29 May 2008
AR307c	EE Joint ICT Plan, Sep08 baseline, V1.2, 19 January 2009
AR308c	EE Joint ICT Finances Sep08 Baseline, V1.4, 2 February 2009
AR310c	KPMG IT Service Delivery Efficiency Assessment, 18 December 2008
AR311c	KPMG IT Expenditure Forecast Prudency Assessment - ENERGEX, Ergon Energy and SPARQ Solutions, 12 March 2009
AR312	KPMG ENERGEX and Ergon IT Efficiency and Prudency Summary Report, 27 March 2009
AR314	EE Cost Allocation Method, AER Approved
AR323c	SPARQ EE Service Level Agreement (SLA) 2008-2009
AR537c	EE Statement of Corporate Intent 2009-10, May 2009

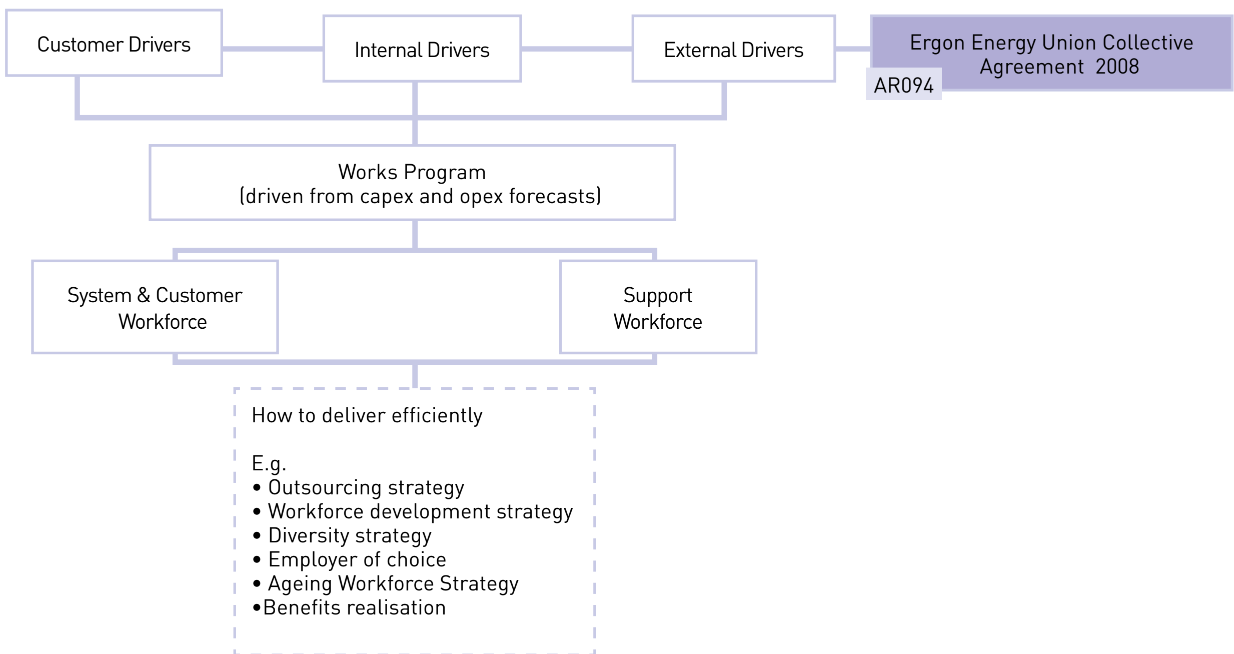
35. DELIVERING THE EXPENDITURE PROGRAM

Rules – Clauses 6.5.6(c) and 6.5.7(c).

This chapter provides information regarding Ergon Energy's ability to successfully deliver the system expenditure forecasts for Standard Control Services for the regulatory control period 1 July 2010 to 30 June 2015.

Figure 59 provides an overview of the process for delivering Ergon Energy's expenditure program.

Figure 59: *Overview of Delivering the Expenditure Program*



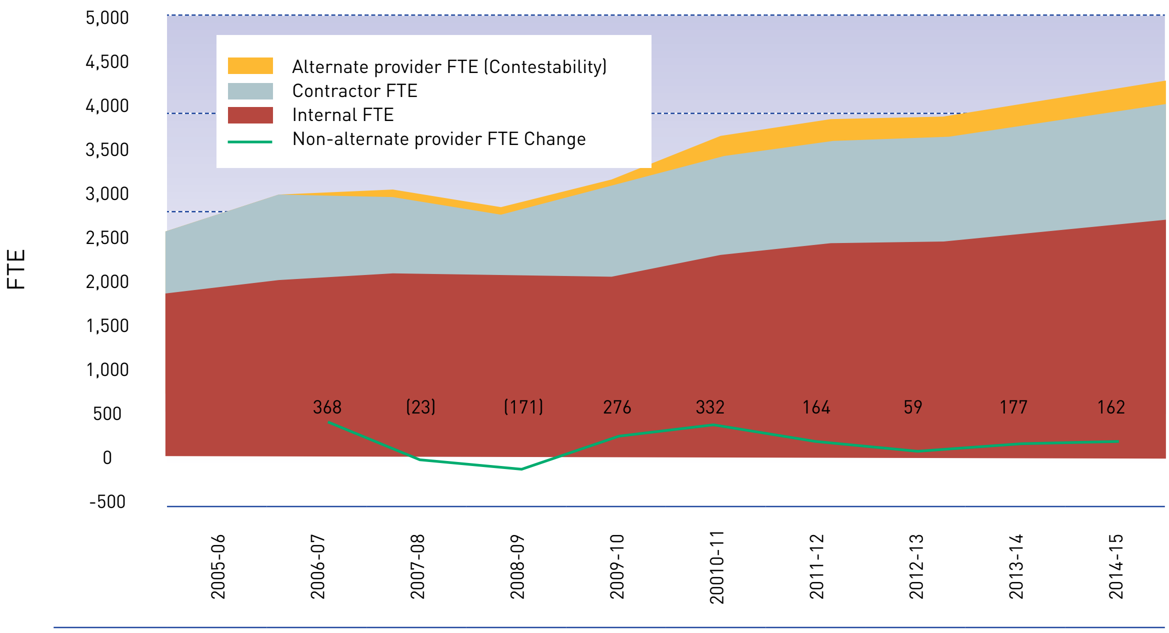
The forecast capital and operating expenditure program for the 2010-15 regulatory control period will continue a steady ramp up in line with long-term historical trends. This constitutes an average 9.5 per cent annual increase in physical work to be delivered to the end of the next regulatory control period, against a 2008-09 baseline.[59]

Allowing for a 3 per cent annual productivity improvement, the delivery of this work requires an average annual system workforce growth of around 6.5 per cent, with a peak annual growth of around 11 per cent or 332 full time equivalent (FTE) employees and contractors in 2010-11.

[59] Based on full-year projection from actuals to the end of April 2009.

This is illustrated in Figure 60[60]. A significant portion of this workforce growth will be delivered through outsourcing and through increasing the amount of work eligible to be undertaken by alternative providers, which will help build market competition and drive efficient delivery outcomes.

***Figure 60:** Annual change in Ergon Energy full time equivalent staff and contractors associated with system work for 2005-06 to 2014-15 (regulated and unregulated[61])*



Ergon Energy has previously achieved this level of FTE growth, such as in 2006-07 (albeit against a smaller historic base) during tight labour market conditions, which gives it confidence that it can readily be achieved again.

It is also intended that the alternative provider model (involving the contestability of works) for Urban Residential Development (URD) subdivisions be extended to include Commercial and Industrial and Large Customer Initiated Capital Works (CICW) from 2010. This will further support the deliverability of the forecast work program.

A temporary reduction in capital expenditure during 2008-09 was driven by a number of internal and external factors including:

- An unexpected reduction in CICW as a result of the economic downturn;
- Delays in gaining approvals for some major capital projects; and
- Ergon Energy taking advantage of the period of reduced workload resulting from the above factors to implement various organisational improvements as part of a range of 'Get Fit' strategies designed to position Ergon Energy for future workload growth.

Ergon Energy plans to recover the level of its expenditure program in the coming years and return to the increasing capital expenditure profile seen in the first three years of the current regulatory control period.

Other factors that contribute to confidence in the deliverability of the forecast system work program for the next regulatory control period include:

- In addition to its ability to draw on external resources, Ergon Energy has around 360 apprentices and 70 technical trainees that are now graduating at a rate that is making Ergon Energy largely self-sufficient in trade and technical roles;

[60] FTE for 2005-06 to 2008-09 are based on actuals, and figures from 2009-10 onwards are forecasts.

[61] Unregulated system work is included as it is carried out by the same resources as the regulated work.

- There are also approximately 25 graduate engineers in the internal graduate program, which provides a high level of self-sufficiency in maintaining and building the engineering workforce;
- Attrition levels are low by industry standards and, in the system-related workforce, attrition is only around 6 per cent per annum. These low levels have remained relatively stable over the last two to three years, despite the strong economic growth and constrained labour market. Attrition levels have reduced further since late 2008, since the economic downturn began;
- Ergon Energy does not expect to be materially impacted by ageing workforce issues (i.e. increased age attrition) during the next regulatory control period;
- Existing diversity strategies, including Aboriginal and Torres Strait Islanders, Women in Workforce and International Recruitment, will help to maintain a broad resource pool. Combined with Ergon Energy's Employer of Choice strategies, the diversity strategies will help to ensure Ergon Energy is able to maintain and grow its workforce to successfully deliver the work program in the next regulatory control period; and
- Ergon Energy's existing support workforce is adequate to enable successful delivery of the forecast system work. Note that the support workforce is excluded from Figure 60.

35. DELIVERING THE EXPENDITURE PROGRAM – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

Nil

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR094	Ergon Energy Union Collective Agreement 2008

36. EXPENDITURE WITH OTHER PERSONS

RIN – Section 2.3.12
RIN Pro forma - 2.3.12

Section 2.3.12 of the Regulatory Information Notice (RIN) details the requirement for Ergon Energy to include information in this Regulatory Proposal in relation to its expenditure with other persons. Specifically:

- Section 2.3.12(a)(1) requires a list of Ergon Energy's top 10 expenditures, in descending order, that it has had with other persons for the supply of goods and/or services over the current regulatory control period;
- Section 2.3.12(a)(2) requires, for each transaction arising under section 2.3.12(1), details of:
    a. The nature of the expenditure, including a description of the goods and/or services provided;
    b. An estimation of the total value of the expenditure (excluding GST);
    c. A description of the procurement process for the goods and/or services;
    d. Whether it is likely Ergon Energy will transact for the supply of goods and/ or services with the parties in the next regulatory control period; and
    e. Whether Ergon Energy has a relationship, for the purposes of section 2.3.2 of the RIN, with any of the parties supplying the goods and/or services.
- Section 2.3.12(a)(3) requires details of each transaction that has an end date after 30 June 2010 and of whether Ergon Energy has factored this into its capital and operating expenditure forecasts for the next regulatory control period;
- Section 2.3.12(a)(4) requires, for each transaction arising under section 2.3.12(3), details of:
    a. The nature of the expenditure, including a description of the goods and/or services to be provided;
    b. An estimation of the total value of the expenditure (excluding GST);
    c. A description of the procurement process for the goods and/or services; and
    d. Whether Ergon Energy has a relationship, for the purposes of section 2.3.2 of the RIN, with any of the parties supplying the goods and/or services.

This chapter, together with the completed pro forma 2.3.12 of the RIN, provides the information to address these requirements.

36.1 TOP 10 EXPENDITURES FOR 2005-10

The top 10 expenditures that Ergon Energy has had with other persons for the supply of goods and/or services over the current regulatory control period are as follows:

1.
2.
3.
4.
5.
6.
7.
8.
9.
10.

36.1.1

Table 94 provides information to address the requirements of section 2.3.12 of the RIN in relation to , as one of the top 10 persons who have supplied goods and/or services to Ergon Energy over the current regulatory control period.

Table 94: *RIN requirements in relation to*

RIN Requirement	Ergon Energy Response
Nature of Expenditure [2.3.12(a)(2)(i)]	
Description of Goods/Services [2.3.12(a)(2)(i)]	
Current Regulatory Control Period	
Estimation of Total Value of Expenditure [2.3.12(a)(2)(ii)]	
Procurement Process [2.3.12(a)(2)(iii)]	
Likelihood of having arrangement in next regulatory control period [2.3.12(a)(2)(iv)]	
Is entity a Related Entity? [2.3.12(a)(2)(v)]	
Do any of the transactions identified have an end date after 30 June 2010? [2.3.12(a)(3)(i)]	
Is the contract/s factored into Capital Expenditure & Operating Expenditure forecasts for 2010-15? [2.3.12.(a)(3)(ii)]	
Nature of Expenditure [2.3.12(a)(4)(i)]	
Description of goods and/or services to be provided [2.3.12(a)(4)(i)]	
Next Regulatory Control Period	
Estimation of total value of proposed expenditures (excl GST) and the amount that has been estimated for inclusion in forecast expenditures [2.3.12(a)(4)(ii)]	
Description of proposed procurement process [2.3.12(a)(4)(iii)]	
Is it a related entity [2.3.12(a)(4)(iv)]	

36.1.2 [redacted]

Table 95 provides information to address the requirements of section 2.3.12 of the RIN in relation to [redacted], as one of the top 10 persons who have supplied goods and/or services to Ergon Energy over the current regulatory control period.

Table 95: *RIN requirements in relation to* [redacted]

RIN Requirement	Ergon Energy Response
Nature of Expenditure [2.3.12(a)(2)(i)]	[redacted]
Description of Goods/Services [2.3.12(a)(2)(i)]	[redacted]
Current Regulatory Control Period	
Estimation of Total Value of Expenditure [2.3.12(a)(2)(ii)]	[redacted]
Procurement Process [2.3.12(a)(2)(iii)]	[redacted]
Likelihood of having arrangement in next regulatory control period [2.3.12(a)(2)(iv)]	[redacted]
Is entity a Related Entity? [2.3.12(a)(2)(v)]	[redacted]
Do any of the transactions identified have an end date after 30 June 2010? [2.3.12(a)(3)(i)]	[redacted]
Is the contract/s factored into Capital Expenditure & Operating Expenditure forecasts for 2010-15? [2.3.12.(a)(3)(ii)]	[redacted]
Nature of Expenditure [2.3.12(a)(4)(i)]	[redacted]
Description of goods and/or services to be provided [2.3.12(a)(4)(i)]	[redacted]
Next Regulatory Control Period	
Estimation of total value of proposed expenditures (excl GST) and the amount that has been estimated for inclusion in forecast expenditures [2.3.12(a)(4)(ii)]	[redacted]
Description of proposed procurement process [2.3.12(a)(4)(iii)]	[redacted]
Is it a related entity [2.3.12(a)(4)(iv)]	[redacted]

36.1.3

Table 96 provides information to address the requirements of section 2.3.12 of the RIN in relation to , as one of the top 10 persons who have supplied goods and/or services to Ergon Energy over the current regulatory control period.

Table 96: *RIN requirements in relation to*

RIN Requirement	Ergon Energy Response
Nature of Expenditure [2.3.12(a)(2)(i)]	
Description of Goods/Services [2.3.12(a)(2)(i)] Current Regulatory Control Period	
Estimation of Total Value of Expenditure [2.3.12(a)(2)(ii)]	
Procurement Process [2.3.12(a)(2)(iii)]	
Likelihood of having arrangement in next regulatory control period [2.3.12(a)(2)(iv)]	
Is entity a Related Entity? [2.3.12(a)(2)(v)]	
Do any of the transactions identified have an end date after 30 June 2010? [2.3.12(a)(3)(i)]	
Is the contract/s factored into Capital Expenditure & Operating Expenditure forecasts for 2010-15? [2.3.12.(a)(3)(ii)]	
Nature of Expenditure [2.3.12(a)(4)(i)]	
Description of goods and/or services to be provided [2.3.12(a)(4)(i)] Next Regulatory Control Period	
Estimation of total value of proposed expenditures (excl GST) and the amount that has been estimated for inclusion in forecast expenditures [2.3.12(a)(4)(ii)]	
Description of proposed procurement process [2.3.12(a)(4)(iii)]	
Is it a related entity [2.3.12(a)(4)(iv)]	

36.1.4

Table 97 provides information to address the requirements of section 2.3.12 of the RIN in relation to , as one of the top 10 persons who have supplied goods and/or services to Ergon Energy over the current regulatory control period.

Table 97: *RIN requirements in relation to*

RIN Requirement	Ergon Energy Response
Nature of Expenditure [2.3.12(a)(2)(i)]	
Description of Goods/Services [2.3.12(a)(2)(i)] Current Regulatory Control Period	
Estimation of Total Value of Expenditure [2.3.12(a)(2)(ii)]	
Procurement Process [2.3.12(a)(2)(iii)]	
Likelihood of having arrangement in next regulatory control period [2.3.12(a)(2)(iv)]	
Is entity a Related Entity? [2.3.12(a)(2)(v)]	
Do any of the transactions identified have an end date after 30 June 2010? [2.3.12(a)(3)(i)]	
Is the contract/s factored into Capital Expenditure & Operating Expenditure forecasts for 2010-15? [2.3.12.(a)(3)(ii)]	
Nature of Expenditure [2.3.12(a)(4)(i)]	
Description of goods and/or services to be provided [2.3.12(a)(4)(i)] Next Regulatory Control Period	
Estimation of total value of proposed expenditures (excl GST) and the amount that has been estimated for inclusion in forecast expenditures [2.3.12(a)(4)(ii)]	
Description of proposed procurement process [2.3.12(a)(4)(iii)]	
Is it a related entity [2.3.12(a)(4)(iv)]	

36.1.5 [redacted]

Table 98 provides information to address the requirements of section 2.3.12 of the RIN in relation to [redacted], as one of the top 10 persons who have supplied goods and/or services to Ergon Energy over the current regulatory control period.

Table 98: *RIN requirements in relation to* [redacted]

RIN Requirement	Ergon Energy Response
Nature of Expenditure [2.3.12(a)(2)(i)]	[redacted]
Description of Goods/Services [2.3.12(a)(2)(i)] Current Regulatory Control Period	[redacted]
Estimation of Total Value of Expenditure [2.3.12(a)(2)(ii)]	[redacted]
Procurement Process [2.3.12(a)(2)(iii)]	[redacted]
Likelihood of having arrangement in next regulatory control period [2.3.12(a)(2)(iv)]	[redacted]
Is entity a Related Entity? [2.3.12(a)(2)(v)]	[redacted]
Do any of the transactions identified have an end date after 30 June 2010? [2.3.12(a)(3)(i)]	[redacted]
Is the contract/s factored into Capital Expenditure & Operating Expenditure forecasts for 2010-15? [2.3.12.(a)(3)(ii)]	[redacted]
Nature of Expenditure [2.3.12(a)(4)(i)]	[redacted]
Description of goods and/or services to be provided [2.3.12(a)(4)(i)] Next Regulatory Control Period	[redacted]
Estimation of total value of proposed expenditures (excl GST) and the amount that has been estimated for inclusion in forecast expenditures [2.3.12(a)(4)(ii)]	[redacted]
Description of proposed procurement process [2.3.12(a)(4)(iii)]	[redacted]
Is it a related entity [2.3.12(a)(4)(iv)]	[redacted]

36.1.6

Table 99 provides information to address the requirements of section 2.3.12 of the RIN in relation to , as one of the top 10 persons who have supplied goods and/or services to Ergon Energy over the current regulatory control period.

***Table 99:** RIN requirements in relation to*

RIN Requirement	Ergon Energy Response
Nature of Expenditure [2.3.12(a)(2)(i)]	
Description of Goods/Services [2.3.12(a)(2)(i)] Current Regulatory Control Period	
Estimation of Total Value of Expenditure [2.3.12(a)(2)(ii)]	
Procurement Process [2.3.12(a)(2)(iii)]	
Likelihood of having arrangement in next regulatory control period [2.3.12(a)(2)(iv)]	
Is entity a Related Entity? [2.3.12(a)(2)(v)]	
Do any of the transactions identified have an end date after 30 June 2010? [2.3.12(a)(3)(i)]	
Is the contract/s factored into Capital Expenditure & Operating Expenditure forecasts for 2010-15? [2.3.12.(a)(3)(ii)]	
Nature of Expenditure [2.3.12(a)(4)(i)]	
Description of goods and/or services to be provided [2.3.12(a)(4)(i)] Next Regulatory Control Period	
Estimation of total value of proposed expenditures (excl GST) and the amount that has been estimated for inclusion in forecast expenditures [2.3.12(a)(4)(ii)]	
Description of proposed procurement process [2.3.12(a)(4)(iii)]	
Is it a related entity [2.3.12(a)(4)(iv)]	

36.1.7

Table 100 provides information to address the requirements of section 2.3.12 of the RIN in relation to , as one of the top 10 persons who have supplied goods and/or services to Ergon Energy over the current regulatory control period.

Table 100: *RIN requirements in relation to*

RIN Requirement	Ergon Energy Response
Nature of Expenditure [2.3.12(a)(2)(i)]	
Description of Goods/Services [2.3.12(a)(2)(i)] Current Regulatory Control Period	
Estimation of Total Value of Expenditure [2.3.12(a)(2)(ii)]	
Procurement Process [2.3.12(a)(2)(iii)]	
Likelihood of having arrangement in next regulatory control period [2.3.12(a)(2)(iv)]	
Is entity a Related Entity? [2.3.12(a)(2)(v)]	
Do any of the transactions identified have an end date after 30 June 2010? [2.3.12(a)(3)(i)]	
Is the contract/s factored into Capital Expenditure & Operating Expenditure forecasts for 2010-15? [2.3.12.(a)(3)(ii)]	
Nature of Expenditure [2.3.12(a)(4)(i)]	
Description of goods and/or services to be provided [2.3.12(a)(4)(i)] Next Regulatory Control Period	
Estimation of total value of proposed expenditures (excl GST) and the amount that has been estimated for inclusion in forecast expenditures [2.3.12(a)(4)(ii)]	
Description of proposed procurement process [2.3.12(a)(4)(iii)]	
Is it a related entity [2.3.12(a)(4)(iv)]	

36.1.8 [redacted]

Table 101 provides information to address the requirements of section 2.3.12 of the RIN in relation to [redacted], as one of the top 10 persons who have supplied goods and/or services to Ergon Energy over the current regulatory control period.

Table 101: *RIN requirements in relation to* [redacted]

RIN Requirement	Ergon Energy Response
Nature of Expenditure [2.3.12(a)(2)(i)]	[redacted]
Description of Goods/Services [2.3.12(a)(2)(i)] Current Regulatory Control Period	[redacted]
Estimation of Total Value of Expenditure [2.3.12(a)(2)(ii)]	[redacted]
Procurement Process [2.3.12(a)(2)(iii)]	[redacted]
Likelihood of having arrangement in next regulatory control period [2.3.12(a)(2)(iv)]	[redacted]
Is entity a Related Entity? [2.3.12(a)(2)(v)]	[redacted]
Do any of the transactions identified have an end date after 30 June 2010? [2.3.12(a)(3)(i)]	[redacted]
Is the contract/s factored into Capital Expenditure & Operating Expenditure forecasts for 2010-15? [2.3.12.(a)(3)(ii)]	[redacted]
Nature of Expenditure [2.3.12(a)(4)(i)]	[redacted]
Description of goods and/or services to be provided [2.3.12(a)(4)(i)] Next Regulatory Control Period	[redacted]
Estimation of total value of proposed expenditures (excl GST) and the amount that has been estimated for inclusion in forecast expenditures [2.3.12(a)(4)(ii)]	[redacted]
Description of proposed procurement process [2.3.12(a)(4)(iii)]	[redacted]
Is it a related entity [2.3.12(a)(4)(iv)]	[redacted]

36.1.9

Table 102 provides information to address the requirements of section 2.3.12 of the RIN in relation to , as one of the top 10 persons who have supplied goods and/or services to Ergon Energy over the current regulatory control period.

***Table 102:** RIN requirements in relation to*

RIN Requirement	Ergon Energy Response
Nature of Expenditure [2.3.12(a)(2)(i)]	
Description of Goods/Services [2.3.12(a)(2)(i)] Current Regulatory Control Period	
Estimation of Total Value of Expenditure [2.3.12(a)(2)(ii)]	
Procurement Process [2.3.12(a)(2)(iii)]	
Likelihood of having arrangement in next regulatory control period [2.3.12(a)(2)(iv)]	
Is entity a Related Entity? [2.3.12(a)(2)(v)]	
Do any of the transactions identified have an end date after 30 June 2010? [2.3.12(a)(3)(i)]	
Is the contract/s factored into Capital Expenditure & Operating Expenditure forecasts for 2010-15? [2.3.12.(a)(3)(ii)]	
Nature of Expenditure [2.3.12(a)(4)(i)]	
Description of goods and/or services to be provided [2.3.12(a)(4)(i)] Next Regulatory Control Period	
Estimation of total value of proposed expenditures (excl GST) and the amount that has been estimated for inclusion in forecast expenditures [2.3.12(a)(4)(ii)]	
Description of proposed procurement process [2.3.12(a)(4)(iii)]	
Is it a related entity [2.3.12(a)(4)(iv)]	

36.1.10 [redacted]

Table 103 provides information to address the requirements of section 2.3.12 of the RIN in relation to [redacted], as one of the top 10 persons who have supplied goods and/or services to Ergon Energy over the current regulatory control period.

Table 103: *RIN requirements in relation to* [redacted]

RIN Requirement	Ergon Energy Response
Nature of Expenditure [2.3.12(a)(2)(i)]	[redacted]
Description of Goods/Services [2.3.12(a)(2)(i)]	[redacted]
Current Regulatory Control Period	
Estimation of Total Value of Expenditure [2.3.12(a)(2)(ii)]	[redacted]
Procurement Process [2.3.12(a)(2)(iii)]	[redacted]
Likelihood of having arrangement in next regulatory control period [2.3.12(a)(2)(iv)]	[redacted]
Is entity a Related Entity? [2.3.12(a)(2)(v)]	[redacted]
Do any of the transactions identified have an end date after 30 June 2010? [2.3.12(a)(3)(i)]	[redacted]
Is the contract/s factored into Capital Expenditure & Operating Expenditure forecasts for 2010-15? [2.3.12.(a)(3)(ii)]	[redacted]
Nature of Expenditure [2.3.12(a)(4)(i)]	[redacted]
Description of goods and/or services to be provided [2.3.12(a)(4)(i)]	[redacted]
Next Regulatory Control Period	
Estimation of total value of proposed expenditures (excl GST) and the amount that has been estimated for inclusion in forecast expenditures [2.3.12(a)(4)(ii)]	[redacted]
Description of proposed procurement process [2.3.12(a)(4)(iii)]	[redacted]
Is it a related entity [2.3.12(a)(4)(iv)]	[redacted]

36.1.11 Description of Ergon Energy's Procurement Process for Current Regulatory Control Period

Ergon Energy's procurement strategies, policies and practices are based on the following principles:

- Ensuring value for money and commercial sustainability;
- Supporting Ergon Energy's corporate and business strategies;
- Developing and sustaining professional relationships with suppliers;
- Probity, accountability and ethical behaviour; and
- Alignment with Queensland Government objectives.[62]

Ergon Energy's Procurement Business Rules[63] stipulate the minimum requirements that have been established to ensure that it meets its Corporate Governance obligations, while at the same time allowing it to operate in a commercially responsive manner. These Procurement Business Rules have been issued under the Procurement Policy (EP19) and therefore apply to:

- Ergon Energy employees and consultants/contractors;
- All forms of goods and services; and
- All expenditures by Ergon Energy, unless specifically excluded through this Policy.

The Procurement Business Rules are defined within four purchase value ranges:

- $0-$5000;
- $5000-$10,000;
- $10,000-$100,000; or
- $100,000 or more.[64]

Ergon Energy's Strategic Procurement Group must be used if the purchase of goods and services is above $100,000. They will invite public tenders for all purchases above this threshold and manage: commercial and legal issues, risk mitigation strategies, negotiations, corporate governance, certain aspects of the tender evaluations, contract recommendation and award.

Ergon Energy generally uses the following media to advertise tenders: the Ergon Energy internet site, the Queensland Government Marketplace (QGM) internet site, and regional and/or national newspapers.[65] Tender submissionsmay only be received either by registered/regular post, hand delivered or delivery by a recognised carrier. Tender submissions are accepted by fax or e-mail.[66] Personal declarations must be completed by all members of Ergon Energy's evaluation team prior to commencing the evaluation of tenders.[67]

Evaluation of tenders is complex with substantial legal and ethical implications. Commercial, financial, technical and operational assessments are carried out during the evaluation process. After the evaluation of the tender submissions, a recommendation is made and approval is gained from an Ergon Energy delegate with the appropriate financial approval authority. Tenders over $10 million require board approval.[68]

Ergon Energy's Procurement and Logistics Team has developed internal guidelines to ensure employees are aware of their responsibilities when entering into and administering contracts for the provision of goods and services. Generally the procedure that Ergon Energy applies when establishing and managing contracts for goods or services is to:

- Request, prepare and advertise tenders;
- Issue tender packs, receive and open tenders;
- Assess tenders for conformance and undertake evaluation;
- Undertake best and final offer negotiations, recommend and obtain approval; and
- Manage, extend and complete contracts.[69]

[62] Ergon Energy's Procurement Policy, EP19, Ver. 1.

[63] Ergon Energy, "Procurement Policy Business Rules", MP000200R100 V8.

[64] ibid

[65] Ergon Energy "Request, Prepare and Advertise Tenders for Goods or Services Work Instruction", MP000901W100 Ver 2.

[66] Ergon Energy "Issue Tender Packs, Receive and Open Tenders Work Instruction", MP000901W101 Ver 2.

[67] ibid

[68] Ergon Energy, "Evaluate, Recommend, Obtain Approval and & Award Contract", MP000902W101 Ver 2.

[69] Ergon Energy, "Establish & Manage Contracts for Goods and Services Guidelines", MP000901R100 Ver 2.

36. EXPENDITURE WITH OTHER PERSONS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice

Codes and Rules

Nil

Ergon Energy Documents

AR510c	SKM Review of Estimates for Regulatory Proposal, 28 May 2009
AR514c	EE Establish & Manage Contracts for Goods and Services Guidelines, MP000901R100, V2
AR515c	EE Evaluate, Recommend, Obtain Approval and Award Contract, MP000902W101, V 2
AR516c	EE Issue Tender Packs, Receive and Open Tenders Works Instruction, MP000901W101 V2
AR517c	EE Procurement Policy Business Rules, MP000200R100 V8
AR518c	EE Request, Prepare and Advertise Tenders for Goods or Services Work Instructions, MP000901W100, V2
AR519	EE EP19 Procurement Policy
AR535c	EE Evaluate, Recommend, Obtain Approval and Award Contract, MP000902W101, V2

37. DEPRECIATION

Rules – Clauses 6.4.3(a)(3), 6.4.3(b)(3), 6.5.5, 6.12.1(8), 6.12.1(18), S6.1.3(12), S6.2.1(e)(5)
PTRM Handbook – Section 2.3 pages 9-10
RFM Handbook – Sections 2.3 and 2.4

This chapter details Ergon Energy's forecast of Regulatory Asset Base (RAB) depreciation for the next regulatory control period in order to address the requirements of the Rules, the Roll Forward Model (RFM) Handbook and the Post Tax Revenue Model (PTRM) Handbook.

Clause 6.4.3(a) of the Rules provides that Ergon Energy's annual revenue requirement for each year of the next regulatory control period must be calculated using a building block approach. Clause 6.4.3(a)(3) of the Rules provides that one of the building blocks to be used in this approach is to be depreciation. Clause 6.4.3(b)(3) of the Rules requires this forecast to be determined in accordance with clause 6.5.5 of the Rules, which details the basis on which depreciation must be calculated and depreciation schedules must be presented. Clause S6.1.3(12) of the Rules requires the depreciation schedules to be included as part of this Building Block Proposal.

Clause S6.2.1(c)(2) details how Ergon Energy must go about rolling forward the regulatory asset base. Clause S6.2.3 of the Rules details requirements for the roll forward of the RAB within a regulatory control period.

As discussed in section 40.1 of this Regulatory Proposal, the Queensland Competition Authority (QCA) wrote to the Australian Energy Regulator (AER) on 6 October 2008 in relation to the 1 July 2005 opening RAB value. In that letter, the QCA stated that:

> *Ergon Energy's opening asset base value was revised to $4,232.4 million in nominal dollars at 1 July 2005. The adjustment was made to reflect actual capex data for 2004-05 that become available after the Authority completed its 2005 Final Determination. This amendment was provided for in the Authority's Final Determination.*

As a result, the AER's F&A Stage 2 states that it "will adopt the 1 July 2005 opening RAB value of $4,232.4 million (July 2005 dollars) nominated by the QCA".[70]

37.1 PROPOSED DEPRECIATION SCHEDULES PER RFM AND THE RULES

Ergon Energy proposes that its Annual Revenue Requirement for Standard Control Services for the next regulatory control period, 2010-15, include the regulatory depreciation building blocks detailed in Table 104.

Table 104: *Depreciation Building Blocks for Standard Control Services for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Straight-line Depreciation	274.84	313.78	339.62	385.52	420.28	1,734.05
Inflation on Opening RAB	171.49	197.01	225.91	255.05	285.98	1,135.44
Regulatory Depreciation	103.36	116.77	113.71	130.46	134.30	598.60

Source: Tables for Proposal 37.1

[70] AER, "Final framework and approach paper Application of schemes - Energex and Ergon Energy 2010–15", November 2008, page 54

Ergon Energy has prepared depreciation schedules in accordance with the AER's RFM and PTRM. The depreciation values in Table 104 (see previous page) are a summary of the depreciation schedules in the PTRM.

In accordance with the requirements of clause 6.5.5 of the Rules, these amounts have been calculated:

- On the value of the assets in Ergon Energy's RAB as at the beginning of the regulatory control period and for each year of the regulatory control period thereafter;
- Using the RFM and the PTRM;
- Using a straight-line approach over the remaining economic lives of the asset classes for assets within the opening RAB. Ergon Energy believes this reflects the nature of the assets or category of assets over their economic lives. It should be noted that within an asset class the individual assets may have a standard life that is different to the weighted average life calculated for the asset class;
- Using a straight line approach over the standard economic life applied to forecast capital expenditure within the 2010-15 regulatory control period. Ergon Energy believes this reflects the nature of the assets or category of assets over their economic lives;
- Are developed on the basis that the sum of the real value for any asset over its economic life (such real value being calculated as at the time the value of that asset was first included in the regulatory asset base) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base; and
- Are calculated using depreciation methods and rates that are consistent with those determined for the same assets on a prospective basis in the Distribution Determination for that period.

In accordance with clause S6.1.3(12)(i) to (iv) of the Rules, Ergon Energy confirms that it's RFM and PTRM:

- Categorise assets according to well accepted asset classes;
- Provide details of all amounts, values and inputs used by Ergon Energy to compile the depreciation schedules; and
- Demonstrate that the depreciation schedules conform to the requirements set out in clause 6.5.5(b) of the Rules.

As required by clause S6.1.3(12)(v) of the Rules, Table 105 details the standard lives and average remaining lives in years for system and non-system assets used to provide Standard Control Services.

Table 105: Standard Lives and Average Remaining Lives for System and Non-System Assets (Years)

Asset Class	Standard Life	Average Remaining Life
Overhead Sub-transmission Lines	55.0	40.6
Underground Sub-transmission Cables	45.0	29.3
Overhead Distribution Lines	50.0	40.6
Underground Distribution Cables	60.0	55.0
Distribution Equipment	35.0	27.5
Substation Bays	45.0	36.4
Substation Establishment	60.0	36.4
Distribution Substation Switchgear	45.0	44.1
Zone Transformers	50.0	30.8
Distribution Transformers	45.0	26.2
Low Voltage Services	35.0	4.6
Metering	25.0	5.9
Communications – Pilot Wires	35.0	23.4
Generation Assets	30.0	5.0
Other Equipment	40.0	42.4
Control Centre - SCADA	7.0	4.5
Land & Easements (System)	n/a	n/a
Buildings (System)	40.0	45.0
Communications	30.0	7.3
IT Systems	5.0	1.9
Office Equipment & Furniture	7.0	6.1
Motor Vehicles	10.0	9.0
Plant & Equipment	10.0	8.7
Buildings	40.0	14.9
Land & Easements	n/a	n/a
Land Improvements	40.0	42.7

Source: Tables for Proposal 37.1

37.2 ACTUAL OR FORECAST DEPRECIATION

Clause 6.12.1(18) of the Rules requires the AER to make a decision as to whether depreciation for establishing the RAB as at the commencement of the next regulatory control period is to be based on actual or forecast capital expenditure.

Ergon Energy proposes that depreciation for establishing the RAB as at the commencement of the 2010-15 regulatory control period be based on its:

- Actual capital expenditure for the period 2005-06 to 2007-08; and
- Forecast capital expenditure for the period 2008-09 to 2009-10.

37. DEPRECIATION – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR524	AER Post Tax Revenue Model Handbook
AR526	AER Roll Forward Model Handbook

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR370c	EE Annual Regulatory Accounts for 2007-08
AR539c	EE Regulatory Proposal Models, Roll Forward Model
AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

38. CORPORATE INCOME TAX

Rules – Clauses 6.4.2(b)(4), 6.4.3(a)(4), 6.4.3(b)(4), 6.5.3, 6.12.1(7) and S6.1.3(11)
RIN – Section 2.4.5(a)
PTRM Handbook – Section 2.1
RFM Handbook – Section 2.5

This chapter deals with Ergon Energy's corporate income tax for Standard Control Services for the next regulatory control period, 1 July 2010 to 30 June 2015.

38.1 CHANGE IN TREATMENT OF CORPORATE INCOME TAX

The Queensland Competition Authority (QCA) has applied a post tax revenue regime to the regulation of Ergon Energy's Aggregate Annual Revenue Requirement (AARR) for the current regulatory control period, 1 July 2005 to 30 June 2010. However, the QCA did not establish a tax asset base for Ergon Energy for this period. Instead, as stated in its Final Determination:

> *The Authority has decided to adopt the actual cost of tax paid and will include the forecast cost of tax for each DNSP approved by the Authority at the start of the regulatory period, with any differences between forecast and tax paid subject to an unders and overs process on an annual basis.*[71]

The QCA determined that Ergon Energy's AARR for each year of the current regulatory control period should include a zero allowance for corporate income tax, on the basis that Ergon Energy would not be in a tax paying position during this period. This means that the QCA examined Ergon Energy's actual tax accounts, rather than those of a benchmark efficient entity, in determining the allowance for the corporate income tax building block for the current regulatory control period.

Ergon Energy has not paid any corporate income tax during the current regulatory control period and the QCA has therefore not needed to apply any annual under or over adjustments to Ergon Energy's Aggregate Annual Revenue Requirements. This tax assessment is confirmed in a letter from the Australian Taxation Office (ATO) to Ergon Energy dated 16 March 2009, which has been made available to the Australian Energy Regulator (AER) with this Regulatory Proposal.

The approach to the calculation of the corporate income tax building block has changed with the amendment to Chapter 6 of the Rules. Clause 6.5.3 of the Rules requires that the estimated cost of corporate income tax for Ergon Energy should be calculated having regard for the taxable income that:

> *would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than the Distribution Network Service Provider, operated the business of the Distribution Network Service Provider, such estimate being determined in accordance with the post-tax revenue model.*

On this basis, the estimate of the corporate income tax building block for the next regulatory control period must relate to a benchmark efficient entity, rather than Ergon Energy per se. This contrasts with the approach taken by the QCA in the current regulatory control period, which estimated corporate income tax based on Ergon Energy's actual tax paid and payable.

Therefore, Ergon Energy has applied the AER's Post Tax Revenue Model (PTRM) and Roll Forward Model (RFM) to estimate the cost of corporate income tax to be included in the Standard Control Service's building block calculation of the Annual Revenue Requirement.

38.2 ATO'S ASSESSMENT OF TAX PAYABLE UNDER NTER

Section 2.4.5(a) of the RIN requires Ergon Energy to provide certain information to substantiate the value of assets for tax purposes.

Section 2.1 of the PTRM Handbook and section 2.5 of the RFM Handbook detail how the opening tax asset values for each asset class are to be determined in the respective models.

Ergon Energy is able to provide actual National Tax Equivalent Regime (NTER) values for its total business, as assessed by the ATO[72], up until 2007-08. This information is detailed in Table 1 of pro forma 2.4.5 of the completed Regulatory Information Notice (RIN) and is set out in Table 106.

[71] QCA, Final Determination – Regulation of Electricity Distribution, April 2005, page 124

[72] Australian Taxation Office letter to Ergon Energy dated 16 March 2009

Table 106: *NTER Asset Values for Standard Control Services 2001-02 to 2007-08 ($M Nominal)*

	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Total NTER Opening Asset Value	1,943.36	1,884.39	1,865.29	1,865.30	1,852.06	1,945.68	2,004.50
Disposals	9.12	11.49	21.86	23.27	15.28	75.09	46.96
Tax Depreciation	172.30	181.33	187.82	189.88	196.42	218.84	182.78
Actual Capex	122.45	173.71	209.69	199.90	305.32	352.75	324.35
Total NTER Closing Asset Value	**1,884.39**	**1,865.29**	**1,865.30**	**1,852.06**	**1,945.68**	**2,004.50**	**2,099.11**

Source: Tables for Proposal 38.2

Ergon Energy's NTER values are not broken down between regulated assets and non-regulated assets when data is supplied to the ATO.

However, Ergon Energy is able to use the AER's RFM to roll forward the tax asset base (using tax depreciation lives as set by the ATO) for Standard Control Services from 1 July 2005 to 30 June 2010, noting that it will use forecast net capital expenditure for 2008-09 and 2009-10. Importantly, the values determined from the RFM used to roll forward the tax asset base for Standard Control Services are not National Tax Equivalent Regime (NTER) values. This information is detailed in Table 2 of pro forma 2.4.5 of the completed RIN and is set out in Table 107 below.

Table 107: *Forecast Tax Asset Values for Standard Control Services for 2005-06 to 2009-10 ($M Nominal)*

	2005-06	2006-07	2007-08	2008-09	2009-10
Opening Asset Value	1,693.78	2,111.37	2,591.24	2,955.59	3,410.00
Tax Depreciation	179.03	212.66	259.50	205.83	210.24
Net Capex	596.62	692.53	623.85	660.23	800.63
Total Closing Asset Value	**2,111.37**	**2,591.24**	**2,955.59**	**3,410.00**	**4,000.39**

Source: Tables for Proposal 38.2

Similarly, Ergon Energy is able to use the AER's RFM to roll forward the tax asset base for street lighting Alternative Control Services from 1 July 2005 to 30 June 2010, noting that it will use forecast net capital expenditure for 2008-09 and 2009-10. Importantly, the values determined from the RFM used to roll forward the tax asset base for street lighting Alternative Control Services are not NTER values. This information is detailed in Table 4 of pro forma 2.4.5 of the completed RIN.

Ergon Energy has not completed Table 3 of pro forma 2.4.5 of the RIN in relation to Non-RAB assets because it is not possible to deduct the NTER values for Ergon Energy's total business in Table 1 of pro forma 2.4.5 of the RIN from the values determined from the RFM for Standard Control Services in Table 2 of pro forma 2.4.5 of the RIN. This is because, as noted above, Table 1 contains NTER values whereas Table 3 does not contain NTER values. Ergon Energy's taxation policies preclude it from subtracting the RFM values from the NTER values to derive Non-RAB values because they are not comparable.

Section 49.2.4 provides further information about Ergon Energy's tax calculations.

38.3 CORPORATE INCOME TAX ALLOWANCE

Clause 6.4.3(a) of the Rules provides that Ergon Energy's annual revenue requirement for each year of the next regulatory control period must be calculated using a building block approach. Clause 6.4.3(a)(4) of the Rules provides that one of the building blocks to be used in this approach is to be an estimate of the cost of corporate income tax. Clause 6.4.3(b)(4) of the Rules requires this forecast to be determined in accordance with clause 6.5.3 of the Rules, which details the basis on which corporate income tax must be estimated.

Clause S6.1.3(11) of the Rules requires an estimate of the cost of corporate income tax to be included as part of this Building Block Proposal.

Ergon Energy has calculated its estimate of the cost of corporate income tax for each year of the regulatory control period, 2010-11 to 2014-15, in accordance with the requirements of the PTRM and the RFM. The estimated amounts are detailed in Table 108.

Table 108: *Corporate Income Tax for 2010-11 to 2014-15 ($M Nominal) Forecast*

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Tax payable	0.00	21.67	77.22	94.56	100.49	293.94
Less value of imputation credits	0.00	4.33	15.44	18.91	20.10	58.79
Net corporate income tax allowance	**0.00**	**17.34**	**61.77**	**75.65**	**80.39**	**235.15**

Source: Tables for Proposal 38.3

38. CORPORATE INCOME TAX – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice
AR524	AER Post Tax Revenue Model Handbook
AR526	AER Roll Forward Model Handbook

Codes and Rules

AR364	National Electricity Rules

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005

Ergon Energy Documents

AR322c	ATO Letter to EE, NTER Tax Losses Carried Forward, 16 March 2009
AR539c	EE Regulatory Proposal Models, AER Roll Forward Model
AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

39. OTHER REVENUE ADJUSTMENTS

Rules – Clauses 6.4.3(a)(6) and 6.4.3(b)(6)

The Rules require Ergon Energy's Annual Revenue Requirement (ARR) for each year of the 2010-15 regulatory control period to be adjusted for revenue increments or decrements arising from the current regulatory control period. In particular:

- Clause 6.4.3(a)(6) of the Rules requires that the Annual Revenue Requirement (ARR) for a Distribution Network Service Provider (DNSP) for each year of a regulatory control period must be determined using a building block approach, which incorporates other revenue increments or decrements for that year arising from the application of a control mechanism in the previous regulatory control period; and
- Clause 6.4.3(b)(6) of the Rules indicates that the other revenue increments or decrements referred to in clause 6.4.3(a)(6) are those that are to be carried forward to the next regulatory control period as a result of the application of a control mechanism in the current regulatory control period and are apportioned to the relevant year under the distribution determination for the next regulatory control period.

Ergon Energy has identified the following revenue adjustments arising from the current regulatory control period that should be reflected into the ARR for the next regulatory control period:

- Adjustment for accelerated depreciation associated with Severe Tropical Cyclone Larry;
- Adjustment to reflect unders and overs associated with revenue recovery in 2008-09 and 2009-10;
- Adjustment for Queensland Competition Authority (QCA) approved cost pass through amounts;
- Adjustment for difference between forecast revenue from shared assets and actual revenue from shared asset usage; and
- Adjustment for disposal of distribution assets before the end of their useful lives.

Each of these adjustments are discussed below.

39.1 ADJUSTMENT FOR ACCELERATED DEPRECIATION ASSOCIATED WITH SEVERE TROPICAL CYCLONE LARRY

On 20 March 2005 Severe Tropical Cyclone Larry crossed the Queensland coast near Innisfail, causing significant damage to Ergon Energy's distribution system. Ergon Energy subsequently sought approval from the QCA in May 2007 for the pass through of operating expenditure, and a return on and of capital expenditure associated with Ergon Energy's emergency response to Cyclone Larry.

Ergon Energy sought approval to pass through operating costs of $7.9 million, capital expenditure of $12.1 million and $8.0 million of accelerated depreciation for distribution assets that were destroyed by Cyclone Larry.

The QCA assessed Ergon Energy's application and approved the pass through of $7.9 million ($2005-06) of operating expenditure and $6.7 million ($2005-06) of capital expenditure.[73] The QCA made no adjustment for accelerated depreciation since it determined that these assets remained in Ergon Energy's asset base until the end of the current regulatory control period and Ergon Energy therefore suffered no financial loss in relation to those assets during the current regulatory period. The QCA indicated that:

> *The treatment of disposed assets was best determined in the overall context of the next regulatory review rather than in an ad hoc manner in responding to a cost pass-through application.*

Ergon Energy considers that it is entitled to recoup accelerated depreciation of $8.0 million ($2006-07) in the 2010-15 regulatory control period in relation to assets destroyed by Cyclone Larry.[74] This represents the amount of foregone depreciation that it would have been able to recover if these assets had not been destroyed. In relation to the calculation of the $8.0 million in accelerated depreciation, Ergon Energy notes that:

[73] QCA, Cost pass-through application – Ergon Energy – Tropical Cyclone Larry – Final Decision, September 2008.

[74] The accelerated depreciation reflects the write-off of distribution assets in 2006-07 as a result of Cyclone Larry. Based on Ergon Energy's disposal records, Ergon Energy attributed these assets to three broad asset categories – poles, wires and others. Details of the amounts attributed to each of these asset categories is contained in the QCA's consultant report at http://www.qca.org.au/files/E-CPT-Evans&Peck-SevTropCycLar-App-0708.pdf

- The QCA's consultant, Evans and Peck, confirmed that the total value of accelerated depreciation calculated by Ergon Energy was 'reasonable'[75]; and
- The value reflects net depreciation, that is, in calculating the accelerated depreciation, Ergon Energy removed the depreciation allowance associated with the destroyed assets that would have been included in the QCA's 2005 Determination.[76]

Ergon Energy considers that when a Distribution Network Service Provider (DNSP) makes a prudent capital investment, the DNSP can reasonably expect to recover that investment over time, including earning a rate of return on capital (i.e. Weighted Average Cost of Capital (WACC)). This is central to the financial capital maintenance concept. This means that over a certain period, the Net Present Value (NPV) of revenues earned from an investment and the NPV of the residual value of the investment should equal the initial investment. If Ergon Energy cannot obtain an accelerated depreciation amount for the assets that it was forced to remove before the end of their useful lives, then the financial capital maintenance concept will not hold.

Ergon Energy notes that it routinely disposes of assets before the end of their useful lives for a variety of reasons but does not seek an allowance for accelerated depreciation for such disposals. However, Ergon Energy considers that the circumstances associated with the assets destroyed by Cyclone Larry are sufficiently different from other asset disposals to warrant an allowance for accelerated depreciation during the 2010-15 regulatory control period. In particular:

- The assets were destroyed as a result of a single significant exogenous event over which Ergon Energy had no control. In the absence of an allowance for accelerated depreciation Ergon Energy will therefore have suffered a loss in revenue through no fault of its own;
- The event resulted in sufficient damage to Ergon Energy's distribution system to meet the QCA's materiality threshold for a cost pass through event; and
- The assets that were destroyed had a significant useful remaining life and would have remained within Ergon Energy's regulatory asset base for a considerable time.

Ergon Energy notes that there is considerable regulatory precedent for regulators allowing network service providers to recover accelerated depreciation through their network charges:

- The Western Australian Economic Regulation Authority (ERA) allowed Western Power to recover accelerated depreciation following the undergrounding of certain electricity distribution assets, which caused above-ground assets to be redundant prior to the end of their useful lives. This is set out in paragraph 419 on page 122 of its 2007 Final Decision for Western Power's South West Interconnected Network, which states that:

  Western Power will apply accelerated depreciation in respect of those distribution assets that will be decommissioned as a result of the retrospective undergrounding project undertaken by Western Power on behalf of the Western Australian government.[77]

- The Tasmanian Energy Regulator determined that it would consider allowing accelerated depreciation for assets identified by the Tasmanian DNSP, Aurora Energy, as redundant or likely to become redundant during the regulatory control period.[78] This approach was consistent with the approach adopted by the Australian Competition and Consumer Commission (ACCC) in relation to electricity Transmission Network Service Providers (TNSPs); and
- The Australian Competition and Consumer Commission's Draft Statement of Principles for the Regulation of Transmission Revenues[79] provided that assets identified by a TNSP as 'redundant', likely to become 'redundant' or partially 'redundant', could receive accelerated depreciation allowances and once fully depreciated would be removed from the regulatory asset base.

