ENERGEX

Regulatory Proposal

for the period July 2010–June 2015

July 2009

energex

positive energy

energex
positive energy

ENERGEX Limited trading as ENERGEX
ABN: 40 078 849 055
150 Charlotte Street
BRISBANE QLD 4000

www.energex.com.au

Requests and inquiries concerning this document should be addressed to:

Director Revenue Strategy
ENERGEX
PO Box 1461
BRISBANE QLD 4001

Table of Contents

1 Overview

1.1 Introduction

ENERGEX Limited is a Queensland Government Owned Corporation (GOC) that builds, owns, operates and maintains the electricity distribution network in the fast growing region of South East Queensland (SEQ). ENERGEX provides distribution services to almost 1.3 million connections, delivering electricity to 2.8 million residents and businesses across the region. ENERGEX's network covers around 25,000 square kilometres, stretching from Gympie in the north to Withcott in the west, Stradbroke Island in the east and Coolangatta in the south. ENERGEX's assets include more than 50,000 kilometres of underground cables and overhead lines, over half a million power poles, some 43,000 distribution transformers, 250 zone and bulk supply substations, and approximately 300,000 street lights.

ENERGEX's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

ENERGEX is submitting this *Regulatory Proposal* to the Australian Energy Regulator (AER) in accordance with the requirements of Clause 6.8 of the National Electricity Rules (the *Rules*)[1] and with consideration of the transitional arrangements for Queensland under Clause 11.6 of the *Rules*. This *Regulatory Proposal* is also submitted in accordance with other relevant regulatory instruments, including the AER's *Regulatory Information Notice* (RIN), the AER's first distribution guidelines package[2], and the AER's final decisions on Classification of services and control mechanisms and Application of schemes as outlined in the Framework and approach papers[3].

This *Regulatory Proposal* applies to the *regulatory control period* from 1 July 2010 to 30 June 2015 (the *2010-15 regulatory control period*) and has been developed to satisfy relevant regulatory requirements. ENERGEX submits this *Regulatory Proposal* to the AER to make a distribution determination to apply to ENERGEX for the *2010-15 regulatory control period*.

---

1 All references to Clauses henceforth refer to *the National Electricity Rules* unless otherwise specified.

2 The first distribution guidelines released on 26 June 2008 consist of the Post Tax Revenue Model, Roll Forward Model, *Efficiency Benefit Sharing Scheme*, *Service Target Performance Incentive Scheme* and Cost Allocation Guidelines. AER subsequently revised the STPIS and a new STPIS Version 1.1 was released in May 2009.

3 Source: AER, *Framework and approach paper Classification of services and control mechanisms ENERGEX and Ergon Energy 2010-15*, August 2008 (Stage 1: Framework and approach paper) and the AER *Final Framework and approach paper Application of schemes ENERGEX and Ergon Energy 2010-15*, November 2008 (Stage 2: Framework and approach paper).

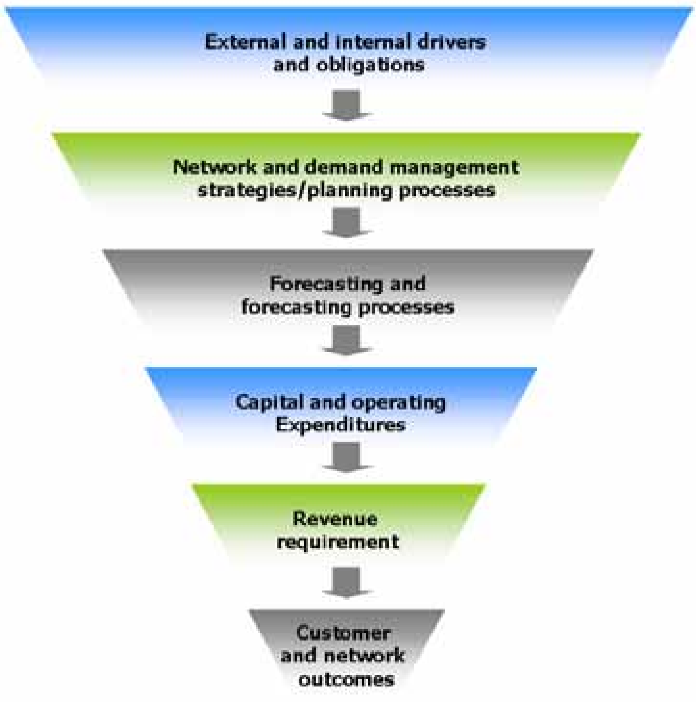
This *Regulatory Proposal* provides details of ENERGEX's proposed capital and operating programs and the required revenue for the *2010-15 regulatory control period*. These programs are based on the external drivers and regulatory obligations required to deliver the *standard control services* and *alternative control services*. It also articulates how ENERGEX's Network and Demand Management Strategies are addressing these drivers in an efficient and prudent manner.

This overview provides a summary of:

- key network challenges facing ENERGEX as a distribution business;
- strategies to meet the challenges;
- current performance against targets and forecasts;
- forecasts for the *2010-15 regulatory control period*;
- building block revenues; and
- outcomes arising from this *Regulatory Proposal*, including impacts on customers.

The structure of this proposal is summarised in Figure 1.1.

Figure 1.1 Structure of ENERGEX's *regulatory proposal*



1.2 ENERGEX's key challenges

Section 7(a) of the *National Electricity Law's* (NEL) objective 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".*

This *Regulatory Proposal* focuses on this objective, recognising that investment in electricity infrastructure requires long-term financial sustainability, based on sound management of electricity assets with an operational life expectancy of between 40-60 years.

Following eight decades of experience in distributing electricity in SEQ, ENERGEX submits a *Regulatory Proposal* that allows a continuation of the supply-side capital expenditure response in relation to building and operating infrastructure. At the same time, ENERGEX has provided for investment in accepted technologies to modernise the existing infrastructure for the provision of a smart network, establish the capability for effective demand-side solutions and enable distributed generation from alternative sources, such as solar power.

While the full benefit of these technologies is unlikely to be realised until after 2015, ENERGEX believes they provide a platform to enable electricity consumers to participate in managing their energy needs and influencing the shape of the SEQ electricity network into the future. Further technological advances will allow selection of sustainable options from a suite of alternative energy sources.

In common with other electricity distributors in the National Electricity Market (NEM), ENERGEX recognises that sole reliance on managing infrastructure using established asset-centric practices will not address emerging challenges, such as climate change and increased community reliance on reliability and security to power a digital economy. However, any alternatives must continue to serve the long-term interests of consumers in terms of price, quality, safety, reliability and security of electricity supply.

As an organisation, ENERGEX's ultimate goal is to improve the balance between supply-side management, involving meeting demand through building capacity into the system, and demand-side solutions that focus on reducing demand or the provision of alternative energy solutions. This must be achieved while improving the security of the network.

In early 2004, the Queensland government commissioned the Electricity Distribution for Service Delivery in the 21st Century (EDSD Review). The review recommended ENERGEX adopt planning processes that will return all bulk supply substations, zone substations and sub-transmission feeders to an 'N-1' philosophy. The review also recommended ENERGEX adopt a 10 PoE[4] forecasting assumption in planning its network capacity to meet demand, with the position to be reviewed when asset utilisation is reduced to the order of 60-65 per cent.

In assessing ENERGEX's expenditure program on behalf of the Queensland Competition Authority (QCA), in 2006 consultants WorleyParsons found that 'the ENERGEX's network falls far short of meeting the standards detailed in the EDSD Review'. They noted that even if the additional funds sought under the capital expenditure pass through were provided, 'the full suite of EDSD system performance outcomes will not be achieved by the end of the current regulatory period'[5].

During the *current regulatory control period*, ENERGEX has made progress toward the EDSD security requirement through improving the reliability of its network in an environment of significant challenge. These challenges have required ENERGEX to meet customer demands in some of the fastest growing regions in Australia, address increasing peak demand arising from more extensive use of air-conditioning at the same time as improving network security and reliability.

To ensure the long-term interests of consumers are served, investment in new technologies must be co-ordinated with augmentation of the network, and for this reason ENERGEX's forecast capital and operating expenditure included in this *Regulatory Proposal* reflects investment in capacity projects while seeking to modernise the network through demand management (DM) initiatives and investment in a telecommunications enabled smart network.

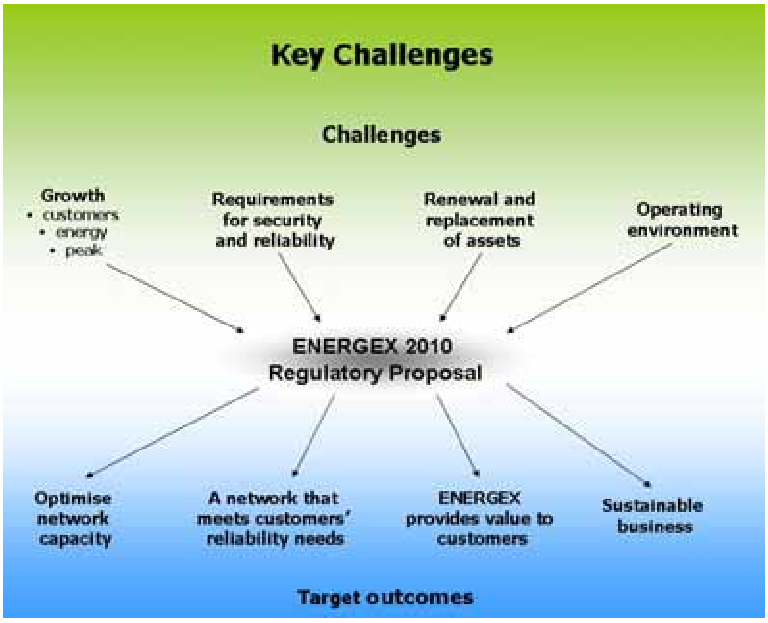
The key challenges and the outcomes anticipated for the *2010-15 regulatory control period* are shown in Figure 1.2 and summarised below:

- moving closer toward EDSD compliance, in terms of security and reliability;
- the renewal and replacement of assets;
- meeting sustained growth; and
- addressing the changing operating environment of SEQ.

4 A percentage Probability of Exceedence (PoE) for demand refers to the likelihood that a forecast will be met or exceeded in a particular season of any given year. That is, 10 PoE demand projections are expected to be met or exceeded, on average, one year in every 10. A 50 PoE projection will be met or exceeded, on average, one year in every two.

5 Source: QCA, *Review of Capital Expenditure Proposed by ENERGEX for Pass-through to Distribution Network Customers in Queensland*, December 2006, page 6 section 1.11 Implementation of EDSD Recommendations.

Figure 1.2 ENERGEX's key challenges



1.2.1 Requirements for security and reliability

A major focus for ENERGEX's forecast capital and operating expenditure for the *2010-15 regulatory control period* is improving security of the network.

In 2004, as part of ENERGEX's response to the Queensland government's EDSD findings, ENERGEX reviewed its probabilistic reliability assessment planning approach. In conjunction with the then Queensland Mines and Energy (QME)[6], a practical implementation of the deterministic 'N-1' philosophy, in the form of supply security standards was developed. ENERGEX publicly reports achievements against these standards annually in the Network Management Plan (NMP).

A review of these standards and their appropriateness in achieving a balanced outcome was conducted by ENERGEX in 2008. The assessment considered:

- expectations of our customers and their communities;
- willingness to pay for service delivery; and
- management of network risk.

[6] Department of Mines and Energy is now a function area under the Department of Employment, Economic Development and Innovation, which was established on 26 March 2009. For the purpose of this *Regulatory Proposal*, the reference used will be QME. The Regulator for the purposes of the *Electricity Act 1994* is the Associate Director General, Mines and Energy.

ENERGEX's supply security standards were independently reviewed by engineering consultant Evans & Peck, who concluded that with the implementation of identified safeguards, the revised standards were in accord with the 'N-1' philosophy envisaged by the EDSD Review.

The capital and operating expenditure forecasts in this proposal have been prepared in accordance with these proposed security standards.

ENERGEX's capital program has been prepared to continue delivery of the EDSD security compliance throughout the *2010-15 regulatory control period*.

Another significant compliance requirement arising from the EDSD Review was reliability enhancements, with the codification of Minimum Service Standards (MSS) and Guaranteed Service Levels (GSL) in the Queensland Electricity Industry Code (EIC) under the *Electricity Act 1994*.

The forecast capital and operating expenditure in this *Regulatory Proposal* has been based on compliance with these codified reliability and service standards.

1.2.2 Meeting demand growth in ENERGEX's network area

For the past decade ENERGEX has faced sustained growth driven by the strong economic performance of SEQ. Although predicted to moderate, ENERGEX's growth challenge is set to continue with ongoing growth in peak demand, numbers of new connections and ongoing energy usage.

Key drivers for high demand growth have been population increases, changing customer needs with more reliance on energy-intensive appliances and increased penetration of air-conditioning units in existing premises – a latent driver of peak demand that ENERGEX must be prepared to meet.

The SEQ region continues to see tracts of land being released for new subdivisions on the urban fringe, which is the primary driver of demand growth arising from residential and commercial sectors. In addition, ENERGEX is also experiencing increased demand from a strong urban renewal program resulting in increased density housing in suburban regions.

ENERGEX's network supply area contains two of Australia's fastest growing statistical divisions, being the Gold Coast and the Sunshine Coast. Together with steady growth in the Brisbane area, they contribute to a sustained increase in the capacity required and the number of new connections to the network.

Peak demand continues to play a major part in ENERGEX's growth challenge. In September 2008 demand was forecast to grow at an average annual growth rate of 4.36 per cent. Meeting demand growth is a significant part of ENERGEX's capital program to both supply the load and to maintain the required level of network security.

Analysis of ENERGEX's demand profile highlights the correlation between high demand and high temperatures.

Electricity distribution networks are required to meet peak demand requirements of which air-conditioning use is a significant contributor. However, retail tariffs, particularly for domestic customers, are applied on an energy use basis. When demand growth outstrips energy consumption growth, which is the forecast trend, additional pressure will be placed on the energy-based tariff rate to increase.

ENERGEX's Customer Strategy has been developed to better understand and predict changes in the patterns of electricity use by customers and stakeholder groups within ENERGEX's area. Over the long term, ENERGEX's DM Strategy aims to curtail peak demand and reduce the need for large network investment. This *Regulatory Proposal* recognises that, while DM practices will assist in ameliorating the impact of customers' demands on the network, significant supply-side solutions will be required for the *2010-15 regulatory control period* to meet the forecast capital and operating expenditure objectives.

1.2.3 Renewal and replacement of ageing asset base

In addition to the challenge of meeting the compliance requirements and growth on its network, ENERGEX is faced with the challenge of replenishing its ageing asset base.

Many of ENERGEX's assets were constructed during the 1960s. This was followed by the construction boom of the 1980s, particularly in the Gold Coast region. Many of these assets are now nearing the end of their useful lives and will require replacement.

Even though the QCA provided a record allowance to ENERGEX in the *current regulatory control period*, the allowance was not sufficient to meet high growth in demand, keep pace with requests for new connections to the network and focus on asset replacement. As a consequence, the risk profile associated with the ageing assets is rising and becoming unacceptable. ENERGEX's position is that renewal and replacement of aged assets needs increased focus in the *2010-15 regulatory control period* and beyond.

1.2.4 Operating environment

ENERGEX's operating environment has changed significantly since the last regulatory determination in 2005, creating new challenges for the electricity distribution network in SEQ.

A major driver for the change during the *2010-15 regulatory control period* will be the impact of climate change initiatives.

In addition to implementing internal policies that reduce the corporation's own carbon emissions, the three fundamental impacts of climate change on the ENERGEX network include the:

- emerging impact of government policy measures, such as the anticipated Carbon Pollution Reduction Scheme (CPRS);
- potential changes in customer usage patterns; and

- wide-scale connection of embedded generation to the distribution network driven by the government's incentives.

The sale of the retail and gas network businesses in 2007, together with the transition to Full Retail Competition (FRC), significantly changed ENERGEX's business operations. To operate in the FRC environment, systems and processes were modified to manage transactions between the retailers, National Electricity Market Management Company (NEMMCO) and ENERGEX. These changes have enabled ENERGEX to facilitate an orderly transfer of customers to different retailers and to respond efficiently to service requests.

In the first year of FRC in Queensland, a record number of approximately 350,000 customers on ENERGEX's network were transferred onto market contracts offered by energy retailers. This number is almost three times the number processed in the first 12 months of FRC in New South Wales (NSW). The business continues to successfully adapt and perform in an FRC environment whilst maintaining its relationships with retailers and customers.

A further change has occurred in the area of customer expectations in terms of reliability needs and engagement with the community in relation to electricity infrastructure. Reliability expectation has been driven by increased reliance on 'interruption free' electricity supply with the emergence of the use of digital equipment. Heightened community pressure for infrastructure that is less intrusive has increased as ENERGEX meets demand through record augmentation of the network.

In recognition of these changing attitudes, ENERGEX seeks to undertake network investment that provides value to customers and is in the long-term interests of the SEQ community.

1.3 Strategies to meet challenges

ENERGEX has an overarching corporate strategy to govern the whole of business response to challenges and achieve a balanced commercial outcome. ENERGEX's future success and sustainability is based on the ability to balance positive customer outcomes, financial performance and business risks as depicted in Figure 1.3.

Figure 1.3 The ENERGEX challenge: delivering a balanced outcome

ENERGEX has developed integrated strategies to respond to external challenges and obligations while taking account of the business needs and the condition of the assets. This section outlines ENERGEX's strategies for the *2010-15 regulatory control period*.

1.3.1 Network strategy

ENERGEX's Network Strategy identifies priorities for the network business and provides fundamental guidance for decisions over the *2010-15 regulatory control period*.

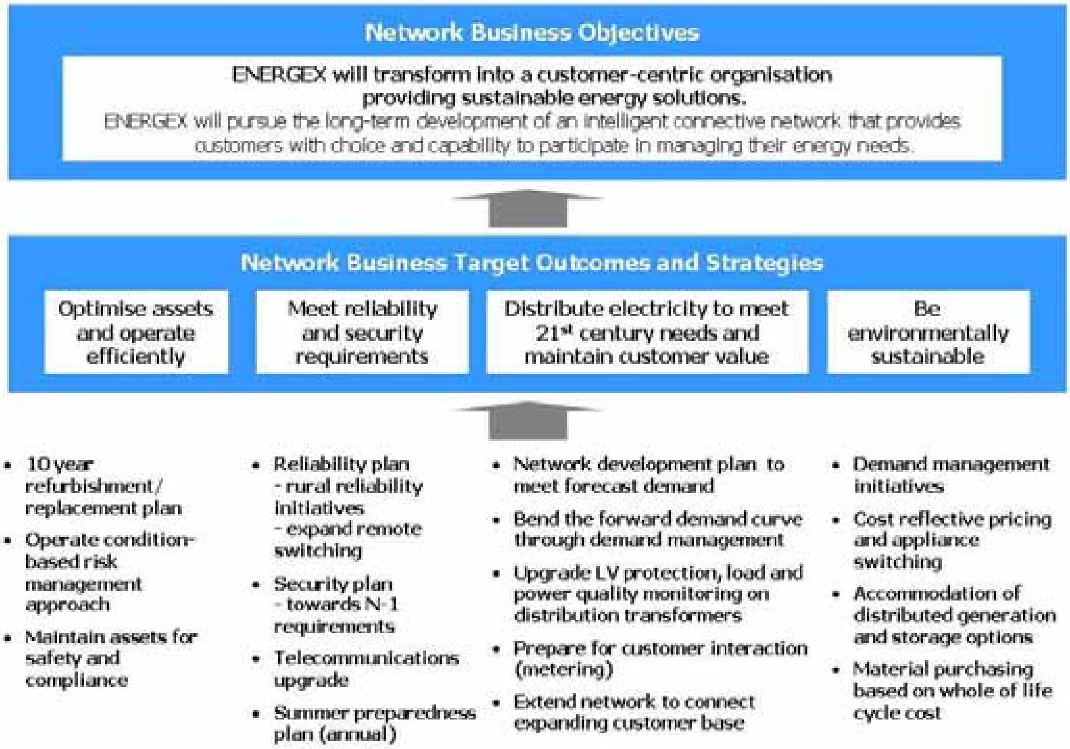
ENERGEX's Network Strategy utilises a long-term vision for distribution of electricity in SEQ, while the network development and management framework identifies programs and projects to achieve the Network Strategy. ENERGEX's expenditure forecasts are derived from the programs and discussed in this *Regulatory Proposal*.

The Network Strategy responds to the key network business challenges by:

- meeting growth and security requirements in ENERGEX's network area via the Network Development Plan (NDP);
- achieving customer requirements through the Reliability and Power Quality Plans;
- applying a Condition Based Risk Management (CBRM) approach to renewal and replacement of assets;
- network demand management to accommodate the variable operating environment; and
- progressing the modernisation of the distribution network through the development and deployment of a smart network with improved communications, network operations and control technology.

ENERGEX's Network Strategy is summarised in Figure 1.4.

Figure 1.4 ENERGEX's network strategy



The Network Strategy guides the business response to external challenges and obligations, while at the same time considering business needs and condition of assets.

Key outcomes of ENERGEX's network strategy are to achieve reliability and security standards, meet regulatory requirements and deliver efficient expenditure for the longer term. To deliver this, ENERGEX will progressively overlay the electricity grid with communications technology, increasing the capacity for the remote management of faults and allowing quicker restoration of supply.

Another initiative in ENERGEX's capital program is ensuring network assets are technologically enabled to improve reliability performance in addition to providing options for customers to manage their own consumption.

1.3.2 Demand management strategy

In addition to developing supply solutions, ENERGEX pursues efficient management of the network by utilising demand management and promotion of energy efficiency. ENERGEX recognises its DM strategies are fundamental to stemming electricity demand, conserving resources and reducing the environmental impacts of today's energy-intensive living. ENERGEX also recognises that customer appliances drive peak demand and therefore any DM strategy must be a partnership with customers.

For more than five decades ENERGEX has been a leading proponent of demand-side management. This is evidenced by the flattening of the winter peak load profile due to the successful voluntary hot water load control program supported by an off-peak tariff. This hot water load control program has been a highly successful and enduring partnership between ENERGEX and customers. ENERGEX's expertise in demand management with hot water is now being applied to meet the new challenges posed by air-conditioning load during the summer peak.

ENERGEX is an active participant in the broad-based demand management and energy conservation package developed in conjunction with Ergon Energy and QME.

ENERGEX has developed an integrated DM Strategy with the objective to reduce demand by a total of 144 MW over the *2010-15 regulatory control period*. ENERGEX will achieve this goal through a combination of broad-based energy management and peak DM strategies.

Major initiatives include:

- residential targeted initiatives that provide customers with demand management and energy conservation choices;
- commercial and industrial (C&I) targeted initiatives that deliver practical examples of demand management for business;
- reward-based tariffs that better reflect the cost of the capital utilised to meet peak demand for short periods of time;
- promotion of 'energy conservation communities' to connect demand management technologies with electricity end users; and
- load curtailment agreements with customers to manage peak demand, particularly in network constrained areas.

An overview of ENERGEX's DM Strategy is shown in Figure 1.5.

Figure 1.5 ENERGEX's DM strategy

1.3.3 Customer strategy

Many of the challenges ENERGEX has faced in the *current regulatory control period* will continue into the *2010-15 regulatory control period*, while new challenges such as the flow-on effect of the Global Financial Crisis (GFC) and the CPRS will also emerge.

At the same time as responding directly to these challenges, ENERGEX will also move toward continual improvement of its investment decisions through increased understanding of its customers.

The Customer Strategy is fundamental to determining and delivering value for customers to improve ENERGEX's business decisions over the *2010-15 regulatory control period* and beyond. It is intended to support ENERGEX's response to major network challenges and ensure that business decisions reflect improved analysis of customer information.

This Customer Strategy addresses the business response to the external environment in tandem with ENERGEX's business needs and the status of the network. It acknowledges the importance of effectively engaging and managing stakeholders. Environmental factors and obligations are considered, in addition to the reporting and monitoring requirements essential to establishing and maintaining service standards and extending the services to offer enhanced customer services.

ENERGEX's Customer Strategy is summarised below at Figure 1.6.

Figure 1.6 ENERGEX's customer strategy

1.3.4 Risk management framework

ENERGEX has a robust risk management framework that promotes an active culture of risk and compliance management across the entire workforce to maximise customer and shareholder value.

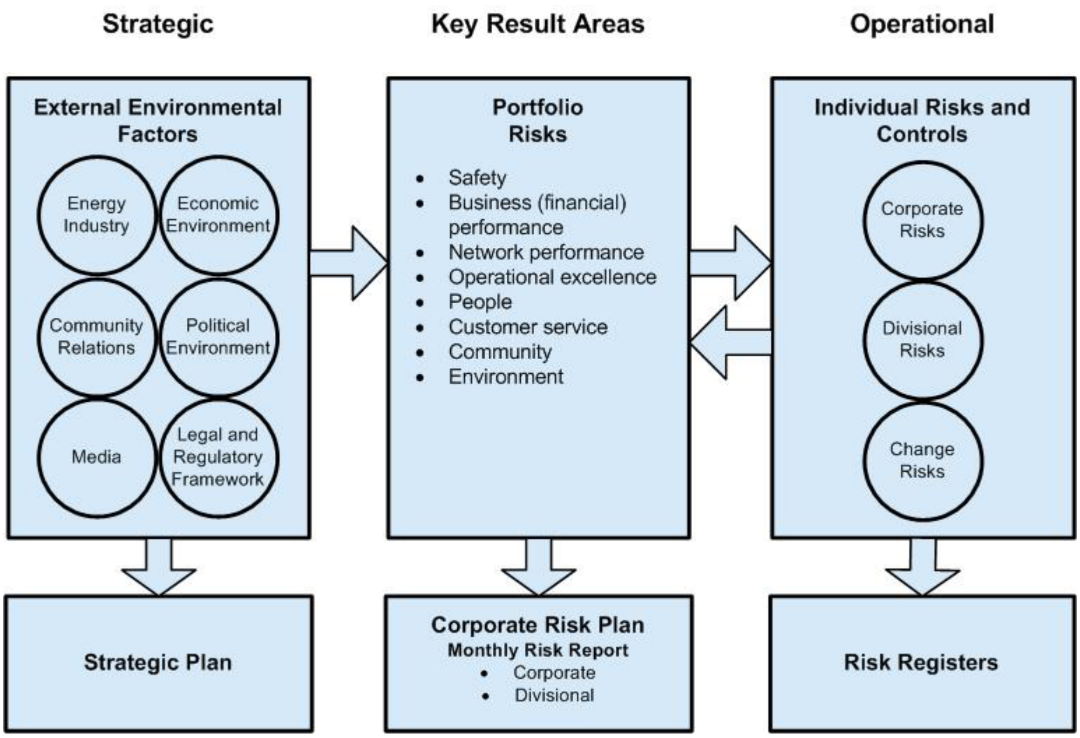
As an integral part of corporate governance, ENERGEX's Enterprise Risk Management Strategy supports the ENERGEX Board and management executives in exercising their corporate governance and oversight responsibilities to meet the organisation's objectives.

ENERGEX has implemented integrated risk management into the strategic business planning process through the following steps and as depicted in Figure 1.7.:

- Detailed the business objectives as specified in the Strategic Plan;
- Established key result areas as a framework for achievement of objectives;
- 'Top down' identification of significant risks with potential for material impact on achievement of targets in key result areas including assessment of external environmental factors;
- 'Bottom up' continuous Divisional risk profile assessment to identify risks associated with business-as-usual activities;

- Divisional and Executive Management Team analysis and review; and
- Validation, further input/feedback and final approval are sought from the ENERGEX Board.

Figure 1.7 ENERGEX's risk management framework



1.4 Current performance scorecard

Despite the challenges of upward pressure on costs and continued growth in peak demand, ENERGEX has, in most cases, achieved or outperformed the targets.

ENERGEX's weather-corrected peak demand growth has been comparatively higher than other distributors even though it has experienced extremely mild summer seasons over the recent years. This demand is driven by a combination of new customer connections and increasing penetration of air-conditioning units.

Residential air-conditioning penetration for a single air-conditioning unit has risen to approximately 69 per cent in suburban Brisbane, 70 per cent on the Gold Coast, 54 per cent on the Sunshine Coast and 63 per cent in western regions. Despite these increases, air-conditioning load in SEQ is unlikely to reach saturation point before 2017.

Despite the mild summer seasons of recent years, air-conditioning sales continue unabated. ENERGEX believes that this has created a significant amount of latent air-conditioning load on the network that is likely to be realised in future summer seasons. When this happens, the peak demand growth rate could be significantly higher as occurred in summer 2003-04.

While customer number growth is slightly lower than the *QCA's 2005 final determination*, new customer connections remain high with ENERGEX connecting more than 81,000 new customers over the past three years.

The mild weather has also seen energy consumption less than forecast with reduced volumes recorded due to the lower than expected air-conditioning use.

Improving reliability performance was one of the key recommendations of the EDSD Review and resulted in the establishment of MSS as outlined in the EIC. Since 2005 ENERGEX's Central Business District (CBD) and urban networks have out-performed the MSS targets. Performance on the rural network has improved and has generally met the MSS, with the exception of System Average Interruption Frequency Index (SAIFI) in 2005-06 and 2007-08 and System Average Interruption Duration Index (SAIDI) in 2007-08. This reliability performance is shown in Table 8.1.

A significant part of the reliability improvement ENERGEX has recorded has been achieved through a combination of capital initiatives, targeted maintenance and improved customer response. The latter is assisted by the introduction of in-field computer technology for ENERGEX work crews in the form of Field Force Automation (FFA). The implementation of a feeder improvement program, in line with the EDSD recommendations, has further improved the reliability performance of the network. Good performance can also be partially attributed to the mild weather conditions experienced over the past few years.

ENERGEX has demonstrated the capability to deliver record operating expenditure based on its performance during the *current regulatory control period*. During the first three years of the *current regulatory control period*, ENERGEX's actual operating expenditure is 1.9 per cent above the level allowed by the QCA, putting ENERGEX on track to spend the $1.6 billion forecast to 30 June 2010.

ENERGEX adopted a systems-based approach to the inspection of its assets. This program has also contributed to the overall improvement in the reliability and safety performance of the network.

Vegetation management is a major preventative strategy used to improve customer safety and reduce interruptions during storms and high winds. ENERGEX has invested heavily in the management of vegetation near powerlines, spending approximately $60 million per annum. This level of funding allows the continuation of the two and a half year vegetation management cycle for its entire network including the low voltage (LV) network. ENERGEX's vegetation management program involves 12,000 kilometres of tree trimming per annum, resulting in an improvement in network reliability performance.

Actual capital expenditure for the first three years of the *current regulatory control period* is $2.1 billion, or an average of $709 million per annum. This is 106 per cent higher than the investment made in the previous *regulatory control period*.

More than 3000 MV.A has been added to the network capacity at bulk supply and zone substations levels of the SEQ network during the past four years – an effective 33 per cent increase on the 2004-05 capacity.

During this time, ENERGEX has delivered capacity for the construction of major infrastructure development projects such as the temporary electricity supply to Brisbane's North-South bypass tunnel and the Gold Coast Desalination Plant.

ENERGEX's delivery of this record program represented a 124 per cent increase on the capital expenditure for the previous *regulatory control period* (2001-05) and demonstrates ENERGEX's capacity to significantly ramp up its resources to deliver the capital program to meet the high growth in peak demand, deliver MSSs and work toward meeting security compliance.

1.5 Forecasts for the 2010-15 regulatory control period

1.5.1 Demand, customer numbers and energy forecasts

ENERGEX's 2008 baseline forecasts for peak demand, customer numbers and energy consumption that underpin this *Regulatory Proposal* are based on a detailed analysis of the weather conditions and the relevant demographic and socio-economic factors and trends.

In preparation for the revenue determination, ENERGEX engaged an economic and forecasting consultant, ACIL Tasman, to review its forecasting methodology including a review of forecasts against actual peaks recorded during recent mild summers. Following this review, ENERGEX revised its forecasting methodology which provides for improved sensitivity to temperature variation and enhanced statistical rigour.

The baseline forecast annual growth rates for demand, customers and energy consumption for the *2010-15 regulatory control period* are discussed in Chapter 10 and summarised in Table 10.1.

As forecast in September 2008, the challenge posed by sustained high growth was set to continue for ENERGEX over the five-year period. Baseline peak demand was expected to grow at a rate of 4.36 per cent while customer numbers were forecast to increase at an average annual growth rate of 2.07 per cent. ENERGEX adopted the baseline energy forecasts developed by economic forecasting specialist, the National Institute of Economic and Industry Research (NIEIR) as they incorporated a preliminary assessment of the impact of CPRS. Energy consumption is therefore expected to grow at an average annual rate of 2.99 per cent.

The need to meet compliance requirements and peak demand continues to drive a significant part of ENERGEX's capital program to both supply the load and to provide for the required level of network security. The temperature sensitivity of ENERGEX's demand means that the network must be planned and developed to meet the high demand requirements experienced during hot summer periods, even though this drives network investment that is only utilised for a limited number of days in the year.

These demand forecast numbers were relied upon, in conjunction with security compliance, to produce the forecast capital and operating programs that form the basis of ENERGEX's *Regulatory Proposal*.