In order to accommodate the revenue adjustment for accelerated depreciation into the first year of the next regulatory control period (2010-11), Ergon Energy will make the following adjustments:

- The opening regulatory asset base for the next regulatory control period will be reduced by the value of asset disposals over the current regulatory control period (including for any assets that were destroyed as a result of Cyclone Larry). Chapter 40 of this Regulatory Proposal provides details regarding the adjustment for asset disposals;
- In order to preserve the time value of the accelerated depreciation adjustment, the original $8.0 million ($2006-07) will be indexed forward to 2010-11 using the WACC applicable in the current regulatory control period. This increases the adjustment from $8.0 million ($2006-07) to $11.27 million ($2010-11); and

[75] http://www.qca.org.au/files/E-CPT-Evans&Peck-SevTropCycLar-App-0708.pdf

[76] See http://www.qca.org.au/files/E-CostPass-CycLar-Ergon-Sub-0808.PDF for further details.

[77] http://www.era.wa.gov.au/cproot/5020/2/20070302%20Final%20Decision%20WP%20AA%20SWIN.pdf

[78] http://www.energyregulator.tas.gov.au/domino/otter.nsf/LookupFiles/Approach%20to%20the%20Calculation%20of%20Distribution%20MAR.pdf/$file/Approach%20to%20the%20Calculation%20of%20Distribution%20MAR.pdf,

[79] http://www.aer.gov.au/content/item.phtml?itemId=659998&nodeId=f5c277ba5d04828ea4e46c2c9633d5da&fn=Draft%20statement%20of%20regulatory%20%20principles%20(27%20May%201999).pdf,

- The $11.27 million adjustment for accelerated depreciation will be added to Ergon Energy's ARR for 2010-11.

39.2 ADJUSTMENT FOR PREVIOUS RECOVERY OF REVENUE

Under the revenue cap form of regulation applying to Ergon Energy during the current regulatory control period, the QCA makes annual adjustments to Ergon Energy's Aggregate Annual Revenue Requirement (AARR) in order to correct for any over- or under-recovery of revenue that may have occurred in previous years.[80] The extent of over- or under-recovery in any financial year is provided to the QCA by Ergon Energy as part of Ergon Energy's audited annual regulatory reporting statements. These reporting statements are provided to the QCA by 31 October of the following financial year.

Due to the lag in the receipt of information, the earliest that any over- or under-recovery of revenue in year *t* of the current regulatory control period can be incorporated in the AARR is in year *t+2*. As such, any over- or under-recovery of revenue occurring in 2008-09 or 2009-10 of the current regulatory control period has yet to be incorporated in the Anuual Revenue Requirement (ARR) for the next regulatory control period (years 2010-11 and 2011-12 respectively).

Ergon Energy propose that the 2010-11 and 2011-12 ARR values for the next regulatory control period be updated following the completion of the 2008-09 and 2009-10 regulatory reporting statements in 31 October 2009 and 31 October 2010 respectively.

39.3 ADJUSTMENT FOR QCA-APPROVED COST PASS THROUGH AMOUNTS

The QCA's Final Determination for Ergon Energy for the current regulatory control period included a general cost pass through provision as well as cost pass through provisions that specifically relate to large customer connections.

The QCA's general cost pass through mechanism provides that "The Authority will introduce a materiality threshold for consideration of a general cost pass through event of 1 per cent of actual annual regulated revenue per event, based on the regulated revenue in the year of the event."[81]

There are two pass through provisions for large customer connections. The QCA's Final Determination states that:

- "The Authority will consider pass through for large customer projects, with a cost in excess of $10 million, that occur during the next regulatory period but were totally unanticipated at the time of preparing this Determination"[82]; and
- "...identified capital projects likely to proceed during the next regulatory period, but with a probability of less than 80 per cent certainty of proceeding. As this mechanism is only meant to protect Ergon from significant financial consequences (not remove all forecasting risk), each project will also have to have a potential (Capital Expenditure) cost of at least $5 million."[83]

These cost pass through provisions recognised the considerable uncertainty in relation to Ergon Energy's capital expenditure requirements for large customer connections.

Under the revenue cap form of regulation applying to Ergon Energy during the current regulatory control period, the QCA makes annual adjustments to Ergon Energy's AARR for approved pass throughs in order to allow for appropriate recovery of revenues that may have occurred in previous years. The extent of revenues allowed to be recovered in any financial year is provided by the QCA following the assessment and approval of an application by Ergon Energy for pass through of operational expenditure, and/or a return on and of capital expenditure under the relevant mechanism/s.

Due to the timeframe for the occurrence of a potential pass through event, the gathering of necessary supporting information, the submission of a cost pass through application by Ergon Energy and the assessment and approval by QCA, the earliest that any revenue approved for year *t* of the current regulatory control period can be incorporated in the AARR is in year *t+2*. As such, it is possible that Ergon Energy may successfully apply to the QCA for the approval of a cost pass through event in 2008-09 or 2009-10 and not be able to recover the approved costs during the current regulatory control period. Ergon Energy proposes that, in these circumstances, it should be able to recover its QCA-approved revenue in its ARRs for the next regulatory control period.

It is noted that this circumstance is different to that contemplated under clause 11.16.9 of the Rules, which allows Ergon Energy to apply to the AER by 1 July 2011 for cost pass through events that occur before 1 July 2010.

Ergon Energy therefore proposes that the AER agree that any cost pass through that is approved by the QCA during the current regulatory control period, but not recovered through an uplift in revenues in the current period, be able to be added to its ARRs in the next regulatory control period so that the revenues can be recovered in that next period. At the time of submitting this Regulatory Proposal, Ergon Energy is not able to identify the nature (or cost of) pass through events that may fall into this category.

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[80] This includes under and over recovery of revenue associated with the provision of Distribution Services and in relation to capital contributions.

[81] QCA, Final Determination - Regulation of Electricity Distribution, April 2005, page 50

[82] Ibid, page 90

[83] Ibid, page 88

39.4 ADJUSTMENT FOR SHARED ASSET USAGE

At present, Ergon Energy's regulatory asset base consists of some assets that are shared between Prescribed Distribution Services (and therefore Standard Control Services), Excluded Distribution Services (and therefore Alternative Control Services) and unregulated services.

As part of its 2005 Final Determination, the QCA incorporated the full value of these 'shared assets' into Ergon Energy's regulated asset base. That is, the assets are attributed to Prescribed Distribution Services and are therefore a component of the QCA's AARR calculation for the current regulatory control period.

However, to ensure that the full cost of the shared asset used is borne by the beneficiary, the QCA requires Ergon Energy annually to apply an internal service charge for the use of these shared assets. This charge reflects:

- Direct and indirect costs of usage;
- Depreciation associated with the asset (if applicable); and
- Return on assets.

In its Final Determination for the current regulatory control period, the QCA made an initial $8 million per annum reduction to Ergon Energy's revenue for Prescribed Distribution Services over the current regulatory control period to reflect forecast revenue from the use of shared assets by other parts of the Ergon Energy business.

The actual annual charge for the use of shared assets is identified by Ergon Energy in its annual regulatory reporting statements provided to the QCA by 31 October each year. Based on this information, the QCA compares the actual revenue to the forecast of revenue from the use of shared assets and adjusts Ergon Energy's subsequent AARR accordingly. This ensures that the regulated business is fully compensated for the use of its assets by other Ergon Energy businesses and customers of the Prescribed Distribution Services business is not subsidising the provision of other services provided by Ergon Energy.[84]

In the same way as applies for the unders and overs adjustment, the lag in the receipt of information means that any difference between actual and forecast revenue from the use of shared assets in year t cannot to be incorporated into Ergon Energy's AARR until year *t+2*. As a result, adjustments for shared asset usage in 2008-09 and 2009-10 will be made to Ergon Energy's 2010-11 and 2011-12 ARRs respectively.

Ergon Energy therefore proposes to update the 2010-11 and 2011-12 ARR values to reflect shared asset usage after the relevant information is available in 31 October 2009 and 31 October 2010 respectively.

[84] Queensland Competition Authority, Final Determination - Regulation of Electricity Distribution, April 2005.

39.5 ADJUSTMENT FOR THE DISPOSAL OF ASSETS BEFORE THE END OF THEIR USEFUL LIVES

As part of its 2005 Final Determination, the QCA incorporated a revenue adjustment to reflect the disposal of assets by Ergon Energy before the end of their useful lives.[85] The QCA indicated that Ergon Energy continue to earn a rate of return and depreciation on these assets until such time as they are removed from the regulated asset base at the next regulatory reset.

In order to prevent Ergon Energy earning revenue from assets that have been disposed of, the QCA reduced its revenue by $1.5 million per annum for each of the five years of the current regulatory control period. The QCA indicated that at the end of the current regulatory control period, it would review actual versus forecast disposals and adjust Ergon Energy's revenue in the next regulatory control period accordingly.[86]

The information required to perform the reconciliation between actual and forecast asset disposals for the current regulatory control period will be provided as part of Ergon Energy's 2009-10 regulatory reporting statements. These statements are required to be provided to the QCA by 31 October 2010.

Ergon Energy therefore proposes that its ARRs for the 2010-15 regulatory control period be updated for actual versus forecast asset disposals following completion of the regulatory reporting statements on 31 October 2010.[87]

[85] http://www.qca.org.au/files/ACF14.pdf

[86] http://www.qca.org.au/files/ACF14.pdf p. 96.

[87] Ergon Energy notes that any such adjustment will be affected by the AER's treatment of Ergon Energy's accelerated depreciation claim (since the that claim removes the depreciation allowance associated with the assets destroyed by Cyclone Larry that would have been included in the QCA's 2005 Determination).

39. OTHER REVENUE ADJUSTMENTS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

Nil

Codes and Rules

AR364	National Electricity Rules

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005
AR527	QCA's Final Decision on Cyclone Larry

Ergon Energy Documents

Nil

40. REGULATORY ASSET BASE

Rules – Clauses 6.3.2(a)(2), 6.4, 6.4.2(b)(1), 6.4.3(a)(1), 6.4.3(b)(1), 6.5.1, 6.12.1(6), S6.1.3(7) and (10), S6.2.1, S6.2.3 and 11.16.3
RFM Handbook
PTRM Handbook
CAG – Section 5.1(b)(5)

This chapter details the basis for calculating Ergon Energy's Regulatory Asset Base (RAB) for Standard Control Services for the next regulatory control period, in order to address the requirements of the Rules, the Roll Forward Model (RFM) Handbook and the Cost Allocation Guidelines (CAG).

40.1 REGULATORY REQUIREMENTS

There are a series of provisions in the Rules that deal with the indexation of the RAB:

- Clause 6.3.2(a)(2) requires the AER to specify in its Building Block Determination appropriate methods for the indexation of the RAB;
- Clause 6.4.2(b)(1) requires the Post Tax Revenue Model (PTRM) to include a method that the Australian Energy Regulator determines is likely to result in the best estimates of expected inflation;
- Clause 6.4.3(a)(1) identifies the indexation of the RAB as one of the building blocks for the purposes of determining the Annual Revenue Requirement (ARR); and
- Clause 6.4.3(b)(1) requires the indexation of the RAB to be determined in accordance with clauses 6.5.1, S6.2 and S6.2.3(c)(4) of the Rules.

Clause 6.5.1 of the Rules details the basis on which the AER must develop and apply the RFM in order to roll forward the RAB from the current to the next regulatory control period and from one year to another.

Clause S6.1.3(7) requires Ergon Energy to calculate the RAB for each year of the next regulatory control period using the Roll Forward Model and to:

- Provide details of all amounts, values and other inputs that it has used;
- Demonstrate that the amounts, values and other inputs comply with the relevant requirements of Part C of Chapter 6 of the Rules; and
- Explain the calculation of the RAB for each year of the next regulatory control period and of all amounts, values and other inputs that have been used.

Clause S6.2.1(c)(1) of the Rules specifies that the value of Ergon Energy's RAB as at the beginning of the first year of the next regulatory control period must be determined by rolling forward the 1 July 2005 value of $4,192 million (in July 2005 dollars) or a different amount that the QCA nominates in writing to the AER. The remainder of clause S6.2.1(c) details how Ergon Energy must go about rolling forward the RAB. Clause S6.2.3 of the Rules details requirements for the roll forward of the RAB within a regulatory control period.

Clause S6.1.3(10) of the Rules requires Ergon Energy's Building Block Proposal to include the completed PTRM and RFM.

Clause 11.16.3 of the Rules allows Ergon Energy to treat Standard Control Services and other services in the RAB in the next regulatory control period in the same manner as the QCA did in its 2005 Final Determination.

Clause 11.16.10 of the Rules allows Ergon Energy to retain its current capital contributions policy in the next regulatory control period provided that it remains consistent with its approved Pricing Principles Statement. Consistent with Ergon Energy's current approach, the forecast annual capital contributions will be included in its RAB and will be deducted from the annual revenue caps in order to determine the Annual Revenue Requirements (ARR).

Clause 6.12.1(6) of the Rules requires the AER's Distribution Determination to include a decision on the RAB as at the commencement of the regulatory control period.

Clause 5.1(b)(5) of the CAG requires Ergon Energy to apply its Cost Allocation Method (CAM) in preparing its actual or estimated capital expenditure for the purposes of increasing its RAB under clause S6.2.1(f) of the Rules.

40.2 COMPLETED ROLL FORWARD MODEL AND POST TAX REVENUE MODEL

The AER has prepared:

- A RFM, in accordance with clause 6.5.1 of the Rules, and has issued an accompanying RFM Handbook; and
- A PTRM, in accordance with clause 6.4 of the Rules, and has issued an accompanying PTRM Handbook.

Ergon Energy has completed both of these models in accordance with the requirements of the Rules and their respective handbooks. It has provided copies of the completed models to the AER as part of this Building Block Proposal as required by clause S6.1.3(10) of the Rules.

Ergon Energy's completed RFM calculates its RAB as at the end of the current regulatory control period, 30 June 2010, to be $6,999 million. This value will become the opening asset value as at the commencement of the next regulatory control period, 1 July 2010. Table 109 provides an overview of this calculation.

Table 109: *Ergon Energy's Regulatory Asset Base for 2005-06 to 2009-10 ($M Nominal)*

	2005-06	2006-07	2007-08	2008-09	2009-10
Opening Regulatory Asset Base	4,146.17	4,648.62	5,285.04	5,792.37	6,294.07
Capital Expenditure (net of additions and disposals)	621.19	724.10	648.46	684.33	833.92
Regulatory Depreciation	-118.74	-87.67	-141.13	-182.64	-128.60
Closing Regulatory Asset Base	4,648.62	5,285.04	5,792.37	6,294.07	6,999.39

Source: Tables for Proposal 40.2

Ergon Energy's completed PTRM calculates its RAB as at the commencement of each subsequent year of the next regulatory control period. Table 110 provides an overview of these calculations.

Table 110: *Ergon Energy's Regulatory Asset Base for 2010-11 to 2014-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15
Opening Regulatory Asset Base	6,999.39	8,041.17	9,220.93	10,410.39	11,672.77
Capital Expenditure (net of additions and disposals)	1,145.14	1,296.53	1,303.17	1,392.84	1,559.42
Regulatory Depreciation	-103.36	-116.77	-113.71	-130.46	-134.30
Forecast Closing Regulatory Asset Base	8,041.17	9,220.93	10,410.39	11,672.77	13,097.89

Source: Tables for Proposal 40.2

40.3 CALCULATION OF OPENING RABS FOR 2010-15 REGULATORY CONTROL PERIOD

40.3.1 Asset Classes

Ergon Energy confirms that, consistent with the AER's Regulatory Information Notice (RIN):

- The asset categories it has used in the RFM and the PTRM are those that it currently reports to the QCA in its regulatory accounts. Ergon Energy notes that the asset classes used in the regulatory accounts are different to those that the QCA used in its 2005 Final Determination; and
- It has not included street lighting assets in the RAB for Standard Control Services for the purposes of the RFM and the PTRM, as these relate to Alternative Control Services.

40.3.2 Asset Lives

Ergon Energy confirms that it has applied in its completed RFM and the PTRM:

- Asset standard lives for each asset class that are consistent with the asset classes that are currently annually reported to the QCA;
- Asset remaining lives for each asset class, correct as of 1 July 2005, that are based on the asset lives in Ergon Energy's asset register, adjusted to reflect the asset classes in the 2005-06 regulatory accounts; and
- Asset remaining lives for each asset class, correct as of 1 July 2010, that are based on the forecast mix of assets as at that date.

40.3.3 Calculation of 1 July 2010 Opening RAB Value

Clause S6.1.3(7) requires Ergon Energy to calculate the RAB for each year of the next regulatory control period using the RFM and to:

- Provide details of all amounts, values and other inputs that it has used;
- Demonstrate that the amounts, values and other inputs comply with the relevant requirements of Part C of Chapter 6 of the Rules; and
- Explain the calculation of the RAB for each year of the next regulatory control period and of all amounts, values and other inputs that have been used.

Clause S6.2.1(c)(1) of the Rules specifies that the value of Ergon Energy's RAB as at the beginning of the first year of the next regulatory control period must be determined by rolling forward the 1 July 2005 value of $4,192 million (in July 2005 dollars) or a different amount that the QCA nominates in writing to the AER.

The QCA wrote to the AER on 6 October 2008. In that letter, the QCA stated that:

> *Ergon Energy's opening asset base value was revised to $4,232.4 million in nominal dollars at 1 July 2005. The adjustment was made to reflect actual Capital Expenditure data for 2004-05 that become available after the Authority completed its 2005 Final Determination. This amendment was provided for in the Authority's Final Determination.*

The AER's F&A Stage 2 states that it "will adopt the 1 July 2005 opening RAB value of $4232.4 million (July 2005 dollars) nominated by the QCA".[88]

Ergon Energy proposes to adjust the $4,232.4 million value by deducting:

- $39.0 million, which was included by the QCA as a working capital allowance. Given that the PTRM now has this inherent in its calculations, inventory is no longer required as part of the opening 2005-06 RAB; and
- $47.0 million, which represents the value of street lighting assets, which are an Alternative Control Service, rather than a Standard Control Service.
- $0.2 million which is an adjustment for Market Metering incorrectly included in the RAB determined by the QCA.

Ergon Energy has calculated the adjusted opening RAB as at 1 July 2005 (in nominal dollars) for Standard Control Services to be $4,146.2 million.

In accordance with clause S6.2.1 of the Rules and the AER's RFM, Ergon Energy has:

- Rolled forward the RAB for Standard Control Services as at 1 July 2005 to 30 June 2008 by:
  - → Adding actual prudent capital expenditure over this period, inclusive of capital contributions, to the opening RAB for each respective year;
  - → Deducting actual depreciation for each year;
  - → Deducting actual disposals for each year; and
  - → Indexing the annual closing RAB for actual inflation for each year.
- Rolled forward the RAB for Standard Control Services as at 1 July 2008 to 30 June 2010 by:
  - → Adding the projected efficient capital expenditure, inclusive of capital contributions, to the opening Regulatory Asset Base for each respective year;
  - → Deducting projected depreciation for each year;
  - → Deducting projected disposals for each year; and

[88] AER, "Final framework and approach paper Application of schemes - Energex and Ergon Energy 2010–15", November 2008, page 54

→ Indexing the annual closing RAB for projected inflation for each year.

The RFM calculates the RAB for Standard Control Services as at the end of the current regulatory control period, 30 June 2010, to be $7,462.7 million. This value becomes the opening asset value as at the commencement of the next regulatory control period, 1 July 2010.

This Regulatory Proposal provides further details of actual and projected amounts, values and other inputs that have been used to determine the value of the RAB for Standard Control Services as at 1 July 2010. In particular:

- Capital expenditure is dealt with in Chapters 23 and 24;
- Depreciation is dealt with in Chapter 37;
- Capital contributions are dealt with in Chapter 47; and
- Inflation is dealt with in Chapter 33.

40.3.4 Calculation of Opening Asset Values in 2010-15 Regulatory Control Period

The roll forward of the RAB for Standard Control Services from the beginning of one year to the next year within a regulatory control period is undertaken in the AER's PTRM. Ergon Energy has used the PTRM to roll forward the RAB for Standard Control Services as at 1 July 2010 to 30 June 2015 by:

- Adding forecast capital expenditure over this period, inclusive of forecast capital contributions, to the opening RAB for each respective year;
- Deducting forecast depreciation for each year;
- Deducting forecast disposals for each year; and
- Indexing the annual closing RAB for forecast inflation for each year.

This Regulatory Proposal provides further details of forecast amounts, values and other inputs that have been used to determine the value of the RAB for Standard Control Services for each regulatory year of the next regulatory control period. In particular:

- Capital expenditure is dealt with in Chapters 23 and 24;
- Depreciation is dealt with in Chapter 37;
- Capital contributions are dealt with in Chapter 47; and
- Inflation is dealt with in Chapter 33.

40.3.5 Application of Clause 11.16.3 of the Rules

Clause 11.16.3 of the Rules allows Ergon Energy to treat Standard Control Services and other services in the RAB in the next regulatory control period in the same manner as the QCA did in its 2005 Final Determination. The reason for the introduction of clause 11.16.3 is discussed in detail in section 11.1 of this Regulatory Proposal.

As discussed in section 11.1.3 of this Regulatory Proposal, Ergon Energy proposes to apply clause 11.16.3 of the Rules so that:

- Street lighting is removed from the RAB for Standard Control Services and included in a separate street lighting RAB;
- Contributed assets for large customer connection assets will be treated as Alternative Control Services in the next regulatory period. They will not form part of the RAB for Standard Control Services;
- Any 'shared assets' that service other Alternative Control Services (i.e. not street lighting or large customer connections), Standard Control Services and unregulated services will be included in the RAB for Standard Control Services;
- The other Alternative Control Services and unregulated services will be permitted to utilise shared regulatory assets in the RAB for Standard Control Services;
- Standard Control Services will apply an internal charge in relation to the other Alternative Control Services and unregulated services for the use of assets in the RAB, in the same manner as the QCA provided in its 2005 Final Determination for regulated and unregulated services. An estimate of the charge will be made in preparing the Regulatory Proposal and adjustments for the actual calculated charge has been made during the regulatory control period. The charge incorporates:
  - → Direct and indirect costs of asset usage;
  - → Depreciation; and
  - → Return on assets.
- Standard Control Services will record the revenue received from the use of regulated assets by Alternative Control Services and unregulated services as an additional source of regulated revenue;
- The additional revenue would then be deducted from the ARR for Standard Control Services; and
- Accordingly, Ergon Energy's Standard Control Services' tariffs would be reduced as part of the annual price setting process in order to avoid double recovery of costs associated with this asset usage.

40. REGULATORY ASSET BASE – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR367c & 368c	AER Regulatory Information Notice
AR417 & 418	AER Cost Allocation Guidelines, Final Decision and Guidelines, 26 June 2008
AR524	AER Post Tax Revenue Model Handbook
AR526	AER Roll Forward Model Handbook

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR314	EE Cost Allocation Method, AER Approved
AR329	EE Pricing Principles Statement, Release 5, April 2009
AR370c	EE Annual Regulatory Accounts for 2007-08
AR539c	EE Regulatory Proposal Models, Roll Forward Model
AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

41. RATE OF RETURN ON CAPITAL

NEL – Sections 7, 7A(2), 7A(5), 7A(6), 16(1)(a) and 16(2)(a)
Rules – Clauses 6.4.3(a)(2), 6.4.3(b)(2), 6.5.2, 6.5.4(c), 6.5.4(e), 6.5.4(f),6.5.4(g), 6.5.4(h), 6.5.4(i), 6.12.1(5), S6.1.3(8) and S6.1.3(9) [11.16.7 is not relied on given the Rule change for AER's SoRI]
RIN – Section 2.4.3
AER's Final Statement of Regulatory Intent

This chapter details the basis for calculating Ergon Energy's rate of return on capital for Standard Control Services for the next regulatory control period, addressing the relevant provisions of the National Electricity Law (NEL), the Rules, the Regulatory Information Notice (RIN) and the outcomes of the AER's 'Final - Electricity Transmission and Distribution Network Service Providers - Statement of the Revised WACC Parameters (Transmission) - Statement of Regulatory Intent on the Revised WACC parameters (Distribution)' (the final SoRI).

The indicative values provided in this chapter are provided for the purposes of this Regulatory Proposal.

41.1 REQUIREMENTS OF THE NEL

Section 7 of the NEL states that the objective of the NEL is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, safety, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system.

Section 7A(2) of the NEL states that a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs.

Section 7A(5) of the NEL states a price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

Section 7A(6) of the NEL states that regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider.

Section 16(1)(a) of the NEL states that the Australian Energy Regulator (AER) must, in performing or exercising an AER economic regulatory function or power, perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the national electricity objective.

Section 16(2)(a) of the NEL states that the AER must take into account the revenue and pricing principles (contained in section 7A of the NEL) when exercising a discretion in making those parts of a distribution determination relating to direct control network services.

41.2 REQUIREMENTS OF THE RULES

Clause 6.4.3(a)(2) of the Rules identifies a return on capital as one of the building blocks for determining the annual revenue requirement for Standard Control Services. Clause 6.4.3(b)(2) of the Rules requires the return on capital to be calculated in accordance with clause 6.5.2 of the Rules.

Clause 6.5.2(a) of the Rules provides that the return on capital for each year must be calculated by applying a rate of return to the value of the Regulatory Asset Base (RAB) as at the beginning of that regulatory year.

Clause 6.5.2(b) of the Rules defines the rate of return and requires that it be calculated as the nominal post tax Weighted Average Cost of Capital (WACC).

Clause 6.5.2(c) of the Rules details the meaning of the nominal risk-free rate and clause 6.5.2(e) of the Rules details the meaning of the debt risk premium.

Clause 6.5.4(c) of the Rules provides that the AER must issue a final Statement of Regulatory Intent (SoRI) after conducting a review of the rate of return in accordance with the distribution consultation procedures detailed in clause 6.16 of the Rules. Clause 6.16(b)(1) of the Rules requires the AER to publish a proposed SoRI and an explanatory statement before it issues the final SoRI.

Clause 6.5.4(e)(1) of the Rules states that the rate of return should be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing standard control services.

Clause 6.5.4(e)(2) of the Rules states that the rate of return on debt should reflect the current cost of borrowings for comparable debt.

Clause 6.5.4(e)(3) of the Rules states that the credit rating levels or the values attributable to, or the methods of calculating, the parameters referred to in paragraph 6.5.4(d) that vary according to the efficiency of the Distribution Network Service Provider (DNSP) should be based on a benchmark efficient DNSP.

Clause 6.5.4(e)(4) of the Rules states that, where the credit rating levels or the values attributable to, or the method of calculating, parameters referred to in paragraph 6.5.4(d) cannot be determined with certainty, the AER needs to achieve an outcome that is consistent with the national electricity objective.

Clause 6.5.4(f) of the Rules states that a SoRI adopting a revised value, method or credit rating level applies only for the purposes of a Building Block Proposal submitted to the AER after the publication of the SoRI. The SoRI released by the AER on 1 May 2009 therefore applies to Ergon Energy's Building Block Proposal.

Clause 6.5.4(g) of the Rules requires that a Distribution Determination to which a SoRI applies must be consistent with that SoRI unless there is persuasive evidence justifying a departure, in the particular case, from a value, method or credit rating level set in the SoRI.

Clauses 6.5.4(h) and 6.5.4(i) of the Rules detail the obligations on the AER in deciding whether to depart, and in fact departing from, a value, method or credit rating level set in a SoRI, for the purposes of its Distribution Determination.

Clause 6.12.1(5) of the Rules provides that a decision on whether to apply or depart from a value, method or credit rating level set out in a SoRI is one of the constituent decisions of the AER's Distribution Determination.

Clause S6.1.3(8) of the Rules requires Ergon Energy's Building Block Proposal to propose the commencement and length of the period for the purposes of calculating the nominal risk-free rate under clause 6.5.2(c)(2) of the Rules.

Clause S6.1.3(9) of the Rules requires the Building Block Proposal to propose Ergon Energy's calculation of the rate of return, including any proposed departure from the values, methods or credit rating levels set out in the applicable SoRI.

41.3 REQUIREMENTS OF THE RIN

Section 2.4.3(a) of the AER's RIN requires Ergon Energy to provide the following financial parameters for the purposes of being applied in the Post Tax Revenue Model (PTRM) for the next regulatory control period:

- The averaging period for bond rates;
- The start of the averaging period for bond rates;
- The indicative nominal risk-free rate;
- The indicative debt risk premium; and
- The inflation forecast.

The RIN section 2.4.3(b) also requires that, if Ergon Energy wishes the AER to consider a departure from a value, method or credit rating level set out in the SoRI, evidence to support such a departure must be provided as part of Ergon Energy's Regulatory Proposal.

41.4 OUTCOMES OF AER'S STATEMENT OF REGULATORY INTENT

This section has been prepared having regard for clauses 6.4.3(a)(2), 6.4.3(b)(2), 6.5.2, 6.12.1(5) and S6.1.3(9) of the Rules.

On 11 December 2008, in accordance with clauses 6.5.4 and 6.16(b)(1) of the Rules, the AER released its proposed SoRI.

On 1 May 2009, following consultation on the proposed SoRI, the AER issued the final SoRI in accordance with clauses 6.5.4 and 6.16 of the Rules.

Section 3 of the final SoRI adopts the following values, methods and credit rating levels for use in calculating the rate of return:[89]

> *3.2 In relation to the method to calculate the nominal risk free rate (rf):*
>
> *a. it is to be on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years,*
>
> *b. the period of time in which it is to be calculated is either:*
>
> *1. a period ('the agreed period'), being one which is as close as practically possible to the commencement of the regulatory control period, proposed by the relevant Distribution Network Service Provider, and agreed by the AER (such agreement is not to be unreasonably withheld), or*
>
> *2. a period specified by the AER, and notified to the provider within a reasonable time prior to the commencement of that period, if the period proposed by the provider is not agreed by the AER under paragraph 3.2(b)(i),*
>
> *and is also to be calculated in accordance with clauses 6.5.2(c)(1), 6.5.2(c)(2)(iii) and 6.5.2(c)(2)(iv) of the NER.*
>
> *3.3 In relation to clause 6.5.2(d) of the NER:*
>
> *a. the maturity period is a maturity of 10 years, and*
>
> *b. the bond rate is the annualised yield on Commonwealth Government bonds.*
>
> *3.4 The equity beta (ße) is 0.80.*
>
> *3.5 The market risk premium (MRP) is 6.5 per cent.*
>
> *3.6 The value of debt as a proportion of the value of equity and debt (D/V) is 0.60*

[89] AER, "Electricity Transmission and Distribution Network Service Providers - Statement of the Revised WACC Parameters (Transmission) - Statement of Regulatory Intent on the Revised WACC parameters (Distribution)", May 2009, page 7

3.7 The credit rating level is BBB+.

3.8 The assumed utilisation of imputation credits (γ) is 0.65.

41.5 PROPOSED VALUES, METHODS AND CREDIT RATING LEVELS

Ergon Energy is required to propose certain values, methods and credit rating levels for the purposes of calculating its rate of return on capital for the next regulatory control period.

Clause S6.1.3(9) of the Rules allows Ergon Energy to propose departures from the values, methods or credit rating levels set out in the applicable SoRI. The applicable SoRI is the final SoRI released on 1 May 2009.

Section 2.4.3(b) of the RIN requires that, if Ergon Energy wishes the AER to consider a departure from a value, method or credit rating level set out in the SoRI, evidence to support such a departure must be provided as part of Ergon Energy's Regulatory Proposal.

41.5.1 Averaging Period in Days and Start Date for Bond Rates

Clause S6.1.3(8) of the Rules requires Ergon Energy's Building Block Proposal to propose the commencement and length of the period for the purposes of calculating the nominal risk-free rate under clause 6.5.2(c)(2) of the Rules.

Section 2.4.3(a)(1) of the RIN requires Ergon Energy to propose the averaging period in days, and the start date of the averaging period, for bond rates.

Ergon Energy notes that, in accordance with clause 6.5.2(c)(2)(iii) of the Rules, its proposed nominal risk-free rate period may be kept confidential but only until after the expiry of that period.

Clause 6.5.2(c)(2)(iv) of the Rules provides that the AER will inform Ergon Energy within 30 days of submitting this Regulatory Proposal whether it agrees with the proposed period.

Ergon Energy's indicative averaging period for bond rates is the 40 business days commencing 27 January 2009 and ending 23 March 2009 (inclusive).

41.5.2 Indicative Nominal Risk-Free Rate

Section 2.4.3(a)(2) of the RIN requires Ergon Energy to propose an indicative nominal risk-free rate.

Clause 6.5.2(c) of the Rules details the meaning of the nominal risk-free rate. This methodology has been adopted in the final SoRI, but the AER has formalised its preferred approach to the 'agreed period'.

Clause S6.1.3(9) of the Rules allows Ergon Energy to propose departures from the values, methods or credit rating levels set out in the applicable SoRI. Based on new evidence, not available to Ergon Energy or submitted by others during the WACC review process prior to the SoRI being issued, the consideration given to the underlying criteria, and the evidence already put before the AER as part of the WACC review, Ergon Energy proposes a departure from the SoRI methodology to determine the nominal risk-free rate.

Ergon Energy proposes a nominal risk-free rate equal to the annualised yield on nominal Commonwealth Government bonds with a maturity of 10 years plus a convenience yield of 0.79 per cent per annum. Ergon Energy's proposed nominal risk-free rate methodology reflects Ergon Energy's assessment of the optimal method to calculate the nominal risk-free rate at the current time. Evidence supporting this position is detailed in the Competition Economists Group (CEG) report entitled 'Estimating the risk-free rate in the context of the NER and the Global Financial Crisis' which accompanies this Regulatory Proposal.

The methodology used to annualise the yield on Commonwealth Government bonds is that used by the AER in the April 2009 Final Determinations for the NSW and ACT Distribution Network Service Providers (DNSPs) and is therefore consistent with regulatory precedent.

Ergon Energy proposes 5.08 per cent per annum as its indicative nominal risk-free rate.

41.5.3 Inflation Forecast

Section 2.4.3(a)(4) of the RIN and section 2.4.3(b) of the RIN requires Ergon Energy to provide an inflation forecast for the next regulatory control period.

Ergon Energy's proposed method to determine the best estimate of expected inflation is to use the arithmetic average of the Reserve Bank of Australia's (RBA) short-term inflation forecasts published in its February 2009 Statement on Monetary Policy, and for subsequent years, the mid-point of the RBA's target inflation band (that is, 2.5 per cent per annum).

Based on this approach Ergon Energy's inflation forecast for the next regulatory control period is 2.45 per cent per annum. This is calculated using a 10 year term consistent with the term adopted for the nominal risk-free rate.

41.5.4 Equity Beta

Ergon Energy has adopted the value of 0.8 for the equity beta from the AER's final SoRI.

41.5.5 Market Risk Premium

Clause 6.5.4(e)(1) of the Rules states that the rate of return should be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing standard control services.

In accordance with this requirement, as part of the consultation conducted by the AER with industry in its WACC review, the Joint Industry Association (JIA) submitted that the most appropriate estimate for the

Market Risk Premium (MRP) is 7.0 per cent per annum and provided persuasive evidence to support this proposal. Having regard to the importance placed on the need to achieve an outcome that is consistent with the National Electricity Objective and based on the underlying criteria, Ergon Energy does not resile from that position and the supporting materials provided by industry at that time but notes that those materials have already been submitted to the AER in the WACC review.

At this time Ergon Energy does not have new material to submit to the AER on this parameter and consequently Ergon Energy must propose the market risk premium of 6.5 per cent per annum as set out in the final SoRI.

41.5.6 Debt Risk Premium

Section 2.4.3(a)(3) of the RIN and section 2.4.3(b) of the RIN requires Ergon Energy to propose an indicative debt risk premium.

Clause 6.5.2(e) of the Rules provides that the debt risk premium for a regulatory control period is the premium determined for that regulatory control period by the AER as the margin between the annualised nominal risk-free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk-free rate and a credit rating from a recognised credit rating agency. Clause 6.5.4(e)(2) of the Rules states that the rate of return on debt should reflect the current cost of borrowings for comparable debt.

The proposed methodology to determine the annualised nominal risk-free rate is detailed in section 41.5.2 of this Regulatory Proposal. The methodology used to annualise the Australian benchmark corporate bond rate for corporate bonds is consistent with the approach proposed to annualise the nominal risk-free rate.

Ergon Energy's proposed averaging period in days, and the start date of the averaging period for bond rates is provided in section 41.5.1.

Ergon Energy has engaged CEG to advise the optimal method to determine the debt risk premium as defined in the Rules, in light of the approach adopted by the AER for NSW DNSPs in its 2009 Final Decision and which was incorporated by reference in the SoRI. CEG's advice is provided in the confidential report entitled 'Estimating the cost of 10 year BBB + debt' which accompanies this Regulatory Proposal and was requested to enable Ergon Energy to consider the latest available information following release of the SoRI. The information and reasoning relied upon by the AER in its April 2009 Final Decisions for the NSW DNSPs was not readily available to Ergon Energy or referenced by others during the WACC review process.

On the basis of the additional new evidence provided in CEG's report, Ergon Energy does not consider that the AER's methodology for estimating the benchmark rate in the Rules is reasonable.

The CEG report finds that the AER's method:

- Materially underestimates alternative potential estimates of the benchmark rate in the Rules; and
- Did not seem to adequately capture the impact of the escalation of the financial crisis in September 2008.

In addition, theory and evidence presented in the CEG report supports the view that the AER/Bloomberg fair value estimate would tend to underestimate the cost of issuing benchmark 10 year BBB+ debt, even in more normal market conditions.

CEG advises that the CBASpectrum BBB+ 10 year fair value yield performs better but cannot be presumed to be perfect as a proxy for the benchmark rate.

Consistent with CEG's recommendation and having regard to the underlying criteria and the need to achieve an outcome that is consistent with the National Electricity Objective, Ergon Energy proposes a simple average of the AER/Bloomberg and CBASpectrum BBB+ 10 year fair value estimates to be utilised when calculating the debt risk premium.

Ergon Energy's indicative debt risk premium applies this methodology and the averaging period used to calculate the indicative nominal risk-free rate (40 days commencing 27 January 2009). The proposed indicative debt risk premium is 3.88 per cent per annum.[90]

41.5.7 Gearing

Ergon Energy has adopted the value of 0.60 for the value of debt as a proportion of the value of equity and debt (D/V) from the AER's final SoRI.

41.5.8 Gamma

The generally accepted approach to gamma in Australia has been to define it as the product of the imputation credit 'payout ratio' and theta. The AER's final SoRI adopts a value for gamma of 0.65.

Clause S6.1.3(9) of the Rules allows Ergon Energy to propose departures from the values, methods or credit rating levels set out in the applicable SoRI. Based on new evidence not available to Ergon Energy during the WACC review process prior to the SoRI being issued, the consideration given to the underlying criteria and the evidence already put before the AER as part of the WACC review, Ergon Energy proposes a departure from the SoRI value of 0.65. Section 2.4.3(b) of the RIN requires that, if Ergon Energy wishes the AER to consider a departure from a value, method or credit rating level set out in the SoRI, evidence to support such a departure must be provided as part of Ergon Energy's Regulatory Proposal.

[90] The proposed convenience yield of 79 basis points has been effectively removed from the indicative debt risk premium.

By adopting a value of 0.65, Ergon Energy contends that, having regard to the underlying criteria and the need to achieve an outcome that is consistent with the National Electricity Objective, among other things, the final SoRI has not given sufficient weight to the volume of evidence previously provided to the AER in several reputable recent studies. Expert reports provided as part of the JIA's submission in response to the proposed SoRI highlighted a number of significant concerns with the AER's analysis (including the work undertaken by its consultant).[91]

Ergon Energy has engaged Synergies to provide expert advice as to an appropriate estimate for gamma. Synergies' expert report entitled 'Gamma - New Analysis Using Tax Statistics' accompanies this Regulatory Proposal.

Considering the evidence put before the AER in the WACC review and the explanatory material used to support the AER's SoRI, Synergies measured the maximum possible amount that could be ascribed to gamma (but not the value of gamma) by examining taxation statistics. This analysis was not available to Ergon Energy prior to the final SoRI and as far as Ergon Energy is able to discern, was not contained in other material submitted during the WACC review process.

Synergies' report notes that not all imputation credits created are distributed and of those distributed, not all are claimed by individual shareholders. Based on the actual payout ratios observed from the statistics, the maximum possible amount of credits claimed is 23 per cent. If this is adjusted to reflect the AER's assumed payout ratio, the maximum is 35 per cent.

Synergies concludes that, while it has not sought to re-examine evidence from market prices, a range between 0 and 0.2 is a more reasonable and plausible value for gamma. On this basis, Ergon Energy proposes a conservative point estimate of 0.2 for gamma.

41.6 CALCULATION OF THE RATE OF RETURN

Clause 6.5.2(b) of the Rules defines the rate of return and requires that it be calculated as the nominal post tax WACC.

Ergon Energy's proposed indicative nominal post tax vanilla WACC is 9.49 per cent per annum.

Ergon Energy has calculated this rate of return in its completed PTRM by applying the values detailed in Table 111.

Ergon Energy has engaged Strategic Finance Group (SFG) to assess the reasonableness of Ergon Energy's proposed return on equity and compare it, on an economic basis, with the return on equity that would be derived from the AER's SoRI. The SFG report concludes that Ergon Energy's proposed return on equity is more reasonable that the return on equity that would be derived from the values and methodologies contained within the final SoRI.

SFG's report entitled 'The reasonableness of regulatory estimates of the cost of equity capital' accompanies this Regulatory Proposal.

Table 111: *Parameters to calculate Nominal Post Tax Weighted Average Cost of Capital*

Parameter	Symbol	Value
Nominal Risk-Free Rate	Rf	5.08%
Real Risk-Free Rate	Rrf	2.57%
Inflation Rate	f	2.45%
Cost of Debt Margin	DRP	3.88%
Market Risk Premium	MRP	6.50%
Corporate Tax Rate	T	30.0%
Gamma	γ	0.20
Proportion of Equity Funding	E/V	40.0%
Proportion of Debt Funding	D/V	60.0%
Equity Beta	ße	0.80

Source: SCPTRM Submission Model

[91] Refer: SFG (2009), Market Practice in Relation to Franking Credits and WACC: Response to AER Proposed Revision of WACC Parameters, Report Prepared for ENA, APIA and Grid Australia, February; NERA Economic Consulting (2009), AER's Proposed WACC Statement – Gamma, A Report for the Joint Industry Associations, January; SFG (2009), Using Redemption Rates to Estimate Theta: Response to AER Proposed Revision of WACC Parameters, Report Prepared for ENA, APIA and Grid Australia, February; SFG (2009), The Value of Imputation Credits as Implied by the Methodology of Beggs and Skeels (2006), Report Prepared for ENA, APIA and Grid Australia, February; SFG (2009), The Consistency of Estimates of the Value of Cash Dividends, Report Prepared for ENA, APIA and Grid Australia, February; Synergies Economic Consulting (2009), Peer Review of SFG Consulting Reports on Gamma, A Report to the ENA, APIA and Grid Australia, January.

41. RATE OF RETURN ON CAPITAL – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR369	National Electricity Law

AER Documents

AR367c & 368c	AER Regulatory Information Notice
AR520	AER Statement of Regulatory Intent
AR524	AER Post Tax Revenue Model Handbook

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR528	CEG Estimating the Risk Free Rate in the Context of the NER and the Global Financial Crisis, 12 June 2009
AR529	RBA February 2009 Statement on Monetary Policy, 6 February 2009
AR530	CEG Estimating the Cost of 10 Year BBB+ Debt, 12 June 2009
AR531	Synergies, Gamma – New Analysis Using Tax Statistics, 28 May 2009
AR532	SFC The Reasonableness of Regulatory Estimates of the Cost of Equity Capital, 28 May 2009
AR534c	Synergies Debt and Equity Raising Costs, 28 May 2009
AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

42. X FACTORS

Rules – Clauses 6.5.9, 6.12.1(11), S6.1.3(6)(i) and 11.16.7
RIN – Sections 2.4.2(a)(1),(2) and (3)
PTRM Handbook – Section 2.6 pages 16-18

This chapter details Ergon Energy's proposed X factors for the next regulatory control period in order to address the requirements of the Rules, the Regulatory Information Notice (RIN) and the Post Tax Revenue Model (PTRM) handbook.

As noted in the PTRM handbook, the X factor is simply a price or revenue adjustment mechanism. It does not relate to actual productivity improvements in Ergon Energy's operations.

Clause 6.5.9(a) of the Rules provides that the Australian Energy Regulator's (AER) Building Block Determination is to include the X factor for each control mechanism for each year of the regulatory control period. Further, clause 6.12.1(11) of the Rules requires that determining the X factor (as part of the control mechanism) is to be one of the constituent decisions of the AER's Distribution Determination.

Clause S6.1.3(6) of the Rules requires Ergon Energy's Building Block Proposal to include the calculation of revenues or prices for the purposes of the control mechanism proposed by the provider together with:

- Details of all amounts, values and inputs (including X factors) relevant to the calculation;
- An explanation of the calculation and the amounts, values and inputs involved in the calculation; and
- A demonstration that the calculation and the amounts, values and inputs on which it is based comply with relevant requirements of the NEL and the Rules.

Clause 6.5.9(b) of the Rules details the basis on which the X factors must be set. Section 2.4.2 of the RIN outlines the information to be provided regarding X factors. This information and the factors detailed in clause 6.5.9(b) of the Rules are discussed in detail in the remainder of this chapter. Clause 6.5.9(c)(1) of the Rules allows there to be different X factors for different regulatory years of the regulatory control period.

42.1 EXPLAIN HOW X FACTORS HAVE BEEN SET

Clause 2.4.2(a)(1) of the RIN requires Ergon Energy to explain how the X factors have been set.

Ergon Energy's proposed X factors for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15, are detailed in Table 112.

Table 112: *X Factors for Standard Control Services for 2010-15 (per cent)*

	2010-11	2011-12	2012-13	2013-14	2014-15
X factors	-27.05	-7.69	-7.69	-7.69	-7.69

Note: A negative X factor represents a real increase in distribution prices.
Source: Tables for Proposal 42.1

Ergon Energy has calculated the proposed X factors for each regulatory year of the next regulatory control period in the PTRM, in accordance with the requirements of clause 6.5.9 of the Rules. In particular, Ergon Energy has set the X factors:

- Having regard to the DNSP's Total Revenue Requirement, as required by clause 6.5.9(b)(1) of the Rules;
- In order to minimise, as far as reasonably possible, variance between expected revenue for the last regulatory year of the regulatory control period and the annual revenue requirement for the last regulatory year, as required by clause 6.5.9(b)(2) of the Rules;
- In order to equalise (in terms of net present value) the revenue to be earned by Ergon Energy from the provision of Standard Control Services over the regulatory control period with Ergon Energy's Total Revenue Requirement for the regulatory control period, as required by clause 6.5.9(b)(3)(i) of the Rules; and
- To include different values, as is permitted under clause 6.5.9(c)(1) of the Rules.

42.2 EXPLAIN HOW X FACTORS SATISFY 6.5.9 OF RULES AND PTRM HANDBOOK

Clause 2.4.2(a)(2) of the RIN requires Ergon Energy to explain how the X factors satisfy the requirements of clause 6.5.9 of the Rules and the guidance in the PTRM handbook.

The X factor for the first year of the regulatory control period has been set so as to equate the annual revenue requirement and smoothed revenue forecast for that year. The remaining X factors have been set equal to each other in order to satisfy the requirements of clause 6.5.9 of the Rules and section 2.6 of the PTRM handbook to:

- Minimise, as far as reasonably possible, variance between expected revenue for the last regulatory year of the regulatory control period and the annual revenue requirement for the last regulatory year; and
- Equalise (in terms of net present value) the revenue to be earned by Ergon Energy from the provision of Standard Control Services over the regulatory control period with Ergon Energy's Total Revenue Requirement for the regulatory control period.

On this basis, Ergon Energy considers that there is not combination of X factors that better achieves the requirements of clause 6.5.9 of the Rules and section 2.6 of the PTRM handbook than those detailed in Table 112 of this Regulatory Proposal.

42.3 PROVIDE OTHER RELEVANT JUSTIFICATIONS OF X FACTORS

Clause 2.4.2(a)(3) of the RIN allows Ergon Energy to provide any other justifications that it considers are relevant to its proposed X factors.

Ergon Energy does not consider that any other matters are relevant to justifying its proposed X factors than the explanations that are provided in section 42.2 of this Regulatory Proposal.

42. X FACTORS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR369	National Electricity Law

AER Documents

AR367c & 368c	AER Regulatory Information Notice
AR524	AER Post Tax Revenue Model Handbook

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

C CONFIDENTIAL INFORMATION

43. EFFICIENCY BENEFIT SHARING SCHEME (EBSS) – PARAMETERS

Rules – Clauses 6.3.2(a)(3), 6.4.3(a)(5), 6.4.3(b)(5), 6.5.8, 6.6.3(d), 6.8.1(b)(3), 6.12.1(9), S6.1.3(3), and 11.16.4
RIN - Section 2.3.2 and 2.3.4
EBSS Guideline – Clauses 2.3.2 and 2.3.3
F&A Stage 2 – Section 3

In accordance with clause 6.5.8 of the Rules, the Australian Energy Regulator (AER) has developed an Efficiency Benefit Sharing Scheme (EBSS) to apply to Ergon Energy during the next regulatory control period.

The AER's EBSS seeks to provide a financial incentive for Ergon Energy to improve the efficiency of its operating expenditure and to share any resulting efficiency gains (or losses) with distribution network users. Any efficiency gains (or losses) are retained by Ergon Energy for five years after the gain (or loss) is realised. This will result in efficiency gains (or losses) being shared between Ergon Energy and distribution network users in a ratio of 30:70.

Clause 6.5.8(b) of the Rules allows for the EBSS to also cover efficiency gains and losses related to capital expenditure and/or distribution losses. However, in its EBSS Guidelines and Framework and Approach papers, the AER has indicated that the EBSS shall only apply to operating expenditure for the next regulatory control period.

43.1 ADJUSTMENTS

The AER's F&A Stage 2 and clause 2.3.2 of the EBSS details the basis for making adjustments to forecast operating expenditure allowances for the purposes of calculating carryover amounts. This chapter allows Ergon Energy to propose a range of additional cost categories for exclusion from the operation of the EBSS.

Ergon Energy does not propose any further adjustments to the EBSS other than those set out in the EBSS and Section 3 of the AER's F & A Stage 2.

43.1.1 Capitalisation Policy as at 1 July 2010

The AER's F&A Stage 2 and clause 2.3.2 of the EBSS requires Ergon Energy to provide a detailed description of any changes in capitalisation policies and a calculation of the impact of those changes in capitalisation policy on forecast and actual operating expenditure.

Ergon Energy's capitalisation policy accompanies this Regulatory Proposal. Ergon Energy does not anticipate that this policy will change during the remainder of the current regulatory control period and cannot foresee any changes to this policy during the next regulatory control period.

In the event that the capitalisation policy does change at any time prior to, or during, the next regulatory control period, Ergon Energy will, in accordance with clause 2.3.2 of the EBSS:

- Adjust the forecast operating expenditure used to calculate the carryover amounts so that the forecast operating expenditure is consistent with the capitalisation changes; and
- Provide the AER with a detailed description of any changes to the capitalisation policy and a calculation of the impact of those changes on forecast and actual operating expenditure.

43.1.2 Growth Adjustment Method

Section 2.3.2 of the EBSS requires that, for the purposes of calculating the carryover amounts, the forecast operating expenditure must be adjusted for the cost consequences of any differences between forecast and actual demand growth over the regulatory control period. These adjustments must be made using the same relationship between growth and expenditure used in establishing the forecast operating expenditure. Adjustments must only be applied to those components of operating expenditure that have a direct relationship to growth.