The demand and customer forecasts were produced prior to the Federal government's CPRS announcement and the onset of the GFC.

The energy forecasts, relied upon for the revenue and price modelling contained in this *Regulatory Proposal*, were prepared taking account of a preliminary view of the impact of CPRS but not the effect of the GFC.

A new summer forecast is due post summer 2008-09. Although not available for the preparation of this *Regulatory Proposal*, ENERGEX has sought to accommodate the impacts of these recent events in our forecasts for the next seven years. The anticipated effect of this reduction of network demand growth on ENERGEX's forecasts has been reflected in ENERGEX's forecast capital expenditure. The methodology for this adjustment is discussed in Chapter 11 of this *Regulatory Proposal*.

ENERGEX recognises that this *Regulatory Proposal* has been prepared in uncertain economic times. ENERGEX will continue to review its capital expenditure forecasts against updated demand forecast data and include relevant information as part of its response to the AER's draft decision.

1.5.2 Reliability targets

The MSS continues to be a critical driver of the reliability program. The QCA delivered its decision for revised MSS for 2010-15 in April 2009 which required improved targets for each of the network feeder groups commencing in July 2010. Throughout the next *regulatory control period* both the urban and rural networks require progressive improvement (18 per cent and five per cent for SAIDI and 12 per cent and eight per cent for SAIFI respectively), whilst the MSS for the CBD network has a step improvement (25 per cent and 55 per cent respectively for SAIDI and SAIFI), which remains fixed for the period.

The introduction of a *Service Target Performance Incentive Scheme* (STPIS) for Queensland will provide a further focus on reliability performance in relation to unplanned outages. ENERGEX has no experience with schemes of this nature and will focus on its introduction in the *2010-15 regulatory control period*.

ENERGEX's Customer Strategy is directed at developing a better understanding of customers and their expectations, including their propensity to pay and the value they place on reliability improvements. This information will be used to frame the discussion around future application of the STPIS.

1.5.3 Forecast operating expenditure

ENERGEX proposes a forecast operating expenditure of $1,843.1 million for the *2010-15 regulatory control period*. This operating forecast has been prepared to efficiently deliver the obligations and meet the challenges facing the business, including the forecast impact of SEQ's summer storm season.

The breakdown of the proposed operating expenditure program is provided in Table 1.1.

Table 1.1 Proposed operating expenditure for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Inspection	19.2	20.8	22.5	23.3	25.0	**110.8**
Planned maintenance	66.0	65.0	66.9	68.5	69.6	**336.0**
Corrective repair	39.9	41.1	41.4	41.9	42.1	**206.4**
Network operating costs	25.5	26.8	27.4	28.3	28.9	**137.0**
Emergency response/storms	8.6	8.9	9.1	9.3	9.4	**45.2**
Vegetation	77.2	79.5	81.1	82.2	82.5	**402.6**
Metering	14.6	15.2	15.8	16.5	17.1	**79.2**
Customer services (inc. call centre)	21.0	21.9	22.4	23.1	23.6	**111.9**
DM initiatives	24.6	23.2	25.3	30.6	23.2	**126.9**
Total system operating expenditure	**296.7**	**302.4**	**311.9**	**323.5**	**321.5**	**1,556.0**
Levies	8.6	8.9	9.2	9.5	9.9	**46.1**
Other operating costs (incl. self insurance)	22.1	21.7	22.4	21.8	20.9	**108.9**
Subtotal operating expenditure	**327.3**	**333.0**	**343.5**	**354.8**	**352.2**	**1,710.9**
Debt raising allowance	7.2	8.1	9.0	9.9	10.7	**44.8**
Equity raising allowance	20.6	19.8	18.8	15.7	12.6	**87.4**
Total operating expenditure	**355.1**	**360.9**	**371.3**	**380.4**	**375.5**	**1,843.1**

Expenditure includes overheads.
Total may not add due to rounding.

The core network operating expenditure forecasts have been derived by:

- establishing an efficient base year (2007-08);
- incorporating a growing asset base;
- incorporating forecast cost increases over the *2010-15 regulatory control period*; and
- meeting obligations such as the MSS.

ENERGEX has increased investment in demand management as part of its continued commitment to reducing peak demand on the network. An additional $28 million in funds has been committed in 2009-10 to commence the implementation of initiatives that were successfully trialled over the last three years. These initiatives will continue to be rolled out across the *2010-15 regulatory control period*.

As outlined in the AER's final decision on Application of schemes, an *Efficiency Benefit Sharing Scheme* (EBSS) will apply to the operating expenditure in the *2010-15 regulatory control period*.

ENERGEX's forecast operating expenditure has been prepared in line with Clause 6.5.6 of the *Rules*. It has been prepared to efficiently meet or manage the expected demand for *standard control services* and maintain reliability, safety and security of the distribution system, within SEQ's operating environment.

1.5.4 Forecast capital expenditure

ENERGEX's forecast capital expenditure has been prepared in line with Clause 6.5.7 of the *Rules*. It is based on a realistic expectation of forecast demand and cost inputs and represents efficient costs that a prudent operator would invest to meet the requirements of the Queensland government and the demand of electricity customers in SEQ.

ENERGEX's proposed capital expenditure program of $6,466 million for the *2010-15 regulatory control period*, summarised in Table 1.2, has been developed to meet the key network challenges of EDSD compliance requirements, meeting demand growth and refurbishment/replacement of assets. It has been prepared in accordance with the robust network planning and governance process to ensure prudency and efficiency of the capital spend.

Table 1.2 Proposed capital expenditure for the 2010-15 *regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Growth	416.7	457.0	533.0	569.3	637.2	**2,613.2**
Asset replacement/renewal	160.5	255.7	212.9	280.2	256.0	**1,165.3**
Reliability and quality of service enhancement	85.8	50.6	72.6	51.6	45.7	**306.3**
Security compliance	384.0	381.6	385.0	328.1	338.6	**1,817.4**
Total system*	**1,047.1**	**1,144.9**	**1,203.6**	**1,229.2**	**1,277.5**	**5,902.3**
End-use computing assets	3.2	4.3	1.3	1.8	2.2	**12.8**
Land and buildings	143.0	67.8	44.4	18.5	24.7	**298.4**
Fleet	32.8	41.8	42.0	32.3	47.4	**196.3**
Tools and equipment	13.3	10.9	10.7	10.6	10.7	**56.2**
Total capital expenditure**	**1,239.5**	**1,269.7**	**1,301.9**	**1,292.4**	**1,362.5**	**6,466.0**

** Includes capital contributions for assets in the RAB.*
*** Expenditure on ICT is discussed in Chapter 12.*
Total may not add up due to rounding.

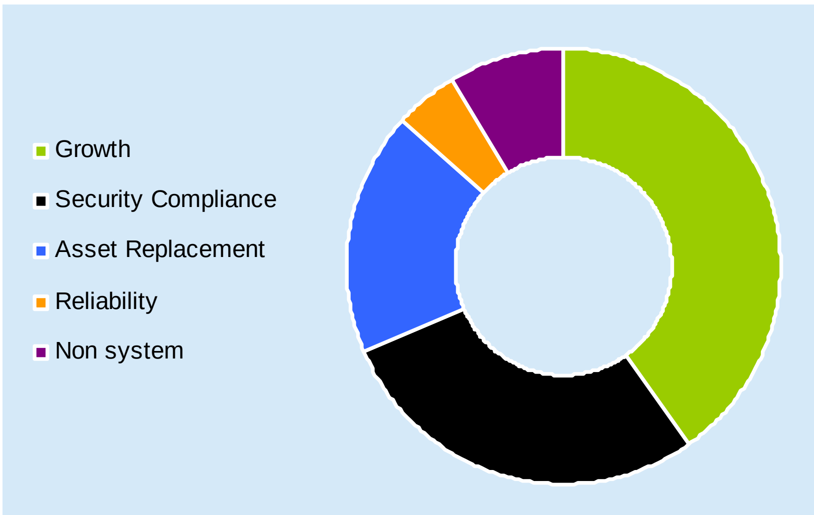
For the *2010-15 regulatory control period*, ENERGEX will be adopting a property strategy which includes replacement of existing facilities that no longer meet operational needs and standards. The strategy also provides for the acquisition of a number of smaller sites closer to developing areas to improve operational efficiency and customer response time. This has contributed to an increase in the non-system capital requirement. Other elements of the non-system capital requirement include fleet, equipment and plant and computing requirements.

The main components of the proposed capital program for the *2010-15 regulatory control period* are growth, security compliance, replacement and refurbishment of assets and reliability expenditure. These components account for 90 per cent of the capital expenditure forecast.

1.6 Capital expenditure asset categories

The main components of the proposed capital program for the *2010-15 regulatory control period* are illustrated in Figure 1.8.

Figure 1.8 Components of the capital progrm



Growth accounts for 40 per cent of capital expenditure while security compliance contributes 28 per cent. Expenditure on replacing and refurbishing assets accounts for 18 per cent and reliability expenditure five per cent. The remaining nine per cent consists of non-system capital expenditure to support the operation of the business such as motor vehicles and expenses associated with offices and depots.

Major projects represent 52 per cent of the total proposed capital program. In summary, the planning of capital expenditure projects takes into account the varying characteristics of each region and their development.

All major capital projects are reviewed annually prior to commencement and are subjected to rigorous internal processes for design, planning, governance and project management to ensure that they are prudent and delivered efficiently.

ENERGEX's planning process includes compliance with the *regulatory test* as outlined in Clause 5.6.5A of the *Rules*. ENERGEX has embraced the *regulatory test* as an important planning and consultative tool that promotes economically efficient investment in the electricity grid and provides a framework whereby the economic contribution or feasibility of network augmentation proposals and non-network alternatives can be assessed.

ENERGEX has a resource plan based on practices successfully deployed in the *current regulatory control period* and is confident that it has the capability to deliver the proposed capital program for the *2010-15 regulatory control period*.

Central to the delivery of these outcomes will be an increase in business support. Investment in non-system assets, such as fleet and building programs to enable the field workforce, are necessary to support the capital and operating programs required to deliver a safe and reliable electricity supply and to prepare for future challenges through network modernisation, automation and infield communications technology.

1.7 Building block revenues

This section summarises the key building block parameters, revenue requirements and indicative pricing outcomes contained in this *Regulatory Proposal*.

1.7.1 Return on capital

ENERGEX's return on capital element of this *Regulatory Proposal* largely reflects the parameter decisions made by the AER in the SoRI, dated 1 May 2009. The *Weighted Average Cost of Capital* (WACC) for the *2010-15 regulatory control period* has been calculated as 9.49 per cent. The WACC, in line with Clause 6.5.2(b) of the *Rules*, represents the cost of capital measured as the rate of return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by ENERGEX.

ENERGEX has made conservative estimates of the empirical market data for two variables necessary to calculate the return on capital – the nominal risk rate and the debt risk premium. This data will not be available until the averaging period is set at a point in time closer to the commencement of the *2010-15 regulatory control period*.

1.7.2 Revenue requirements

ENERGEX's revenue, required to fund its forecast capital and operational programs, has been calculated in accordance with the requirements of the *Rules* and by applying the Post Tax Revenue Model (PTRM) and Roll Forward Model (RFM) as developed by the AER.

ENERGEX's revenue requirement is constructed based on the individual building block components being the return on capital, return of capital (regulatory depreciation), operating expenditure and benchmark tax liability. The sum of the building blocks represents the forecast revenue stream for the *2010-15 regulatory control period* and is summarised at Table 1.3.

Table 1.3 Proposed revenue requirements for the *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Notional building block revenue (PTRM)	1,282.5	1,430.7	1,592.9	1,760.4	1,900.0
Revenue adjustments	(142.4)	(73.2)	(75.9)	(79.1)	(80.7)
Adjusted Notional Revenue	1,140.1	1,357.5	1,517.1	1,681.3	1,819.3
Smoothing	62.6	(21.3)	(32.6)	(32.1)	12.2
Smoothed building block revenue	1,202.7	1,336.2	1,484.5	1,649.2	1,831.5

1.7.3 X factors

ENERGEX has adopted a balanced approach to the establishment of X factors to transition the annual revenue variation over the *2010-15 regulatory control period*. The X factors were selected to minimise the variance between expected revenue and the annual (smoothed) revenue for the last regulatory year, while at the same time maintaining the Net Present Value (NPV) of the total revenue over the *2010-15 regulatory control period*.

ENERGEX's proposed X factors for the *2010-15 regulatory control period*, including adjustments to revenue for capital contributions, *Demand Management Incentive Scheme* (DMIS) and under and over recoveries are outlined in Table 1.4.

Table 1.4 Proposed X factors for the *2010-15 regulatory control period*

	2010-11	2011-12	2012-13	2013-14	2014-5
X factor	-25.3%	- 8.4%	-8.4%	-8.4%	-8.4%

Under the Rules the control mechanism must be in the CPI minus X form, indicating a revenue increase.

Taking into account the forecast consumption growth, the anticipated impact on average network prices in real terms is initially 24.7 per cent, followed by an average of 4.6 per cent for the remaining years of the *2010-15 regulatory control period*.

1.8 Outcomes of regulatory proposal

ENERGEX has previously accelerated operations to efficiently deliver record capital and operating programs. ENERGEX has the capability, capacity and resources to efficiently deliver the proposed capital and operating programs for the *2010-15 regulatory control period*.

The following outcomes are targeted by this *Regulatory Proposal*:

- management of sustained growth;
- meeting security, reliability and service requirements;
- ensuring reliability and prudent management with the renewal and replacement of assets;
- working efficiently within the characteristics of SEQ's operating environment;
- establishing a sound platform for an effective response to the management of electricity distribution in a contemporary age; and
- value for customers' long-term interests through information, choice and participation.

The following sections discuss the outcomes that arise from ENERGEX's *Regulatory Proposal* in terms of reliability, impacts on prices and sustainability for the ENERGEX business.

1.8.1 Service performance outcomes

ENERGEX is committed to high standards of customer service delivery. In addition to meeting Queensland government legislated MSS and GSL, ENERGEX will be participating in the national STPIS that targets improved levels of reliability and customer service. These targets and application of the schemes are in line with the AER's final decision on the application of the schemes and are further outlined in this *Regulatory Proposal*.

1.8.2 Customer pricing impacts

ENERGEX's pricing strategy is cognisant of the changing expectations of customers and the current upward pressure being exerted on energy prices. As an organisation ENERGEX is committed to achieving a balanced commercial outcome between meeting the requirements of customers and managing sustainability and risk.

The forecast capital and operating expenditure contained in this *Regulatory Proposal* will provide customers with an electricity network with:

- a 40 per cent increase or 6,514 MV.A of additional capacity;
- infrastructure with capacity to accommodate a 24 per cent increase or an additional 1,247 megawatts in demand;
- 56 new zone substations and four bulk supply substations;
- a 12 per cent improvement in reliability as measured by the SAIDI;

- reduction in compliance load at risk from 135 MV.A to 7 MV.A for bulk supply substations and from 444 MV.A to 213 MV.A for zone substations programs;
- ongoing safety, service delivery and operation of the electricity network to levels required by SEQ customers; and
- development of alternative solutions to manage the network in a financial and environmentally sustainable way.

The ongoing average price increases across the *regulatory control period* are necessary for ENERGEX to deliver these expenditure programs which support development and growth in SEQ as well as improving reliability and security of supply.

Overall the network charges that will be applied through electricity prices will rise as a result of this investment program from 4.20 c/kW.h[7] to 5.37 c/kW.h in 2010-11. Using the Benchmark Retail Cost Index published by the QCA, ENERGEX has calculated the impact of the changes in network prices on the notified prices that customers pay. If all other components of the notified prices increase at the rate of predicted inflation, the increase in 2010-11 will be approximately 10 per cent. This will be followed by annual increases of approximately 4 per cent for the following four years.

ENERGEX's *Regulatory Proposal* represents a balanced outcome that provides value for customers, manages risk, and builds a sustainable future for the electrical network of SEQ.

1.8.3 Financial implications

ENERGEX has assessed the implications of its *Regulatory Proposal* on the financial sustainability of the network business. The analysis identified that the revenue requirement outlined in this *Regulatory Proposal* is necessary to maintain ENERGEX's investment grade credit rating.

[7] All indicative prices are exclusive of GST.

2 Regulatory proposal structure

The AER is responsible, under the NEL and the *Rules*, for the economic regulation of electricity distribution businesses.

To allow the AER to make its distribution determination for the *2010-15 regulatory control period*, ENERGEX would ordinarily be required to submit a *Regulatory Proposal* at least 13 months before the expiry of ENERGEX's current distribution determination on 30 June 2010.

However, as a result of the Australian Energy Market Commission's National Electricity Amendment (WACC Reviews: Extension of Time) Rule 2009 No. 6, the AER was provided with a one-off extension of one month to complete its first WACC Review for electricity transmission and distribution network service providers. Consequently ENERGEX was granted a one-month extension to submit its *Regulatory Proposal* for the *2010-15 regulatory control period*. ENERGEX is therefore required to submit its *Regulatory Proposal* to the AER on or before 1 July 2009.

This chapter provides a summary of the structure of ENERGEX's *Regulatory Proposal* for the *2010-15 regulatory control perio*d.

2.1 Scope of ENERGEX's regulatory proposal

ENERGEX's *Regulatory Proposal* has been prepared in accordance with Clause 6.8 of the *Rules* and takes into consideration the transitional arrangements for Queensland that are detailed in Chapter 11, Part M, Division 3 of the *Rules*. This proposal has also been prepared in accordance with the requirements of all relevant *regulatory information instruments*.

In meeting the requirements of the *Rules*, this document sets out ENERGEX's required revenue for the *2010-15 regulatory control period*, taking into consideration ENERGEX's key focus of distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risks and builds a sustainable future.

2.2 Required elements of the regulatory proposal

In accordance with Clause 6.8.2(c) of the *Rules*, ENERGEX's *Regulatory Proposal* includes the following elements:

- a classification proposal showing how the distribution services to be provided by ENERGEX should be classified;
- for direct control services classified under the proposal as *standard control services* – a *building block proposal*;

- for direct control services classified under the proposal as *alternative control services* – a demonstration of the application of the control mechanism;
- for direct control services – indicative prices for each year of the *regulatory control period*; and
- an indication of the parts of the proposal that ENERGEX claims to be confidential and wants suppressed from publication on that ground.

In addition, this *Regulatory Proposal* includes the following:

- application of schemes;
- transitional matters; and
- pass through events.

ENERGEX's *Regulatory Proposal* has also been prepared in accordance with the requirements of the following *regulatory information instruments* issued by the AER:

- RIN issued on 22 April 2009;
- Final Decision: *Electricity Distribution Network Service Provider Post Tax Revenue Model* (June 2008);
- Final Decision: *Electricity Distribution Network Service Provider Roll Forward Model* (June 2008);
- *Final Framework and Approach Paper: Classification of Services and Control Mechanisms ENERGEX and Ergon Energy 2010-15* (August 2008); and
- *Final Framework and Approach Paper: Application of Schemes ENERGEX and Ergon Energy 2010-15* (November 2008).

2.3 Regulatory control period specified

Clause 6.12.1(2)(ii) of the *Rules* states that a distribution determination is predicated on the AER's decision in relation to the commencement and length of the *regulatory control period*. In addition, Clause 6.3.2(b) requires that a *regulatory control period* must not be less than five regulatory years and Clause 6.12.3(e) states that the AER must approve a proposed *regulatory control period* if the period consists of five regulatory years.

ENERGEX's *current regulatory control period* concludes on 30 June 2010.

This *Regulatory Proposal* relates to the *regulatory control period* commencing on 1 July 2010 and concluding on 30 June 2015. The length of ENERGEX's next *regulatory control period* is five years which complies with Clause 6.3.2(b) of the *Rules*.

2.4 Regulatory information notice

Section 28F of the NEL provides that the AER may serve a notice on ENERGEX if it considers it reasonably necessary for the performance or exercise of its functions or powers under the NEL or the *Rules*.

Pursuant to Section 28F of the NEL, the AER served a RIN on ENERGEX on 22 April 2009. ENERGEX must provide the information and documentation identified in the RIN in its *Regulatory Proposal*.

Section 9 of the RIN requires that ENERGEX must demonstrate compliance with RIN information requirements. **Appendix 2.1** is an index of where this information and documentation is located in this *Regulatory Proposal*.

2.5 Claim for confidentiality

In accordance with Clause 6.8.2(c)(6) of the *Rules* and Attachment 3 of the RIN, ENERGEX has included a section detailing which parts of this *Regulatory Proposal* are confidential. Reasons in support of a confidentiality claim are also outlined in this section.

All confidential documents have been marked accordingly and two versions of this *Regulatory Proposal* have been provided: a confidential version and a non-confidential version.

2.6 Structure of document

ENERGEX's *Regulatory Proposal* is comprised of this proposal document, attachments, appendixes and RIN supporting documentation and is structured in Table 2.1 as follows:

Table 2.1 Contents

Chapter	Title	Purpose
1	Overview	Chapter 1 provides a summary of ENERGEX's *Regulatory Proposal* for the *2010-15 regulatory control period*.
2	Regulatory proposal structure	Chapter 2 outlines the structure of this *Regulatory Proposal*.
3	Business characteristics and regulatory obligations	Chapter 3 contains an overview of ENERGEX's business and network, including network characteristics, supply area, regulatory obligations, ownership arrangements, organisational structure, key information systems and non-regulated services.
4	Network strategy	Chapter 4 outlines ENERGEX's Network Strategy for the *2010-15 regulatory control period* and key elements of the network development and management framework.

Chapter	Title	Purpose
5	Demand management strategy	Chapter 5 details ENERGEX's DM strategy and the DM projects that ENERGEX will undertake during the *2010-15 regulatory control period*.
6	Classification of services proposal and control mechanism	Chapter 6 outlines ENERGEX's proposal in relation to the classification of services and control mechanisms.
7	Transitional arrangements	Chapter 7 sets out ENERGEX's transitional issues and proposed treatment by the AER for the 2010-15 distribution determination.
PART ONE – BUILDING BLOCK PROPOSAL		
8	Current performance scorecard	Chapter 8 outlines ENERGEX's performance during the *current regulatory control period*, including network reliability and capability, growth, capital expenditure and operating expenditure performance.
9	Service obligations and performance standards	Chapter 9 identifies the main obligations and service performance standards for ENERGEX as a distribution business.
10	Demand forecasts	Chapter 10 outlines ENERGEX's forecast demand, customer numbers and energy for the *2010-15 regulatory control period*. This chapter also discusses ENERGEX's customer usage characteristics and implications and forecasting methodology and assumptions.
11	Forecast adjustments	Chapter 11 discusses forecast capital expenditure adjustments to account for impacts due to the GFC and CPRS.
12	Forecast operating expenditure	Chapter 12 sets out ENERGEX's forecast operating expenditure for the *2010-15 regulatory control period* and explain how this forecast achieves the operating expenditure objectives in relation to *standard control services* as specified in the *Rules*.
13	Forecast capital expenditure	Chapter 13 outlines ENERGEX's forecast capital expenditure for the *2010-15 regulatory control period* and explains how this forecast achieves the capital expenditure objectives in relation to *standard control services* as specified in the *Rules*.
14	Regulatory asset base	Chapter 14 outlines the methodology used by ENERGEX to roll forward its RAB. Details of the establishment of the RAB value as at 1 July 2010 and summaries of the roll forward value of the asset base over the *2010-15 regulatory control period* are also provided.
15	Depreciation	Chapter 15 provides an overview of ENERGEX's approach to calculating depreciation for the 2010-15 regulatory control period. It sets out the depreciation allowance included in ENERGEX's revenue requirements.

Chapter	Title	Purpose
16	Return on capital, inflation and taxation	Chapter 16 sets out how ENERGEX has calculated its proposed return on capital, its estimated cost of corporate tax and its proposed method that is likely to result in the best estimates of inflation, each as used in the derivation of the building block revenue for the *2010-15 regulatory control period*.
17	Application of schemes	Chapter 17 describes ENERGEX's approach to the application of the incentive schemes (EBSS, DMIS, STPIS).
18	Annual revenue requirements	Chapter 18 outlines ENERGEX's revenue requirements for the *2010-15 regulatory control period*, an overview of the completed PTRM, required revenue adjustments and final revenue requirement. This chapter also outlines the methodology used to calculate the proposed smoothed revenue requirement, proposed X factors, proposed Capital Contributions Bank (CC Bank) mechanism, and indicative prices.
19	Outcomes of regulatory proposal	Chapter 19 summarises the outcomes of ENERGEX's *Regulatory Proposal* in relation to reliability targets, customer pricing impacts and financial implications.
20	Pass through events	Chapter 20 sets out ENERGEX's nominated pass through events for direct control services (including *alternative control services*).
PART TWO – ALTERNATIVE CONTROL SERVICES		
21	Street lighting	Chapter 21 provides an overview of ENERGEX's street lighting services as an *alternative control service* and the application of the control mechanism.
22	Other alternative control services	Chapter 22 provides an overview of ENERGEX's fee-based and quoted services and the application of the control mechanism.
PART THREE – ADDENDUM		
23	Governance, assurances and certifications	This section contains ENERGEX governance documents, Directors' certification statement, and Chief Executive Officer's (CEO) statutory declaration.
24	Glossary	Glossary of terms used in this *Regulatory Proposal*.
25	Confidential information	This section details which parts of this *Regulatory Proposal* are confidential and provides reasons in support of a confidentiality claim.

<table>
<tr><th>Chapter</th><th>Title</th><th>Purpose</th></tr>
<tr><td colspan="2">Attachments – NEL compliance documents</td><td>Attachments to this Regulatory Proposal are:
▪ RIN;
▪ RFM;
▪ PTRM – building block;
▪ PTRM – street lights; and
▪ PTRM – revenue adjustments.</td></tr>
<tr><td colspan="2">Appendixes – ENERGEX supporting documents</td><td>Documents referenced in this Regulatory Proposal are provided separately.</td></tr>
<tr><td colspan="2">RIN supporting documentation</td><td>RIN supporting documents are provided separately.</td></tr>
</table>

3 Business characteristics and regulatory obligations

This chapter contains an overview of ENERGEX to assist the AER in assessing the forecast operating and capital expenditure included in this *Regulatory Proposal*.

It discusses ENERGEX's business characteristics and outlines ENERGEX's broader regulatory obligations. Obligations and requirements specific to ENERGEX's services and performance are discussed in Chapter 9.

3.1 Summary

ENERGEX's core business involves the distribution of electricity to more than 1.3 million residential, industrial and commercial customers in SEQ. The network area spans 25,000 square kilometres and 11 local government areas.

ENERGEX maintains assets which include more than 50,000 kilometres of underground cables and overhead lines, over half a million power poles, 250 zone and bulk supply substations, some 43,000 distribution transformers and approximately 300,000 street lights.

A fundamental characteristic of ENERGEX's network is the region's strong rate of growth, resulting in the need for record capital investment in electricity infrastructure. This chapter illustrates the nexus between growth and electricity infrastructure by providing examples of growth regions within the ENERGEX supply area. It also discusses regions that have been earmarked by the State government for future growth.

A further defining factor affecting the network is SEQ's climatic conditions and the resulting management of the network during a summer storm season between the months of September and April. The storm period is characterised by high winds and significant lightning activity. These weather conditions expose the network to direct damage and also to indirect damage caused by overhanging vegetation or flying debris.

This chapter also discusses the challenges ENERGEX faces from the impact of climate change and outlines ENERGEX's regulatory obligations.

3.2 Regulatory information requirements

Clauses 6.5.6 and 6.5.7 of the *Rules* set out the objectives and criteria against which the AER must assess ENERGEX's forecast operating and capital expenditure.

Clauses 6.5.6(e)(9) and 6.5.7(e)(9) of the *Rules* require the AER to have regard to the extent the forecast of required capital and operating expenditure of ENERGEX is referable to arrangements with other persons that, in the opinion of the AER, do not reflect 'arm's length' terms.

Clauses 6.5.6(a)(2) and 6.5.7(a)(2) of the *Rules* require ENERGEX to include forecast expenditure that is required to 'comply with all applicable regulatory obligations or requirements associated with the provision of *standard control services*'.

Clause 2.3.1 of the RIN requires ENERGEX to include some general information in relation to business operations. Specific information requested is ownership arrangements, organisation structure, staffing numbers, information systems, services, customer information and an overview of the network.

Clause 2.3.2 of the RIN requires ENERGEX to provide a list of relationships that ENERGEX has with other entities.

Clause 2.3.4 of the RIN requires ENERGEX to provide information regarding regulatory obligations and requirements relating to provision of direct control services.

3.3 Overview of ENERGEX's business

ENERGEX is a Brisbane-based company with over 3,500 employees and assets worth approximately $7.4 billion[8]. ENERGEX's core business involves the distribution of electricity to more than 1.3 million residential, industrial and commercial connections across SEQ. The company's electricity distribution network spans approximately 25,000 square kilometres throughout SEQ, stretching from Gympie in the north to Withcott in the west, Stradbroke Island in the east and Coolangatta in the south. This supply area encompasses the high growth regions of Brisbane, the Gold Coast and the Sunshine Coast.

ENERGEX is authorised under the *Electricity Act 1994* (*Electricity Act*) as a distribution entity with a supply area covering SEQ. ENERGEX's entire network is classified as a distribution network for the purposes of the *Rules.*

[8] Value as at 30 June 2008 and reported in ENERGEX's *Annual Report 2007-2008*, page 3.

The EIC, made under the *Electricity Act*, prescribes requirements relating to industry planning, reporting and service standards, including MSSs, GSLs and the requirement for an NMP and a Summer Preparedness Plan (SPP). ENERGEX must operate in accordance with these requirements.

3.4 Ownership arrangements and related parties

ENERGEX Limited (ABN 40 078 849 055) is a GOC that plans, builds, operates and maintains the electricity distribution network in SEQ.

The information on the relationships that ENERGEX has with other entities is included in pro forma 2.3.2 in **Attachment 1**. An overview of ENERGEX's corporate structure is provided in **Appendix 3.1**.

SPARQ Solutions Pty Ltd (SPARQ) is the key entity that provides services to ENERGEX as a related party. SPARQ, which is jointly owned by ENERGEX and Ergon Energy Corporation Limited (Ergon Energy), owns and constructs joint Information Communications and Technology (ICT) assets and provides ICT management services for ENERGEX and Ergon Energy.

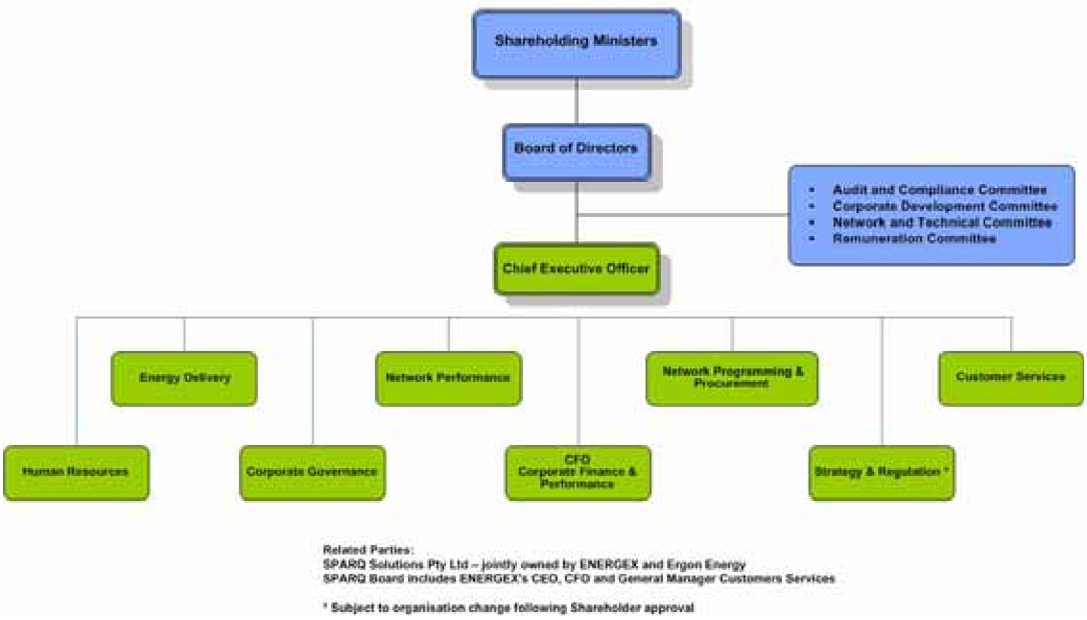
Further details of SPARQ's operation and its impact on ENERGEX's cost are discussed further at Chapter 12.

3.5 Organisation overview

ENERGEX has established an organisational structure to ensure accountability to the Queensland government, its shareholders and customers connected to its network and the people of SEQ.

Following the sale of its retail and gas network businesses in 2007, ENERGEX is now an electricity network only business. In order to execute on strategies and achieve its vision, ENERGEX has structured itself according to the operating divisions as shown in Figure 3.1.

Figure 3.1 ENERGEX's organisational structure



The Energy Delivery, Network Programming and Procurement and Network Performance divisions represent the operating divisions of the electricity distribution network that deliver standard control and *alternative control services*. The majority of ENERGEX's resources are allocated to these three operating divisions. A small number of non-regulated activities are also undertaken within these divisions, with the costs from these activities separately identified and allocated according to the Cost Allocation Method (CAM).