Ergon Energy's demand forecasting process is explained in Chapter 21 of this Regulatory Proposal. Importantly, Ergon Energy only uses its demand forecasts to develop its capital expenditure forecasts for the next regulatory control period – they are not used to prepare the operating expenditure forecasts. As a consequence, Ergon Energy does not consider that its operating expenditure is directly related to demand growth.

Ergon Energy will advise the AER at the end of the next regulatory control period if it considers that, for the purposes of calculating the carryover amounts, any adjustments are required to the forecast operating expenditure for the cost consequences of any differences between forecast and actual demand growth over the regulatory control period. At this stage, Ergon Energy does not expect any such adjustment to be required given that it does not consider that its operating expenditure is directly related to demand growth.

43.1.3 Exclusion of Non-Network Alternatives

Clause 2.3.2 of the EBSS provides that all operating expenditure spent on non-network alternatives will be excluded from the actual and forecast operating expenditure amounts used to calculate carryover gains or losses under the EBSS.

Ergon Energy's forecast operating expenditure relating to non-network alternatives for the next regulatory control period is provided in Chapter 30. The forecast operating expenditure for non-network alternatives is provided in Table 113.

Table 113: *Forecast Non-Network Operating Expenditure 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Non-Network Operating Expenditure	12.61	13.29	13.44	13.60	13.76	66.69	13.34

Source: Table for Proposal 43.1.3

Ergon Energy also proposes that the Demand Management Innovation Allowance (DMIA) be excluded from the operation of the EBSS. The forecast DMIA for the next regulatory control period is provided in Table 114.

Table 114: *Forecast DMIA 2011-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total
DMIA	1.0	1.0	1.0	1.0	1.0	5.0

Source: N/A

43.1.4 Operational Expenditure Associated with Recognised Pass Through Events to be Excluded

The AER's F&A Stage 2 section 3.5.1 and clause 2.3.2 of the EBSS Guideline provides that approved increases or decreases in actual operating expenditure associated with recognised pass through events will be excluded from the actual and forecast expenditure amounts used to calculate carryover gains or losses under the EBSS.

Ergon Energy therefore proposes that approved increases or decreases in actual operating expenditure associated with the pass through events, including those detailed in Chapter 46 of this Regulatory Proposal, be excluded from the operation of the EBSS.

43.1.5 Changes in Responsibilities

Clause 2.3.2 of the EBSS Guideline provides that the operating expenditure forecast must include any necessary adjustments for changes in responsibilities that result from compliance with a new or amended law, licence or other statutory or regulatory requirement.

Ergon Energy will identify and quantify the cost associated with any such change in requirement if it occurred during the next regulatory control period.

43.1.6 Standard Control Service Change

Clause 2.3.2 of the EBSS Guideline provides that where a Standard Control Service does not remain a Standard Control Service in the next regulatory control period, the AER may remove the operating expenditure relating to that service from the actual and forecast operating expenditure used to calculate the carryover amounts.

43.1.7 No Uncontrollable Cost Categories Nominated by Ergon Energy

The AER's F&A Stage 2 section 3.5.1 and clause 2.3.2 of the EBSS allows Ergon Energy to propose additional cost categories for exclusion from the operation of the EBSS.

Ergon Energy does not propose any additional cost categories for exclusion from the operation of the EBSS for the next regulatory control period.

43.2 CARRYOVER PERIOD

Ergon Energy proposes that a carryover period of five years apply to the EBSS, as provided for in clause 2.3.3 of the EBSS.

43.3 APPLICATION OF THE EBSS

43.3.1 Forecast Operational Expenditure

As required by clause 2.3.2 of the EBSS, Table 115 provides a breakdown of Ergon Energy's proposed operating expenditure for use as part of the EBSS.

Table 115: *Forecast Operational Expenditure for purposes of EBSS ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total
Total Operational Expenditure (1)	379.17	400.40	414.52	426.00	422.91	2,043.00
Less (2)						
DMIA Allowance	1.00	1.00	1.00	1.00	1.00	5.00
Self Insurance Costs	5.78	6.22	6.78	7.44	8.15	34.38
Non-Network Alternatives	12.61	13.29	13.44	13.60	13.76	66.69
Operating Expenditure for EBSS	**359.77**	**379.89**	**393.31**	**403.96**	**399.99**	**1,936.93**

1. Total Operating Expenditure excludes Debt and Equity Raising costs.
2. The following adjustments cannot be forecast on reasonable grounds: (a) Changes in Operating Expenditure attributable to differences between Forecast and Actual Demand Growth, (b) Forced Operating Expenditure required to respond to events giving rise to a Major Event Day, and (c) Operating Expenditure associated with a recognised Cost Pass-Through Events.

Source: Tables for Proposal 43.3.1

43.3.2 Annual Carryover Amount

Ergon Energy supports the calculation of the annual carryover amount in accordance with the method set out in section 2.3.4 of the EBSS.

43.3.3 Application of Carryover Amount

In accordance with clause 2.3.4 of the EBSS Guideline, Ergon Energy understands that, subject to the adjustments noted in section 2.3.2 of the EBSS Guideline, the AER will apply all carryovers (both positive and negative) as a building block element in the calculation of a DNSP's allowed revenue for the regulatory control period following the regulatory control period in which the EBSS applied.

43. EFFICIENCY BENEFIT SHARING SCHEME (EBSS) – PARAMETERS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR394 & 395	AER Final Decision EBSS, June 2008 & AER Appendix E EBSS, June 2008

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

Nil

44. SERVICE TARGET PERFORMANCE INCENTIVE SCHEME (STPIS) – PARAMETERS

Rules – Clauses 6.3.2(a)(3), 6.4.3(a)(5), 6.4.3(b)(5), 6.6.2, 6.8.1(b)(2), 6.12.1(9), S6.1.2(4), S6.1.3(4) and 11.16.5
RIN – Section 2.3.5
RIN Pro forma - 2.3.5
STPIS – Clauses 1.3(b), 2.2, 2.4(a), 2.5, 3.1(d), 3.2.1(a) and (b), 3.2.2, 3.3, 5.1(c), 5.2, 5.3.1, 5.3.2, 5.4, 6.1(a) and Appendices
F&A Stage 2 – Clauses 2, 2.5.1, 2.5.2, 2.5.3, 2.5.4, 2.5.5, 2.5.7, 2.6.2 and 3.5.1

The Australian Energy Regulator (AER) has developed a Service Target Performance Incentive Scheme (STPIS) in accordance with clause 6.6.2 of the Rules to apply to Ergon Energy during the next regulatory control period.

The AER's STPIS seeks to provide a financial incentive for Ergon Energy to maintain and improve its service performance. The STPIS, which encompasses reliability performance, quality of supply and customer service parameters as well as Guaranteed Service Levels (GSLs), operates concurrently with the Minimum Service Standards (MSS) and GSL schemes that apply to Ergon Energy under the Electricity Industry Code.

The AER has indicated in its STPIS Guidelines and F&A Stage 2 that the STPIS will only apply to reliability performance and customer service performance for the next regulatory control period.

Under the STPIS, Ergon Energy earns rewards if its actual performance is better than its set targets and incurs penalties if its actual performance is worse than its set targets. These rewards or penalties are realised in the form of increments or decrements to the Annual Revenue Requirement (ARR) two regulatory years after the actual performance is reported, in accordance with clause 6.4.3(a)(5) and 6.4.3(b)(5) of the Rules.

44.1 DESCRIPTION OF HOW STPIS WILL APPLY

Clause 1.3(b)(2)(i) of the STPIS requires Ergon Energy to provide a description in this Building Block Proposal, including relevant explanatory material, of how it proposes the STPIS should apply in the next regulatory control period, in accordance with clause S6.1.3(4) of the Rules.

Ergon Energy proposes that the STPIS apply in accordance with the requirements of:

- Chapter 6 of the Rules;
- The AER's STPIS Guideline; and
- The AER's F&A Stage 2;

with specific modifications, and using the information, detailed in this chapter of Ergon Energy's Building Block Proposal.

44.2 INFORMATION REQUIRED BY THE RIN

Clause 1.3(b)(2)(ii) of the STPIS requires Ergon Energy to provide such information in its Building Block Proposal as is required under any relevant regulatory information instrument issued by the AER.

The relevant regulatory information instrument is the Regulatory Information Notice (RIN) issued to Ergon Energy by the AER on 22 April 2009. Section 2.3.5 is the only element of the RIN that is directly relevant to the STPIS. It details the information that Ergon Energy must provide about its service standard obligations.

Ergon Energy has provided this information in Chapter 12 of this Regulatory Proposal and pro forma 2.3.5 of the completed RIN.

44.3 EXPLANATION AND JUSTIFICATION OF VARIATIONS IN STPIS

Clause 2.2 of the STPIS details the basis on which Ergon Energy may propose variations to the application of the AER's STPIS, including the information that Ergon Energy must provide to support any such proposal.

Ergon Energy does not propose any variations to the application of the STPIS.

44.4 RELIABILITY PERFORMANCE PARAMETERS

Clause S6.1.3(4) of the Rules requires Ergon Energy to provide relevant explanations as to how it proposes the STPIS to apply for the next regulatory control period.

Ergon Energy proposes the following reliability measures be included in the STPIS:

- Unplanned Urban System Average Interruption Duration Index (SAIDI);
- Unplanned Urban System Average Interruption Frequency Index (SAIFI);
- Unplanned Short Rural SAIDI;
- Unplanned Short Rural SAIFI;
- Unplanned Long Rural SAIDI; and
- Unplanned Long Rural SAIFI.

Ergon Energy does not propose Momentary Average Interruption Frequency Index (MAIFI) be included as a parameter for the next regulatory control period.

These parameters are consistent with clauses 2.5.2 and 2.6.2 of the AER's F&A Stage 2.

Ergon Energy calculates SAIDI and SAIFI based on monthly actual customer numbers, rather than average customers for the financial year. This approach is consistent with Ergon Energy's reporting arrangements with the Queensland Competition Authority (QCA) and more accurately reflects the customer base in the SAIDI and SAIFI calculations.

44.4.1 Reliability Data for 2003-04 to 2007-08 to Derive Targets

Clause 3.2.1(a) of the STPIS requires that performance targets must be based on average performance over the past five financial years or another measurement period as described in clause 2.4(a), as appropriate.

Ergon Energy's most recent completed five financial years of data is for 2003-04 to 2007-08 inclusive. Ergon Energy's normalised unplanned annual reliability performance by feeder type is provided in Table 116 by year. Table 116 also provides averages for each parameter for the five year period.

Table 116: *Normalised Unplanned Reliability Performance for 2003-04 to 2007-08*

Parameter	2003-04	2004-05	2005-06	2006-07	2007-08	Average
Actual Urban SAIDI	234	212	240	130	164	**196**
Actual Urban SAIFI	2.84	2.08	2.42	1.66	1.83	**2.17**
Actual Short Rural SAIDI	476	401	502	316	372	**413**
Actual Short Rural SAIFI	5.36	4.11	4.88	3.26	3.31	**4.18**
Actual Long Rural SAIDI	1,057	952	1,025	700	800	**907**
Actual Long Rural SAIFI	9.13	7.18	8.30	5.19	5.74	**7.11**

All planned outages (i.e. outages where advance notice was given to customers) have been excluded from the reliability performance in Table 116. The reliability performance in Table 116 includes 'service fuse and beyond' outages.

In normalising the data presented in Table 116, exclusions have been made in accordance with clause 3.3(a) of the STPIS. In addition to these exclusions, all outages attributable to transmission and generation failures have been excluded, as these are beyond Ergon Energy's control.

44.4.2 Modify Performance Target - Reliability Works Program in Previous Regulatory Proposal for 2008-10

Clauses 3.2.1(a)(1)(ii) and (iii) of the STPIS allow modifications to average reliability performance that reflect the impact of any reliability improvement works planned during the previous regulatory control period that are expected to materially improve supply reliability.

In clause 2.5.3 of its F&A Stage 2, the AER indicated that it does not have a preferred method for how any such modifications should be undertaken, although any proposed modification would need to be supported by statistical analysis.

Given Ergon Energy's network topology, and the large number of relatively small works projects across the network, it is not possible to identify readily the impact of a given works project on the overall network performance, even by feeder type. However, the overall works program, which is focused on meeting the MSS requirements, does impact the overall network performance.

Consequently, Ergon Energy considers that no modifications are required to the average performance on the basis of clauses 3.2.1(a)(1)(ii) and (iii) of the STPIS, as the historical reliability performance data is reflective of the reliability improvements realised from the previous and current regulatory control period works programs.

44.4.3 Modify Performance Target - Reliability Works Program in Regulatory Proposal for 2010-15

Clauses 3.2.1(a)(1)(i) and (iii) of the STPIS allow Ergon Energy to propose modifications to average reliability performance that reflect the expected impact of any planned reliability improvement works, included in the expenditure program for the next regulatory control period that are expected to materially improve supply reliability.

In clause 2.5.3 of its F&A Stage 2, the AER indicated that it does not have a preferred method for how any such modification should be undertaken, although any proposed modification would need to be supported by statistical analysis.

Ergon Energy considers that setting the STPIS targets to be the lower of the annual MSS or the historical average performance meets this requirement because the MSS is reflective of the proposed works program in the next regulatory control period.

44.4.4 Modify Performance Target – Adjustment to Reliability Performance Targets to Correct for Revenue at Risk

Clause 3.2.1(a)(2) of the STPIS allows Ergon Energy to propose modifications to average reliability performance to correct for the revenue at risk (the sum of the s-factors for all parameters) to the extent it does not lie between the upper limit and the lower limit in accordance with clause 2.5(a) of the STPIS.

Clause 5.4.3 of the AER's February 2009 Explanatory Statement for the STPIS further expands on clause 3.2.1(a)(1A) of the STPIS. It requires that performance targets in the next regulatory control period be adjusted to ensure Distribution Network Service Provider (DNSP) does not experience a penalty, by way of increasingly difficult performance targets, in the next regulatory control period, for improved service performance that exceeded the revenue at risk during the current regulatory control period.

Similarly, clause 5.4.3 of the AER's February 2009 Explanatory Statement for the STPIS requires that performance targets in the next regulatory control period be adjusted to ensure that a DNSP does not benefit, by way of easier performance targets, in the next regulatory control period for service performance that fell below the amount of revenue at risk during the current regulatory control period.

Ergon Energy notes that no such adjustment will need to be made during the next regulatory control period as the STPIS does not apply to Ergon Energy until 1 July 2010. Consequently, Ergon Energy does not propose any modifications to the normalised unplanned reliability performance averages to correct for revenue at risk.

44.4.5 Modify Performance Target - Other Factors Materially Affecting Network Performance

Clause 3.2.1(a)(2) of the STPIS allows Ergon Energy to propose modifications to average reliability performance that reflect any other factors that are expected to materially affect network reliability performance.

Ergon Energy does not consider that there are any other modifications that need to be made to the normalised unplanned reliability performance averages.

44.4.6 Explanation of Modifications to Reliability Performance Targets

Clause 3.2.1(b) of the STPIS requires that, if a performance target is to be modified in accordance with clause 3.2.1(a)(1) or 3.2.1(a)(2), Ergon Energy must provide an explanation of how the modified performance targets have been calculated.

Ergon Energy does not propose any modifications to the performance targets in accordance with clause 3.2.1(a)(1) or 3.2.1(a)(2) of the STPIS. Consequently, no explanations of any performance target modifications are required.

44.4.7 Reliability Performance Targets and Principles

Clause S6.1.3(4) of the Rules requires Ergon Energy to provide relevant explanations about how it proposes the STPIS will apply for the next regulatory control period.

44.4.7.1 Adjusted Jurisdictional Minimum Service Standards

The STPIS requires that both the modified average historical reliability performance and the annual MSS need to be considered in setting the performance targets for the STPIS. However, because the annual MSS take account of both planned and unplanned outages they need to be adjusted in order to reflect unplanned outages only.

Unlike the Queensland Electricity Industry Code, the STPIS does not recognise 'service fuse and beyond' outages as allowable exclusions. Given that the annual MSS exclude 'service fuse and beyond' outages they should also be adjusted to reflect the inclusion of 'service fuse and beyond' outages.

Table 117 details the reliability performance parameters in the Queensland Electricity Industry Code for each reliability performance parameter.

Table 117: *Jurisdictional Minimum Service Standard for the Next Regulatory Control Period*

Parameter	2010-11	2011-12	2012-13	2013-14	2014-15
Actual Urban SAIDI	149	148	147	146	145
Actual Urban SAIFI	1.98	1.96	1.94	1.92	1.90
Actual Short Rural SAIDI	424	418	412	406	400
Actual Short Rural SAIFI	3.95	3.90	3.85	3.80	3.75
Actual Long Rural SAIDI	964	948	932	916	900
Actual Long Rural SAIFI	7.40	7.30	7.20	7.10	7.00

Ergon Energy considers it appropriate to multiply the MSS by the average historical percentage of unplanned outages for each parameter in order to account for unplanned outages, and then to escalate the result by the average historical percentage of 'service fuse and beyond' outages for each parameter in order to account for 'service fuse and beyond' outages.

The average historical percentage of unplanned outages for each parameter (based on 2003-04 to 2007-08 data), the average historical percentage of 'service fuse and beyond' outages for each parameter (based on 2003-04 to 2007-08 data) and the adjusted MSS are detailed in Table 118.

Table 118: *Average Historical Unplanned Outage Percentages, Average Historical Single Customer Outage Percentages and Adjusted MSS for the 2010-11 to 2014-15 Regulatory Control Period*

Parameter	Average Historical Per Cent of Unplanned Outages	Average Historical Per Cent of Single Customer Outages	Adjusted 2010-11 MSS	Adjusted 2011-12 MSS	Adjusted 2012-13 MSS	Adjusted 2013-14 MSS	Adjusted 2014-15 MSS
Actual Urban SAIDI	79%	21.592%	143.518	142.554	141.591	140.628	139.665
Actual Urban SAIFI	89%	7.117%	1.882	1.863	1.844	1.825	1.806
Actual Short Rural SAIDI	73%	6.098%	328.519	323.870	319.221	314.572	309.923
Actual Short Rural SAIFI	84%	2.173%	3.401	3.358	3.315	3.272	3.229
Actual Long Rural SAIDI	77%	3.981%	776.238	763.354	750.471	737.587	724.703
Actual Long Rural SAIFI	83%	1.004%	6.216	6.132	6.048	5.964	5.880

Ergon Energy considers that the adjusted annual MSS should be used for the purposes of calculating the reliability performance targets.

44.4.7.2 Application of the reliability performance target principles

In accordance with the principles set out in the F&A Stage 2, Ergon Energy proposes that for each year of the regulatory control period, the STPIS targets should be set equal to the lower of the historical modified average historical reliability performance or the adjusted annual MSS targets for that year for each parameter.

Table 119 details the reliability performance targets for each parameter to apply in the STPIS for the next regulatory control period.

Table 119: *STPIS Reliability Performance Targets for the next regulatory control period*

Parameter	2010-11 STPIS Target	2011-12 STPIS Target	2012-13 STPIS Target	2013-14 STPIS Target	2014-15 STPIS Target
Actual Urban SAIDI	143.518	142.554	141.591	140.628	139.665
Actual Urban SAIFI	1.882	1.863	1.844	1.825	1.806
Actual Short Rural SAIDI	328.519	323.870	319.221	314.572	309.923
Actual Short Rural SAIFI	3.401	3.358	3.315	3.272	3.229
Actual Long Rural SAIDI	776.238	763.354	750.471	737.587	724.703
Actual Long Rural SAIFI	6.216	6.132	6.048	5.964	5.880

44.4.8 Revenue at Risk

Clause 2.5(b) of the STPIS prescribes the maximum revenue at risk for the STPIS components in aggregate for each regulatory year of the next regulatory control period to be +/-5 per cent. However, clause 11.16.5 of the Rules provides that the AER must consider whether the STPIS should be applied by way of a paper trial or whether a lower powered incentive is appropriate in formulating the STPIS to apply to Ergon Energy in the next regulatory control period.

In clause 2.5.4 of its F&A Stage 2, the AER had regard for the transitional requirement in clause 11.16.5 of the Rules and reached a preliminary position that Ergon Energy's maximum revenue at risk for the STPIS components in aggregate for each regulatory year of the next regulatory control period should be +/-2 per cent.

Ergon Energy agrees with the AER's preliminary position in its F&A Stage 2 and proposes that the maximum revenue at risk for the STPIS components in aggregate for each regulatory year of the next regulatory control period should be +/-2 per cent.

44.4.9 Value of Customer Reliability (VCR)

Clause 3.2.2(b) of the STPIS requires that, where the electricity distribution network is divided into segments by network type, the Value of Customer Reliability (VCR) used to determine the incentive rate for central business district (CBD) segments should be set to $95,700/MWh, adjusted by Consumer Price Index (CPI) from September 2008 to the start of the regulatory control period. For urban, short rural and long rural feeders, the VCR should be set to $47,850/MWh, adjusted by CPI from September 2008 to the start of the next regulatory control period.

However, clause 3.2.2(d) of the STPIS allows Ergon Energy to propose an alternative VCR to apply to a parameter segment other than that detailed in the STPIS.

Ergon Energy does not propose any alternative VCR values and accepts the AER's VCR value of $47,850 (in September 2008 dollars) for urban, short rural and long rural feeders. Ergon Energy does not have any CBD segments.

44.4.10 Escalation of VCR by CPI from September 2008

As noted above, clause 3.2.2(b) of the STPIS provides for the VCR for urban, short rural and long rural feeders to be set to $47,850/MWh, adjusted by CPI from September 2008 to the start of the next regulatory control period.

Based on forecast CPI of 1.75 per cent for 2008-09 and 2.75 per cent for 2009-10 (as used to roll forward Ergon Energy's asset base in the Roll Forward Model (RFM)), the VCR of $47,850/MWh in September 2008 has been calculated to be $49,809.78/MWh as at 1 July 2010, being the start of the next regulatory control period.

44.4.11 SAIDI and SAIFI Weightings

Clauses 3.2.2(e), (f) and (g) of the STPIS allows Ergon Energy to propose an alternative weighting for SAIDI and SAIFI if its distribution network is divided into segments by a method other than network type in accordance with clause 3.1(d) of the STPIS.

As Ergon Energy's electricity distribution network is not divided into segments by a method other than network type, Ergon Energy does not propose alternative weightings for SAIDI and SAIFI. Ergon Energy will therefore apply the weightings in Table 1 on page 11 of the AER's STPIS to calculate the incentive rate for each parameter.

44.4.12 Reliability Performance Parameter Exclusions

The AER's F&A Stage 2 clause 2.5.5 and clause 3.3 of the STPIS outlines the allowable exclusions for the reliability parameters for the purposes of calculating the revenue increment or decrement under the STPIS.

Ergon Energy accepts the exclusions in clause 3.3 and will reflect them into its reporting of actual performance to the AER for each year of the next regulatory control period. Ergon Energy notes that these exclusions have also been used in calculating the average historical performance required in setting the STPIS targets.

Ergon Energy wishes to clarify two types of exclusions listed in clause 3.3 of the STPIS. It interprets:

- Clause 3.3(a)(5) relating to load interruptions caused by a failure of the shared transmission network to include all outages relating to transmission faults. This is because Ergon Energy does not own or operate any transmission network infrastructure for the purposes of providing standard control services and all transmission outages are therefore beyond its control; and
- Clause 3.3(a)(2), which relates to load interruptions caused by a generation shortfall, to mean all outages related to generation faults. This is because Ergon Energy does not own or operate any generation infrastructure for the purposes of providing standard control services and all generation outages are therefore beyond its control.

44.4.12.1 Major Event Day Threshold Calculations

Appendix D of the STPIS outlines the methodology by which the Major Event Day threshold is to be calculated in applying the 2.5 Beta Method. The 2.5 Beta Method is an internationally accepted method (detailed in the IEEE 1366:2003 standard) for normalising reliability performance data that removes the impact of extreme events that are beyond the DNSP's control.

In accordance with this methodology, Ergon Energy has calculated the Major Event Day threshold for normalising reliability performance for extreme events in the first regulatory control year to be 9.8 minutes. This threshold was calculated based on five years of actual performance data from 2003-04 to 2007-08.

The Major Event Day threshold will be updated annually, in accordance with the methodology set out in Appendix D of the STPIS, for each year of the next regulatory control period.

44.4.13 Calculation of Reliability Parameter Incentive Rates

Clauses 3.2.2(h) and (i) and Appendix B of the STPIS set out how the incentive rates shall be calculated for SAIDI and SAIFI respectively. Clause 3.2.2(k) of the STPIS requires that these incentive rates be calculated at the commencement of the regulatory control period and apply for the duration of the period.

Table 120 shows the calculation of these incentive rates in accordance with these clauses.

Table 120: *Reliability Parameters Incentive Rates*

Parameter	Incentive Rate
Urban SAIDI	0.023%
Urban SAIFI	1.764%
Short Rural SAIDI	0.020%
Short Rural SAIFI	2.060%
Long Rural SAIDI	0.004%
Long Rural SAIFI	0.601%

These incentive rates are based on the following data:

- The target SAIDI and SAIFI are the performance targets in Table 119;
- VCR for all feeder types is $49,809.78 per MWh (in 2009-10 dollars);
- Average annual energy consumption by feeder type in accordance with Table 121 below; and
- Average nominal smoothed Annual Revenue Requirement (ARR) is $1,352.23 million (based on -7.69 per cent X factor) in shown in Table 122 below.

Ergon Energy expects that these incentive rates will be updated as actual data becomes available from 2008-09 and 2009-10.

Table 121: *Forecast Network Demand for the Next Regulatory Control Period (MWh per annum)*

	2010-11	2011-12	2012-13	2013-14	2014-15	Average
Urban Feeder Demand	5,760,867	5,924,816	6,027,611	6,177,186	6,284,674	5,760,867
Short Rural Feeder Demand	5,120,003	5,265,713	5,357,072	5,490,008	5,585,539	5,120,003
Long Rural Feeder Demand	1,158,345	1,191,310	1,211,979	1,242,055	1,263,667	1,158,345

Table 122: *Proposed Nominal Smoothed ARR for the Next Regulatory Control Period ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	Average
Smoothed ARR	1,100.22	1,213.87	1,339.25	1,477.59	1,630.21	1,352.23

Source: Tables for Proposal 49.2

44.5 CUSTOMER SERVICE PARAMETERS

Ergon Energy proposes that the only customer service parameter that should be included in the STPIS for the next regulatory control period is the telephone answering parameter.

This is consistent with clause 2.6.2 of AER's F&A Stage 2.

44.5.1 Application to Add Customer Service Parameters

The AER's F&A Stage 2 clause 2.5.2 and clause 5.1(c) of the STPIS allows Ergon Energy to propose the inclusion of 'street light repair' and/or 'new connections' and/or 'response to written enquiries' parameters in the STPIS for the next regulatory control period.

Ergon Energy does not propose any other customer service parameters to apply for the next regulatory control period than the telephone answering parameter.

44.5.2 Individual Customer Service Parameter Revenue at Risk Percentage

The AER's F&A Stage 2 clause 2.5.4 and clause 5.2(b) of the STPIS provides that, unless the AER otherwise makes a decision in a relevant distribution determination, the maximum revenue at risk for an individual customer service parameter shall be 0.5 per cent of revenue for each regulatory year of the regulatory control period.

Ergon Energy accepts the AER's decision to apply a +/-0.5 per cent of revenue at risk for each regulatory year of the regulatory control period for individual customer service parameters. On this basis, Ergon Energy supports the revenue at risk for the telephone answering parameter being capped at +/- 0.5 per cent for each year of the regulatory control period.

44.5.3 Customer Service Data for 2003-04 to 2007-08 to Derive Targets

Clause 5.3.1(a) of the Rules requires that performance targets must be based on average performance over the past five financial years or another measurement period as described in clause 2.4(a) as appropriate.

Ergon Energy's most recently completed five financial years of data is for 2003-04 to 2007-08 inclusive. This data is provided in Table 123.

Table 123: *Telephone Answering Performance for the past five years (per cent)*

Telephone Answering Parameter	2003-04	2004-05	2005-06	2006-07	2007-08	Average
Percentage of calls answered within 30 seconds	60	83	78	83	83	77

No normalisation of the data was performed in accordance with clause 5.4 of the STPIS.

44.5.4 Modify Performance Target - Customer Service Works Program in Previous Regulatory Proposal for 2008-10

The AER's F&A Stage 2 clause 2.5.3 and clause 5.3.1(b) of the STPIS allows Ergon Energy to propose modifications to the average customer service performance data for the purposes of establishing performance targets. In particular, clauses 5.3.1(b)(1)(ii) and (iii) require Ergon Energy to propose modifications that reflect the impact of any customer service improvement works planned during the current regulatory control period that materially improve customer service performance.

In clause 2.5.3 of its F&A Stage 2, the AER indicated that it does not have a preferred method for how any such modification should be undertaken, although any proposed modification would need to be supported by statistical analysis.

Ergon Energy considers that no modifications to the average customer service performance data are required, as there will be no specific works planned or completed during the current regulatory control period that will materially affect customer service performance.

44.5.5 Modify Performance Target - Customer Service Works Program in Regulatory Proposal for 2010-15

Clause 5.3.1(b) of the STPIS allows Ergon Energy to propose modifications to the average customer service performance data for the purposes of establishing performance targets. In particular, clauses 5.3.1(b)(1)(i) and (iii) require Ergon Energy to propose modifications that reflect the expected impact of any planned customer service improvement works included in the expenditure program for the next regulatory control period that materially improve customer service performance.

In clause 2.5.3 of its F&A Stage 2, the AER indicated that it does not have a preferred method for how any such modification should be undertaken, although any proposed modification would need to be supported by statistical analysis.

Ergon Energy considers that no adjustments to the average customer service performance data are required, as there are no specific works planned during the next regulatory control period that are expected to materially improve customer service performance.

44.5.6 Modify Performance Target – Adjustment to Customer Service Performance Targets to Correct for Revenue at Risk

Clause 5.3.1(a)(1B) of the STPIS allows Ergon Energy to propose modifications to average customer service performance to correct for the revenue at risk (the sum of the s-factors for all parameters) to the extent it does not lie between the upper limit and the lower limit in accordance with clause 2.5(a) of the STPIS.

Clause 5.4.3 of the February 2009 Explanatory Statement of the STPIS further expands on clause 5.3.1(b)(1B) of the STPIS by requiring that performance targets in the next regulatory control period be adjusted to ensure that a DNSP does not experience a penalty, by way of increasingly difficult performance targets, in the next regulatory control period, for improved service performance that exceeded the revenue at risk during the current regulatory control period.

Similarly, clause 5.4.3 of the February 2009 STPIS Explanatory Statement requires that performance targets in the next regulatory control period be adjusted to ensure that a DNSP does not benefit, by way of easier performance targets, in the next regulatory control period for service performance that fell below the amount of revenue at risk during the current regulatory control period.

Ergon Energy notes that this adjustment will not need to be made during the next regulatory control period as the STPIS does not apply to Ergon Energy until 1 July 2010. Consequently, Ergon Energy does not propose any modifications to the customer service performance averages to correct for revenue at risk.

44.5.7 Modify Performance Target - Other Factors Materially Affecting Customer Service Performance

Clause 5.3.1 of the STPIS allows Ergon Energy to propose modifications to the average customer service performance data for the purposes of establishing performance targets. In particular, clause 5.3.1(b)(2) requires Ergon Energy to propose modifications that reflect any other factors that are expected to materially affect customer service performance.

Ergon Energy does not consider that there are any other modifications that need to be made to the customer service performance averages.

44.5.8 Explanation of Modifications to Customer Service Targets

The AER's F&A Stage 2 clause 2.5.3 and clause 5.3.1(c) of the STPIS requires that, if performances targets are modified in accordance with clause 5.3.1(b)(1) or 5.3.1(b)(2) of the STPIS, Ergon Energy must provide an explanation of how the modified performance targets have been calculated.

Ergon Energy does not propose any modifications to the performance targets in accordance with clause 5.3.1(b)(1) or 5.3.1(b)(2) of the STPIS. Consequently, no explanations of any performance target modifications are required.

44.5.9 Customer Service Performance Parameter Target

Clause S6.1.3(4) of the Rules requires Ergon Energy to explain how it proposes the STPIS to apply for the next regulatory control period.

Table 124 details the proposed customer service performance target for the telephone answering parameter for the next regulatory control period.

Table 124: *STPIS Customer Service Performance Targets for the next regulatory control period*

Parameter	Adjusted Historical Performance	Adjusted MSS	STPIS Target
Telephone Answering	77%	N/A	77%

44.5.10 Telephone Answering Parameter Incentive Rate

The AER's F&A Stage 2 clause 2.5.7 and clause 5.3.2(a) of the STPIS requires that an incentive rate of either -0.04 or a value determined from an applicable assessment of the value that customers attribute to the level of service proposed be applied for the telephone answering parameter.

Clause 5.3.2(c) and (d) of the STPIS states that where the requirements in clause 5.3.2(a) of the STPIS cannot be complied with, the DNSP must propose an appropriate alternative methodology for setting an incentive rate that is consistent with the objectives in clause 1.5 of the STPIS and the requirements of clause 2.2 of the STPIS.

Ergon Energy proposes applying the incentive rate of -0.04 for the telephone answering parameter for the regulatory control period. Consequently, Ergon Energy does not propose an alternative methodology for setting the telephone answering incentive rate.

44.5.11 Customer Service Parameter Exclusions

Clause 5.4(a) of the STPIS outlines the allowable exclusions for the customer service parameters for the purposes of calculating the revenue increment or decrement under the STPIS.

Ergon Energy accepts these exclusions in clause 5.4(a) and will reflect them into its reporting of actual performance to the AER for each year of the regulatory control period.

Clause 5.4(b) and (c) allow Ergon Energy to propose exclusions for other customer service parameters, if appropriate, consistent with the objectives set out in clause 1.5 and 2.2 of the STPIS.

As Ergon Energy does not propose any other customer service parameters than the telephone answering parameter, Ergon Energy does not propose any other exclusions.

44.5.12 Confirmation of Queensland Jurisdictional GSL Regime

Clause 6.1(a) of the STPIS provides that where jurisdictional electricity legislation imposes an obligation on a DNSP to operate a Guaranteed Service Level (GSL) scheme, clauses 6.2 to 6.4 of the STPIS do not apply to the DNSP. Clauses 6.2 to 6.4 of the STPIS relate to the application of the GSL component of the STPIS.

Ergon Energy is currently subject to the jurisdictional GSL regime prescribed in the Queensland Electricity Industry Code and expects this to apply throughout the next regulatory control period. Consequently, in accordance with clause 6.1(a) of the STPIS, and consistent with the AER's position outlined in clause 2.5.1 of its F&A Stage 2, Ergon Energy proposes that the GSL component of the AER's STPIS will not apply to Ergon Energy during the next regulatory control period.

44.6 APPLICATION OF THE STPIS

44.6.1 Determining and Applying Annual s-factors

Clause S6.1.3(4) of the Rules requires Ergon Energy to explain how it proposes the STPIS to apply for the regulatory control period.

Appendix C of the STPIS provides equations and methodologies outlining the AER's approach to calculating the STPIS adjustments to the ARR. Appendix E of the STPIS provides a methodology and a worked example outlining the AER's approach for calculating the s-factor that is applied to revenues. Based on the methodologies and equations outlined in these Appendices, Ergon Energy proposes the following approach for calculating the s-factor that is applied to revenues:

1. The raw s-factor for the telephone answering parameter is calculated using equation (5B) in Appendix C of the STPIS, whereby the difference between the target and actual performance is multiplied by the telephone answering incentive rate and the result is checked to ensure that it does not exceed the upper or lower percentage limits on the revenue at risk (+/- 0.5 per cent);

2. The raw s-factor for the reliability parameters is calculated by summing the raw s-factors for each individual reliability parameter using equation (5A) in Appendix C of the STPIS. For each parameter, the difference between the target and actual performance is multiplied by the incentive rate for the relevant parameter;

3. The sum of the raw s-factors for all parameters is checked to ensure that it does not exceed the upper or lower percentage limits on the revenue at risk (+/- 2 per cent) using equation (4A) in Appendix C of the STPIS;

4. If Ergon Energy chooses to employ the s-bank mechanism, equation (3) in Appendix C of the STPIS will be applied. Ergon Energy's proposed approach to implementing the s-bank mechanism is detailed in section 44.6.2 of this chapter;

5. Equation (6) in Appendix C of the STPIS, which is used to account for any step change in the revenue from one regulatory control period to the next, will be applied to the first two years of the next regulatory control period. Ergon Energy's proposed approach to addressing the overlap between regulatory control periods is detailed in section 44.6.3 of this chapter; and

6. The effect of the s-factor from the previous regulatory year is removed using equation (2) in Appendix C of the STPIS.

The resulting adjusted s-factor is applied to the control mechanism using equation (1A) in Appendix C of the STPIS. In this way, the adjusted s-factor affects the ARR two regulatory years after the performance giving rise to the s-factor is reported.

44.6.2 Application of the 's-bank' Mechanism

Clause S6.1.3(4) of the Rules requires Ergon Energy to explain how it proposes the STPIS to apply for the regulatory control period.

Appendix C of the STPIS sets out the methodology by which the s-bank mechanism will be applied. The s-bank mechanism is intended to reduce the volatility in prices when service performance varies around the target performance from year to year. The AER has allowed DNSPs to delay making a revenue increment or decrement or a portion of the revenue increment or decrement for one regulatory year.

Ergon Energy supports this methodology, and a summary of how Ergon Energy intends to implement the s-bank mechanism throughout the next regulatory period is provided below.

- Each year, Ergon Energy has the option to 'bank' all or part of the revenue adjustment for a given year. Banking involves adjusting the current year's ARR by a portion of the total revenue adjustment, and adjusting the ARR in the next regulatory year by the banked adjustment. Should Ergon Energy wish to bank a portion of the revenue adjustment, Ergon Energy will notify the AER of the portion of the revenue adjustment to be banked; and
- The banked amount for any given year will be applied, in accordance with equation (3) in Appendix C of the STPIS, to adjust the revenue in the next regulatory year.

44.6.3 Overlap Between Regulatory Control Periods

Clause S6.1.3(4) of the Rules requires Ergon Energy to explain how it proposes the STPIS to apply for the regulatory control period.

The AER recognised that a DNSP's service performance in the last year of a regulatory control period will affect the revenues in the first two years of the following regulatory control period.

Appendix C of the STPIS sets out the methodology by which this overlap between regulatory control periods should be addressed, namely by adjusting the total s-factor for the first two years of the following regulatory control period by the percentage change between the ARR in the last regulatory year of the previous regulatory control period and the ARR for the first regulatory year of the next regulatory control period taken from the Post Tax Revenue Model (PTRM).

Ergon Energy supports this approach, but notes that this adjustment will not need to be made during the 2010-11 to 2014-15 regulatory control period. Ergon Energy will provide further details on how it intends to apply this approach in its Regulatory Proposal for the 2015-16 to 2019-20 regulatory control period.

44. SERVICE TARGET PERFORMANCE INCENTIVE SCHEME (STPIS) - PARAMETERS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR367c & 368c	AER Regulatory Information Notice
AR396 & 397	AER Final Decision STPIS, June 2008 & AER Appendix C STPIS, June 2008
AR524	AER Post Tax Revenue Model Handbook –
AR526	AER Roll Forward Model Handbook

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR364	National Electricity Rules

Ergon Energy Documents

AR539c	EE Regulatory Proposal Models, Roll Forward Model
AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

45. DEMAND MANAGEMENT INCENTIVE SCHEME (DMIS) – PARAMETERS

Rules – Clauses 6.3.2(a)(3) 6.4.3(a)(5) 6.4.3(b)(5) 6.6.3, 6.8.1(b)(4), 6.12.1(9) and S6.1.3(5)
DMIS – Section 2.2
F&A Stage 2 – Clause 4

This chapter details the parameters to apply to the Demand Management Incentive Scheme (DMIS) for Ergon Energy in the next regulatory control period, in order to address the requirements of the Rules, the AER's DMIS and the AER's F&A Stage 2.

Clause 6.4.3(a) of the Rules provides that Ergon Energy's Annual Revenue Requirement (ARR) for each regulatory year of the next regulatory control period be calculated using a building block approach. Clause 6.4.3(a)(5) of the Rules provides that one of the building blocks to be used in this approach is to be a revenue increment or decrement (if any) for the regulatory year arising from the application of the DMIS. This increment or decrement is to be calculated in accordance with clause 6.4.3(b)(5) of the Rules.

Clause 6.3.2(a)(3) of the Rules provides that the AER's Building Block Determination must specify how any applicable DMIS is to apply to Ergon Energy. Clause 6.12.1(9) of the Rules provides that a decision on how the DMIS is to apply is one of the constituent decisions of the AER's Distribution Determination.

The AER has developed a DMIS, in accordance with clause 6.6.3 of the Rules, to apply to Ergon Energy during the next regulatory control period. This DMIS has two potential elements:

- Part A – this is a demand management innovation allowance (DMIA) that is provided to the DNSP as an annual, ex-ante allowance in the form of a fixed amount of additional revenue at the commencement of each regulatory year of the regulatory control period; and
- Part B – this allows a DNSP to recover revenue forgone in a regulatory control period resulting from a reduction in the quantity of energy sold directly attributable to a project approved under part A of the DMIS within that period. Part B can only be applied to a DNSP to which part A of the DMIA applies. Part B will not automatically apply, and will not apply on its own.

Clause 6.8.1(b)(4) of the Rules requires the AER's Framework and Approach paper for Ergon Energy to set out its likely approach, together with the reasons for the likely approach, to the application of the DMIS.

The AER indicated in its F&A Stage 2 that its likely approach will be to apply only Part B of the DMIS to Ergon Energy, relating to the DMIA, in the next regulatory control period. The F&A Stage 2 states that:

> *The DMIA will be capped at a total of $5 million over the forthcoming regulatory control period, nominally allocated in five equal annual instalments of $1 million. This allowance will enable Ergon to carry out a number of small-scale demand management projects, or a single larger-scale demand management project, in each year of the forthcoming regulatory control period.*[92]

In accordance with clause S6.1.3(5) of the Rules, Ergon Energy supports the AER's view expressed in the F&A Stage 2 that:

- Part A of the DMIS, being the DMIA, should apply in the next regulatory control period;
- The amount of the DMIA should be $1 million (Nominal) for each regulatory year of the next regulatory control period; and
- Part B of the DMIS, being the foregone revenue recovery mechanism, should not apply in the next regulatory control period.

Accordingly, in accordance with clause 6.4.3(a)(5) of the Rules, Ergon Energy has included a revenue increment of $1 million (Nominal) for the DMIS building block in its calculation of the annual revenue requirement for each regulatory year of the next regulatory control period in the Post Tax Revenue Model (PTRM).

[92] AER, "Final framework and approach paper - Application of schemes - Energex and Ergon Energy 2010–15", November 2008, page 46

45. DEMAND MANAGEMENT INCENTIVE SCHEME (DMIS) PARAMETERS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR407 & 408	AER Final Decision DMIS, October 2008 & AER DMIS (Scheme), October 2008
AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR524	AER Post Tax Revenue Model Handbook

Codes and Rules

AR364 National Electricity Rules

Ergon Energy Documents

AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

46. COST PASS THROUGH – ADDITIONAL PASS THROUGH EVENTS

Rules – Clauses 6.2.6(c), 6.6.1, 6.12.1(14), S6.1.3 and 11.16.9

The Rules provide for the cost pass through of costs associated with unexpected events that are beyond the control of the Distribution Network Service Providers (DNSPs). In particular, clause 6.6.1 of the Rules discusses pass through arrangements in the next regulatory control period. Chapter 10 of the Rules defines the following four pass through events:

- A regulatory change event;
- A service standard event;
- A tax change event; and
- A terrorism event.

In addition to these four events, the Rules allows the DNSP to nominate events that it believes should be classified for the distribution determination as pass through events. Clause S6.1.3 of the Rules requires Ergon Energy to include in its building block proposal a pass through clause with a proposal as to the events that should be defined as pass through events.[93] Ergon Energy further notes that under clause 6.12.1(14) of the Rules the Australian Energy Regulator (AER) must include in its distribution determination a decision on the additional pass through events that are to apply for the regulatory control period.

This chapter identifies the pass through events that Ergon Energy proposes the AER should approve for the next regulatory control period.

46.1 TRANSITIONAL ARRANGEMENTS

Clause 11.16.9 of the Rules establishes transitional arrangements for cost pass through events that apply in the current regulatory control period. This clause provides that:

a. *If an event or circumstance occurs before 1 July 2010 which would constitute a pass through under the 2005 determination and no application for a pass through has been made in relation to that event or circumstance, ENERGEX or Ergon Energy may apply to the AER within a year of the event or circumstance occurring to accommodate the impact of the event in the regulatory control period.*

b. *The AER must allow a pass through of such amounts if the event or circumstance would have constituted a pass through under the 2005 determination as if the amounts were approved pass through amounts under clause 6.6.1.*

For clarity, Ergon Energy interprets this clause to apply to pass through events that apply in the current regulatory control period, but which have not been approved by the Queensland Competition Authority (QCA) as at 30 June 2010, not to events that the AER may approve as applying in the next regulatory control period. This section does not cover these types of pass through events.

46.2 APPLICATION TO ALL DIRECT CONTROL SERVICES

The cost pass through provisions in Chapter 6 of the Rules are contained within Part C, which relates to Standard Control Services. Clause 6.2.6(c) of the Rules allows the control mechanism for Alternative Control Services to utilise elements of Part C of the Rules.

Ergon Energy therefore proposes that the cost pass through arrangements in section 6.6.1 of the Rules should apply to both Standard Control Services and Alternative Control Services.

This is consistent with the requirement in section 7A(2) of the National Electricity Law (NEL) provides that:

> *A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in-*
>
> - *providing direct control network services; and*
> - *complying with a regulatory obligation or requirement or making a regulatory payment.*

Accordingly, unless otherwise stated, the pass through events discussed in this chapter of the Regulatory Proposal relate to Direct Control Services, which includes both Standard Control Services and Alternative Control Services.

[93] Clause 11.16.9 of the Rules also provides for the AER's consideration of pass through events that occur before 1 July 2010 but for which no application for a pass through has been made.

46.3 NATURE OF PASS THROUGHS EVENTS

There are a number of risks borne by Ergon Energy in providing its distribution services, which are not compensated through the Weighted Average Cost of Capital (WACC). These risks are typically beyond Ergon Energy's ability to control and forecasting their probability of occurring, severity and associated costs is difficult. Because of the uncertainties associated with these events, it is difficult for Ergon Energy to prepare an accurate forecast for inclusion in the 'baseline' expenditure building block to be provided as part of its Regulatory Proposal.

In several instances, Ergon Energy has sought to mitigate these risks through insurance (either market or self insurance).[94] However, a number of these events are uninsurable because there is considerable uncertainty about whether or not the event will occur and, if it does, when it will happen and the associated costs. Ergon Energy is seeking to have the AER recognise these events as specific nominated pass through events under Chapter 6 of the Rules.

Ergon Energy confirms that the proposed nominated pass through events are:

- Associated with the provision of Direct Control Services;
- Not able to be insured either through market insurance or self insurance; and
- Not included in Ergon Energy's baseline expenditure forecasts for the next regulatory control period.

If Ergon Energy is denied the ability to pass through the costs of these types of events, it would not be provided a reasonable opportunity to recover its efficient costs.

46.4 CATEGORIES OF ERGON ENERGY'S NOMINATED PASS THROUGH EVENTS

In accordance with clause S6.1.3 of the Rules, Ergon Energy has identified a number of events which could take place during the next regulatory control period, which it considers should be eligible for cost pass through.

The Rules provide for four categories of pass through events - a regulatory change event, a service standard event, a tax change event and a terrorism event. Without limiting the nature of events that may occur under each category, Ergon Energy sets out in sections 46.4.1 and 46.5.1 certain specific events that are considered to fall within the regulatory change event category.

Ergon Energy's other nominated events are set out in sections 46.4.2 and 46.5.2.

46.4.1 Regulatory Change Event

Chapter 10 of the Rules defines a regulatory change event as a change in a regulatory obligation or requirement that:

a. Falls within no other category of pass through event;
b. Occurs during the course of a regulatory control period;
c. Substantially affects the manner in which the DNSP provides Direct Control Services; and
d. Materially increases or materially decreases the costs of providing those services.

Ergon Energy considers that the following events are consistent with this definition and seeks approval from the AER that these events will be included as regulatory change events should they arise in the next regulatory control period:

- Change to minimalist transitioning approach;
- Introduction of smart meters and smart meter trials;
- Transfer of functions to a national regulatory framework;
- Introduction of an emissions trading scheme;
- Distribution loss event;
- Network obligation in relation to electric and magnetic fields;
- Changes in reporting requirements; and
- Changes in taxes or other levies.

Each of the events is described in further detail below.

46.4.2 Other Nominated Events

Ergon Energy requests that the following nominated events be approved for pass through should they arise in the next regulatory control period:

- Force majeure; and
- Change of business structure (that is externally imposed).

Both of the events are described in further detail below.

[94] Details of Ergon Energy's proposed self insurance claim for the next regulatory control period are provided in section 28.1 of this Regulatory Proposal.

46.5 DETAILS OF ERGON ENERGY'S PASS THROUGH EVENTS

46.5.1 Regulatory Change Events

This section is not an exhaustive listing of possible regulatory change events in the next regulatory control period.

46.5.1.1 Change to minimalist transitioning approach

Under section 6 of the Queensland Electricity Industry Code (Code) and clause 11.20.5 of the Rules, Ergon Energy is allowed to operate under a "minimalist transitioning approach" when processing National Metering Identifier (NMI) discovery and creation requests and populating Market Settlement and Transfer Solution (MSATS) for the purposes of Full Retail Competition (FRC) in Queensland.

The minimalist transitioning approach was introduced by the Queensland Government to allow Ergon Energy to operate a manual system in responding to retailer requests for NMI information, rather than requiring Ergon Energy to implement a more expensive automated process. This reflected the fact that relatively low levels of customer churn were expected (and have occurred) in Ergon Energy's distribution area. Under section 6 of the Code, the QCA is required annually to review whether the minimalist transitioning approach should remain in place for Ergon Energy.

If the minimalist transitioning approach were to be significantly amended or removed altogether, it is likely that Ergon Energy would need to invest in an automated system to be able to populate and maintain MSATS with the NMI and associated standing data for every individual customer. Should the QCA give Ergon Energy notice that the minimalist transitioning approach should no longer apply, Ergon Energy would have a year to implement an automated system.[95]

Ergon Energy therefore seeks to include the significant amendment or removal of the minimalist transitioning approach as a pass through event where the event:

- Is not included in another category of pass through event; and
- Materially increases the cost to Ergon Energy of providing Direct Control Services.

46.5.1.2 Introduction of smart meters

The potential rollout of smart meters is discussed in section 7.5 of this Regulatory Proposal.

Ergon Energy defines a smart metering event as an event which results in Ergon Energy being required to install smart meters for some or all of its customers or to conduct large scale metering trials during the course of the next regulatory control period, regardless of whether that requirement takes the form of the imposition of a statutory obligation, and which:

- Is not included in another category of pass through event; and
- Materially increases the cost to Ergon Energy of providing Direct Control Services.

Ergon Energy reiterates that this Regulatory Proposal does not otherwise include any provision for capital or operating expenditure in relation to any smart meter rollout or trials (other than the initial trial known at the time of making this Regulatory Proposal) that Ergon Energy may be required to undertake.

46.5.1.3 Transfer of regulatory functions to a national regulatory framework

This event refers to changes to Ergon Energy's regulatory obligations as a result of national regulatory reforms, including the creation of a National Energy Customer Framework by the Ministerial Council on Energy (MCE), which transfers functions from Queensland to a national regulatory framework.

The transfer of the Laws and Rules relating to retail and distribution activities to the national framework is the final major stage of the energy market reforms agreed in the Australian Energy Market Agreement (AEMA). This includes determining DNSPs' obligations with regard to the provision of connection services and the interface with retailers and embedded generators and the arrangements for a national Retailer of Last Resort (ROLR) scheme.