The remaining divisions constitute the shared services component of the business. A shared services model is employed by ENERGEX in order to benefit from economies of scale in the provision of services to the three key operating divisions. These divisions support Energy Delivery, Network Performance and Network Programming and Procurement which are responsible for and provide *standard control services* and *alternative control services*.

Details of the roles and responsibilities of each of the divisions are detailed in **Appendix 3.2**.

Further information regarding ENERGEX's corporate governance in relation to this *Regulatory Proposal* is discussed in Chapter 23.

ENERGEX's current and forecast staffing numbers are presented in Table 3.1.

Table 3.1 Current and forecast staffing numbers

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
FTEs	**Actual***	**Projected**					
CEO's Office	2	2	2	2	2	2	2
Energy Delivery	2,200	2,215	2,234	2,253	2,253	2,234	2,215
Network Performance	263	278	288	297	297	288	278
Network Programming & Procurement	539	587	597	606	606	597	587
Customer Services	464	481	481	481	481	481	481
Chief Financial Officer (CFO); - Corporate Finance & Performance - Strategy and Regulation**	119	136	136	136	136	136	136
Human Resources	80	77	77	77	77	77	77
Corporate Governance	27	26	26	26	26	26	26
Total	**3,694**	**3,802**	**3,841**	**3,878**	**3,878**	**3,841**	**3,802**

** Figures as at 26 April 2009.*

*** Subject to organisation change following stakeholder approval.*

3.6 Overview of ENERGEX's network

ENERGEX is responsible for the distribution network in SEQ. It takes supply of electricity from Powerlink[9] at transmission connection points and distributes the supply via the sub-transmission and distribution network to customers throughout the region. Zone substations and distribution substations convert the voltages as necessary to minimise network losses and meet customers' voltage requirements. ENERGEX also operates some distributed generation which supports this network during normal and contingency situations.

Providing electricity to a mixture of urban and rural zones, the ENERGEX electricity network is characterised by:

- connection to Powerlink's high voltage transmission network at various connection points;
- high density/CBD areas such as the Brisbane CBD, Gold Coast and Sunshine Coast city areas which are supplied by 110/11 kV, 110/33 kV, 132/33 kV, or 132/11 kV injection points;

[9] Powerlink Queensland is the registered business name of the Queensland Electricity Transmission Corporation Limited.

- suburban/urban/short rural feeder areas where 110/33 kV or 132/33 kV bulk supply substations are used to supply 33/11 kV zone substations;
- Brisbane suburban areas close to the CBD which have extensive older, meshed 33 kV underground cable networks that supply zone substations;
- outer suburbs and growth areas to the north, south and west of Brisbane which are supplied via modern indoor substations of modular design that enable further modules to be readily added;
- an increasing proportion of new network comprised of underground cables (seven per cent growth in proportion of asset growth) compared to overhead construction (0.4 per cent growth); and
- new subdivisions in urban/suburban areas which are supplied by underground networks with padmount substations.

A high level map of ENERGEX's supply area is provided in **Appendix 3.3**.

ENERGEX is committed to the objectives of the NEL in relation to the management and operation of the electricity network in the long-term interests of customers with respect to price, quality, safety, reliability and security of supply.

As an electricity distribution business operating in SEQ, the current challenges for ENERGEX are meeting sustained growth, improving security and reliability, and renewal and replacement of assets within a changing operating environment.

To ensure its short-term objectives and strategies are met, ENERGEX is required to invest significant capital and operating expenditure in supply-side solutions during the *2010-15 regulatory control period*. At the same time, ENERGEX's longer term strategies will guide the business towards delivering sustainable future performance by improving the balance between supply-side management and demand-side solutions.

ENERGEX recognises that building a sustainable future and meeting increasing customer needs and expectations, means it must not only invest in building additional capacity into the network to meet demand, but must simultaneously move towards modernising its electricity network through implementation of effective demand response solutions and investment in new 'smart' technologies.

3.6.1 Operating environment

One of the fundamental factors affecting the management of the distribution network in SEQ is the region's strong rate of growth. Population and electricity demand growth has been consistently high for many years and is expected to remain so in the *2010-15 regulatory control period*.

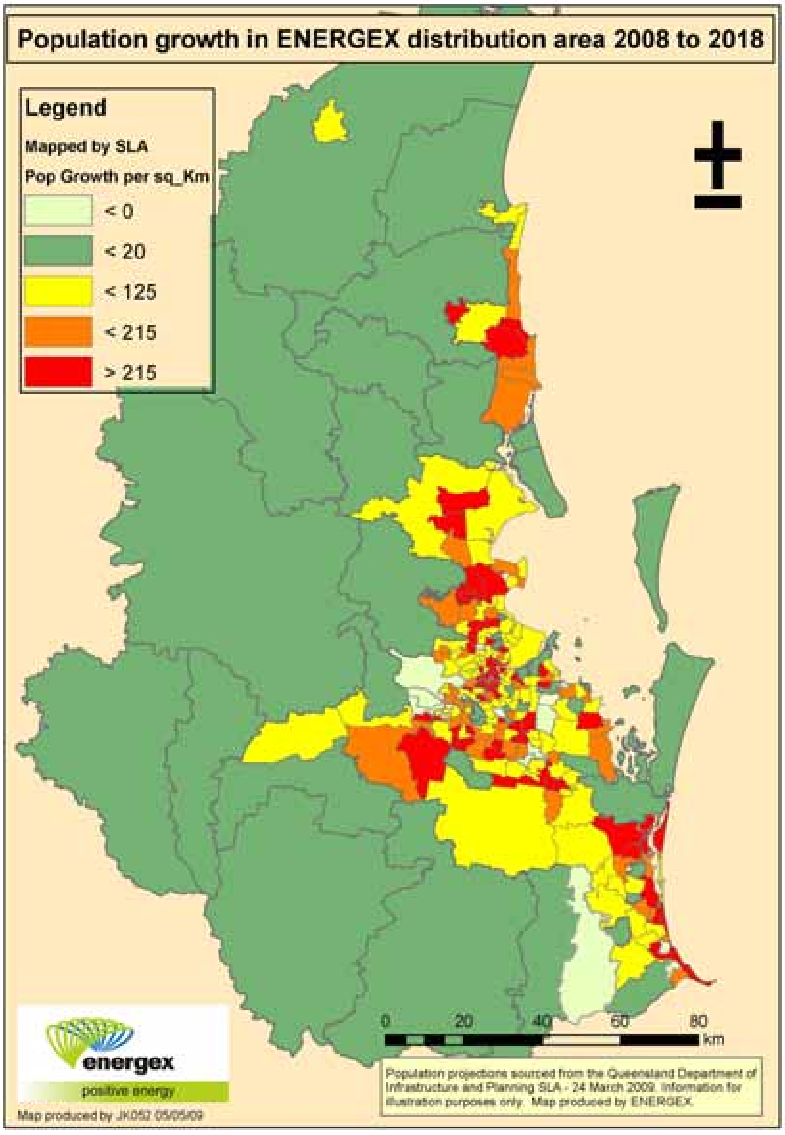
Some of the issues arising from this sustained development include:

- high customer growth;
- high regional economic growth;

- large-scale commercial and residential redevelopment in inner Brisbane suburbs;
- three high density growth areas with significant commercial and high rise residential developments – Brisbane CBD, the Gold Coast and the Sunshine Coast;
- high commercial and tourism growth;
- urban and semi-rural sprawl into previously forested or farming areas (supply made available to 20,781 lots in 2007-08);
- increased community infrastructure development including roads, rail, water, hospitals and educational facilities;
- significant growth in new air-conditioner loads, which are increasing the summer load at a time when equipment ratings are already adversely affected by higher temperatures; and
- redevelopment of older low density areas to higher density.

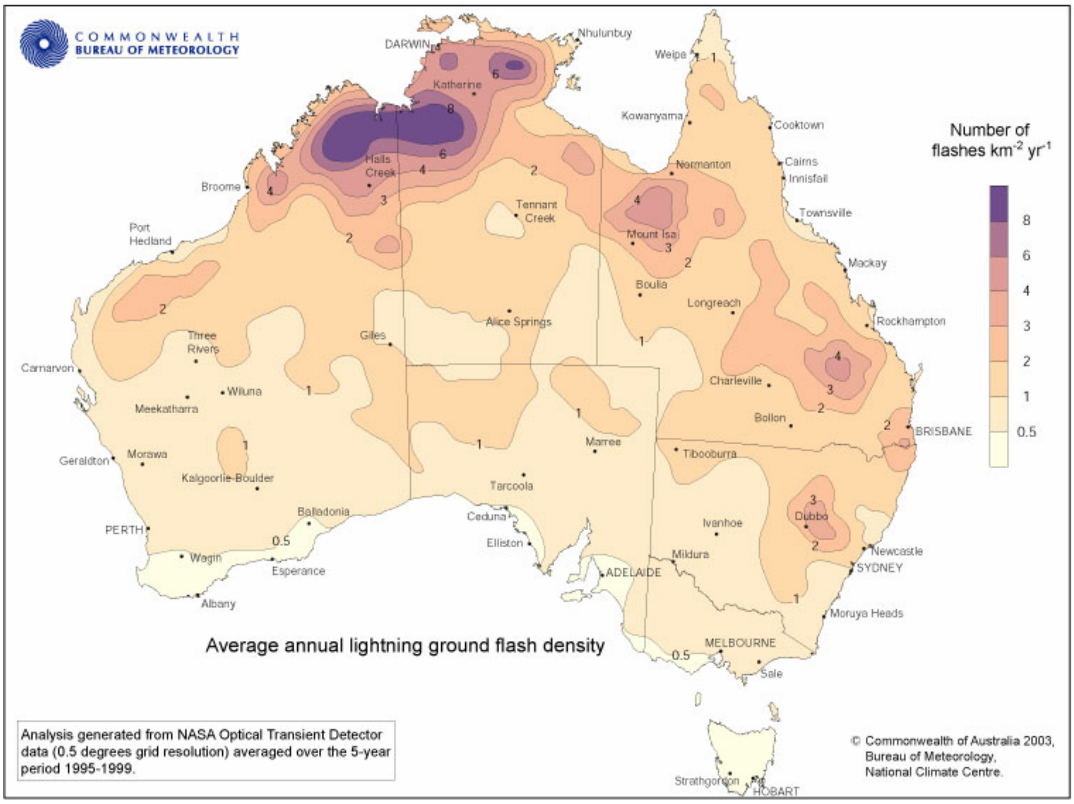
Figure 3.2 highlights the key growth areas in ENERGEX's distribution area.

Figure 3.2 Future population density



A further defining characteristic affecting the network is SEQ's climate and weather. Lightning is a significant contributor to outages within ENERGEX's service areas. Each year, between the months of September and April, the network area is subject to high summer storm activity. This season is characterised by a significant number of lightning strikes as illustrated in Figure 3.3 from the Bureau of Meteorology (BOM). Queensland has some of the highest incidences of lightning strikes in Australia[10] with Brisbane recording the second highest lightning intensity of the Australian capital cities after Darwin.

Figure 3.3 BOM's average annual lightning ground flash density



Furthermore, the summer season is accompanied by severe storms where wind gusts in excess of 80 km/h are common. Such weather extremes expose the network to direct damage as well as indirect damage caused by overhanging vegetation or flying debris. Other aspects of the region's climatic conditions impacting the distribution network are summarised below:

- high rainfall areas with rapid vegetation growth;
- periods of sustained high temperatures and high humidity; and
- salt spray in exposed coastal areas.

10 For the purposes of this map, lightning is defined as "all of the various forms of electrical discharge produced by thunderstorms" (Bureau of Meteorology, *Estimates of Lightning Occurrences by the satellite-mounted Optical Transient Detector Analysis for the Australian Region*).

The variability of SEQ summer seasons is evident over the past six years. The 2003-04 summer fierce storms, high temperatures and tropical depression caused substantial damage to the network. In contrast, 2004-05 had lower maximum temperature and relatively fewer severe storms. Although the 2005-06 season was not as severe, it was still hot (with most hot days occurring on the weekends) and resulted in 29 severe weather events[11]. Since then, summers in SEQ have been relatively mild, although in 2007-08 the rural network was severely impacted by strong winds and heavy rain.

Temperature sensitive loads are another noteworthy characteristic of the SEQ network. Growth in temperature loads relates to SEQ's historically strong population growth rate and increasing air-conditioner penetration.

Temperature sensitive loads are difficult to forecast due to the variable SEQ weather conditions. The proportion of temperature sensitive load is significant to ENERGEX because of the link between air-conditioner installation levels and extended periods of hot weather driving air-cooling demand. Air-conditioning-related system demand growth will continue to impact ENERGEX's network during the *2010-2015 regulatory control period,* with air-conditioner penetration rates likely to reach saturation around 2017.

Recent mild summers have resulted in lower than expected peak demand. ENERGEX believes this factor has masked demand related growth that is likely to be realised on the network during periods of more typical summer temperatures.

11 ENERGEX defines a severe weather event as one involving activation of emergency storm procedures as per Business Management System 533.

3.6.2 Network statistics

Table 3.2 presents a summary of ENERGEX's major electricity network assets and provides a guide to the growth of the distribution network over the past five years.

Table 3.2 ENERGEX's major electricity network assets[12]

Assets	2003-04	2004-05	2005-06	2006-07	2007-08
Total overhead and underground (km)	46,549	47,780	48,860	50,217	51,349
Lines – length of overhead (km)					
Total	35,525	35,839	36,069	36,373	36,522
LV	14,812	14,842	14,875	14,893	14,905
11 kV	17,090	17,344	17,504	17,709	17,843
33 kV	2,020	2,034	2,059	2,091	2,136
132/110 kV	1,603	1,619	1,632	1,680	1,638
Cables – length of underground (km)					
Total	11,024	11,941	12,791	13,844	14,827
LV	7,117	7,595	8,135	8,592	9,083
11 kV	3,131	3,402	3,666	4,207	4,657
33 kV	691	867	905	942	981
132/110 kV	85	77	85	103	106
Other equipment					
Bulk supply substations	32	33	34	36	37
Zone substations	190	195	200	207	213
Poles	587,969	595,928	596,770	612,638	622,064
Distribution transformers	38,365	39,572	40,826	42,261	43,420
Street lights	243,795	251,282	260,605	296,849	306,892

ENERGEX has a significant number of assets that were installed in the 1960s. High demand growth experienced in SEQ for a number of years resulted in capital expenditure programs primarily focused on meeting demand which resulted in new assets being installed and some older assets replaced.

However, there are still large quantities of assets that are approaching the end of their forecast life and will require refurbishment or replacement depending on service conditions. ENERGEX's asset renewal strategy is based on analysis of the network assets using the CBRM methodology and this is discussed further in Chapter 13.

12 Source: ENERGEX, *Annual Report 2007-2008*.

Figure 3.4, Figure 3.5 and Figure 3.6 show the distribution of age profile of power transformers, poles and distribution transformers.