The changes to existing arrangements could have significant cost impacts that are not included in Ergon Energy's expenditure projections for the upcoming regulatory control period. Therefore, it is proposed that any transfer of functions to Ergon Energy be treated as a pass through event with the incremental costs to be accordingly included in the regulatory framework.

Ergon Energy requests that the transfer of the current regulation of retail and distribution activities to a national framework be considered a pass through event where the event:

- Is not included in another category of pass through event; and
- Materially increases the cost to Ergon Energy of providing Direct Control Services.

46.5.1.4 Introduction of an emissions trading scheme

An emissions trading scheme event is an event which results in the imposition of legal obligations on Ergon Energy arising from the introduction or operation of a carbon emissions trading scheme by the Federal or Queensland Governments during the course of the regulatory control period and which:

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[95] Queensland Competition Authority, Background Paper re: MTA for Ergon Energy, April 2008 http://www.qca.org.au/files/ER-MinTransApp-QCA-BkgInfo-0408.pdf

- Is not included in another category of pass through event; and
- Materially increases the cost to Ergon Energy of providing direct control services.

At the time of submitting this Regulatory Proposal it was not clear whether the Carbon Pollution Reduction Scheme proposed by the Commonwealth Government on 15 December 2008 would financially impact on Ergon Energy. This cost pass through provision is seeking to compensate Ergon Energy in the event that it, or another scheme, does have such an impact.

46.5.1.5 Distribution losses

Consistent with the definition provided by Integral Energy in its Regulatory Proposal to the AER[96] , Ergon Energy considers that a distribution loss event is an event which results in it facing additional costs or legal obligations in relation to distribution losses from the operation of its distribution system. This includes a situation where financial responsibility for distribution losses is transferred to DNSPs or an emissions charge is imposed in relation to distribution losses as part of the Federal Government's greenhouse policy, which:

- Is not included in another category of pass through event; and
- Materially increases the cost to Ergon Energy of providing direct control services.

46.5.1.6 Network obligation in relation to electric and magnetic fields

This event refers to potential obligations imposed on Ergon Energy in the event of the imposition of Australian Radiation Protection and Nuclear Safety Agency draft standard. Ergon Energy considers that there is the potential for such obligations to impose costs on the network business and proposes that the event be considered for pass through where it:

- Is not included in another category of pass through event; and
- Materially increases the cost to Ergon Energy of providing direct control services.

46.5.1.7 Changes in reporting requirements

Ergon Energy's current reporting requirements may change over the next regulatory control period in response to issues such as: changes in regulatory functions; the extension of the national regulatory framework; and the ongoing development of the AER's information requirement. Accordingly, Ergon Energy proposes that a change in reporting requirements from the AER or another Government or regulatory body should be treated as a cost pass through event where these:

- Are not included in another category of pass through event; and
- Materially increase the cost to Ergon Energy of providing direct control services.

46.5.1.8 Changes in taxes or other levies

Chapter 10 of the Rules provides that a tax change event occurs if there is a change in "the application or official interpretation of a relevant tax, in the rate of a relevant tax, or in the way in which a relevant tax is calculated" and the costs to Ergon Energy are materially increased or decreased as a consequence. A "relevant tax" is defined to be any tax payable by a DNSP other than:

a. *income tax and capital gains tax;*
b. *stamp duty, financial institutions duty and bank accounts debits tax;*
c. *penalties, charges, fees and interest on late payments, or deficiencies in payments, relating to any tax; or*
d. *any tax that replaces or is the equivalent of or similar to any of the taxes referred to in paragraphs (a) to (b) (including any State equivalent tax).*

As a result, any changes in corporate income tax arrangements could not be treated as a tax change event. However, Ergon Energy considers that any such change could be treated as a regulatory change event. This is because "regulatory obligation or requirement" is defined in Chapter 10 of the Rules by reference to the NEL. Section 2D(1)(b) of the Law defines a regulatory obligation or requirement to include:

> *(ii) an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, that levies or imposes a tax or other levy that is payable by a regulated network service provider; or*
>
> *(v) an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act (other than national electricity legislation or an Act of a participating jurisdiction or an Act or instrument referred to in subparagraphs (ii) and (iv)), that materially affects the provision, by a regulated network service provider, of electricity network services that are the subject of a distribution determination or transmission determination.*

[96] Integral Energy, Regulatory Proposal to the Australian Energy Regulator 2009 to 2014, June 2008.

Ergon Energy considers that it should therefore be able to claim a pass through for changes in taxes or other levies payable by it in the next regulatory control period. This is because:

- This Regulatory Proposal is based on there being no changes to the regime in relation to taxes or levies;
- Any such changes would be entirely outside of the control of a benchmark efficient entity that is considered in determining Ergon Energy's estimated cost of corporate income tax in clause 6.5.3 of the Rules; and
- Ergon Energy would not otherwise be compensated for any such changes in taxes or levies payable.

Ergon Energy gives the following examples of why this additional pass through provision is necessary:

- If the Australian Government was to increase the corporate income tax rate from the current 30 per cent to, for example, 40 per cent, then the benchmark efficient entity (and therefore Ergon Energy) would not incur a corporate income tax cost that it has not be funded for and would not otherwise be able to recover; and
- If the Australian Tax Office was to release an Interpretive Decision such that the benchmark efficient entity (and therefore Ergon Energy) could not claim tax deductions arising from the capitalisation of salaries, wages, overheads and various internal on-costs, which it currently does deduct.

46.5.2 Ergon Energy's Nominated Events

This section examines the detailed nature of both of Ergon Energy's nominated pass through events.

46.5.2.1 Force Majeure

Ergon Energy considers that a force majeure event relates to any fire, flood, earthquake, storm or other weather-related event or natural disaster, act of nature, riot, civil disorder or rebellion or other similar cause that occurs during a regulatory control period and:

- Is not included in another category of pass through event;
- Is beyond the reasonable control of Ergon Energy;
- Is not covered under Ergon Energy's self insurance allowance; and
- Materially increases the cost to Ergon Energy of providing its Direct Control Services.

Furthermore, Ergon Energy notes the position of the Ministerial Council on Energy's Standing Committee of Officials' (MCE/SCO) Bulletin 77 (5 January 2007) "Electricity amendments and further amendments to the electricity and gas rule-change process"[97] wherein it is stated that "There will be no re-opening for force majeure unless it is defined as a pass through event in a regulatory determination." Ergon Energy notes that opportunities for revocation or substitution of a distribution determination are limited to the material error or deficiency circumstances set out in clause 6.13 of the Rules.

46.5.2.2 Change of Business Structure Event (that is externally imposed)

Ergon Energy proposes that any change in the structure of its distribution business that is mandated by the Government should be classified as a pass through event where the event:

- Is not included in another category of pass through event; and
- Materially increases or decreases the cost to Ergon Energy of providing its Direct Control Services.

46.6 PROCESS FOR ASSESSING PASS THROUGH EVENTS

Clause 6.6.1 of the Rules sets out the requirements in relation to cost pass through. Importantly, clause 6.6.1(j) sets out the relevant factors that the AER must take into account in determining the appropriate positive or negative pass through amount.

However, the Rules do not provide details of:

- How the DNSP is to determine the "eligible pass through amount" for the purposes of making its cost pass through application;
- The AER's information requirements for assessing a cost pass through application;
- How, in a practical sense, the AER will apply clause 6.6.1 of the Rules for the purposes of assessing a DNSP's cost pass through application; and
- What information the AER will provide about its decision. In particular, DNSPs need a break up of the pass through amount into building block components in order to reflect the pass through into their prices.

Ergon Energy requests that the AER prepare a guideline that addresses these issues. This is necessary in order to promote the principles of best practice regulation detailed by the Utility Regulators Forum.[98] In particular, the AER's approach in dealing with cost pass throughs should promote:

- Consistency – the AER should seek to ensure that a consistent approach is applied to the assessment of cost pass through events. This will help to promote confidence amongst DNSPs, customers and other stakeholders in the regulatory regime;

[97] Available from http://www.mce.gov.au/assets/documents/mceinternet/Explanatory%5FMaterial%5Fto%5Fthe%5FElectricity%5FAmendments20070105151202%2Epdf

[98] Utility Regulators Forum, Best practice utility regulation - discussion paper, July 1999.

- Predictability – the AER's approach to the assessment of cost pass through applications should be predictable for DNSPs, customers and other stakeholders. Applying a predictable approach allows DNSPs to confidently plan for the future and to be confident that their investments will not be generally threatened by unreasonable regulatory discretion;
- Transparency - the AER should be clear and transparent about its objectives, information requirements from DNSPs, assessment processes and criteria and its ultimate decisions; and
- Efficiency – where both parties have a fulsome understanding of the process, it will enable them to efficiently prepare and consider cost pass throughs. This will help to increase confidence in the regulatory regime and be compatible with the NEL's objective[99] of efficiency.

[99] National Electricity Law section 7

46. COST PASS THROUGH – ADDITIONAL PASS THROUGH EVENTS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR042	Electricity Regulation 2006 (Qld)
AR369	National Electricity Law

AER Documents

Nil

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR364	National Electricity Rules
AR390	Australian Energy Market Agreement (AEMA)

Ergon Energy Documents

Nil

47. CAPITAL CONTRIBUTIONS

Rules – Clauses 6.21 and 11.16.10
RIN – Section 2.3.13

Clause 6.21 of the Rules details the circumstances in which Distribution Network Service Providers may "minimise financial risks associated with investment in network assets and provides for adoption of cost-reflective payment options in conjunction with the use of average distribution prices". In particular:

- Clause 6.21.2(2) provides that Ergon Energy "may receive a capital contribution, prepayment and/or financial guarantee up to the provider's future revenue related to the provision of direct control services for any new assets installed as part of a new connection or modification to an existing connection, including any augmentation to the distribution network"; and
- Clause 6.21.2(3) provides that "where assets have been the subject of a contribution or prepayment, the Distribution Network Service Provider must amend the provider's revenue related to the provision of direct control services".

In addition, a Queensland-specific transitional rule has been introduced for the next regulatory control period under clause 11.16.10 of the Rules. This clause provides that:

- By 1 July 2009, Ergon Energy must publish on its website a capital contributions policy based on the requirements relating to capital contributions in its Pricing Principles Statement (PPS) immediately in force prior to 1 July 2009;
- The Australian Energy Regulator (AER) may, before 1 January 2010, direct Ergon Energy in writing to revise and republish its capital contributions policy if it is inconsistent with its Pricing Principle Statement (PPS); and
- Ergon Energy may apply to the AER to amend its capital contributions policy after 1 January 2010.

Taken together, the requirements of Chapters 6 and 11 of the Rules mean that Ergon Energy can retain its current capital contributions policy in the next regulatory control period provided that it remains consistent with its approved PPS. Ergon Energy must therefore prepare a forecast of its small customer capital contributions for inclusion in its Regulatory Proposal.[100] The forecast annual capital contributions will be included in its Regulatory Asset Base and deducted from the annual revenue caps in order to determine the Annual Revenue Requirement (ARR).

The AER's Regulatory Information Notice (RIN) section 2.3.13, requires that Ergon Energy's Regulatory Proposal provide information as to the basis on which capital contributions in the current regulatory control period (including estimates for 2008-09 and 2009-10) and next regulatory control period have been determined and:

- The process by which capital contributions have been allocated to the different asset classes in the Post Tax Revenue Model (PTRM); or
- The way in which revenues for customer classes have been adjusted to recognise capital contributions.

47.1 ERGON ENERGY'S CAPITAL CONTRIBUTIONS METHODOLOGY

Consistent with clause 11.16.10 of the Rules, Ergon Energy has elected to retain its current capital contributions methodology in the 2010-15 regulatory control period. Ergon Energy has provided the AER with a copy of its current capital contributions methodology with this Regulatory Proposal.

Section 11.8 of this Regulatory Proposal details the way in which capital contributions are treated in the current regulatory control period and the proposed continuation of this treatment in the next regulatory control period.

47.2 ACTUAL AND ESTIMATED CAPITAL CONTRIBUTIONS FOR THE CURRENT REGULATORY CONTROL PERIOD

Ergon Energy's actual and estimated small customer capital contributions for the current regulatory control period are summarised in Table 125.

[100] The revenue cap control mechanism applies to small customer connections only – large customer connections are regulated under a formula-based price cap control mechanism.

Table 125: *Actual/Estimated Capital Contributions for Current Regulatory Control Period ($M Nominal)*

	2005-06	2006-07(b)	2007-08	2008-09(c)	2009-10(c)
Forecast allowance provided in 2005 Final Determination (a)	28.9	35.9	38.4	43.3	44.9
Cash contributions	36.2	42.0	70.0	40.6	34.9
Gifted assets			0.5	11.2	31.5
Total	36.2	42.0	70.5	51.9	66.4
Variance to forecast	7.3	6.1	32.1	8.6	21.5

(a) Source: Queensland Competition Authority, Regulation of Electricity Distribution - Final Determination, April 2005, page 172

(b) Source: Ergon Energy Audited Regulatory Reporting Statements

(c) Source: CICW Model

Table 125 shows that:

- Actual cash contributions remained relatively stable in 2005-06 and 2006-07 but increased significantly in 2007-08 due to an unprecedented high level of Customer Initiated Capital Works (CICW) experienced across Queensland;
- Gifted assets were first received in 2007-08 following the introduction of alternative providers for Urban Residential Development (URD) subdivisions[101]; and
- Significant variances between the actual and forecast capital contributions began to emerge in 2007-08.

As discussed in section 51.2.1, the current regulatory treatment of capital contributions applies an annual unders and overs adjustment for any difference between the allowance for capital contributions provided for in the QCA's 2005 Final Determination and capital contributions actually received in each year of the regulatory control period.

The process used to forecast capital contributions for the remainder of the current regulatory control period (2008-09 and 2009-10) and next regulatory control period is discussed below.

47.3 FORECAST CAPITAL CONTRIBUTIONS IN THE 2010-15 REGULATORY CONTROL PERIOD

Forecast small customer capital contributions for the 2010-15 regulatory control period are provided in Table 126.

Table 126: *Forecast Capital Contributions for the 2010-15 Regulatory Control Period ($M Real $2009-10)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Cash contribution	42.70	45.26	39.32	41.80	46.94	216.02	43.20
Gifted assets	66.56	70.24	61.02	64.87	72.84	335.53	67.11
Total	**109.26**	**115.50**	**100.34**	**106.67**	**119.78**	**551.55**	**110.31**

Source: Tables for Proposal 47.3

[101] Ergon Energy currently provides developers of new URDs the option of using an alternative provider for design and construction of connection assets. Ergon Energy's plans to extend this option to also include new Commercial and Industrial connections from 2010. Similarly to URD works, Commercial and Industrial works completed by alternative providers will be gifted to Ergon Energy to own, maintain and operate.

47.4 CAPITAL CONTRIBUTION FORECASTING METHODOLOGY FOR 2008-09 TO 2014-15

Ergon Energy has prepared its forecasts of small customer capital contributions for 2008-09 to 2014-15 by:

- Taking the 2007-08 actual baseline value of capital contributions;
- Adjusting the baseline for updates to the CICW price book, which reflect systematic under-estimating of costs to date;
- Applying the National Institute of Economic and Industrial Research (NIEIR) dwelling stock growth forecasts in NIEIR's 'Maximum demand forecasts for Ergon Energy connection points to 2018'; and
- Applying adjustments, as appropriate, to reflect an increased take up of URD subdivisions being built by alternative providers during 2007-08 and 2008-09, and the extension of the alternative provider model to Commercial and Industrial works from 2010.

The small customer contributions incorporate forecast expenditure that:

- Customers or developers fund through cash contributions to Ergon Energy, with Ergon Energy undertaking the required works; and
- Developers fund and undertake the required works and gift the assets that they build to Ergon Energy.

The forecasts for cash capital contributions are broken down between subdivisions and other small CICWs, whereas gifted assets are broken down between URD subdivisions and Commercial and Industrial customers.

Discussion of the components of the capital contributions forecasts is provided below.

47.4.1 Gifted Assets

Ergon Energy currently provides developers of new URD subdivisions with the option of using either Ergon Energy or an alternative provider to design and construct connection assets. Ergon Energy plans to extend this option to include new Commercial and Industrial connections from 2010. As for URD, Commercial and Industrial works completed by alternative providers will be gifted to Ergon Energy for it to own, maintain and operate.

Issues associated with each of these customer categories are discussed below.

47.4.1.1 Subdivisions

Gifted assets first appeared after the introduction of the second (current) alternative provider model for URD subdivisions in April 2007.[102] As such, only a small amount of works were completed through the full alternative provider model by the end of 2007-08, and recorded as gifted assets for 2007-08. Since URD subdivisions were the only area subject to the alternative provider model, all gifted assets in the 2007-08 baseline are attributable to URD subdivisions.

However, Ergon Energy notes that the small amount of gifted assets received in 2007-08 is not reflective of the value of gifted assets in 2008-09. Recent monthly information shows the amount of work delivered through the alternative provider model continues to increase. Based on annualised actual gifted asset amounts capitalised to the end of November 2008, Ergon Energy forecast a value for gifted asset of $11.2 million for 2008-09.

Moreover, Ergon Energy considers that neither the actual value of gifted assets reported in 2007-08 ($483,000), nor the $11.2 million forecast for 2008-09 is reflective of the amounts of gifted assets expected from 2009-10 onwards. This is due to a significant amount of contestable works completed in those years being done under the first alternative provider model, which does not result in any gifted assets. In order to forecast the gifted assets for 2009-10 onward, the work completed under the first alternative provider model has been converted to equivalent amounts expected under the current alternative provider model, which will be in force from 2009-10 onward. This results in a requirement to increase the 2007-08 baseline of $483,000 to $21.7 million for forecasting purposes.

Accordingly, from 2009-10 to 2014-15, gifted assets associated with subdivisions are forecast using the adjusted 2007-08 baseline adjusted in proportion to:

- NIEIR dwelling stock growth forecast; and
- Forecast changes to the uptake rate of contestability.

The amount of subdivision work being provided externally (and resultant gifted assets) is forecast to increase from 51 per cent in 2007-08 to 55 per cent in 2008-09 (based on the introduction of contestability in the first half of 2008-09), and then stabilise at 50 per cent from 2009-10 to 2014-15.

[102] Note that there was URD contestability prior to April 2007, under an earlier alternative provider model in which Ergon Energy acted as an agent between developers and contractors. Under this old model there were no gifted assets.

47.4.1.2 Commercial and Industrial

No gifted assets are attributable to Commercial and Industrial works for either 2007-08 or 2008-09. However, the expansion of the alternative provider model to also include new Commercial and Industrial connections from 2010 is assumed to see alternative provider Commercial and Industrial works average 51 per cent [103] in the first year of introduction (2010), similar to the uptake rate for URD contestability.[104] It is then assumed to stabilise at 50 per cent until the end of 2014-15.

The forecast of gifted assets associated with Commercial and Industrial works from 2009-10 to 2014-15 is based on:

- NIEIR dwelling stock growth forecast; and
- The forecast changes to the uptake rate of contestability as discussed above.

It is assumed for forecasting purposes that the alternative provider model for Commercial and Industrial will be similar to the URD alternative provider model, and restricted to just the connection assets work (that is, exclude headworks, and testing and commissioning), leaving the majority of works able to be provided by alternative providers.

47.4.2 Cash Contributions

Cash contributions are received where a customer or developer funds the new connection through a cash contribution and Ergon Energy undertakes the required work.

Historical cash contributions are attributable to all types of small CICW works, and there is no practicable way of identifying the actual historic allocation between subdivisions, Domestic and Rural and Commercial and Industrial works. It is assumed for determining the 2007-08 baseline, that:

- All internal subdivision work should be recovered by cash contributions; and
- The remainder of total cash contributions is allocated to Domestic and Rural, and Commercial and Industrial works (that is, 'Other Small CICW').

Adjustments have been made to 2007-08 baseline of cash contributions to reflect the understatement of the CICW price book.

Forecasts of cash contributions in relation to subdivisions and Other Small CICW work from 2008-09 to 2014-15 are based on:

- NIEIR dwelling stock growth forecast; and
- The forecast changes to the uptake rate of contestability.

Ergon Energy forecast a marked drop-off in the level of cash contributions for Other Small CICW in 2010-11 due to the assumed full implementation of contestability in Commercial and Industrial works in 2010. That is, much of the type of work currently being undertaken internally by Ergon Energy (and funded through cash contributions) will be completed by the developer and will result in a complementary marked rise in the level of gifted assets.

Similarly, Ergon Energy anticipates a drop-off in cash contributions for subdivisions in 2008-09 as a result of the increased use of alternative providers for URD subdivisions.

47.5 PROCESS FOR ALLOCATING CAPITAL CONTRIBUTIONS TO THE DIFFERENT ASSET CLASSES IN THE PTRM

Section 2.3.13(a)(i) of the AER's RIN requires Ergon Energy to provide information about the process by which capital contributions have been allocated to the different asset classes in the PTRM.

As discussed further in section 11.1 of this Regulatory Proposal, the QCA has applied an approach during the current regulatory control period whereby the connection assets provided by forecast capital contributions are incorporated into Ergon Energy's Regulatory Asset Base (RAB) in the regulatory year in which the capital contribution is received. As explained in section 47.6 below, this value is then offset by a revenue adjustment in order to prevent Ergon Energy recovering the value of the capital contribution twice.

When Ergon Energy builds assets itself that are funded by cash contributions, it separates them into the relevant asset categories in its asset register. These assets are in turn reflected into the different asset classes of Ergon Energy's RAB, which is used for the purposes of the Roll Forward Model (RFM) and the PTRM.

Ergon Energy does not build gifted assets – rather, it receives them once they have been built by developers. Ergon Energy values the gifted assets by applying the unit rates in its price book for the relevant asset categories. Once Ergon Energy has valued the assets, they can then be included in its asset register in the same way as assets that it has built itself.

On this basis, the gifted assets are also reflected into the different asset classes of Ergon Energy's RAB, which is used for the purposes of the RFM and the PTRM.

Ergon Energy proposes continuing to apply this current approach in the next regulatory control period, in accordance with its capital contributions policy.

[103] The uptake of URD contestability under the new contestability model was 51per cent in the first regulatory year of introduction (2007-08). A similar uptake is expected for Commercial and Industrial works with the introduction of the alternative provider model in 2010.

[104] Since Commercial and Industrial contestability will be introduced at the beginning of 2010, and available for only the second half of 2009-10, only half the amount of work is eligible for alternative providers in 2009-10.

47.6 ADJUSTMENTS TO REVENUES FOR CUSTOMER CLASSES TO RECOGNISE CAPITAL CONTRIBUTIONS

Section 2.3.13(a)(ii) of the AER's RIN requires Ergon Energy to provide information about the way in which revenues for customer classes have been adjusted to recognise capital contributions.

As discussed above, Ergon Energy does not itself fund assets that relate to capital contributions. Rather, they are either funded by a cash payment to Ergon Energy from customers or developers or by a developer building the assets and gifting them to Ergon Energy.

However, because Ergon Energy includes the value of all capital contributions in its RAB, there is a need to reduce Ergon Energy's revenues in order to ensure that it does not recover the value of the capital contribution twice.

The QCA has dealt with this matter by:

- Allowing Ergon Energy to incorporate the cost of the assets into its RAB in the regulatory year in which the capital contribution is received. This allows Ergon Energy to earn a return on, and of, the full value of the assets; and
- Deducting the net present value of the cost of the assets (i.e. the capital contribution) from Ergon Energy's revenue requirement at the end of the regulatory year.

The QCA indicated that this approach was based on the theory that the financial impact of a capital contribution over the life of the affected asset can be equated to the present value of the resulting reduction in the regulated income over this period. In theory, the present value of this series should be equal to the original contribution.[105]

Accordingly, in calculating Ergon Energy's Aggregate Annual Revenue Requirement (AARR) for the five regulatory years of the current regulatory control period, the QCA deducted the annual forecast capital contributions from the AARRs, since the assets associated with these contributions are incorporated within the RAB. As discussed in sections 11.8 and 51.2.1 of this Regulatory Proposal, the QCA applies an unders and overs mechanism to capital contributions in order to adjust for differences between forecast and actual capital contributions over the current regulatory control period.

Ergon Energy proposes continuing to apply this current approach in the next regulatory control period, in accordance with its capital contributions policy.

[105] Queensland Competition Authority, *Final Determination – Regulation of Electricity Distribution, April 2005.*

47. CAPITAL CONTRIBUTIONS – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice
AR524	AER Post Tax Revenue Model Handbook

Codes and Rules

AR364	National Electricity Rules

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005

Ergon Energy Documents

AR047	EE Capital Contributions Methodology (QCA Approved), 20 April 2005
AR065c	NIEIR November 2007 Maximum Demand Forecasts
AR128c	NIEIR September 2008 Maximum Demand Forecasts
AR329	EE Pricing Principles Statement, Release 5, April 2009
AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

48. POST TAX REVENUE MODEL

Rules – Clauses 6.3.1(c)(1), 6.4.1, 6.4.2, 6.5.3 and S6.1.3(10)
RIN – Sections 2.4.3(a)(1)-(4)
PTRM Handbook

This chapter details how Ergon Energy has satisfied the requirements of the Rules and the Regulatory Information Notice (RIN) in relation to the completion of the Post Tax Revenue Model (PTRM) published by the Australian Energy Regulator (AER) in accordance with clauses 6.4.1 and 6.4.2 of the Rules.

48.1 COMPLETED PTRM

Ergon Energy confirms that it has:

- Prepared its Building Block Proposal in accordance with the PTRM, as required by clause 6.3.1(c)(1) of the Rules;
- Provided a completed PTRM to the AER as part of this Building Block Proposal that shows its application to Ergon Energy and the Roll Forward Model (RFM), as required by clause S6.1.3(10) of the Rules; and
- Estimated the cost of corporate income tax in accordance with the PTRM, as required by clause 6.5.3 of the Rules.

48.2 FINANCIAL PARAMETERS FOR PTRM

In accordance with section 2.4.3(a) of the RIN, Ergon Energy has provided the following financial parameters in section 41.5 of this Regulatory Proposal that are applied in the PTRM for the next regulatory control period:

- The averaging period for bond rates;
- The start of the averaging period for bond rates;
- The indicative nominal risk-free rate;
- The indicative debt risk premium; and
- The inflation forecast.

48. POST TAX REVENUE MODEL – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice
AR524	AER Post Tax Revenue Model Handbook
AR526	AER Roll Forward Model Handbook

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR539c	EE Regulatory Proposal Models, Roll Forward Model
AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

49. ANNUAL REVENUE REQUIREMENT FOR 2010-15

Rules – Clauses 6.3.2(a)(1), 6.4.2(a), 6.12.1(2)(i), 6.12.3.(d), 6.4.3(a) and (b)

This chapter details the Ergon Energy's proposed Annual Revenue Requirement (ARR) for each regulatory year of the next regulatory control period for its Standard Control Services, in order to address the requirements of the Rules.

49.1 REQUIREMENTS OF THE RULES

Clause 6.3.2(a)(1) of the Rules requires the Australian Energy Regulator (AER) to specify in its Building Block Determination Ergon Energy's ARR for each regulatory year of the next regulatory control period.

Clause 6.12.1(2)(i) of the Rules provides that one of the constituent decisions of the AER's Distribution Determination is whether to approve, or not to approve, the ARR for each regulatory year of the regulatory control period, as set out in the Distribution Network Service Providers (DNSP) building block proposal.

In accordance with clause 6.4.2(a) of the Rules, the Post Tax Revenue Model (PTRM) sets out the manner in which Ergon Energy's ARR for each regulatory year of the next regulatory control period is to be calculated.

Clause 6.12.3(d) of the Rules provides that the AER must approve Ergon Energy's ARR for each regulatory year of the regulatory control period, as set out in Ergon Energy's building block proposal, if the AER is satisfied that the amounts have been calculated using the PTRM on the basis of amounts calculated, determined or forecast in accordance with the requirements of Part C of Chapter 6 of the Rules.

Clause 6.4.3(a) of the Rules provides that Ergon Energy's ARR for each regulatory year of the next regulatory control period must be calculated using a building block approach, under which the building blocks are:

- The indexation of the Regulatory Asset Base (RAB), calculated in accordance with clause 6.4.3(b)(1) of the Rules;
- A return on capital for that regulatory year, calculated in accordance with clause 6.4.3(b)(2) of the Rules;
- The depreciation for that regulatory year, calculated in accordance with clause 6.4.3(b)(3) of the Rules;
- The estimated cost of corporate income tax for that regulatory year, calculated in accordance with clause 6.4.3(b)(4) of the Rules;
- The revenue increments or decrements (if any) for that regulatory year arising from the application of the Efficiency Benefit Sharing Scheme (EBSS), Service Target Performance Incentive Sheme (STPIS) and Demand Management Incentive Scheme (DMIS), calculated in accordance with clause 6.4.3(b)(5) of the Rules;
- The other revenue increments or decrements (if any) for that regulatory year arising from the application of a control mechanism in the current regulatory control period, calculated in accordance with clause 6.4.3(b)(6) of the Rules; and
- The forecast operating expenditure for that regulatory year, calculated in accordance with clause 6.4.3(b)(7) of the Rules.

In addition, Ergon Energy has made the following other adjustments to its building block components in order to determine its ARR:

- Adjustments for capital contributions; and
- Adjustments for the value of shared assets used to provide Alternative Control Services.

Each of these components is discussed in detail below.

49.2 ERGON ENERGY'S ANNUAL REVENUE REQUIREMENT

Ergon Energy confirms that it has prepared its ARR for each regulatory year of the next regulatory control period in accordance with the requirements of Part C of Chapter 6 of the Rules, in particular by applying:

- The PTRM established by the AER under clause 6.4 of the Rules; and
- The building block approach provided for by clause 6.4.3 of the Rules.

Ergon Energy has provided a completed PTRM and a completed Roll Forward Model (RFM) to the AER with this Regulatory Proposal. Ergon Energy's demonstration of the application of the models in calculating the annual revenue requirement, including the assumptions it has made in populating the models, are shown in the models.

Ergon Energy's proposed ARR for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15, is detailed in Table 127.

Table 127: *Annual Revenue Requirement for Standard Control Services for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Annual Revenue Requirement (smoothed)	1,100.22	1,213.87	1,339.25	1,477.59	1,630.21	6,761.15	1,352.23

Source: Tables for Proposal 49.2

The building blocks that comprise the ARR are summarised below.

49.2.1 Indexation of the RAB

Ergon Energy's proposed opening RAB for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15, is detailed in Table 128.

Table 128: *Opening Regulatory Asset Base for Standard Control Services for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15
Opening Regulatory Asset Base	6,999.39	8,041.17	9,220.93	10,410.39	11,672.77

Source: Tables for Proposal 40.2

Ergon Energy has calculated the proposed opening RAB for each regulatory year of the next regulatory control period by applying the AER's RFM. Chapter 40 of this Regulatory Proposal provides a detailed explanation of the basis of this calculation.

Ergon Energy has indexed its RAB by using, as required by clause 6.4.2(b)(1) of the Rules, its best estimates of expected inflation:

- From the current regulatory control period to the beginning of the first regulatory year of the next regulatory control period, in accordance with clause 6.5.1(e)(3) of the Rules; and
- Between each regulatory year of the next regulatory control period.

Ergon Energy's annual inflation for indexation of the RAB for the current regulatory period applies the AER's preferred methodology for calculating actual inflation and the Reserve Bank of Australia's (RBA) February 2009 Statement on Monetary Policy forecasts for 2008-09 and 2009-10. For the next regulatory period, Ergon Energy's proposed inflation is 2.45 per cent per annum. Chapter 41 of this Regulatory Proposal provides a detailed explanation of the basis of the calculation of annual inflation in the next regulatory period.

49.2.2 Return on Capital

Ergon Energy's proposed return on capital for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15, is detailed in Table 129.

Table 129: *Return on Capital for Standard Control Services for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Return on Capital	664.10	762.95	874.88	987.74	1,107.51	4,397.18	879.44

Source: Tables for Proposal 49.2.2

In accordance with clause 6.5.2(b) of the Rules, the rate of return is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by Ergon Energy.

Ergon Energy has calculated the proposed return on capital for each regulatory year of the next regulatory control period by applying the AER's PTRM. In accordance with clause 6.5.2(a) of the Rules, Ergon Energy has determined the proposed return on capital by applying a rate of return to the value of the RAB as at the beginning of the regulatory year.

Chapter 41 of this Regulatory Proposal provides a detailed explanation of the basis of the calculation of the rate of return on capital.

49.2.3 Regulatory Depreciation

Ergon Energy's proposed regulatory depreciation for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15, is detailed in Table 130.

Table 130: *Depreciation for Standard Control Services for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Regulatory Depreciation	103.36	116.77	113.71	130.46	134.30	598.60	119.72

Source: Tables for Proposal 40.2

Ergon Energy has calculated the proposed regulatory depreciation for each regulatory year of the next regulatory control period by applying the AER's PTRM and RFM.

In accordance with clause 6.5.5(a) of the Rules, Ergon Energy has determined the proposed regulatory depreciation for each regulatory year of the next regulatory control period:

- Based on the value of the assets as included in the RAB, as at the beginning of the regulatory year; and
- By preparing regulatory depreciation schedules that conform with the requirements of clause 6.5.5(b) of the Rules.

Chapter 37 of this Regulatory Proposal provides a detailed explanation of the basis of the calculation of the regulatory depreciation building block.

49.2.4 Corporate Income Tax

Ergon Energy's estimated cost of corporate income tax for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15, is detailed in Table 131.

Table 131: *Estimated Cost of Corporate Income Tax for Standard Control Services for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Estimated Cost of Corporate Income Tax	0.00	17.34	61.77	75.65	80.39	235.15	47.03

Source: Tables for Proposal 38.3

Chapter 38 of this Regulatory Proposal provides a detailed explanation of the basis of the estimation of Ergon Energy's corporate income tax building block.

49.2.5 Revenue Increments and Decrements arising from Schemes

Clause 6.4.3(a)(5) of the Rules requires the ARR for each regulatory year of a regulatory control period to include the revenue increments or decrements (if any) for that regulatory year arising from the application of the EBSS, STPIS and DMIS, calculated in accordance with clause 6.4.3(b)(5) of the Rules.

Ergon Energy considers that:

- There will be no revenue increments or decrements arising from the EBSS for any regulatory year of the next regulatory control period, due to the lagged effect of the scheme. Any increments or decrements arising under the scheme, attributable to operating expenditure incurred during the next regulatory control period, will be reflected into the calculation of the annual revenue requirement for the regulatory control period commencing on 1 July 2015. This is discussed further in Chapter 43 of this Regulatory Proposal; and
- The value of any revenue increments or decrements arising under the STPIS for any regulatory year of the next regulatory control period cannot be forecast in this Regulatory Proposal. They will only become known during the course of the next regulatory control period once Ergon Energy's performance against the performance parameters is known. This is discussed further in Chapter 44 of this Regulatory Proposal.

However, Ergon Energy has included a revenue increment of $1 million (Nominal) in each regulatory year of the next regulatory control period for the Demand Management Innovation Allowance (DMIA). The nature of this allowance is discussed further in Chapter 45 of this Regulatory Proposal.

49.2.6 Other Revenue Increments and Decrements

Clause 6.4.3(a)(6) of the Rules requires the ARR for each regulatory year of a regulatory control period to include other revenue increments or decrements arising from the application of a control mechanism in the current regulatory control period.

Ergon Energy's proposed other revenue increments and decrements for each regulatory year of the next regulatory control period, 2010-15, are detailed in Table 132.

Table 132: *Other Revenue Increments and Decrements for Standard Control Services for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Accelerated depreciation associated with Tropical Cyclone Larry	11.27	-	-	-	-	
Total	**11.27**	**-**	**-**	**-**	**-**	**11.27**

Source: Tables for Proposal 49.2.6

In addition, Ergon Energy will adjust its ARRs for the 2010-15 regulatory control period following the completion of Ergon Energy's regulatory reporting statements to the Queensland Competition Authority (QCA) over the coming regulatory years for the following other matters relating to the current regulatory control period:

- Previous under- or over-recovery of revenue;
- Shared asset usage; and
- The disposal of assets before the end of their useful lives.

Chapter 39 of this Regulatory Proposal provides a detailed explanation of the other revenue increments or decrements arising from the application of the control mechanism in the current regulatory control period.

49.2.7 Operating Expenditure

Ergon Energy's forecast operating expenditure for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15, is detailed in Table 133.

***Table 133:** Forecast Operating Expenditure for Standard Control Services for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Operating Expenditure	391.31	417.56	438.20	451.07	446.73	2,144.86	428.97

Source: Tables for Proposal 49.2.7

Ergon Energy has forecast operating expenditure for each regulatory year of the next regulatory control period and applies this in the AER's PTRM.

The forecast operating expenditure is that which is required by Ergon Energy to achieve each of the operating expenditure objectives in clause 6.5.6(a) of the Rules for the provision of Standard Control Services.

Chapter 26 of this Regulatory Proposal provides a detailed explanation of the basis of Ergon Energy's operating expenditure forecast.

Chapter 27 of this Regulatory Proposal explains how Ergon Energy's forecast operating expenditure meets the operating expenditure objectives, factors and criteria in clause 6.5.6 of the Rules.

49.2.8 Other Adjustments

49.2.8.1 Capital contributions

Ergon Energy's forecast capital contributions (and gifted assets) for Standard Control Services for each regulatory year of the next regulatory control period, 2010-15, is detailed in Table 134.

Chapter 47 of this Regulatory Proposal provides a detailed explanation of the basis of Ergon Energy's capital contribution forecast.

The values in Table 134 have been deducted from Ergon Energy's building block components in order to determine its ARR for the next regulatory control period.

***Table 134:** Forecast Cash Contributions and Gifted Assets for Standard Control Services for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Cash Contributions	68.19	73.72	65.62	71.47	82.21	361.21	72.24
Gifted Assets	43.74	47.51	42.29	46.05	52.98	232.56	46.51
Total	**111.94**	**121.23**	**107.91**	**117.52**	**135.19**	**593.77**	**118.75**

Source: Tables for Proposal 49.2.8

49.2.8.2 Shared assets for alternative control services

Ergon Energy's forecast the value of the shared assets that will be used to provide Alternative Control Services for each regulatory year of the next regulatory control period, 2010-15, is detailed in Table 135.

The values in Table 135 have been deducted from Ergon Energy's building block components in order to determine its ARR for the next regulatory control period.

Table 135: *Forecast Alternative Control Services Use of Shared Assets for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Shared Assets for Alternative Control Services	3.21	3.29	3.37	3.46	3.54	16.87	3.37

Source: Tables for Proposal 49.2.8

49. ANNUAL REVENUE REQUIREMENT FOR 2010-15 – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR524	AER Post Tax Revenue Model Handbook
AR526	AER Roll Forward Model Handbook

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR529	RBA February 2009 Statement on Monetary Policy, 6 February 2009
AR539c	EE Regulatory Proposal Models, Roll Forward Model
AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

50. TOTAL REVENUE REQUIREMENT FOR 2010-15

Rules – Clause 6.12.3(d)

This chapter details the Ergon Energy's proposed Total Revenue Requirement for the next regulatory control period for its Standard Control Services.

50.1 REQUIREMENTS OF THE RULES

Chapter 10 of the Rules defines the "total revenue requirement" as:

> *For a Distribution Network Service Provider, an amount representing revenue calculated for the whole of a regulatory control period in accordance with Part C of Chapter 6.*

The Total Revenue Requirement for the next regulatory control period is therefore calculated as the summation of the Annual Revenue Requirement (ARR) for each regulatory year of that regulatory control period.

Ergon Energy notes that clause 6.12.3(d) of the Rules provides that the Australian Energy Regulator (AER) must approve the Total Revenue Requirement set out in Ergon Energy's Building Block Proposal if it is satisfied that the amount has been properly calculated using the Post Tax Revenue Model (PTRM) on the basis of amounts calculated, determined or forecast in accordance with the requirements of the Rules Chapter 6 Part C.

50.2 ERGON ENERGY'S TOTAL REVENUE REQUIREMENT

Ergon Energy's proposed total ARR for the next regulatory control period is $6,761.15 million. The ARR for each year of the next regulatory control period is set out in Table 136 below.

Ergon Energy confirms that it has prepared its Total Revenue Requirement for the next regulatory control period in accordance with the requirements of Part C of Chapter 6 of the Rules, in particular by applying:

- The PTRM established by the AER under clause 6.4 of the Rules; and
- The building block approach provided for by clause 6.4.3 of the Rules.

Ergon Energy has provided a completed PTRM and a completed roll forward model to the AER with this Regulatory Proposal. Ergon Energy's demonstration of the application of the models in calculating the Total Revenue Requirement, including the assumptions it has made in populating the models, are shown in the models.

Table 136: *ARRs for Standard Control Services for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Annual Revenue Requirements (smoothed)	1,100.22	1,213.87	1,339.25	1,477.59	1,630.21	6,761.15	1,352.23

Source: Tables for Proposal 49.2

50. TOTAL REVENUE REQUIREMENT FOR 2010-15 – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR524	AER Post Tax Revenue Model Handbook
AR526	AER Roll Forward Model Handbook

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR539c	EE Regulatory Proposal Models, Roll Forward Model
AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

51. CONTROL MECHANISMS FOR STANDARD CONTROL SERVICES

Rules – Clauses 6.2.5, 6.2.6(a), 6.8.1(c), 6.8.2(c)(3), 6.12.1(11), 6.12.1(13), 6.12.3(c) , S6.1.3(6) and 11.16.6(a)
RIN - Section 2.2.5
F&A Stage 1 – Clause 3.5

This chapter sets out the control mechanism for Standard Control Services for the next regulatory control period and identifies adjustments to that control mechanism required within the next regulatory control period.

Clause 11.16.6(a) of the Rules indicates that, if Ergon Energy submits a proposal to the Australian Energy Regulator (AER) regarding the classification of services and control mechanism for the regulatory control period on or before 31 March 2008, the AER must publish its Framework and Approach paper under clause 6.8.1 in relation to those issues. In particular, clause 6.8.1(c) of the Rules indicates that the Framework and Approach paper must state the form of the control mechanisms to be applied by the Distribution Determination and the AER's reasons for deciding on control mechanisms.

In relation to Standard Control Services, clause 6.2.6(a) of the Rules states that the control mechanism must be of the prospective Consumer Price Index (CPI) minus X form, or some incentive-based variant of the prospective CPI minus X form, in accordance with Part C of Chapter 6.

Consistent with clause 11.16.6(a) of the Rules, Ergon Energy submitted a proposal to the AER on 31 March 2008 in relation to the classification of services and control mechanisms to apply in the next regulatory control period.

51.1 AER'S FRAMEWORK AND APPROACH

Clauses 6.12.1(11) and 6.12.1(13) of the Rules indicate that a Distribution Determination is predicated on a decision by the AER on the control mechanism (including the X factor) for Standard Control Services and a decision by the AER on how compliance with a relevant control mechanism is to be demonstrated. In addition, clause 6.12.3(c) requires that the control mechanisms that are applied must be as set out in the relevant Framework and Approach paper issued by the AER.

In August 2008, the AER published its Final Decision - *Framework and Approach Paper - Classification of Services and Control Mechanisms: Energex and Ergon Energy 2010–15 (F&A Stage 1)*. Consistent with clause 6.2.5 of the Rules, the F&A Stage 1 indicated that:

> *The AER will apply a fixed revenue cap control mechanism to those services classified by the AER as standard control services in the 2010–15 regulatory control period. Each fixed revenue cap will be of the CPI – X form and will be made in accordance with Part C of the NER—using the building block approach.*

The F&A Stage 1 also set out a number of adjustment mechanisms to be applied to the fixed revenue cap during the next regulatory control period. Specifically, the AER indicated that:

- An unders and overs mechanism would be applied for each fixed revenue cap in the next regulatory control period. Ergon Energy interprets this to mean an unders and overs mechanism for both its distribution charges and for the passing through of transmission charges[106];
- Should the AER decide to apply a Service Target Performance Incentive Scheme (STPIS) to Ergon Energy in the next regulatory control period then any revenue increment or decrement associated with the operation of that scheme in a regulatory year will be applied to the smoothed Annual Revenue Requirement (ARR) that applies two regulatory years after the regulatory year in which the service performance was measured;
- Should the AER decide to apply an Efficiency Benefit Sharing Scheme (EBSS) to Ergon Energy in the next regulatory control period any applicable EBSS revenue increment or decrement will be added to operating expenditure. The AER will apply both positive and negative carryovers as part of the operating expenditure building block element in the calculation of a Distribution Network Service Provider's (DNSPs) ARR for the regulatory control period following the regulatory control period in which the EBSS applied; and
- Should the AER decide to apply a Demand Management Incentive Scheme (DMIS) to Ergon Energy in the next regulatory control period

[106] It is noted that the AER's NSW Distribution Determination 2009-10 to 2013-14 included a transmission charges unders and overs mechanism at Appendix 1 pages 462 and 463.

any DMIS allowance will be provided as an amount in addition to the approved efficient operating expenditure. At the end of the next regulatory control period, the AER will calculate a carryover amount to be deducted from, or added to, the allowed revenues in year two of the following regulatory control period, or as specified in the applicable scheme.

51.2 ADJUSTMENTS TO REVENUE CAPS IN THE NEXT REGULATORY CONTROL PERIOD

Ergon Energy supports the adjustments set out in the AER's F&A Stage 1 being applied to its revenue caps in the next regulatory control period. However, Ergon Energy wishes to clarify a number of issues in order to ensure they are features of Ergon Energy's revenue cap for Standard Control Services. These issues are:

- The application of the unders and overs mechanism to capital contributions;
- Adjustments to the ARR for the use of Standard Control Services assets by other business entities within Ergon Energy;
- The application of side constraints on tariffs for Standard Control Services in relation to the above adjustments;
- Payments made under the Queensland Government's Solar Bonus Scheme, or any other equivalent Feed-In Tariff arrangement; and
- Unfunded Shared Network Events.

These issues are discussed below.

51.2.1 Application of Unders and Overs to Capital Contributions[107]

Ergon Energy wishes to confirm that the unders and overs mechanism that applies to its capital contributions in the current regulatory control period will continue to apply in the next regulatory control period.

Clause 11.16.10 of the Rules allows Ergon Energy to retain its current capital contributions methodology in the next regulatory control period provided that it remains consistent with its pricing principles statement in force immediately prior to 1 July 2009.

51.2.1.1 Current treatment of capital contributions

As part of its building block calculations for the current regulatory control period Ergon Energy provided the Queensland Competition Authority (QCA) with annual forecasts of capital contributions for the current regulatory control period. The QCA adopted an approach whereby the connection assets provided by these forecast capital contributions were incorporated into Ergon Energy's regulated asset base and the actual capital contributions were recognised in the year of receipt as a regulated revenue flow. That is, the QCA:

- Recorded the value of the contributed asset in the regulated asset base in the year in which the capital contribution was received. This allows Ergon Energy to earn a return on, and of, the full value of the assets; and
- Deducted the net present value of the cost of these assets (the capital contribution) from Ergon Energy's revenue requirement at the end of the year in order to prevent those cost being recovered twice by Ergon Energy.

The QCA indicated that this approach was based on the theory that the financial impact of a capital contribution over the life of the affected asset can be equated to the present value of the resulting reduction in the regulated income over this period. In theory, the present value of this series should be equal to the original contribution.[108]

Accordingly, in calculating Ergon Energy's Aggregate Annual Revenue Requirement (AARR) across the five years of the current regulatory control period, the QCA deducted the annual forecast capital contributions from the AARRs, since the assets associated with these contributions are incorporated within the regulatory asset base.

The QCA applies an unders and overs mechanism to capital contributions in order to adjust for differences between forecast and actual capital contributions over the current regulatory control period. Differences between forecast and actual capital contributions are reported by Ergon Energy in its annual regulatory reporting statements. Based on this information, the QCA adjusts Ergon Energy's subsequent AARR accordingly.[109]

51.2.1.2 Treatment of capital contributions in the next regulatory control period

In accordance with clause 11.16.10 of the Rules, Ergon Energy proposes retaining the same approach to capital contributions in the next regulatory control period as applies in the current regulatory control period. As a result:

- Ergon Energy has derived a forecast of capital contributions for the next regulatory control period;
- The value of relevant connection assets has been incorporated into Ergon Energy's regulated asset base for the next regulatory control period; and
- The corresponding annual capital contribution has been deducted from Ergon Energy's forecast ARR for each year of the next regulatory control period.

[107] Capital contributions include both cash contributions and gifted assets.

[108] Queensland Competition Authority, *Final Determination – Regulation of Electricity Distribution, April 2005.*

[109] Due to timing issues associated with the receipt of information and the need to set future tariffs, any unders and overs adjustment must be made two years from the original date. That is, where there is a difference between forecast and actual capital contributions resulting in an over or under recovery of the AARR for year *t*, that amount is recovered or returned through the AARR in year *t+2*.

Ergon Energy will report to the AER in its annual regulatory reports on any difference between forecast and actual capital contributions during the next regulatory control period. Where there is a difference between forecast and actual capital contributions that results in an over or under recovery of the ARR for year *t*, Ergon Energy will recover or return this amount to customers in year *t+2*.

51.2.2 Revenue Adjustments for the Use of Standard Control Services Assets by Other Business Entities within Ergon Energy

The AER's F&A Stage 1 highlights that clause S6.2 of the Rules requires that a DNSP's regulatory asset base only consists of assets that provide Standard Control Services. However, the AER also acknowledged that the Queensland transitional arrangements in clause 11.16.3 of the Rules allow Ergon Energy to retain the QCA's current treatment of their asset base into the next regulatory control period.

Accordingly, the AER's F&A Stage 1 indicated that if Ergon Energy proposed to retain the treatment of their asset base as is permitted under clause 11.16.3 of the Rules, the AER would accept that approach if it was consistent with the approach allowed in the QCA's 2005 Final Determination.

51.2.2.1 Current treatment of Ergon Energy's regulatory asset base

Ergon Energy's regulatory asset base in the current regulatory control period consists of some assets that are shared between Prescribed Distribution Services (and therefore Standard Control Services), Excluded Distribution Services (and therefore Alternative Control Services) and unregulated services.

The QCA requires Ergon Energy to apply an internal service charge for the use of shared assets in order to ensure that the full cost of 'shared asset' usage is appropriately borne by the beneficiary.
This charge reflects:

- Direct and indirect costs of usage;
- Depreciation associated with the asset (if applicable); and
- Return on assets.

Ergon Energy provides details of the actual annual charge for the use of shared assets to the QCA as part of its annual regulatory reporting statements to the QCA. The QCA uses this information in order to make an adjustment to Ergon Energy's subsequent AARR to reflect differences between forecast revenue from the use of shared assets and the actual revenue received.

51.2.2.2 Treatment of Ergon Energy's regulatory asset base for the next regulatory control period

In accordance with clause 11.16.3 of the Rules, Ergon Energy proposes retaining the same treatment of the regulatory asset base in the next regulatory control period as applies in the current regulatory control period. As a result:

- Assets that are shared between Ergon Energy's Standard Control Services, Alternative Control Services and unregulated services will be included in the regulatory asset base for the next regulatory control period;
- The ARR for Standard Control Services has been calculated based on the full value of the regulatory asset base (including the shared assets);
- Ergon Energy will continue to operate an internal service charge, whereby Alternative Control Services and unregulated services using the shared assets contained in the regulatory asset base will be charged for the use of those assets. This charge will reflect:
    - Direct and indirect costs of usage;
    - Depreciation associated with the asset (if applicable); and
    - Return on assets.
- The annual amount charged to Alternative Control Services and unregulated services for the use of shared assets contained in the next regulatory asset base will be separately recorded in Ergon Energy's annual regulatory statements provided to the AER; and
- The annual amount charged to Alternative Control Services and unregulated services for the use of shared assets contained in the regulatory asset base will be deducted from the subsequent ARR. Specifically, due to time lags, the amount charged for the use of shared assets in year *t* will be deducted from the ARR in year *t+2*. This adjustment ensures that there is no cross-subsidisation associated with the use of shared assets in the regulatory asset base.