Figure 3.4 Age profile of power transformers

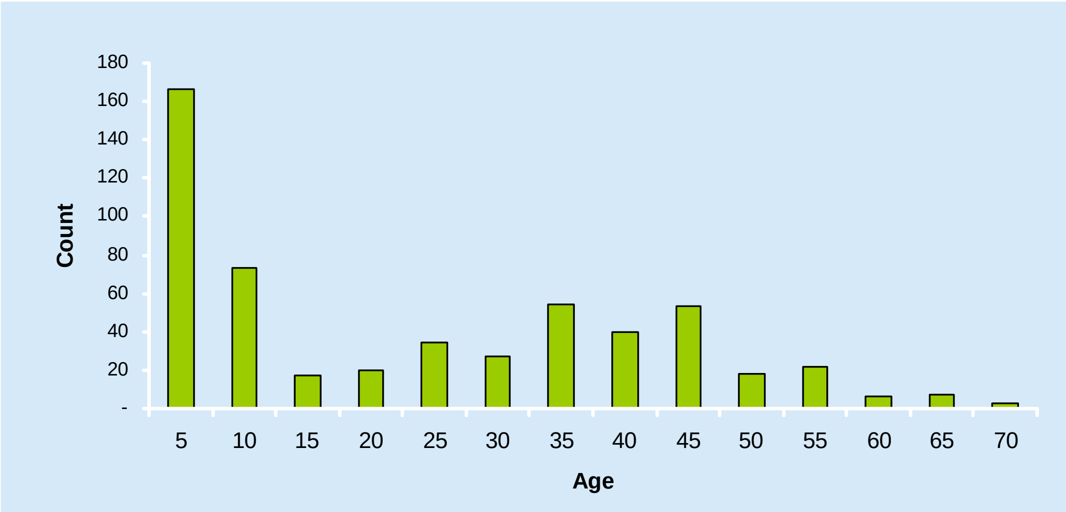


Figure 3.5 Age profile of poles

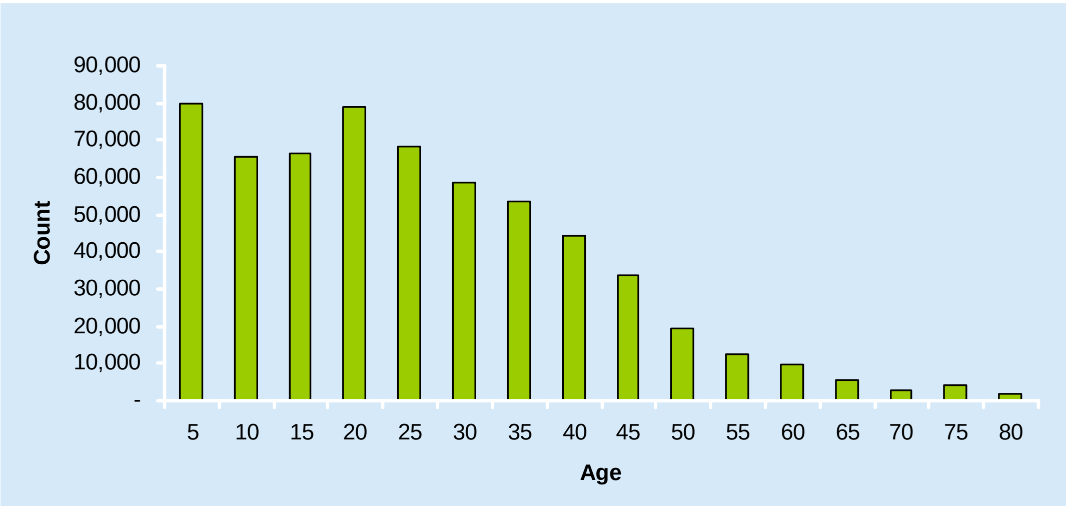
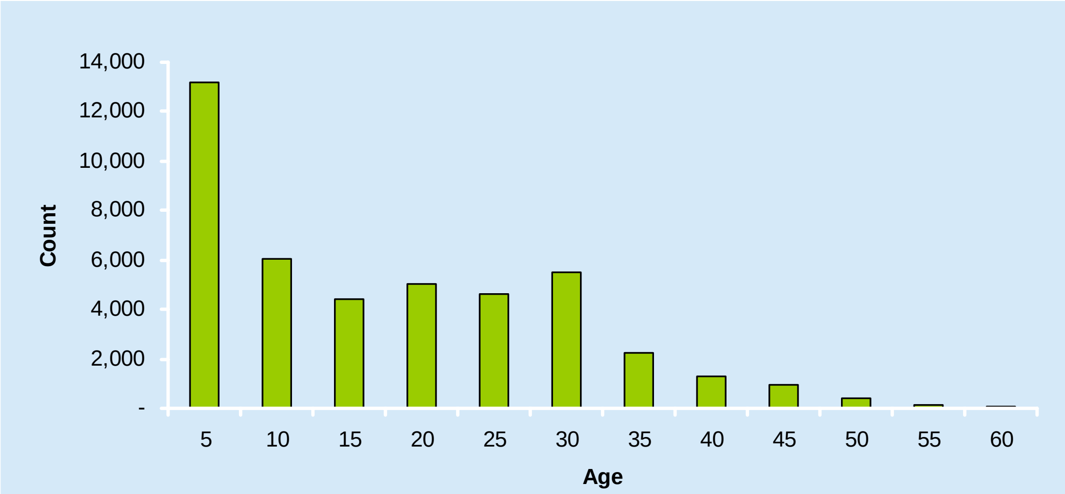


Figure 3.6 Age profile of distribution transformers



3.7 ENERGEX's supply area

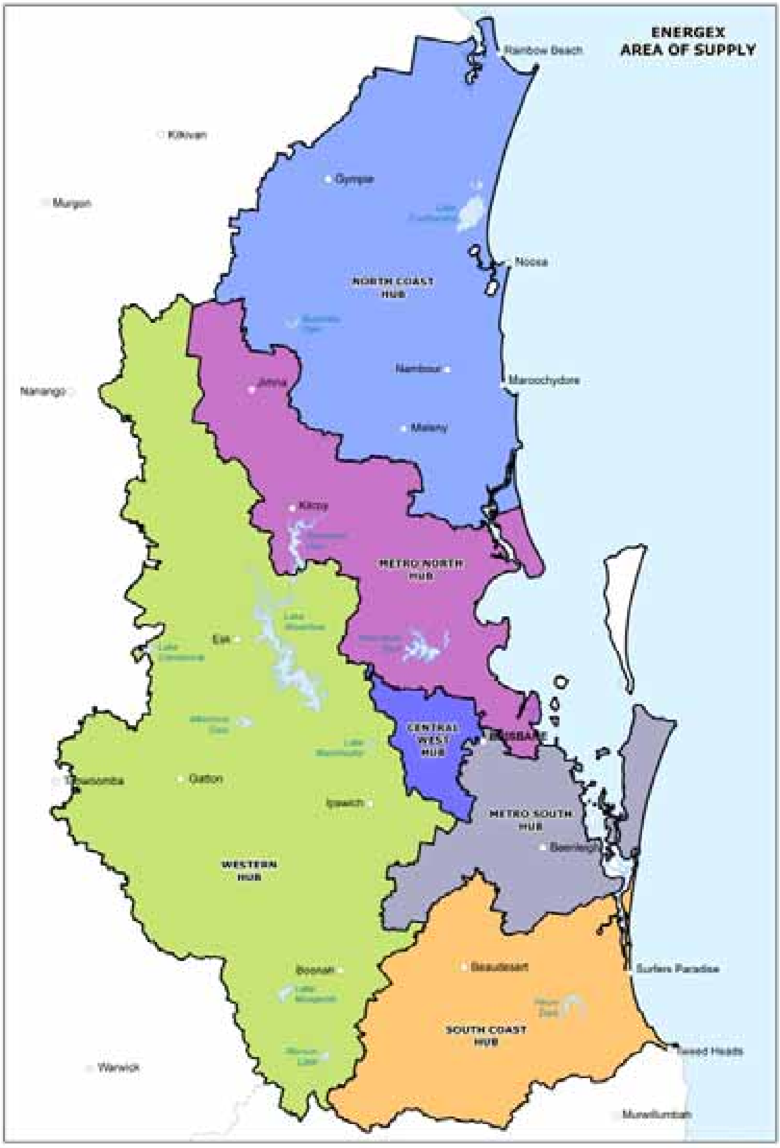
SEQ's population is heavily urbanised and is generally concentrated along the coast between Noosa and Coolangatta but ENERGEX also distributes electricity to many rural communities.

The terrain includes:

- coastal regions sheltered by the islands that form Moreton Bay in the south and exposed to the Coral Sea in the north;
- hinterland foothills and mountains to the west, including the Great Dividing Range in the south and a collection of outlier hills in the north, known collectively as the Glass House Mountains; and
- flood plain areas with eight major river systems and numerous creeks and tributaries.

Across this diverse topography, ENERGEX maintains assets including more than 50,000 kilometres of underground cables and overhead lines, over half a million power poles, 250 zone and bulk supply substations, some 43,000 distribution transformers and approximately 300,000 street lights. Operationally, ENERGEX divides the supply area into six hub areas as illustrated in Figure 3.7.

Figure 3.7 ENERGEX area of supply



3.7.1 Characteristics of the region

ENERGEX's network area spans eleven local government areas, which include two of the fastest growing statistical divisions in Australia – the Gold Coast and the Sunshine Coast.

The local government areas and the broad characteristics of their networks are:

- **Brisbane City Council –** a largely urban area experiencing high density residential growth and urban renewal. A significant number of large C&I customers are concentrated on the mouth of the Brisbane River. The network is characterised by an underground network in the CBD, with a predominantly overhead sub-transmission network in the suburbs that is gradually being replaced with underground cable. The distribution network in the suburbs is a mix of overhead in older suburbs and a growing proportion of underground network in all new housing estates and progressively installed in built up areas.
- **Redland City Council** – an urban and urban fringe area trending towards subdivision of residential land. The network is predominantly overhead with installation of underground network in new residential estates. This area also includes a number of islands that can be difficult to access for network repair and maintenance.
- **Logan City Council** – a mix of rural and urban areas with high concentrations of industrial and commercial customers and an expanding urban fringe. A high percentage of the network in the Logan area is overhead.
- **Gold Coast City Council** – densely populated urban areas concentrated along the coast in high-rise residential dwellings, an increasing number of high-end urban residential estates and a hinterland characterised by high population growth and staged land releases. Activity on the coastal strip is primarily driven by the tourist industry with population growth in summer season resulting in peak demand on the network. In addition, this region has strong industrial and commercial demand demonstrated by the recent commissioning of a large desalination plant in Tugun. The network has a mix of underground and overhead distribution infrastructure.
- **Scenic Rim Regional Council –** typically a rural area supported by small regional centres experiencing moderate growth. The area is serviced by a largely overhead rural network.
- **Somerset Regional Council** – similar to the Scenic Rim, the Somerset area is largely rural in nature, comprised of small regional centres and is subject to steady growth. The distribution network is largely an overhead rural network.
- **Lockyer Valley Regional Council** – a farming community, serviced by small townships, experiencing migration of urban dwellers seeking a sea change. The distribution network in the Lockyer Valley is characterised by a largely rural network.

- **Sunshine Coast Regional Council** – a rapidly-growing coastal region, with increased urbanisation that stretches from Caloundra to Noosa. The region caters to a growing tourism industry and is experiencing strong hinterland development in former rural areas. Commerce and industry are also expanding. The largely overhead rural network is undergoing rapid sub-transmission development driven by growth. The network is transitioning from a radialised distribution system to a more secure urban design with the construction of new nodal supply points.
- **Gympie Regional Council** – ENERGEX services approximately half of this regional area that supports a number of commercial and industry enterprises and is serviced by an expanding major centre in Gympie. The storm-prone, largely rural, overhead network is subject to increasing demand for reliability.
- **Moreton Bay Regional Council** – historically a rural area with vibrant town centres, the area is now experiencing high population growth along the Bruce Highway, particularly at Mango Hill, Morayfield and Narangba. It is a high growth area comprising predominantly overhead distribution assets.
- **Ipswich City Council** – a satellite city characterised by high urban residential growth and increasing demand for power from the C&I sectors. A largely overhead rural network with an underground network in the CBD area.

3.7.2 South East Queensland regional plan

The Draft South East Queensland Regional Plan 2009-2031 (SEQ Plan) in **Appendix 3.4**, is a key planning document for ENERGEX. It offers a long-term view of the region, extending beyond the *2010-15 regulatory control period* and predicts that development is set to continue for the long term, projecting the population to increase from 2.8 million to 4.4 million people by 2031. The region covered by this Plan mirrors the boundaries of the ENERGEX supply area with the exception of the Toowoomba Regional Council area and parts of the Gympie Regional Council area.

The SEQ Plan predicts that the region's growth will result in 735,500 new dwellings and drive the construction of supporting infrastructure and services. The Plan earmarks development of Brisbane's western corridor – an area extending from Wacol, linking to Ipswich and Amberley, including Ebenezer, Swanbank, Ripley Valley and Springfield.

The Queensland government's objective for future planning is to reduce pressure on the heavily populated coast. However, it is expected almost half of the new dwellings will be constructed in established urban areas through infill and redevelopment, with the remainder in identified undeveloped (broad hectare) sites. The data contained in the Plan has been an important input to ENERGEX's own planning process.

ENERGEX has planned for growth in network requirements for the *2010-15 regulatory control period* in the following areas identified in the SEQ Plan:

- Ripley Valley;
- North Maclean;
- Yarrabilba;
- Rosewood;
- Greater Flagstone;
- Caboolture South;
- Beerwah; and
- Southern Redland Bay.

The SEQ Plan is supported by the South East Queensland Infrastructure Plan and Program 2008-2026. ENERGEX, along with transmission company Powerlink, has made contributions to the infrastructure plan, which includes a section on the development of electricity infrastructure.

3.7.3 Regional growth and changing land use

ENERGEX has responded to sustained growth in population, peak demand and energy use in the *current regulatory control period* by adding more than 3000 MV.A to the electricity network, effectively increasing installed capacity by 34 per cent.

Growth has been a major driver for ENERGEX's record capital program. Population increases and associated changes in land use significantly impact electricity need. Many areas have been re-zoned, shifting from rural and semi-rural use to urban use. Together with re-zonings for increased housing density in many of the suburbs of inner Brisbane and the Gold Coast, the requirements for electricity infrastructure have increased.

To demonstrate the considerable growth in SEQ, ENERGEX has selected three examples of regions that have experienced rapid expansion and have been earmarked for continued development into the *2010-15 regulatory control period*.

The following aerial photographs of Mango Hill, Springfield and Coomera illustrate the change in land use and significant growth that has occurred on the ENERGEX distribution network over the past decade.

Mango Hill

The above aerial photographs compare the rural district of Mango Hill in 1995 with today's 1000-hectare master planned township.

For ENERGEX, the growth at Mango Hill has meant upgrading the previous rural distribution network into a largely suburban network with capacity to support 25,000 residents and accommodate a growing number of commercial enterprises. Peak demand is expected to more than double, increasing from 10 MW in 2003-04 to 26.1 MW this year.

This region has been identified for further growth. ENERGEX plans to accommodate this growth by establishing a new substation and associated feeders at Griffin in 2014.

Springfield

In 1997 the development of the Springfield area commenced with plans to become Australia's fastest growing satellite city. By 2008 Springfield had developed to support a population of more than 15,000.

The Springfield CBD now spans 320 hectares and includes health, education, retail and entertainment facilities, with further population and commercial growth predicted.

For electricity infrastructure, growth of Springfield has resulted in the construction of a new substation in 2005 with a further zone substation planned for 2011.

Coomera

The growth of the Coomera area typifies the type of development ENERGEX has experienced in the Gold Coast region.

Since 1997 the population of the area has doubled to more than 14,000, with increased demand for domestic electricity supplemented by rising C&I requirements for electricity with the establishment of the Gold Coast marine precinct and the construction of a $40 million business park.

ENERGEX has responded with a new substation at Coomera in 2005-06 and is forecasting the demand required will increase from 15 MW in 2005-06 to 30.5 MW in 2008-09.

3.8 ENERGEX's climate change challenge

Variable climatic conditions have always had a major impact on the planning and operation of ENERGEX's network and these weather events are expected to become more extreme as climate change impacts SEQ.

In addition to implementing internal policies that reduce the corporation's own carbon footprint, the indirect impacts of climate change on the ENERGEX network include the:

- physical impact of changing weather patterns on the largely overhead distribution network;
- emerging impact of government policy measures, such as the proposed CPRS; and
- connection of higher proportions of photovoltaic (PV) solar generation to the network driven by the Queensland and Commonwealth governments' incentives.

According to a report commissioned by the Energy Networks Association in February 2009, entitled *Energy network infrastructure and the climate change challenge*, climate change will intensify the occurrence of extreme single-weather events in Australia such as an increase in the intensity and reach of cyclones, flooding, hail storms and heat waves.

The predicted increase in severe thunderstorms and associated wind and lightning along the southern Queensland coast is expected to further impact the approximately 36,500 kilometres of overhead powerlines over ENERGEX's 25,000 square kilometre supply area. These changing weather patterns will have implications for the future design of the network and require further enhancement for emergency response.

The other feature of climatic change is the occurrence of extreme temperature. It is anticipated that peak demand will increase dramatically when there are extended periods of hot weather during summer. As demonstrated by the recent events in Victoria and South Australia, the potential for latent air-conditioning load to be realised after an extended period of hot days is a real threat[13]. The last hot summer season experienced in SEQ was in 2005-06. However, most of the hot days in that year occurred on weekends and hence did not have a major impact on system peak demand.

The increase in connection of solar PV generation to the ENERGEX network, as encouraged by government, is a potential challenge (e.g. managing a bi-directional network flow) and ENERGEX has incorporated this in its future planning of the network as outlined in the *Network Vision – Outlook to 2025* (Network Vision) in **Appendix 3.5**.

13 Energy Users' Association of Australia (EUAA), *Media Release*, 3 February 2009 quoted that the hot weather resulted in 3,000 MW of extra load in Victoria and South Australia.

3.9 ENERGEX customer profile

In addition to compliance with legislative obligations, ENERGEX is committed to maintaining value for customers.

Residential and business sectors are ENERGEX's highest energy users. In 2006-07, they accounted for 83 per cent of energy sold, with the remaining 17 per cent distributed across industrial customers and rural, traction (rail system) and street lighting sectors[14].