51.2.3 Solar Bonus Scheme / Feed-In Tariff Payments

The Queensland Government introduced a Feed-In Tariff scheme, the 'Solar Bonus Scheme', from 1 July 2008. The following provisions of the *Electricity Act 1994* enact the scheme:

- DNSPs' obligations – clauses 44A(1)(b) and (c), 44A(2), and 44(A)(3); and
- Retailers' obligations – clause 55DB.

The legislation places on obligation on DNSPs to pay 44 cents per kilowatt hour (kWh) for 'sent-out' electricity generated by a customer's eligible solar photo voltaic generator. There is also an obligation for retailers to pass through the payments from DNSPs to customers.

When implementing the scheme the Queensland Government made a commitment that it would be offered until 2028, but will be reviewed after 10 years (i.e. by 2018) or when 8 MW of solar systems are installed (i.e. the equivalent of 8,000 generators of 1 kW capacity), whichever occurs first.

DNSPs and retailers are required to report each six months on a variety of matters, including the number and amount of payments made.

Details of the scheme are available from the Queensland Department of Employment, Economic Development and Innovation - Mines and Energy's website:

http://www.cleanenergy.qld.gov.au/solar_bonus_scheme.cfm. This site was last updated 22 May 2009; and a fact sheet is available from http://www.energy.qld.gov.au/zone_files/Sustainable/solar_bonus_scheme_fact_sheet.pdf.

51.2.3.1 Proposed treatment of Ergon Energy's Feed-In Tariff payments

It is not possible to prepare a forecast of the number and value of payments that Ergon Energy will be required to make to customers in the next regulatory control period. This is because the Feed-In Tariff scheme has only recently been introduced and the rate of take-up is unpredictable.

Therefore Ergon Energy proposes that its payments to customers (via their retailers) be an annual revenue adjustment (i.e. increase) that is calculated together with other annual revenue adjustments (such as capital contributions unders and overs). Ergon Energy would provide evidence of payments made in the form of the two reports (distribution and retail) that will be provided to the Queensland Government every six months.

51.2.4 Unfunded Shared Network Events

51.2.4.1 Nature of Unfunded Shared Network Events

When a new large customer seeks to be supplied from Ergon Energy's distribution system there is typically a need to build both shared network assets and dedicated connection assets.

The AER's proposal in its F&A Stage 1 to classify the design and construction of new large customers' connection asset as an Alternative Control Service has the effect of removing from Ergon Energy risks relating to the nature, timing and cost of building dedicated assets for new large customer connections. This is because Ergon Energy can provide these services on the same basis as alternative service providers, including by requiring up-front financing of the cost of the works. As a result, Ergon Energy does not need to forecast the cost of works for this Alternative Control Service.

However, the AER's proposal to classify shared network assets associated with the connection of new large customers as Standard Control Services means that Ergon Energy retains a residual risk associated with building these assets. This risk may particularly arise as a result of a major new project occurring during the regulatory control period that was unknowable at the time of preparing this Regulatory Proposal. Examples of Unfunded Shared Network Events could include:

- Major infrastructure initiatives triggered by Government decisions;
- The development of a large new mine; and
- A major expansion of an existing customer's facility.

51.2.4.2 How unfunded shared network events are dealt in the current regulatory control period

In the current regulatory control period, the QCA acknowledged that, in relation to circumstances comparable to Unfunded Shared Network Events:

> *Ergon is more exposed than Energex to such projects due to its customer mix and the dispersed nature of its network - Ergon has more large resource and industrial customers.*
>
> *As a result, the connection of a new large customer to the Ergon network has the potential to require the construction of more supporting infrastructure than would be required on the dense Energex network.*[110]

As a result, the QCA permitted Ergon Energy to adjust its revenue cap for large customer projects that were totally unanticipated with a project cost of more than $10 million on an ex post basis. The project costs related to both shared network assets and dedicated connection assets because both of these elements were classified as Prescribed Distribution Services by the QCA.

51.2.4.3 The effect of the classification of services in the next regulatory control period

The costs of assets that are dedicated to the customer arising from a Unfunded Shared Network Event will be treated as Alternative Control Services in the next regulatory control period and therefore do not present a financial risk to Ergon Energy.

However, the costs of associated shared network assets will not be funded by a single customer because, by their nature, the assets are shared, or are available to be shared, with other customers. These shared network costs will not be included in the Standard Control Services' capital expenditure forecasts at the time of setting the revenue cap because they relate events to events that could not be known by Ergon Energy.

A mechanism is therefore required to allow Ergon Energy to recover the costs equitably from all customers who utilise the shared network assets that are built as a result of an Unfunded Shared Network Event.

51.2.4.4 Proposed treatment of Unfunded Shared Network Events in the next Regulatory Control Period

Ergon Energy's capital expenditure forecasts for Standard Control Services do not make provision, or include contingencies, for the shared network costs of Unfunded Shared Network Events.

[110] QCA, Final Determination – Regulation of Electricity Distribution, April 2005, page 89

Ergon Energy proposes that its revenue cap for Standard Control Services be able to be increased on an ex post basis, by allowing a return on, and of, new shared network assets relating to Unfunded Shared Network Events.

Ergon Energy proposes that an Unfunded Shared Network Event would have the following characteristics. It would need to:

- Involve a total project cost to Ergon Energy for the shared network component of at least $5 million. There would be no revenue impact threshold for such an event;
- Relate to an identifiable event rather than to organic load growth across Ergon Energy's distribution system, although it could relate to several customers triggering the event (such as three mines establishing in close proximity to one another). This is because the shared network is, by definition, built with regard to the total load imposed on the system, not simply to an individual customer's specific needs; and
- Have not been included in Ergon Energy's capital expenditure forecasts for the shared network for the next regulatory control period. This means, for example, that the shared network costs arising from the event would not be included in Ergon Energy's Sub-transmission Network Augmentation Plans (SNAPs) or Distribution Network Augmentation Plans (DNAPs) at the time of submitting the Regulatory Proposal. These plans are being made available to the AER with this Regulatory Proposal and will be able to be referred back to during the next regulatory control period.

51.2.4.5 Reasons why allowance for unfunded shared network events is necessary

Ergon Energy needs to be able to recover the shared network costs of Unfunded Shared Network Events that are incurred in the next regulatory control period because:

- When a new large customer connects to Ergon Energy's network there is typically a need to build both shared network assets and dedicated connection assets;
- Ergon Energy has a statutory obligation to build the shared network assets and cannot refuse to do so on the basis that it has not been funded under its revenue cap;
- No one other than Ergon Energy can build these assets because they relate to the shared network. This is a key reason for why the AER proposed classifying services relating to the shared network as Standard Control Services;
- Ergon Energy's exposure to the risks of Unfunded Shared Network Events will not diminish in the next regulatory control period from that recognised by the QCA in its Final Determination for the current regulatory control period;
- The events are triggered by parties other than Ergon Energy and the nature, timing and size of the works cannot reasonably be forecast by Ergon Energy;
- There would be no basis for Ergon Energy to include any forecast of the cost of Unfunded Shared Network Events in its capital expenditure forecasts for Standard Control Services. Ergon Energy could therefore not satisfy the capital expenditure objectives, factors and criteria under Chapter 6 of the Rules for any such expenditure;
- Allowing Ergon Energy to adjust the Standard Control Services' revenue cap for a return on, and of, new shared network costs means that it can equitably recover this additional revenue from all of the customers that use the related assets according to their proportionate use. Shared network assets are more economically efficient than dedicated assets and it is appropriate to charge all customers that benefit from the use of these shared assets;
- As discussed in section 2.7 of this Regulatory Proposal, a revenue cap of itself does not accommodate Unfunded Shared Network Events. This is a different situation to a price cap where volume increases above those forecast flow through to a DNSP's revenues. The limitations of a revenue cap were recognised by the QCA in the current regulatory control period. The AER should continue the regulatory practice and provide a mechanism for Ergon Energy to manage this risk in the next regulatory control period by allowing a revenue cap adjustment; and
- If Ergon Energy cannot recover the shared network costs of Unfunded Shared Network Events then, given that it cannot refuse to undertake the work, Ergon Energy must either compromise other planned works in the capital expenditure forecasts or incur a major financial loss. Ergon Energy considers that neither of these options is acceptable and was a key focus of the Electricity Distribution and Service Delivery (EDSD) Review, which noted that there was "a significant re-allocation of capital expenditure from reliability and asset replacement works to customer connection works over the period 2000/01 to 2003/04".[111]

[111] Independent Panel, "Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland", July 2004, page 52

51.2.5 Application of Side Constraints

Ergon Energy proposes that any revenue adjustment associated with unders and overs or shared asset usage not be subject to the side constraints on tariffs provided for under clause 6.18.6 of the Rules.

Rather, Ergon Energy proposes that any such adjustment be cleared in a single regulatory year. This approach is consistent with the AER's treatment of Transmission Use of System (TUOS) overs and unders[112] and other such adjustments discussed in clause 6.18.6(d) of the Rules.

51.2.6 Summary of Adjustments for Each Year Within the Next Regulatory Control Period

In summary, Ergon Energy considers that the ARR in the next regulatory control period should be annually adjusted by:

- The difference between forecast and actual capital contributions in year *t*;
- The difference between forecast and actual revenue from standard control services in year *t*;
- Adding the actual amount paid to customers under the existing, or any future, Feed-In-Tariff scheme(s); and
- Adding any allowance for a return on, and of, assets relating to Unfunded Shared Network Events in year *t*.

Once these adjustments have been applied, the adjusted ARR will be determined, from which prices are then developed. Side constraints are applied in determining prices in order to recover the adjusted ARR.

The information required to derive this calculation would be contained in Ergon Energy's annual regulatory reporting statements for year *t* provided to the AER and from Ergon Energy's reports to the Queensland Government regarding the Feed-In-Tariff scheme. Due to lags in the receipt of this information, any adjustment required to Ergon Energy's subsequent ARR would be made in year *t+2*.

Ergon Energy notes that issues associated with TUOS charges and TUOS unders and overs are contained in the Ergon Energy's Pricing Proposal in accordance with clause 6.18.7 of the Rules.

[112] The AER, in its February 2008 final decision on control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations stated that the TUOS unders or overs is to be settled in a single regulatory year and that this approach is more consistent with the requirements of Chapter 6 of the Rules than recovering the unders or overs over a longer period.

51. CONTROL MECHANISMS FOR STANDARD CONTROL SERVICES – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

AR371	Electricity Act 1994 (Qld)

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005

Codes and Rules

AR158	"Detailed Report of the Independent Panel Electricity Distribution and Service Delivery for the 21st Century Queensland" (EDSD Review), July 2004
AR364	National Electricity Rules

Ergon Energy Documents

Nil

52. PRICING FOR STANDARD CONTROL SERVICES

Rules – Clauses 6.1.4, 6.8.2(c)(4), 6.12.1(17), 6.12.1(19), 6.18, 6.18.2(b), 6.18.6, 6.23 and 11.16.8
RIN – Section 2.2.5

This chapter sets out pricing information in relation to Ergon Energy's Standard Control Services.

Importantly, this is not Ergon Energy's Pricing Proposal for the next regulatory control period. In accordance with clause 6.18.2(a)(1) of the Rules, Ergon Energy will submit its initial Pricing Proposal for the next regulatory control period *"as soon as practicable, and in any case within 15 business days, after publication of the distribution determination........for the first regulatory year of the regulatory control period"*.

Clause 6.8.2(c)(4) of the Rules requires Ergon Energy's Regulatory Proposal to detail "indicative prices for each year of the regulatory control period" for its direct control services.

Clauses 6.12.1(17) and (19) of the Rules require the Australian Energy Regulator's (AER) Distribution Determination to include a decision on:

- The procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another (including any applicable restrictions); and
- How Ergon Energy is to report to the AER on its recovery of Transmission Use of System (TUOS) charges for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges.

Clause 6.18 of the Rules details the distribution pricing rules to apply to Ergon Energy in the next regulatory control period.

Clause 6.23 of the Rules details requirements in relation to the separate disclosure of transmission and distribution charges.

52.1 PROPOSAL FOR ASSIGNING CUSTOMERS TO TARIFF CLASSES

Clause 6.12.1(17) of the Rules states that a Distribution Determination is predicated on a decision by the AER on, amongst other things, the procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another, including any applicable restrictions.

Clause 6.18.4 of the Rules sets out Principles governing assignment or re-assignment of customers to tariff classes and assessment and review of basis of the charging. It states that:

a. *In formulating provisions of a distribution determination governing the assignment of customers to tariff classes or the re-assignment of customers from one tariff class to another, the AER must have regard to the following principles:*
    1. *customers should be assigned to tariff classes on the basis of one or more of the following factors:*
        (i) the nature and extent of their usage;
        (ii) the nature of their connection to the network;
        (iii) whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement;
    2. *customers with a similar connection and usage profile should be treated on an equal basis;*
    3. *however, customers with micro-generation facilities should be treated no less favourably than customers without such facilities but with a similar load profile;*
    4. *a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review.*

e. *If the charging parameters for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.*

With respect to clause 6.18.4(a)(1) and 6.18.4(a)(2) of the Rules, Ergon Energy assigns customers to tariffs on the basis of geographical location, usage and size.

Customers are first classified as the Eastern Zone, the Western Zone or Mount Isa, based on geographical location. In order to provide the appropriate economic and cost of supply signals, customers are then assigned into one of four classes of network users, namely:

- Individually Calculated Customers;
- Connection Asset Customers;
- Standard Asset Customers; and
- Embedded Generators.

The purpose of the four network user classes is to enable network prices to be developed that provide individual or direct cost of supply signals to those network users where possible while recognising that it is not possible to price every network user individually. There is a trade-off for a Distribution Network Service Provider (DNSP), such as Ergon Energy, between the complexity of individual price calculation and the inefficiencies created through price averaging. A practical limit also arises in the number of site specific network prices that can feasibly be determined and administered.

Ergon Energy selects the network users for inclusion in any particular network user class.

52.1.1 Individually Calculated Customers

Individually Calculated Customers (ICCs) are those customers:

- With energy consumption typically greater than 40 GWh per annum, or
- With energy consumption lower than 40 GWh per annum where:
  - → A customer has a dedicated supply system which is quite different and separate from the remainder of the supply network; or
  - → There are only two or three customers in a supply system making average prices inappropriate; or
  - → A customer is connected at or close to a transmission connection point and the inclusion of the cost of average shared network would increase their network price above stand-alone; or
  - → Inequitable treatment of otherwise comparable customers arising from the 40 GWh threshold.

ICC distribution prices are based on:

- The actual dedicated connection assets utilised by the customer; plus
- The customer's specifically identified portion of any shared distribution network utilised for the electricity supply.

52.1.2 Connection Asset Customers

Connection Asset Customers (CACs) are those customers:

- With energy consumption typically greater than 4 GWh per annum, or
- With energy consumption lower than 4 GWh per annum where:
  - → A customer has a dedicated supply system which is quite different and separate from the remainder of the supply network; or
  - → Inequitable treatment of otherwise comparable customers arising from the 4 GWh threshold.

CAC distribution prices are based on:

- The actual dedicated connection assets utilised by the customer; plus
- Average charges for use of the shared network.

The CAC class of customer is further subdivided into subcategories based on voltage levels, as detailed in Table 137.

Table 137: *Sub-categories of CAC customers*

CAC Category	Description
66 kV	Connected to either a 66 kV substation or a 66 kV line
33 kV	Connected to either a 33 kV substation or a 33 kV line
22/11 kV Bus	Connected to either a 22 kV or 11 kV substation
22/11 kV Line	Connected to either a 22 kV or 11 kV line

Source: Ergon Energy Network Pricing Principles Statement Release 5 (2009-10)

52.1.3 Standard Asset Customers

All other customers are classified as Standard Asset Customers (SACs).

SAC network prices are based on:

- Average charges for dedicated connection assets; plus
- Average charges for use of the shared network

The categories of network prices used in the SAC price class are set out in Table 138.

Table 138: *Sub-categories of SAC customers*

SAC Category	Description
Demand High Voltage	Any high voltage metered customer; 400 kW minimum chargeable demand
Demand Large	400 kW minimum chargeable demand
Demand Medium	120 kW minimum chargeable demand
Demand Small	30 kW minimum chargeable demand
Volume Large	26 MWh to 100 MWh per annum
Volume Small	0 MWh to 26 MWh per annum
Volume Controlled	Controlled Supply - for those loads that can have the supply interrupted for some periods each day (eg hot water, air conditioning, pool pumps, etc)
Volume Night - Controlled	Night Rate Supply - for those loads where supply is generally available for a limited number of hours each night (eg storage hot water)
Volume Unmetered	Unmetered Supply - for small uniform loads as approved by Ergon Energy

Source: Ergon Energy Network Pricing Principles Statement Release 5 (2009-10)

52.1.4 Embedded Generators

The Embedded Generator (EG) class applies to generators connected to the distribution system. EGs are separated into two categories:

- EGs that are connected to and only generate into the distribution system. EG distribution prices are based on identifying the actual dedicated connection assets utilised by the generator; or
- EGs that are connected to, generate for part of the regulatory year and take load from the distribution system for the other part of the regulatory year. EG distribution prices are based on identifying the actual dedicated connection assets utilised by the generator. For the load side of the EG, distribution prices are based on identifying the actual dedicated and shared connection assets utilised by the load, depending on the user class category allocated (ICC, CAC or SAC).

52.1.5 Meeting the Requirements of the Rules

Ergon Energy's processes for assigning tariffs to customers meet the requirements of clauses 6.18.4(a)(1) and 6.18.4(a)(2) because:

- With respect to clause 6.18.4(a)(1), customers are assigned on the basis of geographical location, the nature of their connection, their forecast usage and size;
- With respect to clause 6.18.4(a)(2), customers with the same connection and usage profiles are treated on a similar basis.

Ergon Energy's processes for assigning tariffs to customers meet the requirements of clause 6.18.4(a)(3) because Ergon Energy does not treat customers with micro-generation less favourably than other customers. Customers with micro-generation facilities are charged the network tariff for supply to their connection point as are any other network customers.

With respect to clause 6.18.4(a)(4), Ergon Energy does not reassign customers without careful review and good reasons. Reassignment would only occur in a situation where a customer alters the underlying characteristics of their connection, in terms of size or nature of usage.

With respect to clause 6.18.4(b), Ergon Energy reviews and, if necessary, alters its tariffs each regulatory year and will continue to do so in the next regulatory control period. It does this within the confines of the control mechanism and applicable side constraints.

52.2 BASIS FOR REPORTING TO AER ON RECOVERY OF TUOS CHARGES

Clause 6.12.1(19) of Rules states that a Distribution Determination is predicated on a decision by the AER on, amongst other things, how the DNSP is to report to the AER on its recovery of TUOS for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges.

Ergon Energy currently reports to the QCA annually on the recovery of TUOS from its network tariffs, and makes adjustments to subsequent pricing periods to account for over or under recovery of those charges. Ergon Energy proposes to continue this process with the AER in the upcoming regulatory control period.

52.3 INDICATIVE PRICES

52.3.1 Customer Numbers for Each Standard Control Service for 2005-10 by Regulatory Year

Section 2.2.5(a)(2) of the Regulatory Information Notice (RIN) requires that Ergon Energy provide in the Regulatory Proposal, for Standard Control Services and Alternative Control Services, actual customer numbers (or job numbers where applicable) for equivalent services provided in each regulatory year of the current regulatory control period.

This information is provided for Standard Control Services in Table 139.

Table 139: *Customer Numbers for the Equivalent of Standard Control Services*

Pricing Category	2005-06	2006-07	2007-08	2008-09 Estimate	2009-10 Estimate
ICC	63	68	68	68	72
CAC	184	184	186	194	199
SAC	625,711	637,897	652,935	663,164	673,571
EG	30	32	33	35	36

Source: AR433c AER Data_v7_data room_28May09.xls

52.3.2 Revenue for Each Standard Control Service for 2005-06 to 2009-10 by Regulatory Year

Section 2.2.5(a)(3) of the RIN requires that Ergon Energy provide in the Regulatory Proposal, for Standard Control Services and Alternative Control Services, the revenue earned for equivalent services provided in each regulatory year of the current regulatory control period.

This information is provided for Standard Control Services in Table 140.

Table 140: *Revenue from equivalent of Standard Control Services by Customer Class ($M Nominal)*

Pricing Category	2005-06	2006-07	2007-08	2008-09 Estimate	2009-10 Estimate
ICC	21.98	26.50	29.19	32.28	34.05
CAC	43.33	42.70	45.71	50.91	56.37
SAC	617.85	622.26	656.84	704.12	754.96
EG	0.97	1.38	1.67	3.14	3.30

Source: AR433c AER Data_v7_data room_28May09.xls

52.3.3 Price for Each Standard Control Service for 2005-06 to 2009-10 by Regulatory Year

Section 2.2.5(a)(4) of the RIN requires that Ergon Energy provide in the Regulatory Proposal, for Standard Control Services, the prices for equivalent services provided in each regulatory year of the current regulatory control period.

This information is provided in the Table 141.

Table 141: *Revenue Yield: Equivalent of Standard Control Services by Customer Grouping 2005-10 (c/kWh Nominal)*

Pricing Category	2005-06	2006-07	2007-08	2008-09 Estimate	2009-10 Estimate
ICC	0.557	0.657	0.708	0.744	0.785
CAC	2.997	3.005	3.349	3.411	3.689
SAC	7.631	7.660	7.891	8.192	8.475
EG	0.097	0.132	0.137	0.208	0.138

Source: AR433c AER Data_v7_data room_28May09.xls

52.3.4 Indicative Prices for Each Standard Control Service for Next Regulatory Control Period

Clause 6.8.2(c)(4) of the Rules requires Ergon Energy's Regulatory Proposal to detail "indicative prices for each year of the regulatory control period" for its Direct Control Services.

Section 2.2.5(a)(5) of the RIN requires that Ergon Energy provide indicative prices for each individual Standard Control Service and Alternative Control Service in each regulatory year of the next regulatory control period.

This information is provided for Standard Control Services in Table 142.

This is an expression of the Annual Revenue Requirement (ARR) forecast for Standard Control Services for the next regulatory period. It is not the basis on which Ergon Energy intends to charge for these services.

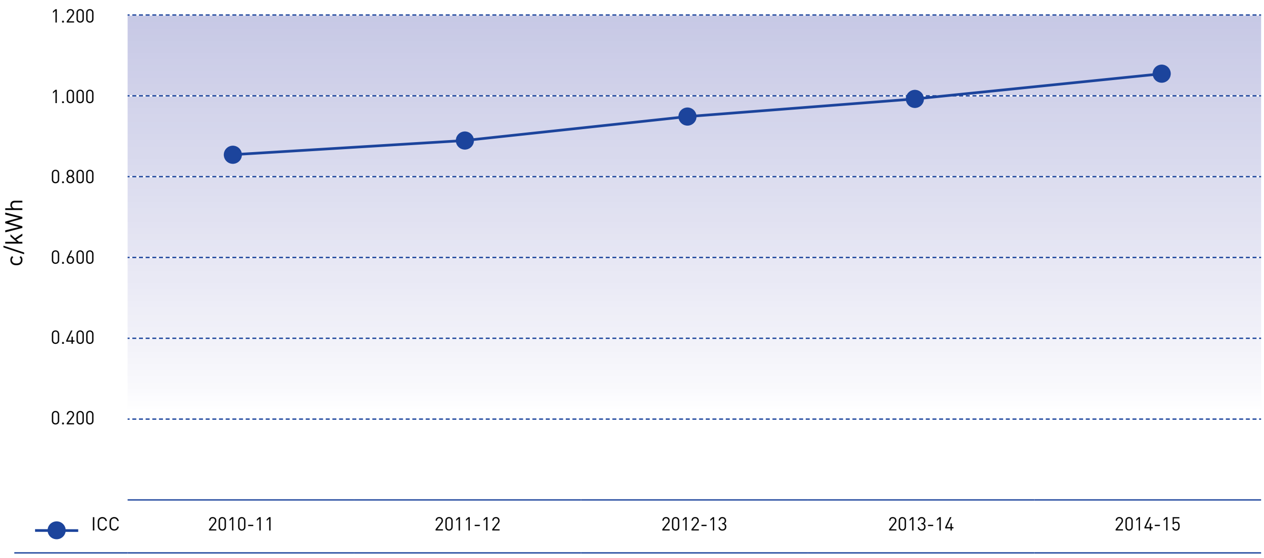
Table 142: *Indicative Prices Standard Control Services by Customer Grouping 2010-15 (c/kWh Real $2009-10)*

Pricing Category	2010-11	2011-12	2012-13	2013-14	2014-15
ICC	0.857	0.889	0.949	0.992	1.057
CAC	4.057	4.230	4.490	4.741	5.060
SAC	10.416	10.821	11.241	11.676	12.126
EG	0.101	0.107	0.113	0.120	0.127

Source: AR433c AER Data_v7_data room_28May09.xls

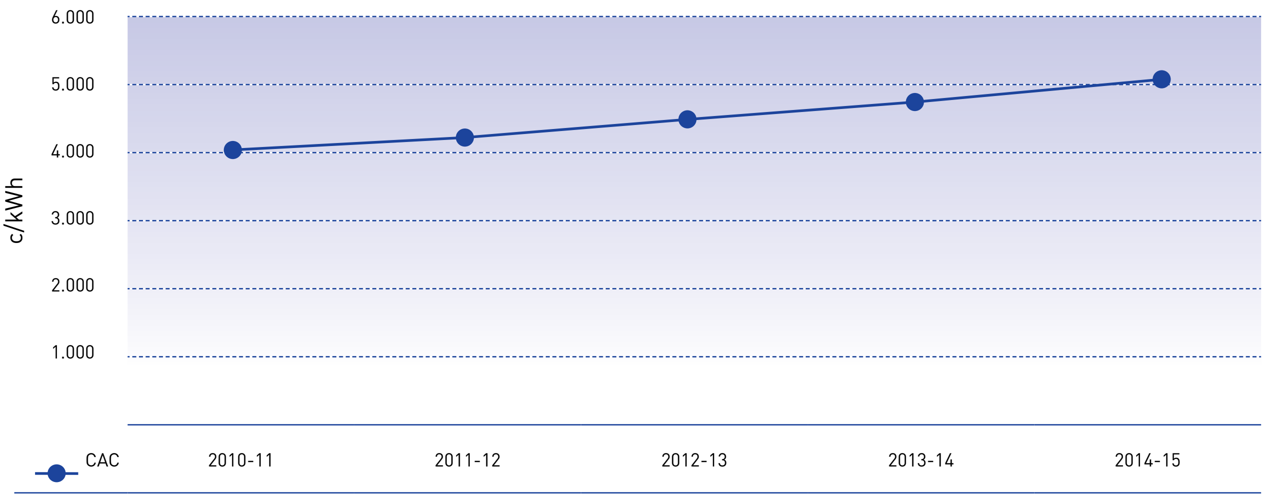
Indicative prices by customer pricing category are depicted in Figure 61, Figure 62, Figure 63 and Figure 64.

Figure 61: *Indicative Prices Standard Control Services for ICC Customers 2010-15*



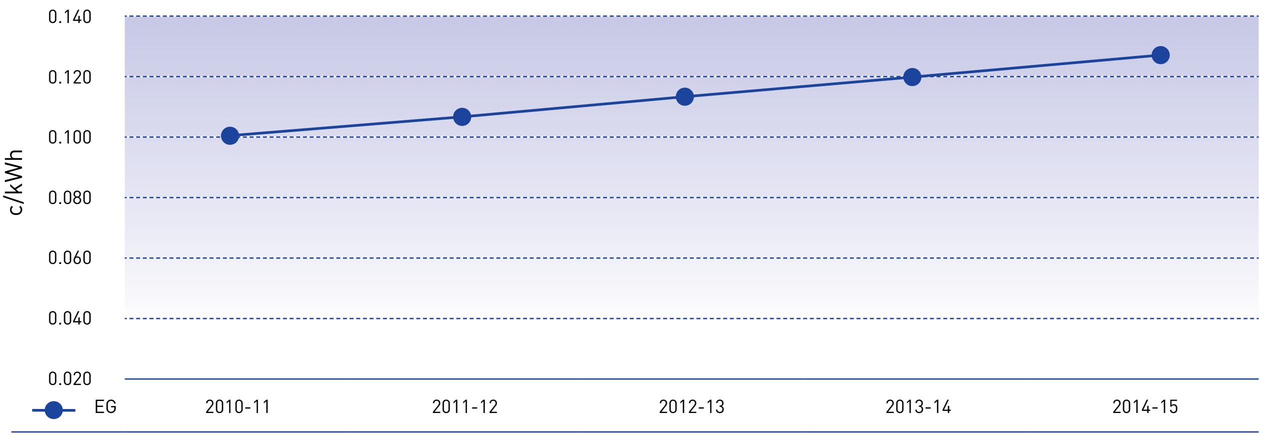
Source: AR433c AER Data_v7_data room_28May09.xls

Figure 62: *Indicative Prices Standard Control Services for CAC Customers 2010-15*



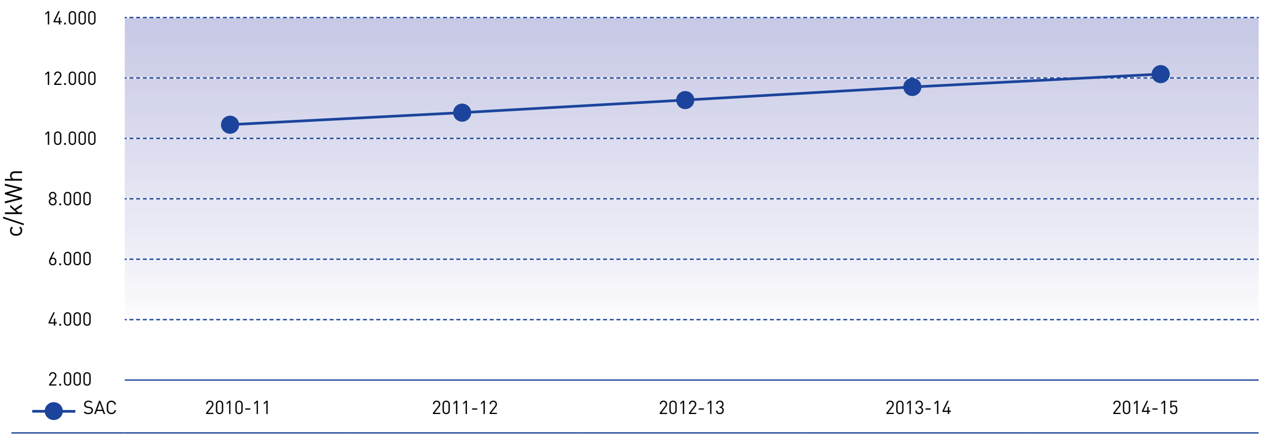
Source: AR433c AER Data_v7_data room_28May09.xls

Figure 63: *Indicative Prices Standard Control Services for Embedded Generators 2010-15*



Source: AR433c AER Data_v7_data room_28May09.xls

Figure 64: *Indicative Prices Standard Control Services for SAC Customers 2010-15*



Source: AR433c AER Data_v7_data room_28May09.xls

52.4 SIDE CONSTRAINTS

Clause 6.18.6(b) of the Rules requires that the expected weighted average revenue to be raised from a tariff class for a particular regulatory year of a regulatory control period must not exceed the corresponding expected weighted average revenue for the preceding regulatory year by more than the permissible percentage.

The permissible percentage is set out in Section 6.18.6(c)(1) and Section 6.18.6(c)(2), and is to be the greater of (CPI–X+2 per cent) and (CPI+2 per cent).

Clause 11.16.8 of the Rules provides that "for the regulatory control period, nothing in clause 6.18.6 should preclude the implementation of any price paths approved by the Queensland Competition Authority (QCA) (including any necessary adjustment of those price paths in light of the expected revenue for the first regulatory year of the regulatory control period)".

Ergon Energy interprets these two clauses to mean that:

- Where a price path has been approved by the QCA in the 2005 Final Determination, and these price paths were clearly envisaged to require a term which extends beyond 30 June 2010, these price paths will be permitted by the AER in the next regulatory control period by the establishment of side constraints that might exceed those set out in clause 6.18.6 of the Rules; and
- Where no price path has been approved, the side constraints will be as set out in clause 6.18.6 of the Rules.

Section 9.3 of the QCA's Final Determination provided one such approval:

> *For contestable customers whose prices are currently below the cost reflective level, the DNSPs are required to propose to the Authority price paths which, by the end of the next regulatory period, desirably achieve full cost reflectivity for these customers. DNSPs must provide these price paths to the Authority as soon as practicable after the release of this Final Determination and with the aim of notifying affected customers by 30 October 2005 of the regulatory yearly price increases agreed with the Authority that they will face over the next regulatory period.*

On 11 May 2006, the QCA approved the imposition of a price path which extended the target date for cost reflectivity for non-cost reflective customers to the end of the 2010-11 to 2014-15 regulatory control period. This followed a letter from Ergon Energy dated 11 April 2006.

Together, the QCA's Final Determination and the letter from the QCA dated 22 May 2006, comprise "price paths approved by the QCA" for the purposes of clause 11.16.8 of the Rules.

The side constraints consequent to these price paths are specific to the customers to which they apply. These are provided in the following confidential Table 143.

Ergon Energy therefore proposes that:

- Those customers identified in Table 143 continue to have side constraints applied to them, being the greater of the side constraint approved by the QCA and that permitted under clause 6.18.6 of the Rules; and
- All other customers have side constraint applied to them as permitted under clause 6.18.6 of the Rules.

Table 143: *Price Paths Approved by the QCA*

NMI	Customer Name	Price Zone	Price Path

Source: AR421c Ch52 Customers with DUOS and TUOS Price Paths_30April09

CONFIDENTIAL INFORMATION

52. PRICING FOR STANDARD CONTROL SERVICES – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Document

AR367c & 368c	AER Regulatory Information Notice

QCA Documents

AR386	QCA Final Determination Regulation of Electricity Distribution, April 2005

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR421c	EE Ch 52 Customers with DUOS & TUOS Price Paths, 30 April 2009
AR329	EE Pricing Principles Statement, Release 5, April 2009
AR353c	QCA Letter to EE, Pricing Matters in Final Determination, 22 May 2006
AR354c	EE Letter to QCA, Cost Reflective Price Paths, 11 April 2006
AR433c	EE AER Data, V7, Data Room, 28 May 2009

53. ALTERNATIVE CONTROL SERVICES – STREET LIGHTING SERVICES

Rules – Clauses 6.2.6(b)(c), 6.3.1, 6.3.2, 6.4, 6.5.1, 6.5.2, 6.5.3, 6.5.4, 6.5.5, 6.5.6(a)-(d), 6.5.6(e)(1)(2)(3) & (5), 6.5.7(a)-(d), 6.5.7(e)(1)(2)(3) & (5), 6.5.9, 6.6.1, 6.8.1(c), 6.8.2(c), 6.12.1(11), 6.12.1(12), 6.12.1(13), 6.12.3(c), 6.18, S6.1.1, S6.1.2 and 11.16.10
RIN – Sections 2.2.1(a)(3), 2.2.2(a)(2), 2.2.4(b), 2.2.5(a)(4) & (a)(5), 2.4.2 and 2.4.6
RIN Pro forma – 2.2.1, 2.2.2, 2.2.5
F&A Stage 1 - Clause 3.4.3, 3.5, 3.5.2

This chapter deals with Ergon Energy's Street Lighting Services. It is structured as follows:

- Section 53.1 overviews the nature and types of Street Lighting Services that Ergon Energy provides. It addresses section 2.4.6(a)(1)(i) of the Regulatory Information Notice (RIN);
- Section 53.2 deals with the control mechanisms that are to be applied to Street Lighting Services for the next regulatory control period. It includes Ergon Energy's interpretation of the requirements of sections 3.5.2 and 3.4.3 of the Australian Energy Regulator's (AER) F&A Stage 1. It also details how Ergon Energy has applied Part C of Chapter 6 of the Rules to Street Lighting Services;
- Section 53.3 deals with service levels relating to Street Lighting Services. It addresses section 2.4.6(a)(5) of the RIN;
- Section 53.4 deals with Street Lighting Services revenues for the current regulatory control period. It addresses section 2.2.5(a)(3) of the RIN;
- Section 53.5 deals with Street Lighting Services customer numbers for the current regulatory control period. It addresses section 2.2.5(a)(2) of the RIN;
- Section 53.6 confirms Ergon Energy's application of a building block approach in accordance with clause 6.3.1 of the Rules;
- Section 53.7 details Ergon Energy's proposed commencement and length of the regulatory control period in accordance with clause 6.3.2 of the Rules;
- Section 53.8 details Ergon Energy's demand forecasts. It addresses section 2.4.6(a)(4) of the RIN;
- Section 53.9 details Ergon Energy's historic and forecast capital expenditure and justifies any material differences between historic and forecast expenditures. It addresses section 2.4.6(a)(2) of the RIN;
- Section 53.10 explains and justifies Ergon Energy's capital expenditure forecasts. It addresses the requirements under clause 6.5.7(b) and relevant requirements of clause S6.1.1 of the Rules;
- Section 53.11 explains how Ergon Energy addresses the capital expenditure objectives, criteria and factors for the purposes of clause 6.5.7(a), (c) and (d) of the Rules;
- Section 53.12 details Ergon Energy's historic and forecast operating expenditure and justifies any material differences between historic and forecast expenditures. It addresses section 2.4.6(a)(2) of the RIN;
- Section 53.13 explains and justifies Ergon Energy's operating expenditure forecasts. It addresses the requirements of clause 6.5.6(b) and relevant requirements of clause S6.1.2 of the Rules;
- Section 53.14 addresses the operating expenditure objectives, criteria and factors for the purposes of clause 6.5.6(a), (c) and (d) of the Rules;
- Section 53.15 provides certain other information that has been used in preparing the capital and operating expenditure forecasts, but which is not specifically required under the Rules, the AER's RIN or the AER's F&A Stage 1;
- Section 53.16 deals with cost pass throughs for the purposes of clause 6.6.1 of the Rules;
- Section 53.17 deals with capital contributions for Street Lighting Services for the purposes of clauses 6.21 and 11.16.10 of the Rules;
- Section 53.18 confirms that Ergon Energy has applied the Post Tax Revenue Model (PTRM) and Roll Forward Model (RFM) for Street Lighting Services, as required by clauses 6.3.1(c)(1) and S6.1.3(10) of the Rules;
- Section 53.19 calculates the Annual Revenue Requirement for Street Lighting Services. It provides information in relation to:
  - → The regulatory asset base to address section 2.4.6(a)(3)(i) of the RIN;
  - → The indexation of the regulatory asset base to address section 2.4.6(a)(3)(ii) of the RIN;
  - → The return on capital to address clause 6.5.2(b) of the Rules and section 3.4.3 of the AER's F&A Stage 1;

- Depreciation to address clause 6.5.5(a) of the Rules;
- Corporate income tax to address clause 6.5.3 of the Rules;
- Operating expenditure in accordance with clause 6.5.6 of the Rules.

- Section 53.19.7 details the X factors for street lighting for the next regulatory control period;
- Section 53.20 demonstrates Ergon Energy's application of the control mechanism for Street Lighting Services to address section 2.4.6(a)(1)(ii) of the RIN; and
- Section 53.21 details actual and indicative prices for Street Lighting Services to address sections 2.2.5(a)(4) and (5) of the RIN.

53.1 OVERVIEW OF NATURE AND TYPES OF STREET LIGHTING SERVICES

Section 2.4.6(a)(1)(i) of the RIN requires that Ergon Energy provide an overview of Street Lighting Services provided by Ergon Energy.

The street lighting system includes the luminaire, lamp, LV supply and the photo-electric cells on the following:

- Pole-mounted street lights on major and minor roads including pedestrian crossings and major intersections forming part of the gazetted retail Rate 1 and retail Rate 2 lighting;
- Catenary lights on major and minor roads;
- Watchman lighting;[113]
- Waterways/crossing signage lighting; and
- Nostalgic lighting.

Under the current arrangements in Queensland, street lighting customers may engage Ergon Energy to construct and/or maintain street lighting assets in the Ergon Energy network area or may engage alternative providers to supply these services. Accordingly, there are three possible street lighting arrangements:

- Street lights are supplied, owned, installed and maintained by Ergon Energy;
- Street lights are funded by others and ownership of the installation is vested in Ergon Energy. Ergon Energy then assumes responsibility for maintenance of the installation; or
- Street lights are owned, installed and maintained by others. Ergon Energy provides only electrical energy to the installation.

At present Ergon Energy owns and maintains approximately 93,950 minor and 32,270 major lights.[114]

For the purposes of this Regulatory Proposal, Ergon Energy has identified three categories of Street Lighting Services:

- Street Lighting Service 1 - Provision of new street lighting assets. These assets are funded by third parties and include assets that Ergon Energy has built as well as those built by third parties and gifted to Ergon Energy. Where Ergon Energy builds these assets, this Alternative Control Service will be charged on a quoted fee basis depending on the type of asset sought. For this reason, this type of Street Lighting Service is not addressed in this Chapter but is instead addressed in Chapter 54 of this Regulatory Proposal;
- Street Lighting Service 2 - Operation, repair, replacement and maintenance of street lighting assets. This service relates to the operation, repair, replacement and maintenance of the existing stock of street lighting assets as at 30 June 2010, as well as the operation, repair and maintenance of new street lighting assets that are installed (by Ergon Energy or by third parties and gifted to Ergon Energy) in the next regulatory control period. This Alternative Control Service is subject to a price cap control mechanism. This service does not include operation, repair, or maintenance of street lights that are owned by parties other than Ergon Energy. This type of Street Lighting Service is addressed in this chapter of the Regulatory Proposal. Unless othewise stated, further reference to 'Street Lighting Services' in this chapter relates to Street Lighting Services 2; and
- Street Lighting Service 3 - Alteration and relocation of existing street lighting assets. These services relate to the physical alteration and relocation of existing street lighting assets, for example as a result of a street widening, and Ergon Energy installing new street lighting assets. This Alternative Control Service will be charged on a quoted fee basis in the same manner as Ergon Energy would charge for its other Alternative Control Services that are to be treated as Quoted Services. For this reason, this type of Street Lighting Service is not addressed in this chapter but is instead addressed in Chapter 54 of this Regulatory Proposal.

Ergon Energy notes that these are the same three categories of services as the AER has specified in its Framework and Approach paper for the Victorian DNSPs for their next regulatory control period commencing on 1 January 2011.

[113] Watchman lights are an unregulated service and thus the expenditures are excluded from the assets and expenditures provided in this proposal

[114] Major road lighting is defined as high intensity lighting (lamp equal to or greater than 100W) installed on major roads, roundabouts and high traffic areas such as pedestrian crossings.

53.2 CONTROL MECHANISMS

53.2.1 Regulatory Requirements

There are a range of requirements under Chapter 6 of the Rules and the AER's F&A Stage 1 that determine the way in which Ergon Energy's Street Lighting Services are to be regulated.

Clause 6.2.6(b) of the Rules states that "for alternative control services, the control mechanism must have a basis stated in the distribution determination".

Clause 6.2.6(c) of the Rules provides that "the control mechanism for alternative control services may (but need not) utilise elements of Part C (with or without modification)". The Rules also provides, as an example, that "the control mechanism might be based on the building block approach".

Clause 6.8.1(c) of the Rules states that "The framework and approach paper must state the form (or forms) of the control mechanisms to be applied by the distribution determination and the AER's reasons for deciding on control mechanisms of the relevant form (or forms).

Clause 6.8.2(c)(3) of the Rules states that "A regulatory proposal must include… for direct control services classified under the proposal as alternative control services – a demonstration of the application of the control mechanism, as set out in the framework and approach paper, and the necessary supporting information".

Clause 6.12.1(12) and (13) state that a distribution determination is predicated on constituent decisions by the AER on the control mechanism for Alternative Control Services (to be in accordance with the relevant Framework and Approach paper), and on how compliance with a relevant control mechanism is to be demonstrated.

Clause 6.12.3(c) requires that "the control mechanisms must be as set out in the relevant framework and approach paper".

Clause S6.1.3(6) provides that a building block proposal must contain at least "the provider's calculation of revenues or prices for the purposes of the control mechanism proposed by the provider together with:

- details of all amounts, values and inputs (including X factors) relevant to the calculation;
- an explanation of the calculation and the amounts, values and inputs involved in the calculation; and
- a demonstration that the calculation and the amounts, values and inputs on which it is based comply with relevant requirements of the Law and the Rules".

Section 3.5.2 of the AER's F&A Stage 1 provided that "the AER will apply a limited building block approach to determine the efficient costs of providing Street Lighting Services under the price cap control mechanism in the first regulatory year of the regulatory control period and establish a price path for remaining regulatory years of the period".

Section 3.4.3 of the AER's F&A Stage 1 also provided that:

- Ergon Energy is not required to provide a separate proposal on the Weighted Average Cost of Capital (WACC) for Alternative Control Services. The AER will apply the same WACC to Street Lighting Services that is applied to Standard Control Services;
- Ergon Energy may propose reasonable simplifying assumptions within the limited building block model. In particular, the AER will accept the current depreciation assumptions; and
- Ergon Energy may base its opening asset valuation for Street Lighting Services on the existing asset valuation, adjusted for capital expenditure and depreciation incurred in the current regulatory period. If Ergon Energy proposes to retain the current treatment of the Regulatory Asset Base (RAB) as permitted under clause 11.16.3 of the Rules the AER considers the opening asset valuation for Street Lighting Services should be derived consistent with that method.

Ergon Energy interprets these requirements to mean that:

- The control mechanism for Street Lighting Services is a price cap, with the initial values to be calculated by a limited building block method, as set out in the Framework and Approach Paper - this is based on clause 6.12.3(c) and 6.8.1(c) of the Rules;
- It may propose deviations from Part C of Chapter 6 of the Rules that would apply to the calculation of the building block – this is based on clause 6.2.6(c) of the Rules and the AER's F&A Stage 1;
- It may propose simplifying assumptions in relation to the limited building block model – this is based on the AER's F&A Stage 1; and

- It must set out the calculation of revenues for the purposes of the control mechanism – this is based on clause S6.1.3(6) of the Rules - and it must demonstrate the application of the control mechanism in the Regulatory Proposal – this is based on clause 6.8.2(c)(3) of the Rules.

53.2.2 Street Lighting Services 1 and 3

These services relate to Ergon Energy installing new street lighting assets and the physical alteration and relocation of existing street lighting assets, for example as a result of a street widening. The defining characteristics of these services are that they are requested by a specific customer and the service that is provided must be tailored to that customer. Because the cost of these services relate specifically to the customer's request, the prices for these services must also be tailored specifically to the individual customer.

It is therefore proposed that Ergon Energy charge for these services on a quoted fee basis in the same manner as it would charge for its other Alternative Control Services that are to be treated as Quoted Services. This reflects the fact that all of these services need to be costed and priced on a customer-specific basis having regard for the specific requirements of the customer. A fixed price cannot be determined in advance based on a forecast of costs and volumes. This formula for Quoted Services is set out in Chapter 54 of this Regulatory Proposal.

Under this approach, Ergon Energy would charge customers up-front for the provision of these services. There would be no ongoing charge that would apply to them for these services.

It is considered that this approach complies with the requirements of the AER's F&A Stage 1 for Street Lighting Services to be regulated under a building block approach and a price cap because:

- The building block would be the build-up of the actual costs of altering or relocating existing street lights, or installing new street lights, on an individual customer-by-customer basis – rather than for the aggregate of Street Lighting Services on a prospective basis; and
- Prices would be capped on an individual customer basis by applying the formula detailed in Chapter 54.

53.2.3 Street Lighting Service 2

Consistent with the AER's F&A Stage 1, it is proposed that Ergon Energy apply a 'limited' building block approach to this Street Lighting Service by:

- Establishing a separate Alternative Control Services' street lighting Regulatory Asset Base by removing the existing street lighting assets from the Regulatory Asset Base for Standard Control Services.

The existing asset values would be used to determine the opening street lighting RAB value. This street lighting RAB would be adjusted using the AER's PTRM by:

  - → Adding replacement street lighting capital expenditure at full value over the next regulatory control period to the opening street lighting RAB;
  - → Adding new street lighting capital expenditure in the next regulatory control period at zero value to the street lighting RAB in the regulatory year in which the asset is commissioned. These new assets include assets that Ergon Energy has built as well as those built by third parties and gifted to Ergon Energy; and
  - → Deducting depreciation on existing assets.

- Calculating an Annual Revenue Requirement (ARR) for this service using the AER's PTRM, which would include the sum of:
  - → A return on the street lighting Regulatory Asset Base by applying the same WACC to Street Lighting Services that is to be applied to Standard Control Services;
  - → A return of the street lighting RAB (i.e. depreciation);
  - → Operating and maintenance expenditure relating to existing and new street lighting assets; and
  - → An allowance for corporate income tax.

Once the street lighting ARR has been determined, Ergon Energy will determine:

- A dollar per regulatory year charge for different types of street lights for the first regulatory year of the regulatory control period. This price cap will be levied on all existing and new street lighting customers; and
- A proposed price path for the dollar per regulatory year charges for regulatory years two to five of the regulatory control period.

It is considered that this approach complies with the requirements of the AER's F&A Stage 1 for Street Lighting Services because it applies:

- A building block approach (being a modification of the approach in Part C of Chapter 6 of the Rules); and
- A price cap control mechanism to the regulation of Street Lighting Services.

53.2.4 Meeting the Requirements of Part C of Chapter 6 of the Rules

As discussed above, Street Lighting Services 1 and 3 are to be charged on a quoted fee basis depending on the service configuration required. Accordingly, Part C of Chapter 6 of the Rules is not applicable to these Street Lighting Services, albeit that the control mechanism will still apply a building block approach and a cap on individual customer prices.

In relation to Street Lighting Service 2 - Operation, repair, replacement and maintenance of street lighting assets, Ergon Energy has applied Part C of Chapter 6 of the Rules as shown below.

Rules Part C	Topic	Application	Regulatory Proposal section
6.3.1	Application of Building Block Approach	Yes – without modification	53.6
6.3.2	Commencement and Length of Regulatory Control Period	Yes – without modification	53.7
6.4	Post Tax Revenue Model	Yes – without modification	53.18
6.5.1	Regulatory Asset Base	Yes – without modification	53.19.1 and 53.19.2
6.5.2	Return on Capital	Yes – without modification	53.19.3
6.5.3	Estimate of Corporate Income Tax	Yes – without modification	53.19.5
6.5.4	Review of Rate of Return	Yes – without modification	53.19.3
6.5.5	Depreciation	Yes – without modification	53.19.4
6.5.6(a)	Operating expenditure objectives	Yes – only clause 6.5.6(a)	53.8 & 53.14
6.5.6(b)	Operating expenditure information	Yes – without modification	53.13
6.5.6(c)	Operating expenditure criteria	Yes – without modification	53.14
6.5.6(d)	Operating expenditure acceptance	Yes – without modification	Not required
6.5.6(e)	Operating expenditure factors	Yes – only clause 6.5.6(e)(1)(2)(3) & (5)	53.12, 53.13 & 53.14
6.5.7(a)	Capital expenditure objectives	Yes – only clause 6.5.7(a)	53.11
6.5.7(b)	Capital expenditure information	Yes – without modification	53.10
6.5.7(c)	Capital expenditure criteria	Yes – without modification	53.11
6.5.7(d)	Capital expenditure acceptance	Yes – without modification	No information required
6.5.7(e)	Capital expenditure factors	Yes – only clause 6.5.7(e)(1)(2)(3) & (5)	53.9, 53.10 & 53.11
6.5.8	Efficiency Benefit Sharing Scheme	No	-
6.5.9	X factor	Yes – without modification	53.19.7
6.6.1	Cost Pass Through	Yes – without modification	53.16
6.6.2	Service Target Performance Incentive Scheme	No	-
6.6.3	Demand Management Incentive Scheme	No	-

53.3 SERVICE LEVEL INFORMATION – DELIVERY OF TARGETS

Section 2.4.6(a)(5) of the RIN requires that Ergon Energy provide, in relation to Street Lighting Services, information to support the application of the proposed control mechanism, including a demonstration of how the forecast expenditures will deliver target levels of service.

There are no target levels of service for Street Lighting Services.

53.4 REVENUE FOR STREET LIGHTING SERVICES FOR 2005-10 BY REGULATORY YEAR

Section 2.2.5(a)(3) of the RIN requires that Ergon Energy provide, for Alternative Control Services in the Regulatory Proposal, the revenue earned for equivalent services provided in each regulatory year of the current regulatory control period (provide an estimate of revenues for the final two regulatory years of the current regulatory control period).

Ergon Energy cannot provide this information to the AER. This is because there were no equivalent Street Lighting Services provided during the current regulatory period due to the re-classification of Street Lighting Services from Standard Control Services to Alternative Control Services. Ergon Energy's revenue data relates to the service of conveyancing to street lights (which is still a Network Service and therefore a Standard Control Service), as well as maintenance and construction services.

53.5 CUSTOMER NUMBERS FOR STREET LIGHTING SERVICES FOR 2005-10 BY REGULATORY YEAR

Section 2.2.5(a)(2) of the RIN requires that Ergon Energy provide, for Alternative Control Services in the Regulatory Proposal, actual customer numbers (or job numbers where applicable) for equivalent services provided in each regulatory year of the current regulatory control period, including estimates for the final two regulatory years of the current regulatory control period.

Ergon Energy notes that these Street Lighting Services were not separately identified during the current regulatory control period. The only historical information available relates to the number of street lighting connections. This information is provided in Table 144.

Table 144: *Connections – Street Lighting Services (Numbers)*

	2005-06	2006-07	2007-08	2008-09 Estimate	2009-10 Estimate
Street Lighting	120,608	123,382	126,220	129,123	132,092

Source: NARMCOS Data Model.

53.6 APPLICATION OF BUILDING BLOCK APPROACH

As discussed above, Ergon Energy has applied clause 6.3.1 of the Rules without modification to Street Lighting Service 2. Clause 6.3.1(c) requires:

- The application of the AER's PTRM, other relevant requirements of Part C of Chapter 6, and clause S6.1 of the Rules; and
- Compliance with the requirements of, and the inclusion of information required by, any relevant regulatory information instrument.

Ergon Energy confirms that in this Regulatory Proposal it has applied a building block approach in accordance with the PTRM, other relevant requirements of Part C of Chapter 6 and clause S6.1 of the Rules, as well as the AER's RIN.

53.7 COMMENCEMENT AND LENGTH OF REGULATORY CONTROL PERIOD

Ergon Energy has applied clause 6.3.2 of the Rules without modification.

Clause 6.3.2(4) imposes requirements on the AER in relation to determining the commencement and length of the regulatory control period.

Ergon Energy proposes that the regulatory control period for Street Lighting Service 2 will be five regulatory years, commencing from 1 July 2010 and ending on 30 June 2015.

53.8 DEMAND FORECASTS (SYSTEM ONLY)

Section 2.4.6(a)(4) of the RIN requires that Ergon Energy provide, for Street Lighting Services in the Regulatory Proposal, demand information, including historic and forecast demand for Street Lighting Services as well as a justification for any material differences between historic and forecast demand.

Ergon Energy's Street Lighting Service 2 involves the building and maintenance of assets that is not dictated by energy usage. Demand for these services is therefore best represented as numbers of streetlights rather than energy usage. Historical street lighting customer information has been provided in section 53.5 of this Regulatory Proposal. Forecast street lighting customer information is set out in the Table 145. It should be noted that the RIN pro forma 2.3.8 contains street lighting customer numbers that are used for network pricing purposes and are drawn from the network billing system.

Table 145: *Connections – Street Lighting Services (Numbers)*

	2010-11	2011-12	2012-13	2013-14	2014-15
Street Lighting	135,131	138,239	141,419	144,671	147,999

Source: NARMCOS Data Model

The forecast growth of 2.3 per cent per annum detailed in Table 145 is based on the average growth in customer connections over the four regulatory years to 2007-08.

There are therefore no material differences between historic and forecast demand for Street Lighting Services.

53.9 CAPITAL EXPENDITURE – HISTORIC AND FORECAST

Sections 2.2.1(a)(3) and 2.4.6(a)(2) of the RIN requires that Ergon Energy provide in this Regulatory Proposal historic and forecast capital and operational expenditure information and justifications for any material differences between historic and forecast capital and operating expenditures.

Ergon Energy's historic capital expenditure for the current regulatory control period is set out in Table 146. Ergon Energy has provided historic capital expenditure for the previous regulatory control period (2001-2005) in the accompanying RIN. However, Ergon Energy does not have data, and is therefore unable to provide further information, about expenditure for the previous regulatory control period.

In addition, the Queensland Competition Authority (QCA) did not prepare a separate building block for Street Lighting Services. Rather the street lighting amount was included in the building block for prescribed distribution services. Furthermore, the expenditure information in Table 146 relates to Street Lighting Services 1 and 2, in relation to new street lighting connections and the replacement of existing street lighting assets. They do not relate to Street Lighting Service 3, which concerns the alteration and relocation of street lighting assets. As a result, Ergon Energy is not able, and does not have information, to compare actual/forecast expenditure to a street lighting building block for the previous and current regulatory control periods. Ergon Energy's records do not enable it to separate out new and replacement street lighting expenditure for the current regulatory control period.

Table 146: *Capital Expenditure – Street Lighting Services – 2005-06 to 2009-10 ($M Nominal)*

	2005-06	2006-07	2007-08	2008-09 Estimate	2009-10 Estimate	5 Year Total	Average of 5 Year Total
Street Lighting	**3.00**	**10.86**	**10.77**	**1.78**	**2.73**	**29.13**	**5.83**

Source: Tables for Proposal 53.9

Ergon Energy's forecast capital expenditure for the next regulatory control period is set out in Table 147.

Table 147: *Capital Expenditure – Street Lighting Services – 2010-11 to 2014-15 ($M Real $2009-10)* [1]

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Street Lighting	2.75	3.14	3.54	4.28	4.97	18.68	3.74

Source: Tables for Proposal 53.9

1 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

These values relate only to replacement capital expenditure for Street Lighting Service 2.

Because Table 146 relates to new and replacement capital expenditure (in Nominal dollars) and Table 147 relates only to replacement capital expenditure (in Real $2009-10) they are not strictly comparable for the purposes of section 2.2.4(a) of the RIN.

However, Ergon Energy notes that the increase in capital expenditure from 2008-09 to 2009-10 reflects Ergon Energy's decision to implement a three regulatory year Bulk Lamp Replacement (BLR) cycle (from the previous four regulatory year cycle) and the extension of this program from minor roads only to include major roads. In addition, the increase from 2010-11 to 2011-12 reflects the implementation of a program to replace obsolete luminaires with energy efficient luminaires. Further discussion of this program is provided below.

53.10 CAPITAL EXPENDITURE – FORECAST AND JUSTIFICATION

This section overviews Ergon Energy's capital expenditure forecasts for Street Lighting Services 2 for the regulatory control period 1 July 2010 to 30 June 2015 (see Table 148).

Replacement capital expenditure is required for Street Lighting Service 2.

Capital expenditure is required for Street Lighting Service 1 and 3, however this is to be recovered on a quoted fee basis, depending on the requirements of the requested work. Accordingly, the values associated with these services are not included in the capital expenditure forecasts for 2010-15.

Table 148: Capital Expenditure – Street lighting – 2010-15 ($M Real $2009-10)

	2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
Street Lighting	11.26	1.78	2.73	2.75	3.14	3.54	4.28	4.97	18.68	3.74

Source: Tables for Proposal 53.10.1

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10).

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

53.10.1 Forecast 2010-15

Ergon Energy's forecast capital expenditure associated with Street Lighting Services 2 for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 148.

The key drivers of the street lighting capital expenditure program in the next regulatory control period are:

- The forecast Preventive Maintenance program and the consequent identification of defective street lighting assets that require replacement; and
- The Queensland Government and Queensland Local Councils' initiative to deploy more energy efficient street lighting.

53.10.2 What the Forecast Relates to

Ergon Energy's street lighting capital expenditure for Street Lighting Service 2 comprises the following activities:

- Replacement of luminaires;
- Replacement of luminaire brackets;
- Replacement of poles;
- Replacement and disposal of asbestos sealed luminaires; and
- Upgrade to energy efficient luminaires.

53.10.2.1 Replacement of luminaires, luminaire brackets and street lighting poles

The condition of luminaires, luminaire brackets and street lighting-only poles is assessed as part of Ergon Energy's Preventive Maintenance program. The Preventive Maintenance program refers to scheduled activity that is carried out at predetermined intervals for the purpose of inspection, condition monitoring, servicing or examination. The Preventive Maintenance program identifies defects according to strict criteria and defects are categorised in line with Ergon Energy's Defect Management Policy. Defects have varying remediation periods depending upon asset type, assigned priority and regulatory requirements.

The condition of these assets is specifically assessed as part of Ergon Energy's four regulatory yearly Overhead and Underground Line Inspection program and the BLR program (set out in Ergon Energy's Network Preventive Maintenance programs). Luminaires and brackets found to be defective as part of the BLR program are replaced when the lamp is replaced in accordance with Ergon Energy's L1 defect policy set out in Ergon Energy's Defect Management Policy. Similarly, street lighting only poles are replaced based on their condition, as set out in Ergon Energy's Defect Management Policy.

This type of capital expenditure relates to assets that have failed or are imminently about to fail. It therefore seeks to avoid the need for Corrective and Forced Maintenance expenditure associated with assets in poor condition or beyond their economic or useful lives by providing for equipment to be replaced in an orderly manner.

Expenditure associated with the replacement of poles relates to both the replacement of dedicated street lighting poles and the replacement of poles with street lights attached (where these poles are used for other purposes such as the distribution of electricity). The forecast replacement expenditure associated with all poles in the Ergon Energy network (including street lighting and other poles) is discussed in Chapter 23. Ergon Energy has attributed a portion of forecast replacement expenditure associated with these poles to street lighting to reflect the fact that Street Lighting Services utilise these poles.

53.10.2.2 Replacement and disposal of asbestos sealed luminaires

In order to effectively manage its organisational risks, and to promote public safety, Ergon Energy instituted a program in 2008-09 to replace and dispose of asbestos sealed luminaires. Based on management estimates of the number of these assets in the street lighting population, Ergon Energy has forecast a continuation of this program to the end of the next regulatory control period.

53.10.2.3 Upgrade to energy efficient luminaires

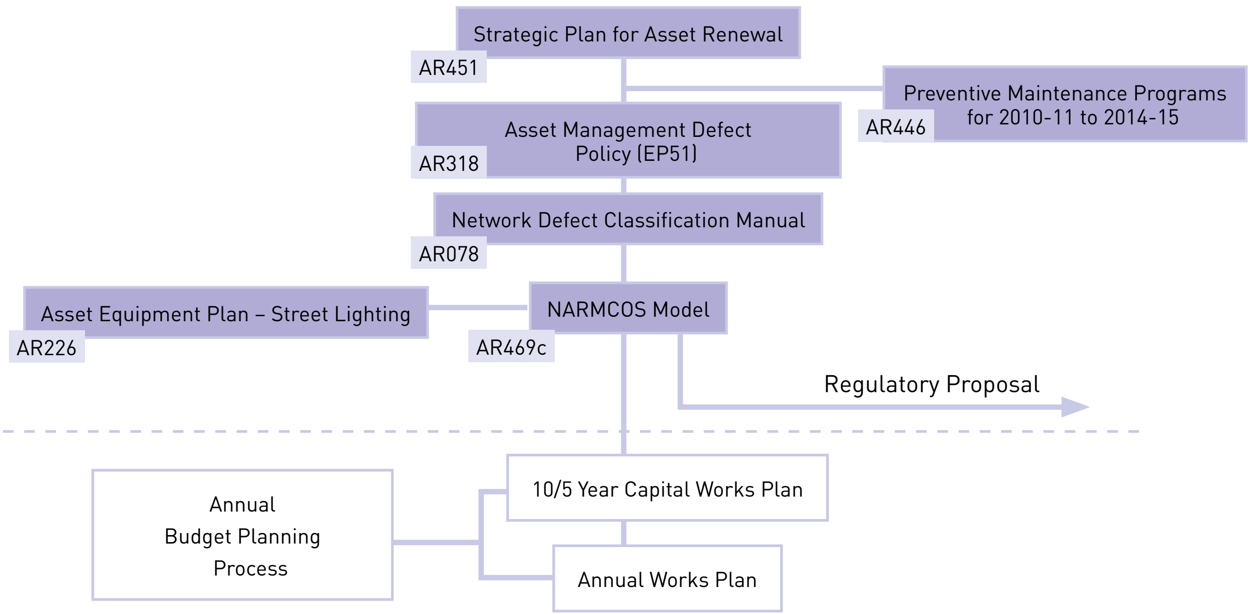
Ergon Energy is a participant in the Queensland Government 'Queensland Energy Efficient Street Lighting Trial.' The trial is a joint exercise with ENERGEX and is designed to collect data on the performance of various lamp technologies under a range of environmental and network conditions.

Arrangements for the trial were initiated in 2007. The trial involves the operation and monitoring of the lamps, and involves installations across 13 locations throughout south-east Queensland and two locations in regional Queensland. Installation of lamps in ENERGEX's area in south-east Queensland has commenced and installation of 102 lamps in Ergon Energy's Cairns and Mount Isa regions is programmed for mid-2009.

The trial will analyse lamp performance and recommended the most appropriate lamps for particular environmental conditions. The trial will also assess the expected greenhouse gas savings and operational and maintenance costs of using the trialled lamp types.

Ergon Energy anticipates that this trial will result in the rollout of the chosen luminaire across the Ergon Energy network. Ergon Energy has therefore forecast a rollout of replacement energy efficient luminaires commencing in 2011-12.

Figure 65: *Capital Expenditure – Street Lighting Service 2*



53.10.3 Estimation Process

An overview of how Ergon Energy has prepared its capital expenditure - Street Lighting Service 2 forecasts for the next regulatory period is provided in Figure 65. The Defect Management Policy details how Ergon Energy will assess when asset replacements are needed in order to avoid an asset failing prior to its next inspection and to mitigate the need for forced operating expenditure.

The Strategic Plan for Asset Renewal commits Ergon Energy to keeping its network assets fit for purpose and in a safe and environmentally sound condition so as to minimise the risk of condition-based and age-related failures.

The document entitled Network Preventive Maintenance Programs for 2010-11 – 2014-15 outlines the asset management policies underpinning the Preventive Maintenance programs and work plans within Ergon Energy for the five regulatory years commencing from 2010-11. While this document details Preventive Maintenance programs and work plans, these dictate the street lighting replacement requirements.

The Asset Equipment Plan (AEP) sets out the asset management methodology for Ergon Energy's street lighting assets. The AEP provide detailed discussions of growth rates, and cycle times and identifies new Preventive Maintenance programs.

The Defect Management Policy describes the way in which Ergon Energy will classify its defects and sets timeframes in which classified defects will be repaired. The Network Defect Classification Manual is designed to assist asset inspectors to identify defects accurately in the field across all of Ergon Energy's classes of system assets. It details the way in which inspections and assessments are to be undertaken for each class of system assets.

53.10.3.1 Replacement of luminaires and brackets

Forecast capital expenditure associated with the replacement of luminaires and brackets is derived from Ergon Energy's Network Assets Replacement Maintenance Capex Opex Summary (NARMCOS) model and is based on:

- The historical proportion of replacements identified as part of Ergon Energy's BLR program; and
- The total cost of replacing a single luminaire or luminaire bracket - generally Ergon Energy replaces like for like, with the exception of obsolete types. The unit rates do not change over the five regulatory years and are based on historical expenditure. Escalation of these unit rates is performed separately from NARMCOS. This process is discussed in Chapter 33 of this Regulatory Proposal.

The increase in capital expenditure for replacement luminaires and brackets between 2008-09 and 2009-10 reflects the movement from a four regulatory year to a three regulatory year BLR program and the extension of the program from minor roads only to include major roads. While the replacement of luminaires and brackets as a proportion of inspections is expected to remain at historic levels, the absolute number of replacements will increase as the number of assets inspected increases as a result of changes to the BLR program.

53.10.3.2 Replacement of poles

Forecast capital expenditure associated with the replacement of dedicated street lighting poles and the replacement of poles with street lights attached is derived from Ergon Energy's NARMCOS model and is based on:

- Identifying the number of street lights in the total pole population; and
- The proportion of the forecast costs associated with the replacement of poles that can be attributed to street lights.

53.10.3.3 Replacement and disposal of asbestos sealed luminaires

Forecast capital expenditure associated with the replacement and disposal of asbestos sealed luminaires is derived from Ergon Energy's NARMCOS model and is based on:

- Continuation of the current 100 replacements per regulatory year until the end of the next regulatory control period; and
- The total cost of replacing and disposing of an asbestos sealed luminaire. This cost reflects the current cost associated with the activity and is not expected to change over the regulatory control period. Escalation of these unit rates is performed separately from NARMCOS. This process is discussed in Chapter 33 of this Regulatory Proposal.

53.10.3.4 Upgrade to energy efficient luminaires

Forecast capital expenditure associated with the upgrade to energy efficient luminaires is derived from Ergon Energy's NARMCOS model and is based on:

- A ramp-up of replacements from 500 per annum commencing in 2011-12 to 3,000 per annum by the end of the next regulatory control period. This escalation reflects the phased rollout of the new energy efficient luminaires; and
- The total cost of replacing the old luminaires with energy efficient luminaires. This cost reflects the anticipated cost associated with the activity and is not expected to change over the regulatory control period. Escalation of these unit rates is performed separately from NARMCOS. This process is discussed in Chapter 33 of this Regulatory Proposal.

53.10.4 Assumptions

The assumptions underlying the Street Lighting Service 2 include:

- The Network Defect Classification Manual reflects the risk profile that Ergon Energy is adopting for the 2010-15 regulatory control period. Defect-related capital expenditure represents an out-working of the Preventive Maintenance inspection program;
- Defect remediation is capitalised based on Ergon Energy's current capitalisation procedures and criteria contained within document "P89C01R31 v4 Property Plant & Equipment";
- Replacement forecasts are based on estimated defect rates arising from the quantity of inspections to be undertaken;
- Replacement of poles is based on the assumption that the total replacement cost of a pole with a major street light attached is attributable to street lighting whereas only one third of the replacement cost of a pole with a minor street light attached is attributable to street lighting;
- A rollout of energy efficient luminaires will to commence following the completion of the Queensland Energy Efficient Street Lighting Trial; and
- Capital expenditure forecasts for the replacement of asbestos sealed luminaires are based on management estimates of the number of asbestos sealed luminaires in Ergon Energy's street lighting asset population.

53.10.5 Capital Expenditure / Operating Expenditure Interactions

There is a strong relationship between the street lighting capital expenditure forecast and:

- The Preventive Maintenance program, which drives the defect related asset replacement capital expenditure forecast for luminaires and luminaire brackets. For example, if more inspections are undertaken, it is likely that more defects will be identified and require rectification (as per the move from a four regulatory year to a three regulatory year BLR program). The converse is also true if fewer inspections are undertaken;
- Defect expenditure offsets Corrective and Forced Maintenance expenditure. Reducing defect expenditure will likely result in a need for increased corrective and Forced Maintenance because defects will not be identified, and addressed. This will increase the probability of assets failing, which will need to be addressed through the other maintenance programs;
- Reducing defect expenditure will increase the risk of asset failures in service, increase Dangerous Electrical Events and cause hazards to staff and public; and
- The replacement of asbestos sealed luminaires and the upgrade to efficient luminaires is expected to reduce operating and maintenance expenditure and reduce potential liability claims from staff and the public.

53.10.6 Justification of the Forecasts

Ergon Energy seeks to rectify defects and condition-based deterioration before assets fail, however this expenditure involves replacing assets that have failed or are assessed as about to fail before the next inspection. Asset Replacement expenditure is therefore designed to ensure that Ergon Energy:

- Minimises the failure of street lights and problems with the quality of street lighting for customers, as well as safety risks to the public and Ergon Energy staff, by undertaking pre-emptive expenditure;
- Avoids the need to incur Corrective and Forced Maintenance expenditure to address asset failures. The planned management of asset replacement results in operating expenditure savings and avoids the need for asset replacements under emergency conditions, including by avoiding callouts and overtime;
- Meets various regulatory and other obligations, such as:
  - → Comply with the minimum Street Lighting Service availability of 95 per cent set out in AS/NZS 1158 "Lighting for Roads and Public Spaces";
  - → Reducing the risk of working with lights with asbestos seals; and
  - → Mitigating public liability risk to Ergon Energy.

53.10.7 Risk Considerations

Ergon Energy has been involved in several legal proceedings that investigated a fatality or injury to a member of the public where a lighting outage was considered as a likely contributor to the incident's occurrence. Ergon Energy has an obligation to maintain public lighting in accordance with AS/NZS 1158, which states that the "service availability should be at least 95%". By implementing strategies to meet AS/NZS 1158, Ergon Energy will ensure the safety risk to the public is minimised and the risk of litigation or prosecution is minimised to Ergon Energy. Ergon Energy's Public Liability Maintenance Strategy provides further information about public lighting maintenance.

Ergon Energy's street lighting capital expenditure forecast is seeking to:

- Prevent any non-compliance with the Street Lighting Service availability recommendations set out in AS/NZS 1158;
- Ensure that the safety of the public and Ergon Energy's staff is maintained; and
- Minimise costs associated with the provision of street lighting through the early detection and replacement of defective street lights thus mitigating the need for forced and Corrective Maintenance.

53.10.8 Customer Outcomes

The capital expenditure program is intended to minimise the probability of street light failure, minimise total life cycle cost, meet required operating conditions and performance standards, and keep Ergon Energy's staff and the public safe. By reducing unplanned asset failures, Ergon Energy seeks to reduce the risk to the public.

A cut in capital expenditure forecast would:

- Increase the risk of street light failure;
- Expose Ergon Energy to potential non-compliance with required street lighting standards;
- Expose the public and Ergon Energy to increased risk; and
- Expose Ergon Energy to potential litigation.

53.11 CAPITAL EXPENDITURE – OBJECTIVES, CRITERIA AND FACTORS

Chapter 24 of this Regulatory Proposal details the nature, and Ergon Energy's interpretation, of the capital expenditure objectives, criteria and factors in clause 6.5.7 of the Rules. This is equally applicable to Ergon Energy's Street Lighting Service 2.

This section demonstrates how Ergon Energy's forecast capital expenditure for Street Lighting Services 2 for the next regulatory control period achieves the capital expenditure objectives, having regard for the capital expenditure criteria and capital expenditure factors.

53.11.1 Capital Expenditure Objectives

Ergon Energy considers that its forecast capital expenditure will enable it to deliver the performance outcomes in the next regulatory control period that are required by clause 6.5.7(a) of the Rules. This means that its forecast capital expenditure will result in capital works so that Ergon Energy can:

- Meet or manage the demand for Street Lighting Services 2; and
- Comply with regulatory obligations that apply to Street Lighting Services 2.

Ergon Energy notes that there are no specific service standards that apply to Street Lighting Services 2 so that clauses 6.5.7(a)(3) and (4) have not been addressed for these services.

The demand for Ergon Energy's Street Lighting Service 2 is dictated by customer demand for street lights (rather than for energy demand) and the need for Ergon Energy to maintain street lighting assets at an acceptable standard. Ergon Energy's street lighting replacement capital expenditure forecasts are directly related to the forecast increase in the population of street lights, which Ergon Energy must maintain. In addition, capital expenditure is needed in order to replace defective assets identified as part of Ergon Energy asset inspection cycles. The replacement of these assets and the length of inspection cycles are designed to ensure that Ergon Energy maintains a safe and efficient level of service in compliance with AS/NZS 1158.

Similarly, capital expenditure related to the rollout of efficient luminaires and the replacement of asbestos sealed luminaires is provided in response to Queensland Government initiatives and in order to ensure the safety of Ergon Energy staff and the public.

Ergon Energy believes its forecast capital expenditure will deliver the capital expenditure objectives for the following reasons:

- Nature of activities – Ergon Energy's capital expenditure for Street Lighting Services 2 relates to asset replacement. Increasing Asset Replacement expenditure will reduce the average lives of Ergon Energy's assets, which will, in turn, reduce the number of asset failures requiring Corrective and Forced Maintenance. The activity that is undertaken as part of this program is therefore critical to ensuring the long-term serviceability of street lighting assets, especially to meet safety requirements;
- Plans, policies, procedures and strategies - As discussed in section 53.10 of this Regulatory Proposal, Ergon Energy uses a series of plans, policies, procedures and strategies to develop and implement its capital expenditure program for the next regulatory control period. Ergon Energy believes that these will enable it to achieve the capital expenditure objectives in the next regulatory control period because they ensure that its capital expenditure forecasts have regard for Ergon Energy's and customers' drivers of capital expenditure and the need to comply with relevant regulatory obligations;
- Estimation process to prepare capital expenditure forecasts - section 53.10 of this Regulatory Proposal details the estimation processes that Ergon Energy has used to prepare each sub-category of its capital expenditure forecasts. Ergon Energy believes that these processes support the development of prudent and efficient capital expenditure forecasts that will achieve the capital expenditure objectives in the next regulatory control period. This is because Ergon Energy's estimation approach effectively translates its plans, policies, procedures and strategies into capital expenditure forecasts for the next regulatory control period; and
- Deliverability of expenditure program - Chapter 35 of this Regulatory Proposal explains how it will resource the delivery of its capital expenditure program in the next regulatory control period, including on street lighting. It follows, given the justifications of the forecast capital expenditure provided above, that Ergon Energy also believes that the physical delivery of its capital expenditure program will ensure that it achieves the capital expenditure objectives detailed in clause 6.5.7(a) of the Rules in the next regulatory control period.

53.11.2 Capital Expenditure Criteria and Factors

Ergon Energy considers that its forecast capital expenditure reasonably reflects the capital expenditure criteria in clause 6.5.7(c) of the Rules having regard for the capital expenditure factors in clause 6.5.7(e) of the Rules. However, Ergon Energy considers that the only sub-clauses of clause 6.5.7(e) that should be applied to Street Lighting Service 2 are clause 6.5.7(e)(1), (2), (3) and (5). Only clauses 6.5.7(e)(1) and (5) require Ergon Energy to provide information as part of this Regulatory Proposal.

Ergon Energy considers that its forecast capital expenditure is consistent with the efficient costs that a prudent operator would incur in Ergon Energy's circumstances to achieve the capital expenditure objectives, based on realistic demand forecasts and cost inputs.

The matters that Ergon Energy believes the AER should consider under clause 6.5.7(e)(1) are as follows:

- Circumstances in which Ergon Energy operates - these circumstances are set out in section 4.19 of this Regulatory Proposal. These circumstances affect all aspects of Ergon Energy's capital investment decision making in relation to its street lighting assets. The plans, policies, procedures and strategies referred to in section 53.10 of this Regulatory Proposal provides further detail about how Ergon Energy's circumstances are reflected in its capital expenditure forecasts;
- Ergon Energy's estimation processes - Ergon Energy's capital expenditure estimation processes are detailed Section 53.10 of this Regulatory Proposal. Ergon Energy believes that its expenditure estimation processes reflect the behaviour of a prudent operator in its circumstances and result in efficient costs because they are based on plans, policies, procedures and strategies that promote the achievement of the capital expenditure objectives;
- Reasonableness of assumptions used to prepare capital expenditure forecasts - Ergon Energy believes that the assumptions detailed in section 53.10 of this Regulatory Proposal are consistent with a prudent operator in its circumstances. This is because the assumptions are:
    - → Necessary for Ergon Energy to make its capital expenditure forecasts;
    - → Consistent with Ergon Energy acting in good faith and with reasonable care in preparing its capital expenditure forecasts; and
    - → Reasonable in the circumstances of Ergon Energy's operations.
- The efficiency of Unit Rates – Ergon Energy believes that the unit rates that it applied in developing its capital expenditure program are efficient for the reasons discussed in Chapter 32 of this Regulatory Proposal; and
- The efficiency of Escalators - Ergon Energy believes that the escalators that it applied in developing its capital expenditure program are efficient for the reasons discussed in Chapter 33 of this Regulatory Proposal.

Clause 6.5.7(e)(5) of the Rules requires the AER to have regard for the actual and expected capital expenditure during the current regulatory control period. As discussed above, Ergon Energy's services are classified differently in the current regulatory control period to how they will be classified in the next regulatory control period. Street lighting was not explicitly separated from the rest of the capital expenditure forecasts in the current regulatory control period. As a result, it is not possible to compare the actual and expected capital expenditure. However, Ergon Energy's actual and forecast capital expenditure on street lighting is detailed in section 53.9.

53.12 OPERATING EXPENDITURE – HISTORIC

Sections 2.2.2(a)(2) and 2.4.6(a)(2) of the RIN requires that Ergon Energy provide in this Regulatory Proposal historic and forecast capital and operational expenditure information and justifications for any material differences between historic and forecast capital and operating expenditures.

Ergon Energy's historic operating expenditure for the current regulatory control period is set out in Table 149. Ergon Energy has provided historic capital expenditure for the previous regulatory control period (2001-05) in the accompanying RIN. However, Ergon Energy does not have data, and is therefore unable to provide further information about expenditure for the previous regulatory control period.

In addition, the QCA did not prepare a separate building block for Street Lighting Services. Rather the street lighting amount was included in the building block for prescribed distribution services. Furthermore, the expenditure information in Table 149 relates to Street Lighting Services 1 and 2, in relation to new street lighting connections and the replacement of existing street lighting assets. They do not relate to Street Lighting Service 3, which concerns the alteration and relocation of street lighting assets. As a result, Ergon Energy is not able, and does not have information, to compare actual/forecast expenditure to a street lighting building block for the previous and current regulatory control periods.

Ergon Energy's historic operating expenditure is set out in Table 149.

Table 149: *Operating Expenditure – Street Lighting Services – 2005-06 to 2009-10 ($M Nominal)*

	2005-06	2006-07	2007-08	2008-09 Estimate	2009-10 Estimate	5 Year Total	Average of 5 Year Total
Street Lighting	8.04	8.53	7.92	11.28	13.28	**49.06**	**9.81**

Source: Tables for Proposal 53.12

Ergon Energy's forecast operating expenditure for the next regulatory control period is set out in section 53.13 below.

The main difference between street lighting operating expenditure in the current and next regulatory control periods reflects Ergon Energy's decision to implement a three regulatory year BLR cycle (from the previous four regulatory year cycle) and the extension of this program from minor roads only to include major roads. Further discussion of the BLR program is provided below.

53.13 OPERATING EXPENDITURE – FORECAST AND JUSTIFICATION

This section overviews Ergon Energy's operating expenditure forecasts for Street Lighting Service 2 for the regulatory control period 1 July 2010 to 30 June 2015.

Sections 2.2.2(a)(2) and 2.4.6(a)(2) of the RIN requires that Ergon Energy provide in this Regulatory Proposal historic and forecast capital and operational expenditure information and justifications for any material differences between historic and forecast capital and operating expenditures. The previous section 53.12 explains the historic operating expenditure, and this section 53.13 explains the forecast operating expenditure.

53.13.1 Forecast 2010-15

Ergon Energy's forecast operating expenditure forecast for the operation repair, replacement and maintenance of street lighting assets for the regulatory control period 1 July 2010 to 30 June 2015 is detailed in Table 150.

Table 150: *Operating Expenditure – Street lighting – 2010-15 ($M Real $2009-10)*

	2007-08[1] AER BASE YEAR	2008-09[2] Estimate	2009-10[3] Estimate	2010-11[4]	2011-12[4]	2012-13[4]	2013-14[4]	2014-15[4]	5 Year Total	Average of 5 Year Total
Street Lighting	8.28	11.26	13.26	14.70	14.29	14.38	14.80	15.10	73.27	14.65

Source: Tables for Proposal 53.10.1

1. 2007-08 actuals escalated to 2009-10 $s.
2. 2008-09 forecast from the RIN i.e. Nominal.
3. 2009-10 forecast from the RIN i.e. Nominal.
4. 2010-15 forecast ($M Real $2009-10).

1, 2, 3 & 4 All numbers are inclusive of Shared Costs (Overheads) allocated in accordance with the AER-approved CAM that will apply from 1 July 2010 onwards.

The key driver of the street lighting operating expenditure program in the next regulatory control period is the BLR program. In particular, the extension of the program from the current minor roads only to include major roads and the move from a four regulatory year BLR cycle to a three regulatory year cycle. These changes to the BLR program are aimed at increasing Street Lighting Service availability from the current 85 per cent to 95 per cent in accordance with Australian Standard AS/NZS1158. Ergon Energy considers that the adoption of Australian Standard AS/NZS1158 delivers an appropriate standard of public safety and is consistent with Ergon Energy's risk management framework. In addition to providing a more reliable service, the proposed changes to the BLR program are forecast to result in reductions to other areas of preventive and Corrective Maintenance and mitigate the need for Forced Maintenance.

53.13.2 What the Forecast Relates to

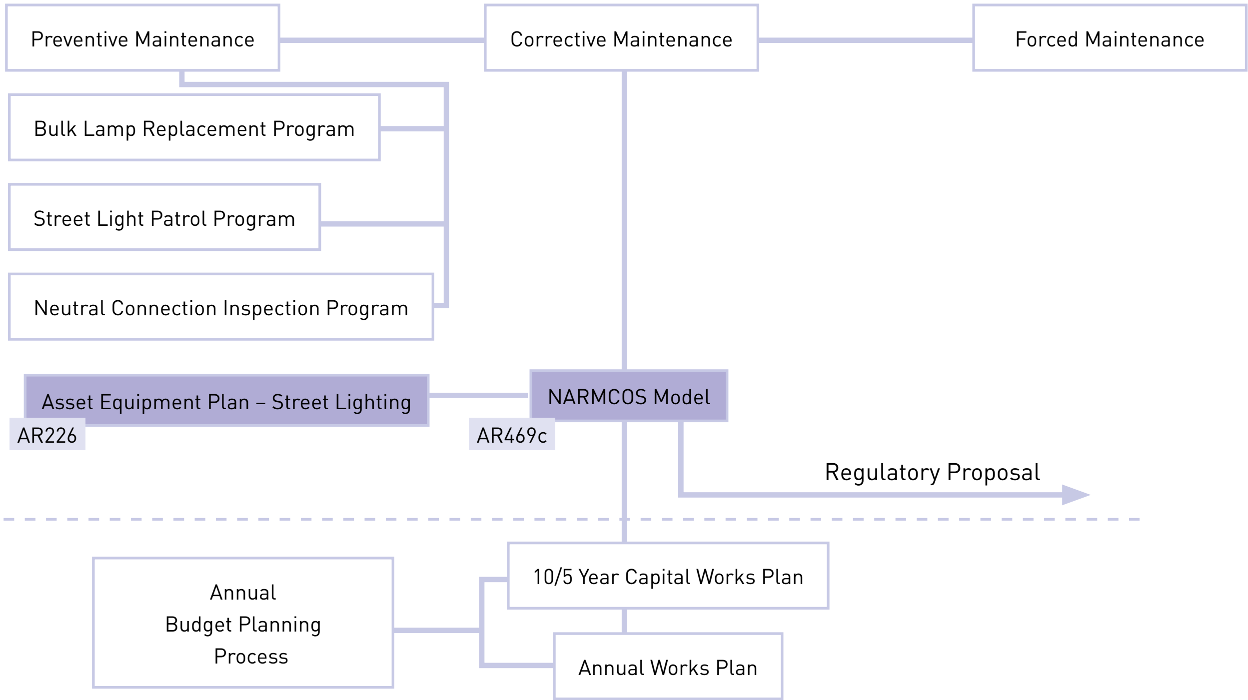
Ergon Energy's operating expenditure comprises:

- Preventive Maintenance – which comprises scheduled inspection and maintenance activity. This work is carried out at predetermined intervals, or in accordance with prescribed criteria, in order to minimise the probability of network failure, minimise total life cycle costs, meet required operating conditions and performance standards, and keep Ergon Energy's staff and the public safe. Work that is identified from this program can be undertaken either as Preventive Maintenance, Corrective Maintenance or capital expenditure, so that Forced Maintenance can be averted. Ergon Energy has also attributed a portion of Preventive Maintenance expenditure associated with poles to street lighting to reflect the fact that Street Lighting Services utilise these poles;

- Corrective Maintenance – which involves repair, replacement or restoration work that is carried out after the occurrence of an event or failure in order to eliminate the source of the failure or to reduce the frequency of its future occurrence. This category of work is planned and carried out regularly. Ergon Energy has also attributed a portion of Corrective Maintenance expenditure associated with poles to street lighting; and
- Forced Maintenance – which involves unplanned repair, replacement or restoration work that is carried out as quickly as possible after the occurrence of an unexpected event or failure. Although it is unplanned, an annual provision must be made for this category of expenditure. As with the previous expenditure categories, Ergon Energy has attributed a portion of Forced Maintenance expenditure associated with poles to street lighting.

The Ergon Energy street lighting operating expenditure applies to both street lights that are supplied, owned, installed and maintained by Ergon Energy and street lights that are funded by others and ownership of the installation is subsequently vested in Ergon Energy, so that it is responsible for ongoing maintenance.

Figure 66: *Operating Expenditure – Street Lighting Service 2*



53.13.3 Estimation Process

Figure 66 overviews the key elements of how Ergon Energy has prepared its operating expenditure - Street Lighting Service 2 forecasts for the next regulatory period.

53.13.3.1 Preventive maintenance

Street Lighting Preventive Maintenance is based on the BLR plan, the Street Light Patrol program or a combination of both. In addition, in response to requirements of the Queensland Electrical Safety Office (ESO), a public lighting neutral connection inspection program is being implemented on a sample of street lights across Ergon Energy's network. Ergon Energy has incorporated forecast expenditure associated with the extension of the neutral connection inspection program in its operating expenditure forecasts for the next regulatory control period.

A portion of Preventive Maintenance expenditure associated with poles is also attributed to street lighting based on the number of street light poles in the total pole population and the proportion of Preventive Maintenance costs associated with poles that can be attributed to street lights.

These components of the forecast Preventive Maintenance program are discussed below.

Table 151: *Bulk Lamp Replacement Program – 2010-15*

	Assets to be inspected	Inspection interval or criteria
a.	Major Road Lighting included in the Street light Patrol Program as per 1.1 (a) & (c) above	3 regulatory year cycle
b.	Major Road Lighting not included in the Street light Patrol Program	3 regulatory year cycle
c.	Pedestrian Crossings	3 regulatory year cycle
d.	Minor Road Lighting Bulk relamping for minor road lamps where the predominant lamp type is 50W or 80W Mercury Vapour	3 regulatory year cycle
e.	Photo-electric (PE) Cell replacement Bulk PE Cell changes are to coincide with bulk lamp changes.	6 regulatory year cycle Change every second cycle.

Source: Asset Equipment Plan

Bulk lamp replacement program

The BLR program is a 'find and fix now' program. The BLR program aims to reduce the frequency of ad-hoc repairs and/or to maintain lumen output. The BLR will be carried out on all street lights that have not previously been identified as part of the Street light Patrol program.

Details of the BLR program for the 2010-15 regulatory control period are provided in Table 151.

The BLR program from 2009-10 onwards has been extended from the current minor roads only (approximately 93,950 lights), to include major roads (approximately an additional 32,270 lights), and the frequency reduced from the current four regulatory year cycle to a three regulatory year cycle. The three regulatory year cycle is based on original equipment manufacturer provided mortality rates and the lumen depreciation calculations as per Australian Standard AS/NZS1158. This program and frequency change is a result of maintenance strategy analysis considering safety, cost, lighting performance and Australian Standard AS/NZS1158. In particular, the three regulatory year cycle is required in order to increase lighting availability from the current approximately 85 per cent to at least 95 per cent, which is specified by Australian Standard AS/NZS1158.

Bulk photo electric (PE) cell changes are to coincide with bulk lamp changes. PE cells are to be changed every second bulk lamp change. This longer cycle is due to the greater stability of the electronic photo cell to switch on and off at the correct light levels.

Bulk re-lamping and PE cell changes on a cyclic basis provides a lower overall long run maintenance cost for the lighting system while providing an improved light failure performance by replacing lamps and cells at the end of their effective life and before they fail.

The NARMCOS model forecasts Operating Expenditure associated with BLR and PE cell replacement based on:

- Identifying the number of BLR and Bulk Lamp and PE Cell Replacements (i.e. in units) that need to be undertaken for each of the five regulatory years based on the population of minor and major street lights and the frequency of the replacement cycle; and
- Identifying the total cost of undertaking each of the replacement types (i.e. minor road BLR, major road BLR, minor road Bulk Lamp and PE Cell Replacement and major road Bulk Lamp and PE Cell Replacement). The unit rates reflect a composite based on the existing Schedule of Rates contract and management estimates of material costs, additional contract items and variances. These unit rates do not change over the five regulatory years. Escalation of these unit rates is performed separately from NARMCOS. This process is discussed in Chapter 33 of this Regulatory Proposal.

Street light patrol program

The Street Light Patrol program is a 'find and fix later' program involving the periodic inspection of major road street lights. Only Local Government Authorities (LGAs) where there are more than 200 major road street lights will undergo a street light patrol and a BLR. All other LGAs undergo a BLR only.

Routine street light patrols for the next regulatory control period are programmed as detailed in Table 152.

Table 152: Street Lighting Patrol Program – 2010-11 to 2014-15

Assets to be inspected	Inspection interval or criteria
• Major highways, thoroughfares and main roads with High Intensity Lighting usually designed to Australian Standards AS/NZS 1158 located within defined geographic areas and identified as having significant numbers of street light patrol lights.	• Six monthly 2010-11 – 2011-12 • 12 monthly 2012-13 onwards One night patrol of each road or defined area (usually September and March if possible)
• Pedestrian Crossings not covered by (a) above, but located within the same geographic area as (a) above – all types of lighting whether incandescent, fluorescent or High Intensity lighting.	• Six monthly 2010-11 – 2011-12 • 12 monthly 2012-13 onwards One night patrol of each intersection (usually September and March if possible)
• Major intersections including roundabouts with High Intensity Lighting not covered by (a) above but located within the same geographic area as (a) above.	• Six monthly 2010-11 – 2011-12 • 12 monthly 2012-13 onwards One night patrol of each pedestrian crossing (usually September and March if possible)
• Suburban and other lighting in built up urban areas not covered by (a), (b), (c) above.	No routine patrols to be carried out.

Source: Asset Equipment Plan

Ergon Energy has forecast a change in the Street Light Patrol cycle from a six to a 12 month frequency upon completion of the first three regulatory year BLR cycle on Major Roads. This reduction reflects the assumption that defect rates will be reduced after implementation of the first round of the three regulatory year BLR cycle. The change to the Street Light Patrol cycle is planned to occur in the 2012-13 financial regulatory year. Consequently, a reduction in operating expenditure associated with the Street Light Patrol program is forecast from 2012-13.

The NARMCOS model forecasts Operating Expenditure associated with Street Light Patrols based on:

- Identifying the amount of Street light Patrols (i.e. in units) that need to be undertaken for each of the five regulatory years based on the population of major street lights and the cycle frequency; and
- Identifying the total cost of undertaking a single unit of Street light Patrols. The unit rates reflect a composite based on the existing Schedule of Rates contract and management estimates of material costs, additional contract items and variances. These unit rates do not change over the five regulatory years. Escalation of these unit rates is performed separately from NARMCOS. This process is discussed in Chapter 33 of this Regulatory Proposal.

Neutral connection inspection program

A recent Electrical Safety Office (ESO) audit audit identified that there was no specific program for checking neutral connectivity faults on street lights to mitigate the risk of electric shock to members of the public. The inspection of street light neutral connections program is aimed at determining the current condition of street light neutral connections and determining the future maintenance strategy. These inspections involve checking the integrity of all connections.

A sample inspection of 500 random connections has been identified in the Ergon Energy network and is being checked to assess the condition of neutral connections. Based on this sample, Ergon Energy proposes moving to a 10 regulatory year inspection cycle at the start of the next regulatory control period.

The NARMCOS model forecasts operating expenditure associated with the proposed neutral inspection program based on:

- Identifying the amount of neutral connection inspections (i.e. in units) that need to be undertaken for each of the five regulatory years based on the population of major street lights and the 10 regulatory year cycle frequency; and
- Identifying the total cost of undertaking a single unit of neutral inspection. The unit rate reflects the actual cost of performing recent inspections. This unit rate does not change over the five regulatory years. Escalation of these unit rates is performed separately from NARMCOS. This process is discussed in Chapter 33 of this Regulatory Proposal.

Preventive Maintenance associated with poles is discussed in Chapter 26. Ergon Energy has attributed a portion of this expenditure to street lighting based on the proportion of street lights in the total pole population and the associated attributable costs.

53.13.3.2 Corrective maintenance

Corrective Maintenance refers to maintenance carried out to correct an unacceptable condition or failure of an asset. Corrective Maintenance is condition based maintenance that does not require an immediate response, but can be planned for some future time once the requirements are established. It is generally proactive maintenance but in some cases it could be reactive depending on how the requirements arise.

Corrective Maintenance requirements may be identified:

- During Preventive Maintenance activities (proactive);
- During other work such as construction or from customer-or employee-initiated reports (proactive);
- As a result of an investigation into an asset failure to prevent a repeat of the same failure mode in other similar assets (proactive); and
- As deferred follow up work on a failed asset that has resulted in Forced Maintenance (reactive) work.

Corrective Maintenance most often involves the replacement of lamps, but can also involve other components of the street lighting assets.

Ergon Energy has forecast Corrective Maintenance for each of its five Regional Asset Management areas. Ergon Energy has assumed a gradual reduction in Corrective Maintenance from 2010-11 to 2012-13 to coincide with the introduction of a three regulatory year Bulk Lamp Replacement cycle (from the current four regulatory year cycle). Ergon Energy has assumed that Corrective Maintenance will be reduced by 25 per cent by 2012-13 as a result of the more frequent lamp replacement cycle.

Ergon Energy's Operating Expenditure - Corrective Maintenance forecasts for Standard Control Services and Alternative Control Services are prepared in NARMCOS at the aggregate level using a top-down/baseline-and-scope-change approach. The aggregate annual amount has been allocated between Ergon Energy's 26 asset equipment types, including Street Lighting Services 2, only for the purposes of preparing this Regulatory Proposal. Ergon Energy does not use forecast information broken down in this manner for operational or budgeting purposes.

The reasons that the forecasts are prepared in this manner are that:

- Corrective Maintenance expenditure is relatively consistent in aggregate but not at the asset equipment type level;
- It is not until within a regulatory year that it becomes evident what Corrective Maintenance expenditure is actually required for each asset equipment type. This is because Corrective Maintenance is significantly affected by weather events. Once defects are identified, work is undertaken to fix the defect and prevent an outage or a dangerous electrical event occurring. Work is also undertaken to repair or replace assets following temporary repairs, involving Forced Maintenance, in order to restore supply following an outage; and
- Corrective Maintenance expenditure cannot efficiently be forecast using a bottom-up (quantity multiplied by unit rates basis) approach by asset equipment type. A bottom-up approach would likely result in an over-estimation of the Corrective Maintenance expenditure requirements.

Corrective Maintenance associated with poles is discussed in Chapter 26. Ergon Energy has attributed a portion of Corrective Maintenance expenditure to street lighting based on the proportion of street lights in the total pole population and the associated attributable Corrective Maintenance costs.

53.13.3.3 Forced maintenance

Forced Maintenance refers to reactive maintenance that must be done immediately to prevent danger to personnel, equipment or address network performance (i.e. restore a loss of supply). For street lighting, this means repairing light outages reported by customers.

The Asset Maintenance Strategy commits Ergon Energy to the effective maintenance of its network assets in order to keep them fit for purpose, and in a safe and environmentally sound condition, so as to minimise the risk of condition-based and age-related failures. This includes undertaking unplanned maintenance to address unexpected events or failures.

The Operating Expenditure - Forced Maintenance forecasts for Standard Control Services and Alternative Control Services are prepared in NARMCOS at the aggregate level using a top-down/baseline-and-scope-change approach. The aggregate annual amount has been allocated between Ergon Energy's 26 asset equipment types, including street lighting, only for the purposes of preparing this Regulatory Proposal. Ergon Energy does not use forecast information broken down in this manner for operational or budgeting purposes.

The reasons that the forecasts are prepared in this manner are that:

- Forced Maintenance expenditure is relatively consistent in aggregate but not at the asset equipment type level; and
- It is not until within a regulatory year that it becomes evident what Forced Maintenance expenditure is actually required for each asset equipment type. This is because Forced Maintenance is significantly affected by weather events. Work is undertaken to fix defects once they occur – this can either be a permanent repair or a temporary repair (which is later addressed permanently through Corrective Maintenance or Asset Replacement expenditure).

Forced Maintenance associated with poles is discussed in Chapter 26. Ergon Energy has attributed a portion of Forced Maintenance expenditure to street lighting based on the proportion of street lights in the total pole population and the associated attributable Forced Maintenance costs.

53.13.4 Assumptions

The key assumptions underlying the Operating Expenditure – Street Lighting Service 2 forecast are that:

- The document entitled Network Preventive Maintenance Programs for 2010-11 to 2014-15 is applied as the basis for the Preventive Maintenance forecast. Importantly, this document summarises the Preventive Maintenance inspection and maintenance intervals and other criteria used to generate the annual maintenance work plans and budgets;
- The requirements of AS/NZS 1158 are maintained in the next regulatory control period;
- The BLR program from 2009-10 onwards has been extended from the current minor roads only to include major roads;
- The frequency of the BLR program from 2009-10 onwards will be reduced from the current four regulatory year cycle to a three regulatory year cycle;
- PE Cell replacements are forecast to coincide with every second lamp replacement (i.e. six regulatory year cycle);
- The Street Light Patrol program is forecast to move from a six to 12 month frequency from 2012-13 onward;
- A 10 regulatory year cycle for the inspection of neutral connections will commence in 2010-11;
- Corrective Maintenance assumes future expenditure will be similar to previous regulatory years expenditure and that the introduction of a three regulatory year Bulk Lamp Replacement cycle will reduce expenditure on Corrective Maintenance;
- The Forced Maintenance forecast assumes that future expenditure will be similar to previous regulatory years' expenditure; and
- Maintenance costs associated with poles are based on the assumption that the total cost of maintenance of a pole with a major street light attached is attributable to street lighting and one third of the maintenance cost of a pole with a minor street light attached is attributable to street lighting.

53.13.5 Capital Expenditure / Operating Expenditure Interactions

There is a strong relationship between the street lighting Preventive Maintenance forecasts and:

- The street lighting asset replacement program because the Preventive Maintenance program identifies where there are defective assets that need to be replaced by undertaking capital works;
- The street lighting Corrective Maintenance program because the Preventive Maintenance program identifies where there are defective assets that need to be maintained through specific Corrective Maintenance activity; and
- The street lighting Forced Maintenance program because, if the Preventive Maintenance program does not identify defective assets that need either to be replaced or otherwise maintained, then there may be a need to increase Forced Maintenance in order to remedy assets that have failed.

Forced Maintenance forecasts are largely driven by severe weather conditions adversely impacting the distribution system. Consequently, changing other maintenance expenditure programs, or undertaking asset replacement expenditure, has in the past proven to have very limited impact on Ergon Energy's Forced Maintenance expenditure requirements.

Ergon Energy therefore considers that it has limited ability to influence its Forced Maintenance expenditure requirements.