The introduction of FRC coincided with structural changes to ENERGEX's operations (sale of retail and gas network businesses) and has created challenges in terms of how ENERGEX as a distribution network business understands and interacts with customers and the SEQ community. ENERGEX recognises the role of changing technologies and customer habits in driving innovation and the development of the network.

ENERGEX's Customer Strategy has been developed to determine and deliver value for customers. The strategy is intended to support ENERGEX's response to major network challenges and ensure that business decisions reflect improved analysis of customer information. This strategy is summarised in Figure 3.8.

Figure 3.8 ENERGEX's customer strategy

14 Source: ACIL Tasman, *System energy – An evaluation of ENERGEX's System Energy Forecasting Methodology*, November 2008.

3.10 ENERGEX demand profile

Over the past 10 years, growth in demand on ENERGEX's network has not only increased significantly but the 'shape' of demand has changed, creating additional challenges in managing the network, particularly during times of peak load.

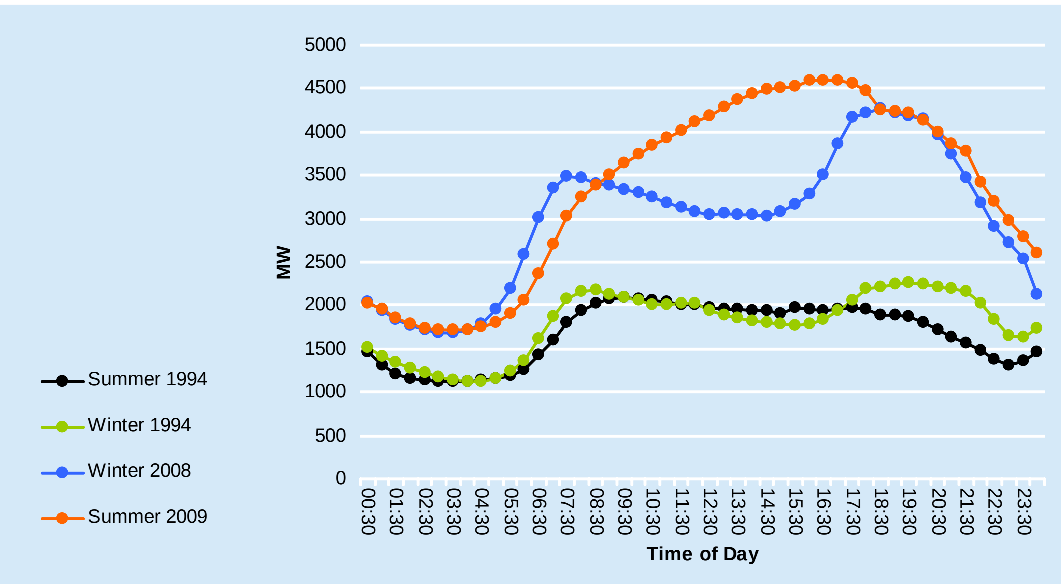
Prior to the early 2000s, ENERGEX's network had a winter peak with the typical load characteristic of a saddle-shaped daily load curve peaking in the morning and evening, and lower consumption between these times as illustrated at Figure 3.9. This winter saddle-shaped curve is the result of customer demand associated with normal daily household routines that consume electricity such as space heating (in the cooler winter months), cooking, showering (hot water heating) and laundry activities.

In more recent years, the load shape at times of maximum demand on the network has changed to a longer, flatter curve during summer that grows in the morning and steadily increases until about 5.00pm when temperatures cool and the load gradually declines.

In the modern summer load shape, the underlying residential characteristics of normal daily household routines still exist. However additional factors such as residential (on a hot summer day), large C&I customer flat load profiles and the proportion and timing of Small to Medium Enterprises' (SME) load (mainly between 7.00am and 5.00pm) are now of increased significance.

Figure 3.9 shows the growth in demand since 1994 and the change from an annual peak demand in winter to a summer peak. The graph compares the changing profile of summer and winter daily load curves over the past 15 years. The higher growth in winter evening peak demand reflects the impact of reverse cycle air-conditioning on winter peak demand.

Figure 3.9 Daily load curve



In addition to the changing daily load profile, ENERGEX's load duration curve indicates the top 11 per cent of load occurs for less than one per cent of the year.

ENERGEX responds to the demand challenge on the SEQ network in two ways. Firstly, ENERGEX develops its forecast capital expenditure to augment the network and ensure peak demand is met. Secondly, ENERGEX has made a significant investment in DM initiatives to build a platform for the future and improve the balance between supply-side and demand-side solutions.

ENERGEX's DM Strategy is discussed further in Chapter 5.

3.11 Regulatory obligations overview

Compliance with legislative requirements and standards is a key driver of the expenditure incurred by ENERGEX in the construction, operation and maintenance of its electricity network. Compliance with applicable regulatory obligations and requirements is one of the four objectives for operating and capital expenditure, as set out in Clauses 6.5.6(a)(2) and 6.5.7(a)(2) respectively of the *Rules*.

Key legislative and regulatory obligations which apply to ENERGEX as a distribution business are outlined in pro forma 2.3.4 in **Attachment 1**. This section has not included laws and regulations of general application, such as the *Trade Practices Act*, *Anti-Discrimination Act*, *Copyright Act* and *Workplace Relations Act*.

ENERGEX is subject to a broad range of Commonwealth and Queensland-specific laws, Acts, Regulations, Codes, Guidelines and Procedures. An overview of the key legislative instruments that apply to electricity distribution businesses in Queensland is provided in **Appendix 3.6**.

These obligations are discussed under the following categories:

- EDSD compliance;
- jurisdictional industry and technical obligations;
- safety obligations;
- environmental and heritage obligations;
- national regulation and electricity market obligations; and
- corporate and business obligations.

3.11.1 EDSD compliance

In January and February 2004, a series of extraordinary storm and hot weather events in SEQ had a significant adverse impact on the performance of Queensland's distribution networks. These events included a succession of fierce storms, record high temperatures and a severe tropical depression which created widespread damage to property and infrastructure. The severe storms experienced at the end of January 2004 caused more damage to ENERGEX's network than any other series of storms in the previous 20 years. Record high temperatures were experienced in February of that same year.

Following these events, ENERGEX's shareholders appointed an independent panel to review the performance, needs and future strategies of ENERGEX (and Ergon Energy). The Report 'Electricity Distribution and Service Delivery for the 21st Century' (EDSD Review) was released in July 2004 and received widespread publicity and comment. The range of findings of the EDSD Review was supported by ENERGEX and its shareholders.

The EDSD Review's findings represented a package of measures to secure the best possible performance by the electricity distribution business into the future and were viewed as a constructive strategic blueprint for the future growth and management of ENERGEX's electricity assets. This was in the context of SEQ's rapid population and electricity-demand growth and the consequential continuing pressure on a range of infrastructure assets, including electricity-related infrastructure.

The review made 44 recommendations and the most substantive findings were:

- MSSs should be mandated;
- the government and the QCA should consider alternative arrangements for increasing the distributors' investment certainty during a *regulatory control period*;
- the distribution authorities should include a requirement to meet a standard equivalent to 'N-1' for bulk and zone substations and for sub-transmission systems;
- ENERGEX should reduce its system utilisation to around 60 to 65 per cent;
- planning in high growth urban areas should be based on a 10 PoE weather assumption[15];
- the distributors should publish an annual NMP;
- the distributors should develop resource plans for the next five to 10 years; and
- the distributors should improve their communications with the public on outages.

15 This recommendation was subsequently adjusted to a 50 PoE weather assumption to represent a more practical application. 10 PoE represents a one year in ten hot summer condition and a 50 PoE represents a one year in two condition (i.e. an average summer).

In response to the EDSD Review, the Queensland government released *An Action Plan for Queensland Electricity Distribution*, *August 2004* in **Appendix 3.7**, which set down ENERGEX's service obligations consisting of:

- mandatory MSSs for reliability;
- a requirement to adopt more conservative planning assumptions so that there would be sufficient back-up capacity in the event of asset failure to ensure that customers do not lose supply (often referred to as the equivalent 'N-1' planning requirements);
- reduction in system utilisation to around 60 to 65 per cent for bulk supply stations and 50 to 55 per cent for zone substations;
- delivery of an effective maintenance program;
- a requirement to base network planning outcomes on analysis that acknowledged the potential for very hot weather. The 10 PoE weather assumption effectively requires a greater contingent capacity be built into the system; and
- the development of an annual NMP to increase the level of rigour and transparency in capital and maintenance expenditure planning and delivery.

ENERGEX's response to the EDSD Review was encapsulated within 'The Powerful New Deal for Electricity Customers in South East Queensland' which included a detailed plan for addressing these objectives. A number of the action items have already been implemented and are demonstrated by ENERGEX's improved current performance. However, ENERGEX recognised that many of the issues identified in the EDSD Review could not be rectified quickly and required a longer term commitment before full resolution of all issues.

ENERGEX has yet to achieve a standard equivalent to 'N-1' for bulk and zone substations. ENERGEX has recently reviewed the security planning criteria. With endorsement from independent consultant Evans & Peck that the revised security standards are in accord with the 'N-1' philosophy envisaged by the EDSD Review, ENERGEX will now adopt the revised standards in the planning and development of its network. The revised security standards are discussed in Chapter 9.

As a consequence of the EDSD Review, the EIC was formulated to encapsulate many of these service standard requirements.

3.11.2 Jurisdictional industry and technical obligations

As a licensed owner and operator of an electricity distribution network in Queensland, ENERGEX is required to comply with a wide range of primary and subordinate legislation relating specifically to participants in the electricity industry. The key pieces of legislation which govern the electricity distribution entities in Queensland are the *Electricity Act 1994*, *Electricity Regulation 2006*, *Energy Ombudsman Act 2006* and the EIC.

Ensuring that all aspects of the operation are compliant with the relevant obligations requires significant resources. These expected costs have been included in ENERGEX's operating and capital expenditure forecasts.

***Electricity Act 1994* (QLD) –** The objectives of the *Electricity Act 1994* are to establish a framework to apply to all electricity industry participants that promotes the efficient, economical and environmentally sound supply and use of electricity. The *Electricity Act 1994* also regulates the electricity industry and electricity use as well as protecting the interests of electricity customers. ENERGEX has a wide range of key obligations under this legislation.

***Electricity Regulation 2006* (QLD) –** The *Electricity Regulation 2006* (the Regulation) operates under the *Electricity Act 1994*, with its primary objectives being to:

- ensure a secure, efficient and economic supply of electricity to customers on fair and reasonable terms;
- ensure customers' interests are adequately protected;
- provide for the proper measurement of energy efficiency and the performance of electrical equipment;
- ensure that the relevant information is provided to the public; and
- prescribe particular conditions of employment for employees of State electricity entities.

The Regulation sets out to achieve these objectives by the implementation of a number of provisions imposing specific obligations on electricity distribution entities.

***Energy Ombudsman Act 2006* (QLD)** – The *Energy Ombudsman Act 2006* provides customers with an effective and independent mechanism for dispute investigation and resolution. The *Electricity Act 1994* empowers the Energy Ombudsman to compel electricity distribution entities to make payments to customers.

Electricity Industry Code (QLD) – The EIC was established under the authority of the *Electricity Act 1994*. An electricity distribution entity's key obligations under the provisions of the EIC are:

- preparation of annual management plans and summer preparedness plans;
- compliance with MSS established by the QCA;
- compliance with GSLs and provisions for customer rebates;
- timeframes for completion of standard service orders; and
- reporting on performance to the Regulator.

The obligations under the EIC are discussed in more detail in Chapter 9.

3.11.3 Safety obligations

The key safety legislation that applies to ENERGEX is the *Electrical Safety Act 2002*, the *Electricity Safety Regulation 2002*, the *Workplace Health and Safety Act 1995* and the *Workplace Health and Safety Regulation 2008*. These laws place obligations upon ENERGEX and its employees with regard to electrical safety and ensuring a safe workplace. Compliance with safety obligations forms an important part of ENERGEX's capital and operating costs.

ENERGEX's commitment to meeting these obligations is reflected in organisational values that place safety of the community and employees first.

Electrical Safety Act 2002 **and** ***Electrical Safety Regulation 2002*** – The *Electrical Safety Act 2002* governs all matters associated with electrical safety, including the licensing of electrical workers and contractors. The Act is administered by the Electrical Safety Office (ESO) within the Department of Industrial Relations. The purpose of the legislation is to eliminate the human cost associated with the death, injury and destruction of property that can be caused by electricity. Queensland electricity distribution entities are required to comply with all relevant provisions under this Act. The most important obligation is the responsibility to ensure that all electricity inspection, testing and maintenance works are operated in a way that is electrically safe.

The *Electricity Safety Regulation 2002* requires that electricity distribution entities implement measures to ensure the electrical safety of their licensed workers and contractors in addition to the safety of consumers and the general public. Distribution entities also have a responsibility under the Regulation to ensure the safe supply of electricity to consumers.

Workplace Health and Safety Act 1995 **and** ***Workplace Health and Safety Regulation 2008*** – The *Workplace Health and Safety Act 1995* applies to health and safety issues in the workplace and the *Workplace Health and Safety Regulation 2008* provides a framework for the management of workplace health and safety issues as identified in the provisions of the Act. The Regulation sets out the legal requirements intended to prevent or control workplace health and safety hazards and the Act identifies the electricity industry as one of the sectors that requires a Workplace Health and Safety Officer under Section 93 of the Act.

The Act does not include provisions that relate to issues addressed by other industry-specific safety legislation. This means the Act does not apply to those issues relating to the electrical safety of workers licensed with electrical entities as these matters are addressed by the *Electrical Safety Act 2002*.

3.11.4 Environmental and heritage obligations

The nature of electricity distribution operations means environmental and heritage obligations have a significant cost implication for ENERGEX relative to other Queensland businesses. Of particular significance are the *Environmental Protection Act 1994*, *Nature Conservation Act 1992*, *Queensland Heritage Act 1992*, *Vegetation Management Act 1999* and *Integrated Planning Act 1997*.

ENERGEX's commitment to the environment is reflected in the objective of ENERGEX's environment strategy to deliver a sustainable environmental position through compliance and business practices that minimise harm to the environment.

Environmental Protection Act 1994 – The *Environmental Protection Act 1994* provides a framework for the protection of Queensland's environment whilst allowing for ecologically sustainable development. The Act stipulates that this objective is to be achieved through the application of a cyclical integrated management program. All participants, including electricity distribution entities, are obliged to comply with two key requirements under the Act: general environment duty (avoid activities likely to cause environmental harm unless all reasonable preventative measures have been undertaken); and duty to notify of environmental harm if an event has not previously been authorised under the framework established by the Act.

This general environmental obligation is relevant to ENERGEX particularly when constructing infrastructure. Compliance entails regular monitoring of environmental exposures and review of incident trends. Compliance with environmental regulations is ensured as part of an ongoing internal Environmental Management System. Electricity distribution entities are also required to comply with the framework established under the Act for the environmental evaluation of individual projects and the obtaining of development approvals or registration certificates prior to engaging in certain activities or projects that have the potential to have a material environmental impact.

***Nature Conservation Act 1992* –** The objective of the *Nature Conservation Act 1992* and its subordinate legislation is the conservation of nature through an integrated and comprehensive conservation strategy. The operation of an electricity supply network is classified as a 'service facility' under the Act. The Act states that operators of service facilities may be granted permission to operate on land situated in a national park providing the land is only to be used for the service facility and the Chief Executive is satisfied that the cardinal principle for the management of national parks will be observed. It is also necessary that the land is used in a manner which is ecologically sustainable and no reasonably practicable alternative exists to the use of the national park land.

This legislation provides the framework under which ENERGEX must operate in order to obtain permission to construct distribution network infrastructure on land lying inside national park boundaries.

Queensland Heritage Act 1992* and *Queensland Heritage Regulation 2003 – The objective of the *Queensland Heritage Act 1992* is to provide for the conservation of Queensland's cultural heritage. The obligations of an electricity entity in relation to this legislation relate to the planning of expansions to its distribution network. Of most relevance to ENERGEX is the requirement for an entity to obtain a permit to enter an area classified as a protected area under the legislation.

Vegetation Management Act 1999* and *Vegetation Management Regulation 2000 – Vegetation management in Queensland is regulated through the *Vegetation Management Act 1999* and *Vegetation Management Regulation 2000* in conjunction with the *Integrated Planning Act 1997* and *Integrated Planning Regulation 1998*. The legislation deals with various aspects of clearing, conservation and management of native vegetation. ENERGEX is required to comply with the provisions of the Act and Regulation when undertaking vegetation management activities.