53.13.6 Justification of the Forecasts

Ergon Energy provides efficient and cost effective street lighting maintenance which complements the business's strategic direction and delivers high standards of safety and environmental responsibility to employees and the community. The street lighting maintenance forecasts seek to:

- Ensure public safety through meeting public lighting availability requirements, leading to a low percentage of failed lamps in service;
- Maintain an acceptable corporate risk profile via ensuring public safety and reducing the likelihood of litigation via addressing lumen depreciation issues;
- Optimise the operating expenditure spend due to the cheaper cost of planned lamp replacement via the BLR program versus more expensive unplanned Forced Maintenance;
- Ensure a public lighting population which maintains compliance with the Australian Standard AS/NZS1158; and
- Address public lighting infant mortality (early life failures) after maintenance activities.

Corrective Maintenance involves planned and regular repair, replacement or restoration work after the occurrence of an event or failure in order to eliminate the source of the failure or to reduce the frequency of its future occurrence. Corrective Maintenance is identified from asset inspections. The street lighting Corrective Maintenance program is structured to ensure that Ergon Energy effectively:

- Maintains street lighting assets in order to keep them fit for purpose, and in a safe and environmentally sound condition, so as to minimise the risk of condition-based and age-related failures; and
- Manages street lighting assets in order to promote public safety, reliable electricity supply and compliance with regulatory obligations.

Forced Maintenance is an estimate of likely unplanned repair, replacement or restoration work that will be required based on the unexpected events or failures that are likely to occur on Ergon Energy's distribution system. Some Forced Maintenance of street lighting assets occurs as a result of reports by customers. A nominal amount of Forced Maintenance expenditure is allowed because most street light maintenance is managed by the BLR program or through Corrective Maintenance.

Storm activity varies from regulatory year-to-regulatory year and so Forced Maintenance costs do not have a direct relationship to other maintenance and replacement programs. It is not possible to forecast accurately the extent of the Forced Maintenance that will be required to address weather impacts. For this reason, the street lighting Forced Maintenance forecast is based on historic trends at a high level. This is considered to be the most accurate way of forecasting this kind of expenditure given that Ergon Energy maintains an extensive street lighting asset base that spans a wide geographic regional area with diverse weather types and patterns.

The Forced Maintenance program is structured to ensure that Ergon Energy, as quickly as possible, brings its street lighting assets back to acceptable and safe operating condition following unexpected events or failures.

53.13.7 Risk Considerations

The Preventive Maintenance program seeks to ensure obligations are met, public and worker safety is maintained and the risk profile to Ergon Energy is appropriate. In particular, the BLR program has been amended to address the requirements of Australian Standard AS/NZS1158.

Reducing the Preventive Maintenance forecasts would result in increased asset replacement expenditure and corrective and Forced Maintenance expenditure. In addition, a reduction in expenditure and consequent impact on service availability is likely to increase the risk to the public and Ergon Energy staff and potentially expose Ergon Energy to increased liability. Further, a reduction in expenditure would result in Ergon Energy's Street Lighting Service being below Australian Standard AS/NZS1158.

Reducing the Corrective Maintenance forecasts would require re-prioritising programs of work. Those that are not undertaken will increase Ergon Energy's risk profile.

There are no specific risk considerations associated with the street lighting corrective and Forced Maintenance forecast, other than that under-funding asset replacement capital and other maintenance expenditure is likely to increase the need for unplanned repair, replacement or restoration work by way of corrective or Forced Maintenance. This is because, if the under-funding is translated into under-spending, there is likely to be an increased incidence of unexpected events or failures.

However, as noted above, the corrective and Forced Maintenance forecast, and the amount ultimately approved by the AER, will not change the work that actually needs to happen as street light outages must be repaired. Ergon Energy will simply need to undertake the works regardless as the need arises following an unexpected event or failure. The street lighting corrective and Forced Maintenance forecast therefore seeks to ensure that Ergon Energy is appropriately funded to undertake the works that are expected to be necessary.

53.13.8 Customer Outcomes

Preventive Maintenance is intended to minimise the probability of network failure, minimise total life cycle cost, meet required operating conditions and performance standards, and keep Ergon Energy's staff and the public safe. By reducing unplanned asset failures, Ergon Energy seeks to maintain an appropriate level of Street Lighting Service availability and minimise risks to the public and Ergon Energy.

A cut in the street lighting Preventive Maintenance forecast would reduce or remove condition monitoring of street lighting assets, and thereby leave them to run to failure without information about their condition. It could be expected that this would have negative customer service impacts, including reduced Street Lighting Service availability.

The street lighting Corrective Maintenance forecast provides an efficient basis for effectively promoting public safety by repairing, replacing or restoring street lighting assets after the occurrence of an event or failure in order to eliminate the source of the failure or to reduce the frequency of its future occurrence; and

When street lighting Forced Maintenance is required, an unexpected event or failure has occurred which typically results in a failure of street lights. The purpose of Forced Maintenance is to ensure that Ergon Energy brings its Street Lighting Service back to at least its minimum acceptable and safe operating condition following any such events or failures. This ensures that the duration of inconvenience or risk experienced by customers is minimised.

53.14 OPERATING EXPENDITURE – OBJECTIVES, CRITERIA AND FACTORS

Chapter 27 of this Regulatory Proposal details the nature, and Ergon Energy's interpretation, of the operating expenditure objectives, criteria and factors in clause 6.5.6 of the Rules. This is equally applicable to Ergon Energy's Street Lighting Service 2.

This section demonstrates how Ergon Energy's forecast operating expenditure for Street Lighting Services 2 for the next regulatory control period achieves the operating expenditure objectives, having regard for the operating expenditure criteria and operating expenditure factors.

53.14.1 Operating Expenditure Objectives

Ergon Energy considers that its forecast operating expenditure will enable it to deliver the performance outcomes in the next regulatory control period that are required by clause 6.5.6(a) of the Rules. This means that its forecast operating expenditure will result in operating and maintenance activity so that Ergon Energy can:

- Meet or manage the demand for Street Lighting Services 2; and
- Comply with regulatory obligations that apply to Street Lighting Services 2.

Ergon Energy notes that there are no specific service standards that apply to Street Lighting Services 2 so that clauses 6.5.6(a)(3) and (4) have not been addressed for these services.

The demand for Ergon Energy's Street Lighting Service 2 is dictated by customer demand for street lighting and the requirements for maintaining those street lighting assets to an acceptable standard.

Ergon Energy's street lighting operating expenditure is forecast to increase in line with increases in the street light population. All three components of Ergon Energy's operating expenditure forecast – preventive, corrective and forced – are directly related to increases in the population of street lights. Deviations from the underlying population growth for Preventive Maintenance reflect the adoption of appropriate inspection cycles.

Ergon Energy believes its forecast operating expenditure will deliver the operating expenditure objectives for the following reasons:

- Nature of activities – Ergon Energy's operating expenditure for Street Lighting Services 2 relates:
  - → Preventive Maintenance expenditure, which is necessary to minimise the probability of network failure, maintain the integrity of the distribution network, meet required operating conditions and performance standards, and keep staff and the public safe;
  - → Corrective Maintenance, which involves planned and regular activity to address the occurrence of an event or failure in order to eliminate the source of the failure or to reduce the frequency of its future occurrence; and
  - → Forced Maintenance, which involves unplanned repair, replacement or restoration activity that is carried out as quickly as possible after the occurrence of an unexpected event or failure in order to bring the network to at least its minimum acceptable and safe operating condition.

These programs are all necessary in order to maintain the serviceability of the distribution system and to supply Street Lighting Services.

a. Plans, policies, procedures and strategies - As discussed in section 53.13 of this Regulatory Proposal, Ergon Energy uses a series of plans, policies, procedures and strategies to develop and implement its operating expenditure program for the next regulatory control period. Ergon Energy believes that these will enable it to achieve the operating expenditure objectives in the next regulatory control period because they ensure that its operating expenditure forecasts have regard for Ergon Energy's and customers' drivers of operating expenditure and the need to comply with relevant regulatory obligations;

b. Estimation process to prepare operating expenditure forecasts - Section 53.13 of this Regulatory Proposal details the estimation processes that Ergon Energy has used to prepare each subcategory of its operating expenditure forecasts. Ergon Energy believes that these processes support the development of prudent and efficient operating expenditure forecasts that will achieve the operating expenditure objectives in the next regulatory control period. This is because Ergon Energy's estimation approach effectively translates its plans, policies, procedures and strategies into operating expenditure forecasts for the next regulatory control period; and

c. Deliverability of expenditure program - Chapter 35 of this Regulatory Proposal explains how it will resource the delivery of its operating expenditure program in the next regulatory control period, including on street lighting. It follows, given the justifications of the forecast operating expenditure provided above, that Ergon Energy also believes that the physical delivery of its operating expenditure program will ensure that it achieves the operating expenditure objectives detailed in clause 6.5.6(a) of the Rules in the next regulatory control period.

53.14.2 Operating Expenditure Criteria and Factors

Ergon Energy considers that its forecast operating expenditure reasonably reflects the operating expenditure criteria in clause 6.5.6(c) of the Rules having regard for the operating expenditure factors in clause 6.5.6(e) of the Rules. However, Ergon Energy considers that the only subclauses of clause 6.5.6(e) that should be applied to Street Lighting Service 2 are clause 6.5.6(e)(1), (2), (3) and (5). Only clauses 6.5.6(e)(1) and (5) require Ergon Energy to provide information as part of this Regulatory Proposal.

Ergon Energy considers that its forecast operating expenditure is consistent with the efficient costs that a prudent operator would incur in Ergon Energy's circumstances to achieve the operating expenditure objectives, based on realistic demand forecasts and cost inputs.

The matters that Ergon Energy believes that the AER should consider under clause 6.5.6(e)(1) are as follows:

- Circumstances in which Ergon Energy operates - these circumstances are set out in section 4.19 of this Regulatory Proposal. These circumstances affect all aspects of Ergon Energy's operating expenditure decision making in relation to its street lighting assets. The plans, policies, procedures and strategies referred to in section 53.13 of this Regulatory Proposal provides further detail about how Ergon Energy's circumstances are reflected in its operating expenditure forecasts;
- Ergon Energy's estimation processes - Ergon Energy's operating expenditure estimation processes are detailed Section 53.13 of this Regulatory Proposal. Ergon Energy believes that its expenditure estimation processes reflect the behaviour of a prudent operator in its circumstances and result in efficient costs because they are based on plans, policies, procedures and strategies that promote the achievement of the operating expenditure objectives;
- Reasonableness of assumptions used to prepare operating expenditure forecasts - Ergon Energy believes that the assumptions detailed in section 53.13 of this Regulatory Proposal are consistent with a prudent operator in its circumstances. This is because the assumptions are:
  - → Necessary for Ergon Energy to make its operating expenditure forecasts;
  - → Consistent with Ergon Energy acting in good faith and with reasonable care in preparing its operating expenditure forecasts; and
  - → Reasonable in the circumstances of Ergon Energy's operations.
- The efficiency of Unit Rates – Ergon Energy believes that the unit rates that it applied in developing its operating expenditure program are efficient for the reasons discussed in Chapter 32 of this Regulatory Proposal; and
- The efficiency of Escalators - Ergon Energy believes that the escalators that it applied in developing its operating expenditure program are efficient for the reasons discussed in Chapter 33 of this Regulatory Proposal.

Clause 6.5.6(e)(5) of the Rules requires the AER to have regard for the actual and expected operating expenditure during the current regulatory control period. As discussed above, Ergon Energy's services are classified differently in the current regulatory control period to how they will be classified in the next regulatory control period. Street lighting was not explicitly separated from the rest of the operating expenditure forecasts in the current regulatory control period. As a result, it is not possible to compare the actual and expected operating expenditure. However, Ergon Energy's actual and forecast operating expenditure on street lighting is detailed in section 53.12.

53.15 OTHER INFORMATION RELATING TO PREPARATION OF FORECASTS

This section provides certain other information that has been used in preparing the capital and operating expenditure forecasts, but which is not specifically required under the Rules, the AER's RIN or the AER's F&A Stage 1.

53.15.1 Escalations

Chapter 33 of this Regulatory Proposal sets out the nature of the cost escalation factors that Ergon Energy has applied to its capital and operating expenditure forecasts. These have been applied without modification to Street Lighting Services.

53.15.2 Shared Costs (Overheads)

Chapter 34 of this Regulatory Proposal sets out the nature of the Shared Costs (Overheads) that Ergon Energy has applied to its capital and operating expenditure forecasts. These have been applied without modification to Street Lighting Services.

53.15.3 Delivering Expenditure Program

The delivery of the forecast street lighting capital and operating expenditure programs is incorporated in the delivery of standard control capital and operating expenditure forecasts covered in Chapter 35 of this Regulatory Proposal.

53.16 COST PASS THROUGHS

The cost pass through provisions in Chapter 6 of the Rules are contained within Part C, which relates to Standard Control Services. Clause 6.2.6(c) of the Rules allows the control mechanism for Alternative Control Services to utilise elements of Part C of the Rules.

Ergon Energy therefore proposes that the cost pass through arrangements in clause 6.6.1 of the Rules should apply to both Standard Control Services and Alternative Control Services.

Chapter 46 of this Regulatory Proposal provides a detailed explanation of the proposed application of the cost pass through arrangements.

53.17 CAPITAL CONTRIBUTIONS

New street lights are funded directly by customers.

Where a customer requests that Ergon Energy build these street lighting assets, Ergon Energy provides this service on a quoted basis. The customer charge represents the full cost of providing this service and as such cannot be classified as a capital contribution.

However, new street lighting assets may also be built by customers and 'gifted' to Ergon Energy for it to operate and maintain in perpetuity. Street lighting assets gifted to Ergon Energy are considered a capital contribution.

Clause 11.16.10 of the Rules allows Ergon Energy to retain its current capital contributions policy in the next regulatory control period. However, Ergon Energy has decided not to adopt clause 11.16.10 in relation to street lighting capital contributions and has instead opted to include these contributions at zero value to the street lighting Regulatory Asset Base in the regulatory year in which the asset is commissioned.

This treatment reflects the fact that Ergon Energy receives no revenue (return on or of capital) associated with holding these assets. Rather, the assets are vested in Ergon Energy to allow Ergon Energy to determine the appropriate ongoing inspection and maintenance requirements of those assets.

53.18 POST TAX REVENUE MODEL

Ergon Energy confirms that it has:

- Prepared its Annual Revenue Requirement for Street Lighting Service 2 by using the Post Tax Revenue Model (PTRM), in accordance with clause 6.3.1(c)(1) of the Rules; and
- Provided a completed PTRM for Street Lighting Service 2 to the AER as part of this Regulatory Proposal that shows its application to Ergon Energy and the completed Roll Forward Model, as required by clause S6.1.3(10) of the Rules.

53.19 ANNUAL REVENUE REQUIREMENT FOR 2010-15

Ergon Energy confirms that it has prepared its Annual Revenue Requirement for each regulatory year of the next regulatory control period in accordance with the requirements of Part C of Chapter 6 of the Rules and clause 3.4.3 of the AER's F&A Stage 1, in particular by applying:

- The PTRM established by the AER under clause 6.4 of the Rules; and
- The building block approach provided for by clause 6.4.3 of the Rules.

Ergon Energy has provided a completed PTRM and a completed RFM to the AER for Street Lighting Service 2 with this Regulatory Proposal. These models demonstrate Ergon Energy's application of the models in calculating the annual revenue requirement, including the assumptions it has made in populating the models.

Ergon Energy's proposed ARR's for Street Lighting Service 2 for each regulatory year of the next regulatory control period, 2010-11 to 2014-15 are detailed in Table 153.

Table 153: *Annual Revenue Requirement for Street Lighting Service 2 for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Annual Revenue Requirement	25.79	26.69	27.62	28.58	29.57	138.24	27.65

Source: Tables for Proposal 53.19

The building blocks that comprise the ARR are summarised below.

53.19.1 Regulatory Asset Base

Section 2.4.6(a)(3)(i) of the RIN requires Ergon Energy to provide the opening asset value for Street Lighting Services as at 1 July 2005 and any calculations or documents to demonstrate is derivation.

Ergon Energy's opening asset value for Street Lighting Service 2 as at 1 July 2005 was $47.02 million in nominal terms. This value was derived from Ergon Energy's audited regulatory reporting statements provided to the QCA.

53.19.2 Indexation of the Regulatory Asset Base

Section 2.4.6(a)(3)(ii) of the RIN requires Ergon Energy to provide the opening asset value for Street Lighting Services as at 1 July 2010 including adjustments to account for capital expenditure and depreciation.

Ergon Energy has calculated the proposed opening RAB for Street Lighting Service 2 for the first regulatory year of the next regulatory control period by applying the AER's Roll Forward Model (RFM). Ergon Energy has used the RFM to roll forward the RAB for Street Lighting Services 2 as at 1 July 2005 to 30 June 2010 by:

- Adding forecast capital expenditure over this period to the opening RAB for each respective regulatory year;
- Deducting forecast depreciation for each regulatory year;
- Deducting forecast disposals for each regulatory year; and
- Indexing the annual closing RAB for forecast inflation for each regulatory year.

Ergon Energy's proposed opening RAB for Street Lighting Service 2 for each regulatory year of the next regulatory control period, 2010-11 to 2014-15, is detailed in Table 154.

Table 154: *Opening Regulatory Asset Base for Street Lighting Service 2 for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15
Opening Regulatory Asset Base	50.47	48.78	47.25	46.25	45.73

Source: Tables for Proposal 53.19.2

Ergon Energy has calculated the proposed opening RAB for Street Lighting Service 2 for each regulatory year of the next regulatory control period by applying the AER's PTRM. Ergon Energy has used the PTRM to roll forward the RAB for Street Lighting Services 2 as at 1 July 2010 to 30 June 2015 by:

- Adding forecast capital expenditure over this period to the opening RAB for each respective regulatory year;
- Deducting forecast depreciation for each regulatory year;
- Deducting forecast disposals for each regulatory year; and
- Indexing the annual closing RAB for forecast inflation for each regulatory year.

53.19.3 Return on Capital

Ergon Energy's proposed return on capital for Street Lighting Service 2 for each regulatory year of the next regulatory control period, 2010-11 to 2014-15, is detailed in Table 155.

Table 155: *Return on Captial for Street Lighting Service 2 for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Return on Capital	4.96	4.79	4.63	4.48	4.39	23.25	4.65

Source: Tables for Proposal 53.19.3

In accordance with clause 6.5.2(b) of the Rules, the rate of return is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by Ergon Energy.

Ergon Energy has calculated the proposed return on capital for each regulatory year of the next regulatory control period by applying the AER's PTRM. In accordance with clause 6.5.2(a) of the Rules, Ergon Energy has determined the proposed return on capital by applying a rate of return to the value of the regulatory asset base as at the beginning of the regulatory year.

Consistent with section 3.4.3 of the AER's F&A Stage 1, Ergon Energy has applied the same rate of return on capital to Street Lighting Services that is applied to Standard Control Services, a detailed in Chapter 41, which provides a detailed explanation of the basis of the calculation of the rate of return on capital.

53.19.4 Depreciation

Ergon Energy's proposed depreciation for Street Lighting Service 2 for each regulatory year of the next regulatory control period, 2010-11 to 2014-15, is detailed in Table 156.

Table 156: *Depreciation for Street Lighting Service 2 for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Depreciation	6.04	6.34	6.67	7.03	7.45	33.52	6.70

Source: Tables for Proposal 53.19.4

Ergon Energy has calculated the proposed depreciation for each regulatory year of the next regulatory control period by applying the AER's PTRM and RFM.

In accordance with clause 6.5.5(a) of the Rules, Ergon Energy has determined the proposed depreciation for each regulatory year of the next regulatory control period:

- Based on the value of the assets as included in the regulatory asset base, as at the beginning of the regulatory year; and
- By preparing depreciation schedules that conform to the requirements of clause 6.5.5(b) of the Rules.

Chapter 37 of this Regulatory Proposal provides a detailed explanation of the basis of the calculation of the depreciation building block.

53.19.5 Corporate Income Tax

Ergon Energy's estimated cost of corporate income tax for Street Lighting Service 2 for each regulatory year of the next regulatory control period, 2010-11 to 2014-15, is detailed in Table 157.

Table 157: *Estimated Cost of Corporate Income Tax for Street Lighting Service 2 for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Estimated Cost of Corporate Income Tax	1.64	1.66	1.69	1.71	1.74	8.44	1.69

Source: Tables for Proposal 53.19.5

Ergon Energy has estimated the cost of corporate income tax for each regulatory year of the next regulatory control period by applying the AER's PTRM. Ergon Energy has applied the formula in cluse 6.5.3 of the Rules in making its estimation.

In accordance with clause 6.5.3 of the Rules, the estimate of the taxable income is that which would be earned by a benchmark efficient entity as a result of the provision of Standard Control Services.

Chapter 38 of this Regulatory Proposal provides a detailed explanation of the basis of the estimation of Ergon Energy's corporate income tax building block.

53.19.6 Operating Expenditure

Ergon Energy's forecast operating expenditure for Street Lighting Service 2 for each regulatory year of the next regulatory control period, 2010-15, is detailed in Table 158.

Ergon Energy has forecast the operating expenditure for each regulatory year of the next regulatory control period by applying the AER's PTRM.

The forecast operating expenditure is that which is required by Ergon Energy to achieve the applicable operating expenditure objectives in clause 6.5.6(a) of the Rules for the provision of Street Lighting Service 2. Section 53.13 of this Regulatory Proposal explains the basis for Ergon Energy's operating expenditure forecast, and how Ergon Energy's forecast operating expenditure meets the applicable operating expenditure objectives, factors and criteria in clause 6.5.6 of the Rules.

Table 158: *Forecast Operating Expenditure for Street Lighting Service 2 for 2010-15 ($M Nominal)*

	2010-11	2011-12	2012-13	2013-14	2014-15	5 Year Total	Average of 5 Year Total
Operating Expenditure	15.07	15.00	15.47	16.31	17.05	78.89	15.78

Source: Tables for Proposal 53.19.6

53.19.7 X Factors

This section details Ergon Energy's proposed X factors for the next regulatory control period for Street Lighting Services 2 in order to address the requirements of the Rules, the RIN and the PTRM handbook.

As noted in the PTRM handbook, the X factor is simply a price or revenue adjustment mechanism. It does not relate to actual productivity improvements in Ergon Energy's operations.

Clause 6.5.9(a) of the Rules provides that the AER's Building Block Determination is to include the X factor for each control mechanism for each regulatory year of the regulatory control period. Further, clause 6.12.1(11) of the Rules requires that determining the X factor (as part of the control mechanism) is to be one of the constituent decisions of the AER's Distribution Determination.

Clause S6.1.3(6) of the Rules requires Ergon Energy's Building Block Proposal to include details, and an explanation of the calculation, of the X factors relevant to the control mechanism, together with a demonstration that the calculation complies with the relevant requirements of the Law and the Rules.

Clause 6.5.9(b) of the Rules details the basis on which the X factors must be set – these factors are discussed in detail in the remainder of this chapter. Clause 6.5.9(c)(1) of the Rules allows there to be different X factors for different regulatory years of the regulatory control period.

Section 2.4.2(a)(1) of the RIN requires Ergon Energy to explain how the X factors have been set.

Ergon Energy's proposed X factors for Street Lighting Service 2 for each regulatory year of the next regulatory control period, 2010-11 to 2014-15, are detailed in Table 159.

Table 159: *X Factors for Street Lighting Service 2 for 2010-15 (per cent)*

	2010-11	2011-12	2012-13	2013-14	2014-15
X factors	-66.04	-1.00	-1.00	-1.00	-1.00

Source: Tables for Proposal 53.19.7
Note: A negative X factor represents a real increase in distribution prices.

Ergon Energy has calculated the proposed X factors for each regulatory year of the next regulatory control period in the PTRM, in accordance with the requirements of clause 6.5.9 of the Rules. In particular, Ergon Energy has set the X factors:

- Having regard to the DNSP's ARRs for the five regulatory years of the next regulatory control period, as required by clause 6.5.9(b)(1) of the Rules;
- In order to minimise, as far as reasonably possible, variance between expected revenue for the last regulatory year of the regulatory control period and the annual revenue requirement for the last regulatory year, as required by clause 6.5.9(b)(2) of the Rules;
- In order to equalise (in terms of net present value) the revenue to be earned by Ergon Energy from the provision of Street Lighting Service 2 over the regulatory control period with Ergon Energy's Street Lighting Service 2 ARRs for the regulatory control period, as required by clause 6.5.9(b)(3)(i) of the Rules; and
- To include different values, as is permitted under clause 6.5.9(c)(1) of the Rules.

Section 2.4.2(a)(2) of the RIN requires Ergon Energy to explain how the X factors satisfy the requirements of clause 6.5.9 of the Rules and the guidance in the PTRM Handbook.

The X factor for the first regulatory year of the regulatory control period has been set to equal the annual revenue requirement for street lighting for that regulatory year. The remaining X factors have been set equal to each other in order to satisfy the requirements of clause 6.5.9 of the Rules and section 2.6 of the PTRM Handbook to:

- Minimise, as far as reasonably possible, variance between expected revenue for street lighting for the last regulatory year of the regulatory control period and the ARR for street lighting for the last regulatory year; and
- Equalise (in terms of net present value) the revenue to be earned by Ergon Energy from the provision of Street Lighting Service 2 over the regulatory control period with Ergon Energy's ARR for Street Lighting Service 2 for the regulatory control period.

On this basis, Ergon Energy considers that there is no combination of X factors that better achieves the requirements of clause 6.5.9 of the Rules and section 2.6 of the PTRM handbook than those detailed in section 53.19.7 of this Regulatory Proposal.

Section 2.4.2(a)(3) of the RIN allows Ergon Energy to provide any other justifications that it considers are relevant to its proposed X factors.

Ergon Energy does not consider that any other matters are relevant to justifying its proposed X factors than the explanations that are provided in section 53.19.7 of this Regulatory Proposal.

The sum of Ergon Energy's proposed ARR for Street Lighting Service 2 for the next regulatory control period is $128.42 million, as detailed in section 53.19 above.

Ergon Energy confirms that it has prepared its ARR for the next regulatory control period in accordance with the requirements of Part C of Chapter 6 of the Rules, in particular by applying:

- The PTRM established by the AER under clause 6.4 of the Rules; and
- The building block approach provided for by clause 6.4.3 of the Rules.

Ergon Energy has provided a completed PTRM and a completed roll forward model to the AER with this Regulatory Proposal. Ergon Energy has identified any assumptions it has made and demonstrated that the calculation of the ARR complies with the relevant requirements of the NEL and the Rules in the models.

53.20 DEMONSTRATION OF THE APPLICATION OF CONTROL MECHANISM

Section 2.4.6(a)(1)(ii) of the RIN requires that Ergon Energy provide, in relation to Street Lighting Services, information to support the application of the proposed control mechanism, including a demonstration of the application of the proposed control mechanism and any supporting information.

The control mechanism for Street Lighting Services, as detailed in section 3.5.2 of the AER's F&A Stage 1, is a price cap control mechanism in the first regulatory year of the regulatory control period and a price path for remaining regulatory years of the period. As required by the AER, Ergon Energy has applied a limited building block approach to determine the efficient costs of providing Street Lighting Services.

Ergon Energy interprets the requirement to demonstrate the application of the proposed control mechanism to be that it must:

- Provide the cost inputs and revenue calculations for the limited building block in a separate PTRMand RFM;
- Acknowledge that it will submit, with its Pricing Proposal, prices which are capped for the first regulatory year of the regulatory control period; and
- Submit a price path for the remaining regulatory years of the regulatory control period.

Ergon Energy discussed the treatment of the three categories of Street Lighting Services in section 53.2 of this Regulatory Proposal. In particular, Ergon Energy proposed that:

- Street Lighting Services 1 and 3, involving the provision of new street lighting assets and the alteration and relocation of existing street lighting assets respectively, be charged on a quoted fee basis in the same manner as for Ergon Energy's other Alternative Control Services that are to be treated as Quoted Services. This reflects the fact that all of these services need to be costed, and priced, on a customer-specific basis having regard for the specific requirements of the customer. A fixed price cannot be determined in advance based on a forecast of costs and volumes.

  Ergon Energy considers that this approach complies with the requirements of the AER's F&A Stage 1 for Street Lighting Services to be regulated under a building block approach and a price cap because:

  a. The building block would be the build up of the actual costs of altering, relocating or installing new street lights on an individual customer-by-customer basis – rather than for the aggregate of Street Lighting Services on a prospective basis; and
  b. Prices would be capped on an individual customer basis by applying the formula.
- Street Lighting Service 2, involving the operation, repair, replacement and maintenance of street lighting assets, be charged on a price cap basis, with ARRs derived on the basis of a limited building block approach. Once the street lighting ARRs have been determined, Ergon Energy will determine:

  c. A dollar per regulatory year charge for different types of street lights for the first regulatory year of the regulatory control period. This price cap will be levied on all existing and new street lighting customers; and
  d. A proposed price path for the dollar per regulatory year charges for regulatory years two to five of the regulatory control period.

Ergon Energy considers that this approach complies with the requirements of the AER's F&A Stage 1 in relation to Street Lighting Service 2 because it applies a building block approach (being a modification of the approach in Part C of Chapter 6 of the Rules) and a price cap control mechanism.

Ergon Energy has provided a separate PTRM and RFM for Street Lighting Service 2. This satisfies the requirement that it provide the cost inputs and revenue calculations to the AER.

Ergon Energy will submit prices for Street Lighting Service 2 for the first regulatory year of the next regulatory control period, which will be fixed for that regulatory year. Ergon Energy will then apply a CPI-X price path to its Street Lighting Service 2, as it does for the revenue cap for its Standard Control Services.

53.21 PRICING INFORMATION

Clause 6.18 of the Rules requires that Ergon Energy submit a Pricing Proposal to the AER after the AER has made its Distribution Determination. Ergon Energy will do this in accordance with the Rules.

Clauses 6.8.2(c)(4) and S6.1.3(6) of the Rules and section 2.2.5(a)(4) of the RIN requires that Ergon Energy provide, for Alternative Control Services in the Regulatory Proposal, the prices for equivalent services provided in each regulatory year of the current regulatory control period (and provide an estimate for the final two regulatory years of the current regulatory control period).

These services have not been separately identified in the current regulatory control period and therefore comparable prices cannot be provided.

Section 2.2.5(a)(5) of the RIN requires that Ergon Energy provide indicative prices for each individual Alternative Control Service in each regulatory year of the next regulatory control period.

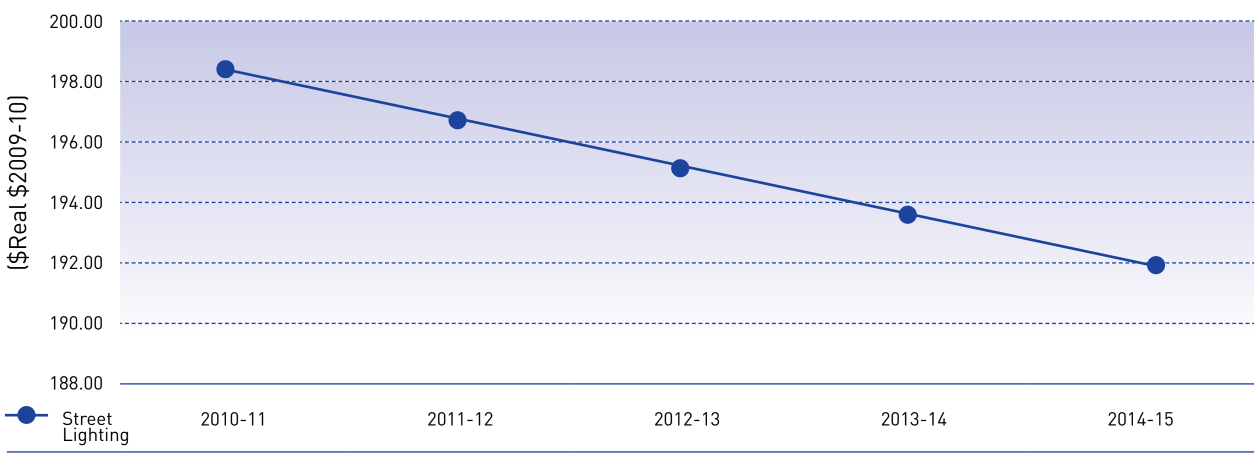
This is an expression of the ARR forecasts for Street Lighting Service 2 for the next regulatory control period. It is not the basis on which Ergon Energy intends to charge for these services when it prepares its Pricing Proposal. This information is provided in Table 160 and depicted in Figure 67.

Table 160: *Indicative Prices for Street Lighting Service 2 for 2010-11 to 2014-15 ($ Real $2009-10)*

Pricing Category	2010-11	2011-12	2012-13	2013-14	2014-15
Street Lighting	198.51	196.89	195.28	193.68	192.09

Source: AR433c AER Data_v7_data room_28May09.xls

Figure 67: *Indicative Prices Street Lighting Service 2 – 2010-15*



Source: AR433c AER Data_v7_data room_28May09.xls

53. ALTERNATIVE CONTROL SERVICES – STREET LIGHTING SERVICES – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Document

AR367c & 368c	AER Regulatory Information Notice
AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR524	AER Post Tax Revenue Model Handbook –
AR526	AER Roll Forward Model Handbook

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR078	EE Network Maintenance Defect Classification Manual
AR119c	EE Annual Regulatory Accounts for 2001-02
AR120c	EE Annual Regulatory Accounts for 2002-03
AR121c	EE Annual Regulatory Accounts for 2003-04
AR122c	EE Annual Regulatory Accounts for 2004-05
AR123c	EE Annual Regulatory Accounts for 2005-06
AR124c	EE Annual Regulatory Accounts for 2006-07
AR226	EE Asset Equipment Plans 2009
AR284	EE Capitalisation Accounting Policy, Property, Plant and Equipment, March 2009
AR318	EE EP51 Asset Management Defect Policy, 1 May 2008
AR337	EE Public Lighting Maintenance Strategy, V1.2
AR355	EE Asset Maintenance Strategy, V8, April 2009
AR370c	EE Annual Regulatory Accounts for 2007-08
AR433c	EE AER Data, V7, Data Room, 28 May 2009
AR451	EE Strategic Plan for Asset Renewal, 3 April 2009
AR446	EE Network Preventive Maintenance Programs for 2010-11 to 2014-15, V7, May 2009
AR539c	EE Regulatory Proposal Models, Roll Forward Model
AR539c	EE Regulatory Proposal Models, NARMCOS Model
AR539c	EE Regulatory Proposal Models, Post Tax Revenue Model

54. ALTERNATIVE CONTROL SERVICES – QUOTED SERVICES

Rules – Clauses 6.2.6(c), 6.8.2(c)(3) and (4), 6.18 and S6.1.3(6)
RIN – Sections 2.2.5(a)(4) and (5), 2.4.6(a)(5) and 2.4.7(a)(1)-(5)
RIN Pro forma - 2.2.5
F&A Stage 1 – Clauses 3.4.3 and 3.5

54.1 OVERVIEW OF QUOTED SERVICES

Clause 6.8.2(c)(4) and section 2.4.7(a)(1) of the Regulatory Information Notice (RIN) requires that Ergon Energy provide information to support the application of the proposed control mechanism for Quoted Services. In particular, section 2.4.7(a)(1)(i) of the RIN requires that Ergon Energy provide an overview of Quoted Services provided by Ergon Energy.

Quoted Services are services for which Ergon Energy must make an assessment of the works required in order to determine the costs associated with their delivery, and hence the charges to be levied. These services are requested by retailers or customers and attract a customer-specific charge.

Ergon Energy provides a large number of Quoted Services, examples of which include:

- The design and construction of new large customer connection assets;
- The provision of emergency recoverable works on Ergon Energy's network, for example, in the event that a car hits and damages an electricity pole; and
- The removal or relocation of Ergon Energy's assets at a customer's request.

New Street Lighting Services and the alteration or relocation of street lighting assets are also classified as Quoted Services, for the purposes of this Regulatory Proposal.

54.2 APPLICATION OF PART C OF CHAPTER 6 OF THE RULES

Clause 6.2.6(c) of the Rules provides that "the control mechanism for Alternative Control Services may (but need not) utilise elements of Part C (with or without modification)". Part C of the Rules sets out the provisions relating to building block determinations for Standard Control Services. This clause of the Rules also notes, as an example, that "the control mechanism might be based on the building block approach".

Ergon Energy has not applied Part C of Chapter 6 of the Rules for Quoted Services.

54.3 SERVICE LEVEL INFORMATION – DELIVERY OF TARGETS

Section 2.4.7(a)(4) of the RIN requires Ergon Energy to provide service level information for Quoted Services, including a demonstration of how the forecast costs will deliver target levels of service.

The Queensland Electricity Industry Code sets out the service levels for Quoted Services that are performed under NEMMCO's "Service Order Process - B2B Procedures". Service levels therefore only apply to a subset of Ergon Energy's Quoted Services.

For customers with consumption greater than or equal to 100 MWh per annum, the timeframe for completion of these services is as agreed between the parties. For customers with consumption less than 100 MWh per annum, these services must be completed on the date agreed or subsequently agreed with the retailer. Where no date is agreed, the services must be completed in accordance with the timeframes contained in Table 161.

Table 161: *Service Levels for Quoted Services*

Service Name	Source of Targets	Details of Targets	
	Code		
Street Lighting – construction of street lighting assets	Not applicable	Not applicable	
Removal/relocation of Ergon Energy's assets at customer request	Not applicable	Not applicable	
Move point of attachment at customer request	Not applicable	Not applicable	
Tiger tails	Not applicable	Not applicable	
Metering Data Provider services	Not applicable	Not applicable	
Metering Data Provider services above minimum requirements (reading and data)	Not applicable	Not applicable	
Meter test	Section 5.7.3 of the Electricity Industry Code	CBD Feeder, Urban Feeder, Short Rural Feeder and Long Rural Feeder	15 business days from receipt of a valid service order request
		Isolated Feeder	30 business days from receipt of a valid service order request
Change tariff	Section 5.7.3 of the Electricity Industry Code	CBD Feeder and "Urban Feeder	20 business days from receipt of a valid service order request
		Short Rural Feeder, Long Rural Feeder and Isolated Feeder	By the business day agreed between the distribution entity and the retail entity after receipt of a valid service order request
Change time switch	Section 5.7.3 of the Electricity Industry Code	CBD Feeder and "Urban Feeder	20 business days from receipt of a valid service order request
		Short Rural Feeder, Long Rural Feeder "and Isolated Feeder	By the business day agreed between the distribution entity and the retail entity after receipt of a valid service order request
Removal of meter	Section 5.7.3 of the Electricity Industry Code	CBD Feeder and 'Urban Feeder	5 business days from receipt of a valid service order request
		Short Rural Feeder and Long Rural Feeder	10 business days from receipt of a valid service order request
		Isolated Feeder	30 business days from receipt of a valid service order request
Removal of load control device	Section 5.7.3 of the Electricity Industry Code	(as per Removal of a meter above)	

Service Name	Source of Targets	Details of Targets	
Special meter read	Section 5.7.3 of the Electricity Industry Code	CBD Feeder, Urban Feeder and Short Rural Feeder	4 business days from receipt of a valid service order request
		Long Rural Feeder	5 business days from receipt of a valid service order request
		Isolated Feeder	By the business day agreed between the distribution entity and the retail entity after receipt of a valid service order request
Reprogram card meters	Section 5.7.3 of the Electricity Industry Code	(as per Change tariffs above)	
Exchange meter	Section 5.7.3 of the Electricity Industry Code	(as per Removal of a meter above)	
Move meter	Section 5.7.3 of the Electricity Industry Code	(as per Removal of a meter above)	
Provision of connection services above minimum requirements	Not applicable	Not applicable	
Overhead service upgrade	Not applicable	Not applicable	
Underground service upgrade	Not applicable	Not applicable	
Provision, installation and maintenance of meters above minimum requirements	Section 5.7.3 of the Electricity Industry Code	(as per Removal of a meter above)	
Prepayment meters at customer request	Section 5.7.3 of the Electricity Industry Code	(as per Removal of a meter above)	
Temporary de-energisation and re-energisation (including de-energisations and re-energisations involving a line drop)	Not applicable	Not applicable	
De-energisation after business hours	Section 5.7.3 of the Electricity Industry Code	CBD Feeder, Urban Feeder and Short Rural Feeder	5 business days from receipt of a valid service order request.
		Long Rural Feeder and Isolated Feeder	10 business days from receipt of a valid service order request.
Re-energisation after business hours	Section 5.7.3 of the Electricity Industry Code	CBD Feeder and Urban Feeder	If a valid service order request is received by 1.00pm on a business day, then on the same day. Otherwise the next business day.
		Short Rural Feeder	The next business day after receipt of a valid service order request.
		Long Rural Feeder and Isolated Feeder	10 business days from receipt of a valid service order request.
Attend loss of supply - not DNSP Fault (after hours)	Not applicable	Not applicable	

Service Name	Source of Targets	Details of Targets
Emergency recoverable works	Not applicable	Not applicable
Design and construct of new large customer connection assets	Not applicable	Not applicable
Subdivision fees	Not applicable	Not applicable
Project fees	Not applicable	Not applicable
High load escorts - lifting of lines	Not applicable	Not applicable
Rectification of illegal connections	Not applicable	Not applicable
Conversion of aerial bundled cables	Not applicable	Not applicable
Provision of service crew / additional crew	Not applicable	Not applicable

Source: Queensland Electricity Industry Code

Ergon Energy has well established internal procedures that set out how the Quoted Services listed in Table 161 are to be delivered to ensure the target levels of service (where applicable) are met.

The forecast costs used in the Quoted Services formula that is detailed in this chapter are reflective of the efficient costs required to deliver the Quoted Services in the next regulatory control period in accordance with Ergon Energy's internal procedures and the requirements of the Queensland Electricity Industry Code.

54.4 REVENUE FOR EACH QUOTED SERVICE FOR 2005-10 BY REGULATORY YEAR

Section 2.2.5(a)(3) of the RIN requires that Ergon Energy detail in this Regulatory Proposal, for Alternative Control Services, the revenue earned from equivalent services provided in each regulatory year of the current regulatory control period, with an estimate of revenues for the final two regulatory years of the current regulatory control period.

Whilst Ergon Energy has historically provided information to the Queensland Competition Authority (QCA) on revenue from its Excluded Distribution Services, due to difficulties with Ergon Energy's data capture and collection systems, it has provided these in 10 categories rather than by individual service. These 10 categories are a mix of fee based and Quoted Services as classified in the current regulatory control period. Ergon Energy's systems do not record information on actual revenue relating to the delivery of these services on an individual service basis. Furthermore, some Quoted Services in the current regulatory control period will become Fee Based Services in the next regulatory control period. There is therefore no 'equivalency' for the purposes of this Regulatory Proposal between the services for which revenue information is currently provided to the QCA and the proposed Quoted Services in the next regulatory control period.

Indeed, there are no equivalent services in 2005-06 and 2006-07 at all, because services were not classified as Excluded Distribution Services until 1 July 2007. For transparency, Ergon Energy has detailed in Table 162 the revenue earned from all Excluded Distribution Services in 2007-08, split across the 10 categories for which revenue is provided to the QCA in Ergon Energy's Regulatory Reporting Statements. These amounts are exclusive of GST.

Table 162: *2005-08 Revenues for Quoted Services ($'000)*

Quoted Services	2005-06	2006-07	2007-08[115]
De-energisation during and after business hours	n/a	n/a	0
High load escorts	n/a	n/a	398
Meter alterations	n/a	n/a	90
Other recoverable works	n/a	n/a	12,471
Other services	n/a	n/a	289
Re-allocate main point of attachment	n/a	n/a	137
Re-energisation during and after business hours	n/a	n/a	32
Revisit to customer's installation during business hours	n/a	n/a	1
Service drops and energisation visits	n/a	n/a	34
Temporary builder's supply	n/a	n/a	287
Total	**n/a**	**n/a**	**13,739**

Source: Regulatory Reporting Statements 2007-08

Prices for the services classified as Fee Based Services in the current regulatory control period are known, therefore Ergon Energy has provided forecast revenue for these services for 2008-09 and 2009-10 in the completed RIN pro forma.[116] Refer also to AR481c EE Quoted Services, Volumes and Revenues, 11 May 2009. These amounts are GST Exclusive. The Queensland Government imposes caps on the prices that Ergon Energy can charge for a number of these services. The actual price caps for 2008-09 are reflected in the estimated revenue. The price caps for 2009-10 are not yet known, however the revenue reflects estimates of the expected price caps.

Given the unpredictable nature of Quoted Services it is not possible to provide an estimate of revenues earned from the remaining services. Further, for new Street Lighting Services and the design and construction of new large customer connection assets, no equivalent services were provided in the current regulatory control period. This was because both services have been reclassified from Standard Control Services to Alternative Control Services. Consequently, Ergon Energy cannot provide estimated revenues for these services.

54.5 CUSTOMER NUMBERS FOR EACH QUOTED SERVICE FOR 2005-10 BY REGULATORY YEAR

Section 2.2.5(a)(2) of the RIN requires that Ergon Energy provide, for alternative control services in this Regulatory Proposal, actual customer numbers (or job numbers where applicable) for equivalent services provided in each regulatory year of the current regulatory control period, with an estimate to be provided for the final two regulatory years of the current regulatory control period.

Whilst Ergon Energy has historically provided information to the QCA on job numbers from its Excluded Distribution Services, due to difficulties with Ergon Energy's data capture and collection systems it has provided these in 10 categories rather than by individual service. These 10 categories are a mix of Fee Based and Quoted Services as classified in the current regulatory control period. Ergon Energy's systems do not record information on actual volumes relating to the delivery of these services on an individual basis. Furthermore, some Quoted Services in the current regulatory period have been reclassified to become Fee Based Services in the next regulatory control period. There is therefore no "equivalency" for the purposes of this Regulatory Proposal between the services for which volume information is currently provided to the QCA and the proposed Quoted Services in the next regulatory control period.

Indeed, there are no equivalent services in 2005-06 and 2006-07 at all, because services were not classified as Excluded Distribution Services until 1 July 2007. For transparency, Ergon Energy has detailed in Table 163 the volume of all Excluded Distribution Services in 2007-08, split across the ten categories for which volume information is provided to the QCA in Ergon Energy's Regulatory Reporting Statements.

[115] The Queensland Government imposes maximum price caps on a number of these services.

[116] Refer also to AR481c EE Quoted Services Volumes and Revenues, 11 May 2009.

***Table 163:** 2005-08 Job Numbers for Quoted Services*

Quoted Services	2005-06	2006-07	2007-08
De-energisation during and after business hours	n/a	n/a	30,286
High load escorts	n/a	n/a	399
Meter alterations	n/a	n/a	312
Other recoverable works	n/a	n/a	426
Other services	n/a	n/a	246
Re-allocate main point of attachment	n/a	n/a	555
Re-energisation during and after business hours	n/a	n/a	17,412
Revisit to customer's installation during business hours	n/a	n/a	3
Service drops and energisation visits	n/a	n/a	169
Temporary builder's supply	n/a	n/a	1,110
Total	**n/a**	**n/a**	**50,918**

Source: Regulatory Reporting Statements 2007-08

Ergon Energy has provided forecast volumes for services classified as Fee Based Services in the current regulatory control period for 2008-09 and 2009-10 in the accompanying completed RIN pro forma [117]. Given the unpredictable nature of Quoted Services it is not possible to provide an estimate of volumes for the remaining services. Further, for new Street Lighting Services and the design and construction of new large customer connection assets, no equivalent services were provided in the current regulatory control period. This was because both services have been reclassified from Standard Control Services to Alternative Control Services. Consequently Ergon Energy cannot provide estimated volumes for these services.

54.6 DEMONSTRATION OF THE APPLICATION OF THE CONTROL MECHANISM

Section 2.4.7(a)(1)(ii) of the RIN and clause 6.8.2(c)(3) of the Rules require Ergon Energy to include a demonstration of the application of the proposed control mechanism for its Quoted Services and any supporting information.

The Australian Energy Regulator (AER) has set out the control mechanism to apply to Quoted Services in its F&A Stage 1. In particular, section 3.5.2 of the AER's F&A Stage 1 provides that the AER will apply:

- A price cap form of control to Ergon Energy's Alternative Control Services in the next regulatory control period. This means that the approved price is the maximum price Ergon Energy is permitted to charge for a particular service; and
- A formula-based approach (a non-building block approach) to determine the efficient costs of providing Quoted Services under a price cap form of control in the first regulatory year of the regulatory control period and establish a price path for the remaining regulatory years of the regulatory control period.

Section 3.5.2 of the AER's F&A Stage 1 has a footnote, which states that the formula-based approach referred to above may contain variable components whereas for Fee Based Services the components for each formula are fixed.

Ergon Energy has interpreted the above requirements to mean that, for Quoted Services, the components of the formula will be subject to a price cap form of control, but the final prices for the service will not be set in advance. The costs of the individual components that are applied in the formula will be fixed where possible but the number of components used in the delivery of the service will be left variable.

This means that Ergon Energy must provide in this Regulatory Proposal:

- A formula which it will use to develop the prices for Quoted Services; and
- Values, wherever possible, for the component parts of the formula that it proposes.

[117] Refer also to AR481c EE Quoted Services, Volumes and Revenues, 11 May 2009.

54.6.1 Control Mechanism Formula

The following formula is proposed for Ergon Energy's Quoted Services.

$$Pi = Li + Mi + OCi + CAi + GSTi$$

Where:

Li = the cost of labour involved in the delivery of the service, calculated as the product of an hourly rate (inclusive of on-costs and overheads) and the time spent by the personnel involved. The amount of time will include both travel time and the time spent delivering the service.

Mi = the cost of non-capitalised materials expensed in the delivery of the service (inclusive of overheads). For large new customer connection services, this could include large scale capital items which are charged directly to customers.

OCi = other one-off costs (inclusive of overheads) relating to the delivery of the service, including hire or supply of additional equipment, assets or labour, and contingency costs.

GSTi = the Goods and Services Tax component of the service charge.

CAi = a charge applied to reflect the use of non-system physical assets owned by Ergon Energy involved in the delivery of the service. This charge reflects the return on and of non-system capital employed in the delivery of the service (e.g. trucks and IT systems). This will be calculated by the following formula:

$$CAi = CNSi + CVi$$

Where:

CNSi = a charge for non-system assets (excluding vehicles), comprising a return on and of non-system assets allocated to the delivery of Quoted Services. This charge will be applied as a percentage of the sum of the total Labour (Li), Materials (Mi) and Other Costs (OCi) based on historical trends.

CVi = a charge to reflect a return on and a return of vehicles used in the delivery of Quoted Services. The return on capital will be calculated using a current cost accounting valuation of vehicles based on the classes set out in Table 164, and the approved weighted average cost of capital used for Standard Control Services. The return of vehicles (depreciation) will be calculated based on the same asset valuation and an average life of 10 regulatory years.

Table 164: *Vehicle Classes*

Table Code	Description
EECLBORLIFHR	Borer/Lifter Unit-Truck
EECLEPV HR	E.P.V.
EECLEPVLL HR	E.P.V. - Live Line
EECLFRKLFT	Forklift
EECLPOLENLHR	Pole Nailer
EECLSUPVEHHR	Supervisory Vehicle
EECLTRU1T HR	Line Truck - 1 tonne
EECLTRU5T HR	Line Truck -3/5 tonne
EECLTRUPL HR	Pole Freighter

Source: Other POA Services_Base Estimates_7May09.xls

54.6.2 Control Mechanism Cost Components

Ergon Energy will charge for:

- The cost of labour by applying labour rates in accordance with the new Ergon Energy Union Collective Agreement 2008, as amended from time to time. The cost of labour includes on-costs, which comprise the costs associated with payroll tax, superannuation, annual leave entitlements, long service leave entitlements, sick leave entitlements, statutory holidays (including special leave) and workers' compensation. Overheads will be applied in accordance with Ergon Energy's approved Cost Allocation Method (CAM);
- The cost of materials by applying Ergon Energy's internal Transmission and Distribution Services (TaDS) estimating tool, Customer Initiated Capital Works (CICW) price book or Ellipse based on the materials used in the provision of each individual quoted service. These costs are obtained from a combination of Ergon Energy's supply system, period contract rates (where available), subject matter experts, suppliers and other third party organisations. Overheads will be applied in accordance with the CAM approved by the AER;
- The 'other costs' at cost as they arise in the provision of each individual quoted service. Overheads will be applied in accordance with Ergon Energy's approved CAM; and
- The cost of non-system physical assets by calculating an amount in accordance with the value of these assets used in the provision of Alternative Control Services and overhead costs allocated in accordance with the CAM as approved by the AER.

Given the nature of Quoted Services, it is not possible to provide examples of typical or representative services, since, by their nature the services are not 'typical'. However, in order to demonstrate the application of the control mechanism, Ergon Energy has provided the following worked examples of the calculation of charges for possible Quoted Services:

- No 1 - Design and construction of new large customer connection assets;
- No 2 - Construction of a new street lighting assets;
- No 3 - De-energisation after hours;
- No 4 - Re-energisation after hours
- No 5 - Move the meter;
- No 6 - Relocation of the point of attachment; and
- No 7 - Special meter read.

54.6.2.1 Example No 1 - Design and Construct of New Large Customer Connection Assets Service

The following example sets out the application of the Quoted Services' formula to a possible design and construction of a new large customer's connection assets.

The service involves the supply and installation of an 11 kV/415 V – 500 kVA pad-mount transformer at a customer's premises, with the service being delivered within a three-month timeframe. For the purposes of this example, it is assumed that the service is provided in 2010-11.

Labour Costs (Li)

The total direct labour cost is obtained by summing the direct labour costs for each Ergon Energy workgroup involved in delivering the service. In this example, the relevant workgroups are 'Line Services', 'Distribution Line Design' and 'Project Services'. The direct labour costs for each workgroup are derived by multiplying the estimated number of hours for each staff classification within the workgroup by the labour rate (inclusive of on-costs) for each staff classification for the appropriate financial regulatory year. Finally, the amount of overhead to be allocated to the total direct labour cost is calculated by multiplying the total overhead to be allocated by the total direct labour cost divided by the total direct labour, materials and 'Other Costs' (exclusive of the Project Risk Held by Asset Manager' cost).

By applying this methodology, the total labour cost (inclusive of on-costs and overheads) is calculated to be .

Materials Costs (Mi)

The total direct materials cost is obtained by summing the direct materials costs for each Ergon Energy workgroup required to deliver the service. The materials costs for each workgroup ('Line Services', Distribution Line Design' and 'Project Services' as set out above) are derived in accordance with the TaDS estimating tool. Finally, the amount of overhead to be allocated to the total direct materials cost is calculated by multiplying the total overhead to be allocated by the total direct materials cost divided by the total direct labour, materials and "other costs" (exclusive of the Project Risk Held by Asset Manager' cost).

By applying this methodology, the total materials cost (inclusive of overheads) is calculated to be .

'Other Costs' (OCi)

The total direct 'other costs' is calculated by summing the sponsor costs and a contingency cost known as the 'Project Risk Held by Asset Manager' cost. This contingency cost is derived from an assessment of the monthly probability and frequency of project delays (such as rain delays). The amount of overhead to be allocated to the total direct 'other costs' is calculated by multiplying the total overhead to be allocated by the total direct 'other costs' divided by the total direct labour, materials and – Other Costs – (exclusive of the Project Risk Held by Asset Manager' cost).

By applying this methodology, the total – other costs – (inclusive of overheads) is calculated to be .

Return On and Return Of Vehicles (CVi)

The return of vehicles associated with the delivery of this service is determined based on:

- The hourly depreciation amount for the vehicles utilised (this is an aggregate rate based on number and type of vehicles utilised);
- The workgroups that will utilise the vehicles; and
- The estimated number of hours that each workgroup will utilise the vehicles.

For each workgroup, the hourly depreciation amount is multiplied by the estimated number of hours the workgroup is expected to utilise the vehicles to give the return of vehicles for the workgroup. The sum of the return of vehicles for each workgroup gives the total return of vehicles for the delivery of this service.

The return on vehicles associated with the delivery of this service is calculated by dividing the total return of vehicles by the aggregated annual depreciation rate for the vehicles utilised (to give the total asset value), then multiplying the result by the Weighted Average Cost of Capital (WACC) of 9.49 per cent to obtain a total return on vehicles. This process for calculating the return on vehicles is consistent with the QCA's approved methodology.

By applying this methodology, the sum of the return on and return of vehicles is calculated to be .

Return On and Return Of Other Non-System Assets (CNSi)

The return on and return of other non system assets is calculated based on a percentage of the sum of the total labour (Li), materials (Mi) and 'Other Costs' (OCi). Based on historical trends, this percentage has been calculated to be 18.13 per cent.

By applying this methodology, the sum of the return on and return of other non-system assets is calculated to be .

The Charge Applied to Reflect the Use of Non-System Physical Assets (CAi)

In accordance with the Quoted Services formulae detailed above, the charge applied to reflect the use of non-system physical assets is calculated as the sum of the return on and return of other non system assets and return on and return of other vehicles.

By applying this methodology, the charge applied to reflect the use of non-system physical assets is calculated to be .

Total Price for the Service in 2010-11

Finally, in accordance with the Quoted Services formulae detailed above, with a GST rate of 10 per cent, the total price for the provision of this service in 2010-11 is . A summary of the price components for the delivery of this service in each regulatory year from 2010-11 through to 2014-15 is detailed in Table 165.

Table 165: *Design and Construct of New Large Customer Connection Assets Service - Worked Example ($)*

	2010-11	2011-12	2012-13	2013-14	2014-15
Li					
Mi					
OCi					
CNSi					
CVi					
CAi					
Pre-GST Sub-total					
GSTi					
Total Price					

Source: EE All Quoted Services_Summary_28May09.xls

54.6.2.2 Example No 2 – Construction of a New Street Light Asset

The following example sets out the application of the Quoted Services formula to a possible construction of a new street light assets service. The service involves the construction a major street light (an 'Aeroscreen' 100 Watt high pressure sodium lamp) on a major column (pole), with a single three-metre outreach mounted at nine meters, to be supplied by an overhead service from an existing 2x25mm² low voltage aerial bundled conductor overhead mains.

The high level methodology used to derive the total price for the provision of this service is similar to that in Example No 1, however, Ellipse is used instead of the TaDS estimating tool to provide the material costs and there are no relevant direct 'other costs'. Consequently, in accordance with the Quoted Services formula detailed above, with a GST rate of 10 per cent, the total price for the provision of this service in 2010-11 is . A summary of the price components for the delivery of this service in each regulatory year from 2010-11 through to 2014-15 is detailed in Table 166.

Table 166: *Construction of New Street Light Assets - Worked Example ($)*

	2010-11	2011-12	2012-13	2013-14	2014-15
Li					
Mi					
OCi					
CNSi					
CVi					
CAi					
Pre-GST Sub-total					
GSTi					
Total Price					

Source: EE All Quoted Services_Summary_28May09.xls

54.6.2.3 Example 3 - De-Energisation After Hours Service

The following example sets out the application of the Quoted Services formula to a possible de-energisation after hours service.

The high level methodology used to derive the total price for the provision of this service is similar to that in Example 1, however, there are no materials or direct 'other costs' relevant to this service. Consequently, in accordance with the Quoted Services formula detailed above, with a GST rate of 10 per cent, the total price for the provision of this service in 2010-11 is . A summary of the price components for the delivery of this service in each regulatory year from 2010-11 through to 2014-15 is detailed in Table 167.

Table 167: *De-Energisation After Hours Service - Worked Example*

	2010-11	2011-12	2012-13	2013-14	2014-15
Li					
Mi					
OCi					
CNSi					
CVi					
CAi					
Pre-GST Sub-total					
GSTi					
Total Price					

Source: EE All Quoted Services_Summary_28May09.xls

54.6.2.4 Example 4 - Re-Energisation After Hours Service

The following example sets out the application of the Quoted Services formula to a possible re-energisation after hours service.

The high level methodology used to derive the total price for the provision of this service is similar to that in Example 1, however, there are no materials or direct 'other costs' relevant to this service. Consequently, in accordance with the Quoted Services formula detailed above, with a GST rate of 10 per cent, the total price for the provision of this service in 2010-11 is . A summary of the price components for the delivery of this service in each regulatory year from 2010-11 through to 2014-15 is detailed in Table 168.

Table 168: *Re-Energisation After Hours Service - Worked Example*

	2010-11	2011-12	2012-13	2013-14	2014-15
Li					
Mi					
OCi					
CNSi					
CVi					
CAi					
Pre-GST Sub-total					
GSTi					
Total Price					

Source: EE All Quoted Services_Summary_28May09.xls

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54.6.2.5 Example 5 - Move the Meter Service

The following example sets out the application of the Quoted Services formula to a possible 'move the meter' service.

The high level methodology used to derive the total price for the provision of this service is similar to that in Example 1, however, there are no materials or direct 'other costs' relevant to this service. Consequently, in accordance with the Quoted Services formula detailed above, with a GST rate of 10 per cent, the total price for the provision of this service in 2010-11 is . A summary of the price components for the delivery of this service in each regulatory year from 2010-11 through to 2014-15 is detailed in Table 169.

Table 169: *Move the Meter Service - Worked Example*

	2010-11	2011-12	2012-13	2013-14	2014-15
Li					
Mi					
OCi					
CNSi					
CVi					
CAi					
Pre-GST Sub-total					
GSTi					
Total Price					

Source: EE All Quoted Services_Summary_28May09.xls

54.6.2.6 Example 6 - Relocate Point of Attachment Service

The following example sets out the application of the Quoted Services formula to a possible Relocation of Point of Attachment service.

The high level methodology used to derive the total price for the provision of this service is similar to that in Example 1, however, there are no materials or direct 'other costs' relevant to this service. Consequently, in accordance with the Quoted Services formula detailed above, with a GST rate of 10 per cent, the total price for the provision of this service in 2010-11 is . A summary of the price components for the delivery of this service in each regulatory year from 2010-11 through to 2014-15 is detailed in Table 170.

Table 170: *Relocate Point of Attachment Service - Worked Example*

	2010-11	2011-12	2012-13	2013-14	2014-15
Li					
Mi					
OCi					
CNSi					
CVi					
CAi					
Pre-GST Sub-total					
GSTi					
Total Price					

Source: EE All Quoted Services_Summary_28May09.xls

54.6.2.7 Example 7 - Special Read Service

The following example sets out the application of the Quoted Services formula to a possible special meter read service.

The high level methodology used to derive the total price for the provision of this service is similar to that in Example 1, however, there are no materials or direct 'other costs' relevant to this service. Consequently, in accordance with the Quoted Services formula detailed above, with a GST rate of 10 per cent, the total price for the provision of this service in 2010-11 is . A summary of the price components for the delivery of this service in each regulatory year from 2010-11 through to 2014-15 is detailed in Table 171.

Table 171: *Special Read Service - Worked Example*

	2010-11	2011-12	2012-13	2013-14	2014-15
Li					
Mi					
OCi					
CNSi					
CVi					
CAi					
Pre-GST Sub-total					
GSTi					
Total Price					

Source: EE All Quoted Services_Summary_28May09.xls

54.7 COST INFORMATION

Section 2.4.7(a)(2) of the RIN requires Ergon Energy to provide information to support the application of the proposed control mechanism for Quoted Services, including:

- A formula-based representation of the costs of providing each individual service, including operating costs and capital costs (return on assets and return of assets);
- Changes in historic and forecast operating costs and capital costs, including any calculations or documents to demonstrate the derivation of these costs; and
- A justification for any material differences between historic and forecast costs.

The formula representation of the costs of providing each service is provided in section 54.6 above. This includes operating costs and capital costs (return on assets and return of assets).

Ergon Energy does not have data, and is therefore unable to provide explanations, about historical and forecast capital and operating expenditure for Quoted Services in the previous, current and next regulatory control periods for the purposes of section 2.4.7(a)(2) of the RIN.

In relation to:

- The cost of labour, time series of labour rates for ordinary time and overtime are provided in Table 172 and Table 173. Standard labour rates were not used in 2005-06. Instead, the actual individual hourly rate of each employee involved in delivering the service was used. All rates are inclusive of on-costs, but exclusive of overheads; and
- Contractor rates are expected to increase by 6 per cent per annum for the remainder of the current regulatory control period and across the next regulatory control period, while all other labour classifications are expected to increase in accordance with the new Ergon Energy Union Collective Agreement 2008.

Table 172: *Labour Classification Ordinary Rates 2005-10 ($ per hour)*

Labour Classification	2005-06	2006-07	2007-08	2008-09	2009-10
Admin Employee	Not applicable				
Professional Managerial	Not applicable				
Power Worker	Not applicable				
Technical Service Person	Not applicable				
Electrical System Designer	Not applicable				
Supervisor	Not applicable				
Para-Professional	Not applicable				
Apprentice	Not applicable				
Contractor	Not applicable	Not applicable	Not applicable		
Manager	Not applicable				
System Operator	Not applicable				
Trainee	Not applicable				

Source: Labour Rates for Alternative Control Services_27March09.xls

***Table 173:** Labour Classification Overtime Rates 2005-10 ($ per hour)*

Labour Classification	2005-06	2006-07	2007-08	2008-09	2009-10
Admin Employee	Not applicable				
Professional Managerial	Not applicable				
Power Worker	Not applicable				
Technical Service Person	Not applicable				
Electrical System Designer	Not applicable				
Supervisor	Not applicable				
Para-Professional	Not applicable				
Apprentice	Not applicable				
Contractor	Not applicable	Not applicable	Not applicable		
Manager	Not applicable				
System Operator	Not applicable				
Trainee	Not applicable				

Source: Labour Rates for Alternative Control Services_27March09.xls

It is noted that Ergon Energy will charge:

- The cost of materials in accordance with its internal TaDS estimating tool, CICW price book or Ellipse based on the materials used in each project. These costs are obtained from a combination of Ergon Energy's supply system, period contract rates (where available), subject matter experts, suppliers and other third party organisations. Overheads will be applied in accordance with the CAM as approved by the AER;
- The 'other costs' as they arise in relation to each project. Overheads will be applied in accordance with the CAM as approved by the AER; and
- The cost of non-system physical assets, by calculating an amount in accordance with the value of these assets used in the provision of alternative control services and overhead costs allocated in accordance with the CAM as approved by the AER.

54.8 DEMAND INFORMATION

Section 2.4.7(a)(3) of the RIN requires Ergon Energy to provide information to support the application of the proposed control mechanism for Quoted Services, including:

- Historic and forecast demand for each individual Fee Based Service and Quoted Service; and
- Justification for any material differences between historic and forecast demand.

Demand for Quoted Services is best represented by customer numbers. Historical customer numbers are discussed in section 54.5. Ergon Energy cannot provide forecasts of customer numbers for Quoted Services in the next regulatory control period due to the variable and unpredictable nature of Quoted Services. Further, for a number of Quoted Services, equivalent services do not exist in the current regulatory control period.

54.9 PRICE FOR EACH ALTERNATIVE CONTROL SERVICE FOR 2005-10 BY REGULATORY YEAR

Section 2.2.5(a)(4) of the RIN requires that Ergon Energy provide the prices for equivalent Quoted Services provided in each regulatory year of the current regulatory control period, using an estimate for the final two regulatory years of the current regulatory control period.

The nature of Quoted Services is that the prices for these services vary with the nature of the service requested by the customer. Ergon Energy therefore cannot provide historical standardised prices for these services. An example of a possible price for each regulatory year in the current regulatory control period for each individual quoted service is set out in the completed RIN pro forma[118].

As a result of the reclassification from Standard Control Services to Alternative Control Services, no equivalent services exist for the design and construction of new large customer connection assets or the construction of new street lighting assets. Therefore prices cannot be provided for these services.

Ergon Energy notes there are no equivalent prices in 2005-06 and 2006-07 because services were not classified as 'Excluded Distribution Services' until 1 July 2007. Further, the QCA did not require indicative prices to be calculated for services classified as Quoted Services in the current regulatory control period in 2007-08. Therefore prices cannot be provided for these services. It should be noted that some services have been reclassified from Fee Based Services in the current regulatory control period to Quoted Services in the next regulatory control period. Prices for these services are not calculated in a manner that is equivalent with the calculation of prices in the next regulatory control period. Further, it is not possible to backcast the prices for these services in the current regulatory control period using the proposed formula for the next regulatory control period.

54.10 PRICING INFORMATION

Clause 6.18 of the Rules requires that Ergon Energy submit a Pricing Proposal to the AER after the AER has made its Distribution Determination. Ergon Energy will do this in accordance with the Rules.

Clauses 6.8.2(c)(4) and S6.1.3(6) of the Rules and section 2.2.5(a)(5) of the RIN require that Ergon Energy provide indicative prices for each individual Alternative Control Service in each regulatory year of the next regulatory control period. For Quoted Services, indicative prices for a representative sample or typical example of each service are required.

In accordance with clause S6.1.3(b) of the Rules, for each individual Alternative Control Service - Quoted Service, an example of a possible price for each regulatory year is set in the RIN pro forma.

[118] Refer also to AR480c EE POA Prices, Current Period, 11 May 2009

54. ALTERNATIVE CONTROL SERVICES – QUOTED SERVICES – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Document

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR367c & 368c	AER Regulatory Information Notice

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR364	National Electricity Rules

Ergon Energy Documents

AR094	Ergon Energy Union Collective Agreement 2008
AR119c	EE Annual Regulatory Accounts for 2001-02
AR120c	EE Annual Regulatory Accounts for 2002-03
AR121c	EE Annual Regulatory Accounts for 2003-04
AR122c	EE Annual Regulatory Accounts for 2004-05
AR123c	EE Annual Regulatory Accounts for 2005-06
AR124c	EE Annual Regulatory Accounts for 2006-07
AR314	EE Cost Allocation Method, AER Approved
AR370c	EE Annual Regulatory Accounts for 2007-08
AR480c	EE POA Prices, Current Period, 11 May 2009
AR481c	EE Quoted Services, Volumes and Revenues, 11 May 2009
AR482c	EE All Quoted Services, Summary, 28 May 2009

55. ALTERNATIVE CONTROL SERVICES – FEE BASED SERVICES

Rules – Clauses 6.2.6(c), 6.8.2(c)(3) and (4), 6.18 and S6.1.3(6)
RIN – Sections 2.2.5(a)(2)-(5) and 2.4.7(a)(1)-(5)
RIN Pro forma - 2.2.5
F&A Stage 1 – Sections 3.4.3 and 3.5

55.1 OVERVIEW OF FEE BASED SERVICES

Section 2.4.7(a)(1) of the Regulatory Information Notice (RIN) requires that Ergon Energy provide information to support the application of the proposed control mechanism for Fee Based Services. In particular, section 2.4.7(a)(1)(i) of the RIN requires that Ergon Energy provide an overview of Fee Based Services provided by Ergon Energy.

Fee Based Services are one-off services, which Ergon Energy provides to specific customers, for which a fixed service fee is charged.

Ergon Energy provides a number of Fee Based Services, examples of which include de-energisations and re-energisations, temporary builder's supplies and supply abolishments. These services are provided as Excluded Distribution Services in the current regulatory control period.

55.2 APPLICATION OF PART C OF CHAPTER 6 OF THE NER

Clause 6.2.6(c) of the Rules provides that "the control mechanism for Alternative Control Services may (but need not) utilise elements of Part C (with or without modification)". Part C of the National Electricity Rules (NER) sets out the provisions relating to building block determinations for Standard Control Services. This clause of the Rules also notes, as an example, that "the control mechanism might be based on the building block approach".

Ergon Energy has not applied Part C of Chapter 6 of the Rules for Fee Based Services.

55.3 SERVICE LEVEL INFORMATION – DELIVERY OF TARGETS

Section 2.4.7(a)(4) of the RIN requires Ergon Energy to provide service level information for Fee Based Services, including a demonstration of how the forecast costs will deliver target levels of service.

The Queensland Electricity Industry Code sets out the service levels for Fee Based Services that are performed under the National Electricity Market Management Company's (NEMMCO) 'Service Order Process - B2B Procedures'. Service levels therefore only apply to a subset of Ergon Energy's Fee Based Services.

For customers with consumption greater than 100 MWh per annum, the timeframe for completion of these services is as agreed between the parties. For customers with consumption less than 100 MWh per annum, these services must be completed on the date agreed or subsequently agreed with the retailer. Where no date is agreed, the services must be completed in accordance with the timeframes contained in Table 174.

Table 174: Service Levels for Fee Based Services

Service Name	Source of Targets	Details of Targets	
Specification and design enquiry fees - Subdivision Fees	Not applicable	Not applicable	
Specification and design enquiry fees - Project Fees	Not applicable	Not applicable	
De-energisation during business hours	Section 5.7.3 of the Electricity Industry Code	Urban Feeder / Short Rural Feeder	5 business days of receipt of a valid service order request.
		Long Rural Feeder / Isolated Feeder	10 business days of receipt of a valid service order request.
Re-energisation during business hours	Section 5.7.3 of the Electricity Industry Code	Urban Feeder	If a valid service order request is received by 1.00pm on a business day, then on the same day. Otherwise the next business day.
		Short Rural Feeder	The next business day after receipt of a valid service order request.
		Long Rural Feeder / Isolated Feeder	10 business days of receipt of a valid service order request.
Re-Test Fee (e.g. if premises fails test the first time)	Not applicable	Not applicable	
Supply Abolishment	Section 5.7.3 of the Electricity Industry Code	Urban Feeder	20 business days of receipt of a valid service order request
		Short Rural Feeder / Long Rural Feeder / Isolated Feeder	By the business days agreed between the distribution entity and the retail entity after receipt of a valid service order request
Temporary Builder's Supply (metered)-	Section 5.7.3 of the Electricity Industry Code	Urban Feeder	5 business days of a receipt of a valid service order request and all relevant documentation
		Short Rural Feeder / Long Rural Feeder	10 business days of a receipt of a valid service order request and all relevant documentation
		Isolated Feeder	30 business days of a receipt of a valid service order request and all relevant documentation
Attend loss of supply - not DNSP Fault (after hours)	Not applicable	Not applicable	Not applicable
Wasted truck visit	Not applicable	Not applicable	Not applicable

Source: Electricity Industry Code

Ergon Energy has well established internal procedures that set out how the Fee Based Services listed in Table 174 are to be delivered to ensure that the target levels of service (where applicable) are met.

The forecast costs set out in the Fee Based Services formula that is detailed in this chapter are reflective of the efficient costs required to deliver the Fee Based Services in the next regulatory control period in accordance with Ergon Energy's internal procedures and the requirements of the Queensland Electricity Industry Code.

55.4 REVENUE FOR EACH FEE BASED SERVICE FOR 2005-10 BY REGULATORY YEAR

Section 2.2.5(a)(3) of the RIN requires that Ergon Energy detail in this Regulatory Proposal, for Alternative Control Services, the revenue earned from equivalent services provided in each regulatory year of the current regulatory control period, with an estimate of revenues for the final two regulatory years of the current regulatory control period.

While Ergon Energy has historically provided information to the Queensland Competition Authority (QCA) on revenue from its 'Excluded Distribution Services', due to difficulties with Ergon Energy's data capture and collection systems it has provided these in 10 categories rather than by individual service. These 10 categories are a mix of Fee Based and Quoted Services as classified in the current regulatory control period. Ergon Energy's systems do not record information on actual revenue relating to the delivery of these services on an individual service basis. Furthermore, Ergon Energy has re-classified many of its Fee Based Services in the current regulatory control period to become Quoted Services in the next regulatory control period. There is therefore no "equivalency" for the purposes of this Regulatory Proposal between the services for which revenue information is currently provided to the QCA and the proposed Fee Based Services in the next regulatory control proposal.

Indeed, there are no equivalent services in 2005-06 and 2006-07 at all, because services were not classified as 'Excluded Distribution Services' until 1 July 2007. For transparency, Ergon Energy has detailed in Table 175 the revenue earned from all Excluded Distribution Services in 2007-08, split across the 10 categories for which revenue us provided to the QCA in Ergon Energy's Regulatory Reporting Statements. These amounts are exclusive of GST.

Table 175: *2005-08 Revenues for Fee Based Services ($'000)*

Fee Based Services	2005-06	2006-07	2007-08 [119]
De-energisation during and after business hours	n/a	n/a	0
High load escorts	n/a	n/a	398
Meter alterations	n/a	n/a	90
Other recoverable works	n/a	n/a	12,471
Other services	n/a	n/a	289
Re-allocate main point of attachment	n/a	n/a	137
Re-energisation during and after business hours	n/a	n/a	32
Revisit to customer's installation during business hours	n/a	n/a	1
Service drops and energisation visits	n/a	n/a	34
Temporary builder's supply	n/a	n/a	287
Total	**n/a**	**n/a**	**13,739**

Source: Regulatory Reporting Statements 2007-08

[119] The Queensland Government imposes maximum price caps on a number of these services.

For 2008-09 and 2009-10, Ergon Energy has provided estimated revenue that will be earned from its Fee Based Services in the accompanying complete RIN profoma. These amounts are GST Exclusive. The Queensland Government imposes caps on the prices that Ergon Energy can charge for a number of these services. The actual price caps for 2008-09 are reflected in the estimated revenue. The price caps for 2009-10 are not known at this stage however, the revenue reflects estimates of the expected price caps. Estimated revenues for Subdivision Fees and Project Fees cannot be provided for 2008-09 and 2009-10 because Subdivision Fees and Project Fees are classified as Quoted Services only in the current regulatory control period. In the next regulatory control period, Subdivision Fees and Project Fees have been classified as both Fee Based Services and Quoted Services. The reallocation of the existing services between the new quoted and fee based Subdivision Fees and Project Fees can not be determined based on existing systems and data, and consequently Ergon Energy cannot provide estimated revenues for these services.

It is noted that the Queensland Government has precluded Ergon Energy from earning any regulated revenue from the provision of the 'De-energisation During and After Business Hours' service.

55.5 CUSTOMER NUMBERS FOR EACH FEE BASED SERVICE FOR 2005-10 BY REGULATORY YEAR

Section 2.2.5(a)(2) of the RIN requires that Ergon Energy provide, for alternative control services in this Regulatory Proposal, actual customer numbers (or job numbers where applicable) for equivalent services provided in each regulatory year of the current regulatory control period, with an estimate to be provided for the final two regulatory years of the current regulatory control period.

While Ergon Energy has historically provided information to the QCA on job numbers from its 'Excluded Distribution Services', due to difficulties within Ergon Energy's data capture and collection systems it has provided these in 10 categories rather than by individual service. These 10 categories are a mix of Fee Based and Quoted Services as classified in the current regulatory control period. Ergon Energy's systems do not record information on actual volumes relating to the delivery of these services on an individual basis. Furthermore, Ergon Energy has re-classified many of its Fee Based Services in the current regulatory control period to become Quoted Services in the next regulatory control period. There is therefore no 'equivalency' for the purposes of this Regulatory Proposal between the services for which volume information is currently provided to the QCA and the proposed Fee Based Services in the next regulatory control period.

Table 176: *2005-08 Job Numbers for Fee Based Services*

Fee Based Services	2005-06	2006-07	2007-08
De-energisation during and after business hours	n/a	n/a	30,286
High load escorts	n/a	n/a	399
Meter alterations	n/a	n/a	312
Other recoverable works	n/a	n/a	426
Other services	n/a	n/a	246
Re-allocate main point of attachment	n/a	n/a	555
Re-energisation during and after business hours	n/a	n/a	17,412
Revisit to customer's installation during business hours	n/a	n/a	3
Service drops and energisation visits	n/a	n/a	169
Temporary builder's supply	n/a	n/a	1,110
Total	**n/a**	**n/a**	**50,918**

Source: Regulatory Reporting Statements 2007-08

Indeed, there are no equivalent services in 2005-06 and 2006-07 at all, because services were not classified as 'Excluded Distribution Services' until 1 July 2007. For transparency, Ergon Energy has detailed in Table 176 (see previous page) the volume of all Excluded Distribution Services in 2007-08, split across the 10 categories for which volume information is provided to the QCA in Ergon Energy's Regulatory Reporting Statements.

Ergon Energy has provided forecast volumes for 2008-09 and 2009-10 in the accompanying completed RIN pro forma. Actual customer numbers for Subdivision Fees and Project Fees cannot be provided for the current regulatory control period. This is because Subdivision Fees and Project Fees are classified as Quoted Services only in the current regulatory control period. In the next regulatory control period, Subdivision Fees and Project Fees have been classified as both Fee Based Services and Quoted Services). The reallocation of the existing services between the new quoted and fee based Subdivision Fees and Project Fees can not be determined based on existing systems and data, and consequently Ergon Energy cannot provide actual or estimated customer numbers for these services.

55.6 DEMONSTRATION OF THE APPLICATION OF CONTROL MECHANISM

Clause 6.8.2(c)(3) of the Rules and section 2.4.7(a)(1)(ii) of the RIN requires Ergon Energy to include a demonstration of the application of the proposed control mechanism for its Fee Based Services and any supporting information.

The AER has set out the control mechanism to apply to Fee Based Services in its F&A Stage 1. In particular, section 3.5.2 of the AER's F&A Stage 1 provides that the AER will apply:

- A price cap form of control to Ergon Energy's alternative control services in the 2010–15 regulatory control period. This means that the approved price is the maximum price Ergon Energy is permitted to charge for a particular service; and
- A formula-based approach (a non-building block approach) to determine the efficient costs of providing Fee Based Services under a price cap form of control in the first regulatory year of the regulatory control period, the establishment of initial prices for the first regulatory year of the regulatory control period and then the establishment a price path for the remaining regulatory years of the regulatory control period.

Section 3.5.2 of the AER's F&A Stage 1 has a footnote which states that the formula-based approach referred to above may contain variable components whereas for Fee Based Services the components for each formula are fixed.

Ergon Energy has interpreted the above requirements to mean that, for Fee Based Services, the components of the formula will be subject to a price cap form of control, as will the final prices for each service.

This means that Ergon Energy must provide in this regulatory proposal:

- A formula which it will use to develop the prices for Fee Based Services; and
- Values for the component parts of the formula that it proposes, where these can be set in advance of the Distribution Determination. Only Labour costs fall into this category.

Ergon Energy will provide prices for fixed fee services in its Pricing Proposal.

55.6.1 Control Mechanism Formula

The following formula is proposed for Ergon Energy's Fee Based Services.

$$Pi = Li + Mi + OCi + CAi + GSTi$$

Where:

Li = the cost of labour involved in the delivery of the service, calculated as the product of an hourly rate (inclusive of on-costs and overheads) and the time spent by the personnel involved. The amount of time will include both travel time and the time spent delivering the service. The labour costs are set out in section 55.6.2 of this Regulatory Proposal.

Mi = the cost of non-capitalised materials expensed in the delivery of the service.

OCi = other one-off costs (inclusive of overheads) relating to the delivery of the service, including hire or supply of additional equipment, assets or labour, and contingency costs.

GSTi = the Goods and Services Tax component of the service charge.

CAi = a charge applied to reflect the use of non-system physical assets owned by Ergon Energy involved in the delivery of the service. This charge reflects the return on and of capital employed in the delivery of the service (e.g. trucks and IT systems). This will be the same calculation as for Quoted Services.

55.6.2 Control Mechanism Cost Components

CAi will be set out in the Pricing Proposal, and will be consequent to the AER's Distribution Determination. Materials and Other one-off costs are not applicable for Fee Based Services.

Labour costs for both ordinary time and overtime are set out in Table 177 and Table 178 for the 2010-11 to 2014-15 regulatory control period. All rates are inclusive of on-costs, but exclusive of overheads.

Contractor rates are expected to increase by 6 per cent per annum throughout the next regulatory control period, while all other labour classifications are expected to increase in accordance with the new Ergon Energy Union Collective Agreement 2008.

Table 177: *Labour Classification Forecast Ordinary Rates 2010-15 ($ per hour)*

Labour Classification	2010-11	2011-12	2012-13	2013-14	2014-15
Admin Employee					
Professional Managerial					
Power Worker					
Technical Service Person					
Electrical System Designer					
Supervisor					
Para-professional					
Apprentice					
Contractor					
Manager					
System Operator					
Trainee					

Source: Labour Rates for Alternative Control Services_27March09

CONFIDENTIAL INFORMATION

Table 178: *Labour Classification Forecast Overtime Rates 2010-15 ($ per hour)*

Labour Classification	2010-11	2011-12	2012-13	2013-14	2014-15
Admin Employee					
Professional Managerial					
Power Worker					
Technical Service Person					
Electrical System Designer					
Supervisor					
Para-professional					
Apprentice					
Contractor					
Manager					
System Operator					
Trainee					

Source: Labour Rates for Alternative Control Services_27March09

55.7 COST INFORMATION

Section 2.4.7(a)(2) of the RIN requires Ergon Energy to provide information to support the application of the proposed control mechanism for Fee Based Services, including:

- A formula based representation of the costs of providing each individual service, including operating costs and capital costs (return on assets and return of assets);
- Changes in historic and forecast operating costs and capital costs, including any calculations or documents to demonstrate the derivation of these costs; and
- A justification for any material differences between historic and forecast costs.

The formula representation of the costs of providing each service is provided in section 55.6.1 above. This includes operating costs and capital costs (return on assets and return of assets).

Ergon Energy does not have data, and is therefore unable to provide explanations, about historical and forecast capital and operating expenditure for Fee Based Services in the previous, current and next regulatory control periods for the purposes of section 2.4.7(a)(2) of the RIN.

In relation to:

- The cost of physical assets, Ergon Energy will charge an amount calculated in accordance with the value of these assets used in the provision of alternative control services and overhead costs allocated in accordance with the Cost Allocation Method (CAM) as approved by the AER.
- The cost of labour, the time series for labour rates for both ordinary time and overtime are set out in Table 179 and Table 180. Standard labour rates were not used in 2005-06 as the actual individual hourly rate of each employee involved in delivering the service were used instead. All rates are inclusive of on-costs, but exclusive of overheads; and
- Contractor rates are expected to increase by 6 per cent per annum for the remainder of the current regulatory control period, while all other labour classifications are expected to increase in accordance with the new Ergon Energy Union Collective Agreement 2008.

***Table 179:** Labour Classification Ordinary Rates 2005-10 ($ per hour)*

Labour Classification	2005-06	2006-07	2007-08	2008-09	2009-10
Admin Employee	Not applicable				
Professional Managerial	Not applicable				
Power Worker	Not applicable				
Technical Service Person	Not applicable				
Electrical System Designer	Not applicable				
Supervisor	Not applicable				
Para-professional	Not applicable				
Apprentice	Not applicable				
Contractor	Not applicable				
Manager	Not applicable				
System Operator	Not applicable				
Trainee	Not applicable				

Source: Labour Rates for Alternative Control Services_27March09

***Table 180:** Labour Classification Overtime Rates 2005-10 ($ per hour)*

Labour Classification	2005-06	2006-07	2007-08	2008-09	2009-10
Admin Employee	Not applicable				
Professional Managerial	Not applicable				
Power Worker	Not applicable				
Technical Service Person	Not applicable				
Electrical System Designer	Not applicable				
Supervisor	Not applicable				
Para-professional	Not applicable				
Apprentice	Not applicable				
Contractor	Not applicable				
Manager	Not applicable				
System Operator	Not applicable				
Trainee	Not applicable				

Source: Labour Rates for Alternative Control Services_27March09

CONFIDENTIAL INFORMATION

55.8 DEMAND INFORMATION

Section 2.4.7(a)(3) of the RIN requires Ergon Energy to provide information to support the application of the proposed control mechanism for Fee Based Services, including:

- Historic and forecast demand for each individual fee based service and quoted service; and
- Justification for any material differences between historic and forecast demand.

Ergon Energy does not have data, and is therefore unable to provide explanations about historical and forecast demand for Fee Based Services in the previous, current and next regulatory control periods for the purposes of section 2.4.7(a)(3) of the RIN.

Customer numbers for the current regulatory control period have been set out in section 55.5. Customer numbers for the next regulatory control period are set out in Table 181. The escalation rates used in developing the forecasts for 2009-10 onwards were sourced from Ergon Energy's Customer Services model.

Furthermore, actual customer numbers for Subdivision Fees and Project Fees cannot be provided for the current regulatory control period. This is because Subdivision Fees and Project Fees are classified as Quoted Services only in the current regulatory control period. In the next regulatory control period, Subdivision Fees and Project Fees have been classified as both Fee Based Services and Quoted Services. The reallocation of the existing services between the new quoted and fee based Subdivision Fees and Project Fees cannot be determined based on existing systems and data, and consequently Ergon Energy cannot provide actual or estimated customer numbers for these services.

Table 181: *2010-15 Forecast Customer Numbers for Fee Based Services*

	2010-11	2011-12	2012-13	2013-14	2014-15
Subdivision Fees (specification and design enquiry)	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable
Project Fees (specification and design enquiry)	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable
De-energisation during business hours	25,503	29,074	33,144	37,784	43,074
Re-energisation during business hours	23,970	27,326	31,151	35,512	40,484
Re-test Fee	60	60	60	60	60
Supply Abolishment	1,170	1,170	1,170	1,170	1,170
Temporary Builder's Supply	1,690	1,690	1,690	1,690	1,690
Attend loss of supply - not DNSP Fault (business hours)	44	44	44	44	44
Wasted Truck Visit	94	94	94	94	94
Total	**52,531**	**59,457**	**67,353**	**76,355**	**86,616**

Source: Fixed Fee services_Volumes and Revenues_7May09

55.9 PRICE FOR EACH ALTERNATIVE CONTROL SERVICE FOR 2005-10 BY REGULATORY YEAR

Section 2.2.5(a)(4) of the RIN requires that Ergon Energy provide the prices for equivalent Fee Based Services provided in each regulatory year of the current regulatory control period, using an estimate for the final two regulatory years of the current regulatory control period.

This information is detailed in Table 182 for 2007-08 to 2009-10. However, there are no equivalent prices in 2005-06 and 2006-07. This is because services were not classified as 'Excluded Distribution Services' until 1 July 2007.

Equivalent prices for Subdivision Fees and Project Fees cannot be provided for the current regulatory control period. This is because Subdivision Fees and Project Fees are currently classified as Quoted Services, and consequently forecast fixed prices are not available for these services.

The general reduction in 2008-09 prices compared to those in 2007-08 is due to a reduction in the on-cost rate (following reductions in payments to ESI Super), a change in the overheads applied to these services and the introduction of a more accurate method of determining the type of staff employed in the provision of each individual service. Prices for services in 2008-09 onwards were calculated using the actual labour rate for the type of staff employed in the provision of the service rather than an average labour rate.

Ergon Energy notes that the prices contained in Table 182 are the prices approved by the QCA. These are not the prices that Ergon Energy charges for some services due to the price caps imposed by the Queensland Government.

55.10 PRICING INFORMATION

Clause 6.18 of the Rules requires that Ergon Energy submit a Pricing Proposal to the AER after the AER has made its Distribution Determination. Ergon Energy will do this in accordance with the Rules.

Section 2.2.5(a)(5) of the RIN and clauses 6.8.2(c)(4) and S6.1.3(6) of the Rules require that Ergon Energy provide indicative prices for each individual alternative control service in each regulatory year of the next regulatory control period.

In accordance with the AER's F&A Stage 1, Ergon Energy has used the formula-based approach to establish the initial prices for the first regulatory year of the regulatory control period. For the remaining regulatory years of the regulatory control period, Ergon Energy has then applied a price path of 4.5 per cent for Subdivision Fees and Project Fees, and a price path of 3.81 per cent for all other Fee Based Services. In accordance with clause S6.1.3(b) of the Rules, for each individual Alternative Control Service - Fee Based Service, an example of a possible price for each regulatory year is set out in the RIN pro forma.

The price path of 4.5 per cent per annum applies only to Subdivision Fees and Project Fees as both these services consist only of labour components, to which the annual Ergon Energy Union Collective Agreement 2008 rate of 4.5 per cent applies.

All other Fee Based Services consist of labour and vehicles components. While the labour component of these services is forecast to increase in accordance with the annual Ergon Energy Union Collective Agreement 2008 rate of 4.5 per cent, the vehicles component is forecast escalate at a rate which is not consistent between the remaining regulatory years of the regulator control period. Furthermore, the proportion of the vehicles component to the total price is different for each service. Consequently, to determine an appropriate price path for these services, Ergon Energy has calculated the average of the change in the total prices for all services (excluding Subdivision Fees and Project Fees) for the remaining regulatory years of the regulatory control period. The price path has therefore been calculated to be 3.77 per cent.

The indicative prices are set out in Table 183.

***Table 182:** 2005-10 Prices for Fee Based Services ($ GST Inclusive)*

Fee Based Services	2005-06	2006-07	2007-08	2008-09	2009-10
Subdivision Fees	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable
Project Fees	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable
De-energisation during business hours - urban/short rural feeders	Not applicable	Not applicable	89.10	88.98	92.27
De-energisation during business hours - long rural / isolated feeders	Not applicable	Not applicable	534.61	416.45	431.86
Re-energisation during business hours - urban/short rural feeders	Not applicable	Not applicable	71.28	73.14	75.84
Re-energisation during business hours - long rural / isolated feeders	Not applicable	Not applicable	498.97	388.92	403.31
Re-test at customer's installation during business hours - urban/short rural feeders	Not applicable	Not applicable	320.77	254.52	263.94
Re-test at customer's installation during business hours - long rural / isolated feeders	Not applicable	Not applicable	641.53	497.41	515.82
Supply Abolishment during business hours - urban/short rural feeders	Not applicable	Not applicable	320.77	254.52	263.94
Supply Abolishment during business hours - long rural / isolated feeders	Not applicable	Not applicable	641.53	497.41	515.82
Temporary Builders Supply, not in permanent position- single phase metered - business hours - urban/short rural feeders	Not applicable	Not applicable	534.61	416.45	431.86
Temporary Builders Supply, not in permanent position- single phase metered - business hours - long rural / isolated feeders	Not applicable	Not applicable	855.38	659.34	683.74
Temporary Builders Supply not in permanent position - multi phase metered - business hours - urban/short rural feeders	Not applicable	Not applicable	534.61	416.45	431.86
Temporary Builders Supply not in permanent position - multi phase metered - business hours - long rural / isolated feeders	Not applicable	Not applicable	855.38	659.34	683.74
Restoration of supply required due to customer action, during business hours - urban/short rural feeders	Not applicable	Not applicable	320.77	254.52	263.94
Restoration of supply required due to customer action, during business hours - long rural / isolated feeders	Not applicable	Not applicable	641.53	497.41	515.82
Wasted truck visit - one person crew - urban/short rural feeders	Not applicable	Not applicable	106.92	54.85	56.87
Wasted truck visit - one person crew - long rural / isolated feeders	Not applicable	Not applicable	427.69	184.51	191.34
Wasted truck visit - two person crew - urban/short rural feeders	Not applicable	Not applicable	Not applicable	92.02	95.43
Wasted truck visit - two person crew - long rural / isolated feeders	Not applicable	Not applicable	Not applicable	333.22	345.55

Source: Fixed Fee Prices_Current Period_7May09

Table 183: *2010-15 Indicative Prices for Fee Based Services ($ GST Inclusive)*

Fee Based Services	2010-11	2011-12	2012-13	2013-14	2014-15
Subdivision Fees	763.16	797.51	833.39	870.90	910.09
Project Fees	763.16	797.51	833.39	870.90	910.09
De-energisation during business hours - urban/short rural feeders	129.86	134.76	139.84	145.11	150.58
De-energisation during business hours - long rural / isolated feeders	621.40	644.83	669.15	694.38	720.96
Re-energisation during business hours - urban/short rural feeders	103.26	107.16	111.20	115.39	119.74
Re-energisation during business hours - long rural / isolated feeders	579.15	600.98	623.64	647.16	671.56
Re-test at customer's installation during business hours - urban/short rural feeders	441.03	457.66	474.92	492.82	511.41
Re-test at customer's installation during business hours - long rural / isolated feeders	882.06	915.32	949.83	985.65	1,022.81
Supply Abolishment during business hours - urban/short rural feeders	441.03	457.66	474.92	492.82	511.41
Supply Abolishment during business hours - long rural / isolated feeders	882.06	915.32	949.83	985.65	1,022.81
Temporary Builders Supply, not in permanent position- single phase metered - business hours - urban/short rural feeders	735.05	762.76	791.53	821.37	852.34
Temporary Builders Supply, not in permanent position- single phase metered - business hours - long rural / isolated feeders	1,176.08	1,220.42	1,266.44	1,314.19	1,363.75
Temporary Builders Supply not in permanent position - multi phase metered - business hours - urban/short rural feeders	735.05	762.76	791.53	821.37	852.34
Temporary Builders Supply not in permanent position - multi phase metered - business hours - long rural / isolated feeders	1,176.08	1,220.42	1,266.44	1,314.19	1,363.75
Restoration of supply required due to customer action, during business hours - urban/short rural feeders	441.03	457.66	474.92	492.82	511.41
Restoration of supply required due to customer action, during business hours - long rural / isolated feeders	882.06	915.32	949.83	985.65	1,022.81
Wasted truck visit - one person crew - urban/short rural feeders	94.82	98.39	102.10	105.95	119.95
Wasted truck visit - one person crew - long rural / isolated feeders	379.28	393.58	408.42	423.82	439.80
Wasted truck visit - two person crew - urban/short rural feeders	145.37	150.86	156.54	162.45	168.57
Wasted truck visit - two person crew - long rural / isolated feeders	581.49	603.42	626.17	649.78	674.29

Source: Fixed Fee Services_Indicative Prices Calculation_28May09

55. ALTERNATIVE CONTROL SERVICES – FEE BASED SERVICES – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR367c & 368c	AER Regulatory Information Notice

Codes and Rules

AR048	Qld Electricity Industry Code (fourth edition)
AR364	National Electricity Rules

Ergon Energy Documents

AR094	Ergon Energy Union Collective Agreement 2008
AR119c	EE Annual Regulatory Accounts for 2001-02
AR120c	EE Annual Regulatory Accounts for 2002-03
AR121c	EE Annual Regulatory Accounts for 2003-04
AR122c	EE Annual Regulatory Accounts for 2004-05
AR123c	EE Annual Regulatory Accounts for 2005-06
AR124c	EE Annual Regulatory Accounts for 2006-07
AR370c	EE Annual Regulatory Accounts for 2007-08
AR433c	EE Fixed Fee Services, Indicative Prices Calculation, 28 May 2009
AR478c	EE Fixed Fee Services, Current Period, 7 May 2009
AR479c	EE Fixed Fee Services, Volumes and Revenues, 7 May 2009

56. NEGOTIATING FRAMEWORK

Rules - 6.7.1, 6.7.2(a)(1), 6.7.3, 6.7.5, 6.8.2(c)(5), 6.12.1(15), 6.12.3(g) and (h), 6.22.2(c)
RIN – 2.2.5(a)(3)
RIN Pro forma - 2.2.5
CAG – 5.1(b)(3)

Clause 6.8.2(c)(5) of the Rules requires a Regulatory Proposal to include the proposed negotiating framework for services classified under the proposal as negotiated Distribution Services.

However, the Australian Energy Regulator's (AER) F&A Stage 2 determined its likely approach in its Distribution Determination for Ergon Energy for the next regulatory control period would be not to require Ergon Energy to include a negotiating framework in its Regulatory Proposal in the absence of any service being proposed as a negotiated distribution service.

Ergon Energy has not proposed in its classification proposal in Chapter 14 of this Regulatory Proposal that any services be classified as negotiated Distribution Services. As a result, Ergon Energy has not included:

- A negotiating framework in this Regulatory Proposal, as it would otherwise be required to do under clause 6.8.2(c)(5) of the Rules;
- Details of the customer numbers for each negotiated Distribution Services by regulatory year for 2005-10, as it would otherwise be required to do under clause 2.2.5(a)(2) of the Rules; and
- Details of the revenue for each negotiated Distribution Services by regulatory year for 2005-10, as it would otherwise be required to do under section 2.2.5(a)(3) of the Regulatory Information Notice.

56. NEGOTIATING FRAMEWORK – DOCUMENT INDEX

References – Chapter 56

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR365 & 366	AER Framework and Approach Paper (Stages 1 & 2)
AR367c & 368c	AER Regulatory Information Notice
AR417 & 418	AER Cost Allocation Guidelines, Final Decision and Guidelines, 26 June 2008

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

Nil

57. CERTIFICATION STATEMENT

Rules – Clauses S6.1.1(5) and S6.1.2(6)
RIN – Clause 2.3.3(b), Attachment 4

The directors certify that:

- In accordance with clause S6.1.1(5) of the Rules, the key assumptions that underlie the capital expenditure forecast set out in pro forma 2.3.3 of the Regulatory Information Notice are reasonable.
- In accordance with clause S6.1.2(6) of the Rules, the key assumptions that underlie the operating expenditure forecast set out in pro forma 2.3.3 of the Regulatory Information Notice are reasonable.

Signed in accordance with a resolution of directors:

10 JUNE 2009

Dr Ralph Howard Craven

Dated

Director

10 JUNE 2009

John Alan Bird

Dated

Director

57. CERTIFICATION STATEMENT – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice

Codes and Rules

AR364	National Electricity Rules

Ergon Energy Documents

AR470	EE RIN Attachment 4: Directors' Certification Statement

58. CHIEF EXECUTIVE'S STATUTORY DECLARATION

RIN – Attachment 5

Oaths Act 1867 (Qld)

I, Ian Leslie McLeod of 34-36 Dalrymple Road, Garbutt, Townsville, Queensland, Chief Executive of Ergon Energy Corporation Limited (Ergon Energy), do solemnly and sincerely declare that:

a. the information and documentation provided to the Australian Energy Regulator (AER) in accordance with the Regulatory Information Notice served on Ergon Energy by the AER on 22 April 2009 is complete in all material respects; and

b. the information and documentation provided to the AER in accordance with the Regulatory Information Notice are accurate in all material respects and can be relied upon by the AER to assess the Regulatory Proposal submitted by Ergon Energy to the AER on or before 1 July 2009 and to make a distribution determination for Ergon Energy.

And I make this solemn declaration conscientiously believing the same to be true and by virtue of the provisions of the *Oaths Act 1867.*

Signature

Declared by Ian Leslie McLeod at Cairns on the 10th June 2009.

Before me,

Signature

GRAEME FINLAYSON, SOLICITOR

Name, address and qualification of person before whom the declaration is made

58. CHIEF EXECUTIVE'S STATUTORY DECLARATION – DOCUMENT INDEX

The following documents (except those marked as confidential) are available electronically on request.

Legislation

Nil

AER Documents

AR367c & 368c	AER Regulatory Information Notice

Codes and Rules

Nil

Ergon Energy Documents

AR471	EE RIN Attachment 5: Chief Executive's Statutory Declaration

ATTACHMENT AR467C – REGULATORY PROPOSAL CROSS-REFERENCED TO REGULATORY REQUIREMENTS (THE 'SKELETON')

Ergon Energy has prepared a document that cross-references each of the requirements for Ergon Energy's Regulatory Proposal arising from the following regulatory instruments - the:

- National Electricity Rules;
- The AER's Regulatory Information Notice dated 22 April 2009 as issued by the AER;
- AER's Framework and Approach Final Decision papers (Stages 1 and 2);
- AER's Cost Allocation Guidelines;
- AER's Efficiency Sharing Benefit Scheme Guideline;
- AER's Service Target Performance Incentive Scheme Guideline;
- AER's Demand Management Incentive Scheme Guideline;
- AER's Statement of Regulatory Intent on the revised Weighted Average Cost of Capital (WACC) parameters (distribution) (SoRI); and
- AER's Final Decision on the Review of the WACC parameters (Final Decision).

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everything in our power