***Integrated Planning Act 1997* and *Integrated Planning Regulation 1998* –** The *Integrated Planning Act 1997* provides a framework to integrate planning and development assessment so that development is managed in an ecologically sustainable fashion. Several of the provisions relate to the responsible management of the environmental impacts of infrastructure development. In terms of the operations of an electricity distribution entity, this is most relevant to the expansion of its distribution network. To ensure compliance with the provisions of this Act, ENERGEX must consider and attempt to minimise, where practicable, any adverse environmental impacts of its network expansion programs.

3.11.5 National regulation and electricity market obligations

As a Distribution Network Service Provider (DNSP) operating in the NEM, ENERGEX has a range of market obligations with which it must comply. These obligations include compliance with the NEL and the *Rules*. Additionally the *Electricity – National Scheme (Queensland) Act 1997* governs Queensland's participation in the NEM.

Electricity* – *National Scheme (Queensland) Act 1997 – The purpose of this legislation is to establish the NEL, as set out in the *National Electricity (South Australia) Act 1996* as a law of Queensland. As a participant in the electricity industry, ENERGEX is obligated to comply with specific requirements imposed on a DNSP and/or Network Service Provider (NSP) under the NEL.

National Electricity Law – The objective of the NEL is to promote efficient investment in, and the efficient use and operation of, electricity services for the long-term interests of electricity consumers. The NEL focuses on price, quality, safety, reliability and security of electricity supply and the reliability, safety and security of the National Electricity System. Electricity distribution entities have a large number of obligations under the NEL.

National Electricity Rules – The *Rules* are established in Queensland under the framework set out in the *Electricity – National Scheme (Queensland) Act 1997*. The *Rules* contain provisions that impose specific obligations on the different entities that operate within the electricity industry. DNSPs, such as ENERGEX, have a number of obligations under the *Rules* which apply to different parts of their operations, including registration as an NSP, determination of network distribution losses and a large number of obligations relating to connections to distribution networks, economic regulation and metering.

3.11.6 Corporate and business obligations

In addition to the obligations detailed above, ENERGEX is required to comply with a range of State and Commonwealth legislation which applies across all businesses operating within Queensland. Obligations imposed under this legislation are not specific to ENERGEX as an electricity entity and apply to all business entities in the same manner.

Government Owned Corporations Act 1993* and *Government Owned Corporations Regulation 2004 – The *Government Owned Corporations Act 1993 (GOC Act)* provides a framework for the corporatisation and structural reform of nominated corporatised government entities. The *GOC Act* is intended to facilitate the application of the corporatisation process in a progressive and flexible fashion. Most of the obligations imposed on Government Owned Corporations (GOCs) by the Act relate to accountability and performance monitoring requirements.

The *Government Owned Corporations Regulation 2004* outlines the procedure for the nomination and declaration of a GOC in addition to providing a list of the GOCs to which the relevant pieces of legislation apply. ENERGEX is listed as a GOC in Schedule 2 of the Regulation.

Financial Administration and Audit Act 1977 – This legislation is intended to provide a framework for the financial administration and auditing of the State's public finances in relation to government departments and statutory bodies. The obligations of a GOC under the *Financial Administration and Audit Act 1977* relate primarily to the provision of information on request to the Treasurer.

State Development and Public Works Organisation Act 1971 – The overriding objective of the *State Development and Public Works Organisation Act 1971* is to provide for State planning and development through a co-ordinated system of public works organisation. The Coordinator-General is empowered under the provisions of this Act, to plan a program of works. As the provider of facilities that are deemed to be 'public works', ENERGEX is obliged under this Act to cooperate with the Coordinator-General and provide information upon request to assist in the planning process for the Queensland government's program of works. In addition, ENERGEX is required to co-ordinate its network investment planning with any public works requirements.

Acquisition of Land Act 1967* and *Acquisition of Land Regulation 2003 – The *Acquisition of Land Act 1967* serves to consolidate the law relating to the acquisition of land for public works and processes. One of the public activities for which land may be subject to the Act is electrical works. The provisions of the Act relate to the taking of land, the discontinuance of taking land and compensation to be paid to landowners in addition to several other general and transitional provisions. Electricity distribution entities are required to comply with all obligations under the Act relating to the acquiring of land for the purpose of constructing an easement and the payment of compensation to the holder of the land over which an easement is to be constructed.

Land Act 1994* and *Land Title Act 1994 – The objective of the *Land Act 1994* is to manage and administer land for the benefit of the people of Queensland, whilst having regard for several key principles including: sustainability; evaluation; development; community purpose; protection; consultation; and administration. A large number of specific obligations that a DNSP is required to comply with under this Act relate to the registration and administration of easements.

The purpose of the *Land Title Act 1994* is to consolidate and reform the law relating to the registration of and interests in freehold land. The specific obligations under the Act that apply to a DNSP relate to the registration and administration of easements.

Public Records Act 2002 – The objective of the *Public Records Act 2002* is to ensure that the public records of Queensland are made, managed, kept and, if appropriate, preserved in a useable form for the benefit of present and future generations; and that public access to records under this Act is consistent with the principles of the *Freedom of Information Act 1992*. A GOC is defined as a public authority for the purpose of the Act. The specific obligation imposed on a public authority, such as ENERGEX, under this Act is to make and keep full and accurate records of its activities and have regard to any relevant policy, standards and guidelines made about making and keeping public records.

3.12 Key information systems

ENERGEX's key information systems, which are detailed in **Appendix 3.8**, comprise a mixture of standard commercial 'off-the-shelf' and in-house developed systems. The systems have been grouped into the following categories:

- **Network Operations** – The primary system for monitoring and control of the distribution network is the SNC-Lavalin Supervisory Control and Data Acquisition Master Station. Other associated systems are the Application for Switching, Service Call Management (SCM) and Netcore systems.
- **Network Planning and Design** – The key systems used for network planning and design functions are the Distribution Network Information System (DINIS), ENERGEX's Master Address System, ESRI, which is the Graphical Information System for ENERGEX, and the Network Facilities Management System.
- **Enterprise Resource Planning (ERP) –** Ellipse ERP is the integrated system used by ENERGEX. The system provides works management, asset management, logistics, financials, accounts payable, accounts receivable, estimation of expenditure, human resources and payroll.

  In addition to Ellipse, ENERGEX also uses Primavera for program management. eSafe is a system specifically designed to manage the safety program of ENERGEX and the Meter Asset Repository System is the master repository of all meters that are installed in customer premises.
- **Workforce Automation –** The Advantex FFA system provides the ability to dispatch works directly to crews in the field without the need to return to office locations. The system is linked back to the Ellipse or Peace system. In addition there is the Hand Held Computing system, which is a mobile computing platform that is used in the inspection of ENERGEX's distribution assets.
- **Customer Information Systems** – The PEACE Customer Information System is the master repository of customer information for ENERGEX. It stores all data relating to a customer required by a distribution provider such as customer name, address, Financially Responsible Market Participant and National Meter Identifier (NMI).

Other customer service systems are the Interactive Voice Response (IVR) system, the Customer View Utility (CVU) system and the Call Line Identifier system which all work in conjunction with Peace as the customer information system.

- **Market and Energy Data Management Systems** – The NEMlink system is the interface between ENERGEX and the electricity market via NEMMCO. NEMlink is responsible for receiving information from the market and routing the request to the relevant system (Peace, TOHT[16], etc).

  The TOHT system is used to send meter reading information to the respective retailers such that retail bills can be calculated.

  The Itron[17] MVRS[18] system is used to manage the actual reading of the non-interval meters. MVRS manages the upload and download of meter reading information between TOHT and hand held devices used by the meter readers.

  The Itron MV90[19] platform is used to manage readings for remote interval meters.

3.13 Other services

ENERGEX currently performs activities that are non-regulated services as defined by the *Rules*. These include provision of the contestable metering services (Type 1 to 4), provision of training services to external parties (by EsiTrain), sale of material and scrap, broadband services and contracting services. Following the recent sale of its New Zealand concern, unregulated services account for approximately 9 per cent of ENERGEX's total company group revenue.

16 A package application from UXC/Datec.

17 A company that provides the products MV90, MVRS and MetrixND.

18 A mass-market meter reading package application.

19 A remote meter reading package application from Itron.

4 Network strategy

ENERGEX's Network Vision in **Appendix 3.5** provides its future view of the operating environment and challenges its sees on the 20-year horizon. ENERGEX's Network Strategy flows from the Network Vision and our core network management principles, identifying priorities for the network business over the 10-year planning period.

The Network Strategy guides the network development and management framework – the key mechanism for delivery of the Network Strategy's outcomes, in particular, the projects and programs discussed as part of the operating and capital expenditure forecasts in Chapters 12 and 13.

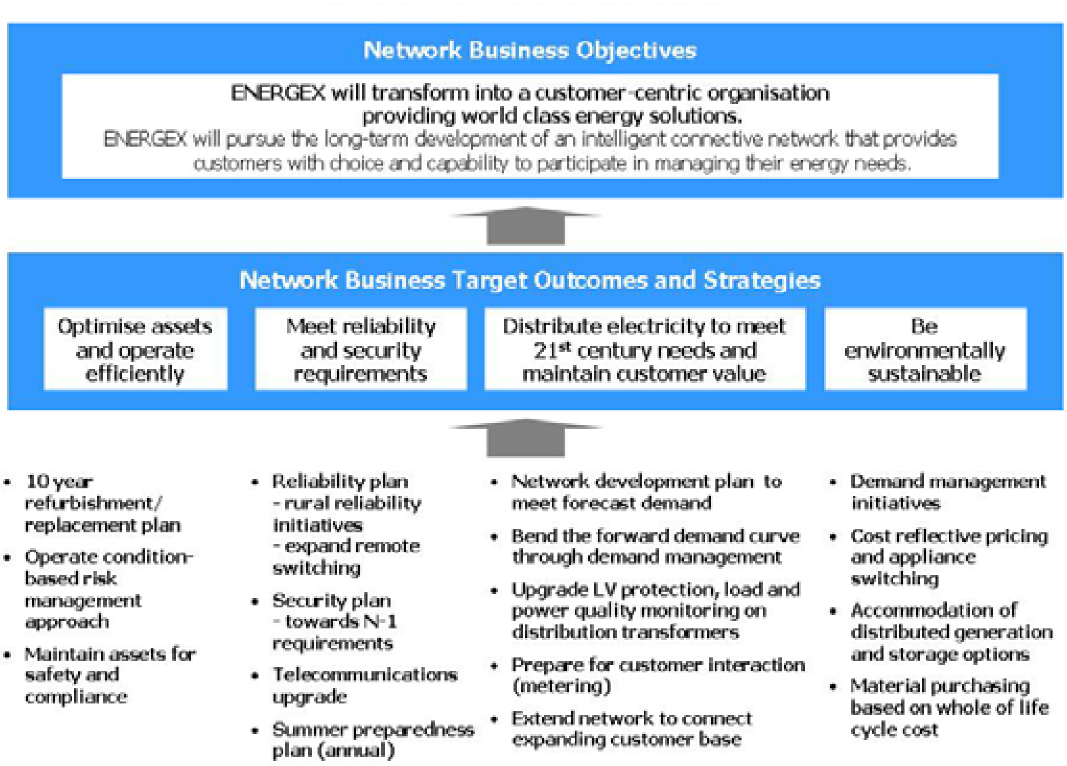
This chapter provides an overview of ENERGEX's Network Strategy for the *2010-15 regulatory control period* and key elements of the network development and management framework.

4.1 Summary

ENERGEX's Network Strategy, as summarised in Figure 4.1, responds to the key network business challenges by:

- meeting security requirements and continuing growth in ENERGEX's network area via the NDP;
- achieving customer expectations through the Reliability and Power Quality Plans;
- implementing the SPP to accommodate the variable operating environment;
- applying a CBRM approach to maintenance, renewal and replacement of assets;
- progressing the modernisation of the distribution network through the development and deployment of a smart network with improved communications, network operations and control technology; and
- reducing the growth in peak demand through the development and implementation of DM initiatives.

Figure 4.1 ENERGEX's network strategy



4.2 Regulatory information requirements

In relation to forecast operating expenditure and forecast capital expenditure, Clauses 6.5.6(b)(1) and 6.5.7(b)(1) of the *Rules* require ENERGEX to comply with any relevant *regulatory information instrument*.

Clause 2.3.6 of the RIN requires ENERGEX to provide information concerning key plans, policies, procedures and strategies that underpin the construction of its expenditure forecasts.

Specifically Clause 2.3.7(a)(3) of the RIN requires copies of key documents used to plan ENERGEX's systems and develop capital and operating expenditure forecasts. These may include:

- a long-term network development plan;
- asset planning and network maintenance polices, standards and principles;
- asset management and network maintenance strategies; and
- asset management and network maintenance plans, such as the NMP, required under the EIC.

Clause 2.3.7(4) requires an explanation of how the key documents support the capital and operating expenditure forecasts and their interrelation.

4.3 Key network challenges

ENERGEX's Network Strategy identifies the following key challenges as drivers for the development and management of the electricity network in SEQ:

- **Growth** – For the past 10 years SEQ has experienced a sustained period of high demand growth and customer numbers. This trend is predicted to continue resulting in the ongoing expansion of ENERGEX's network 'footprint'. ENERGEX must be prepared to continue to expand its network to accommodate the electricity needs of additional customers.
- **Peak demand** – ENERGEX is required to build a network with the capacity to meet the electricity needs of all customers at times of peak demand. This had led to 11 per cent of ENERGEX's $8 billion infrastructure being utilised for just one per cent of the time. Driven by the continuing uptake of air-conditioning, ENERGEX is committed to finding alternatives to the traditional investment solution through its DM Strategy.
- **Asset maintenance, renewal and replacement** – In addition to the challenge of meeting high demand growth on the network, ENERGEX is faced with the challenge of monitoring and replenishing its ageing asset base. Many of ENERGEX's assets were constructed during the 1960s. This was followed by the construction boom of the 1980s, particularly in the Gold Coast region. Following a period of deferred asset renewal and replacement, ENERGEX must develop strategies for the efficient management of ageing infrastructure so as to enable the safe, reliable and secure operation of its electricity network.
- **Meeting obligations and requirements**
  - **Security**: In early 2004, the Queensland government commissioned the EDSD Review. This review recommended ENERGEX adopt planning processes that will return all bulk supply substations, zone supply substations and sub-transmission feeders to an 'N-1' philosophy. ENERGEX will need to continue a high network investment strategy to move towards security compliance.
  - **Reliability**: ENERGEX is required to maintain a number of mandated MSSs in relation to the reliability of electricity supply. ENERGEX is required to meet these standards, as well as achieve STPIS targets from July 2010.

In addition to network challenges, the Network Strategy recognises the impact of emerging issues that ENERGEX must address for continued success in the provision of a safe, reliable electricity supply in the contemporary age.

These emerging issues can be summarised as:

- **Changing customer expectations** – Whilst ENERGEX's customer numbers have increased, so have expectations for more reliable and higher quality electricity supply. In addition, reliance on 'interruption free' electricity supply has increased due to the increased use of digital equipment which requires high levels of reliability.

- **Changing customer behaviour** – Faced with the spectre of rising electricity prices, driven by increasing cost of living and growing environmental concern, customers are changing their behaviour around the consumption of electricity, such as the adoption of energy efficiency and distributed generation products. These changes are compounding the already growing gap between peak demand and energy consumption and will challenge the traditional solutions for expansion of the network infrastructure. ENERGEX needs to enable and promote solutions such as demand management, load control, distributed generation and storage to respond to these changes and make investment decisions that provide value to customers and are in the long-term interests of the people of SEQ.
- **Responding to climate change** – ENERGEX's shareholders and the community have clear expectations that the corporation will contribute towards future environmental sustainability. As a distributor of electricity, ENERGEX is committed to setting an example by reducing its own greenhouse gas emissions, promoting and enabling energy efficiency and peak demand reduction among its customers and preparing the distribution network to transport electricity produced from clean and renewable generation sources and/or storage.
- **Community engagement** – By continuing to meet growing demand with record augmentation of the network, ENERGEX has experienced heightened community pressure for electricity infrastructure that is less intrusive. ENERGEX has committed to high levels of community engagement in planning processes for future infrastructure and to network architecture that minimises the impact on the environment and urban and rural amenities.

The Network Strategy guides ENERGEX's integrated response to developing, managing and operating an electricity network that meets these challenges.

4.4 Delivering network strategy outcomes

The Network Strategy articulates target network outcomes to focus ENERGEX's efforts in addressing the challenges for the continued safe and reliable distribution of electricity.

The target outcomes include:

- optimising assets and efficient operation;
- meeting reliability, quality and security requirements; and
- distributing electricity to meet 21st century needs and maintain customer value while being environmentally responsible.

The interrelated nature of a distribution system means a combination of strategies contribute to the overall delivery of the target outcomes.

Progress in the performance and operation of the network outcomes is communicated annually to stakeholders and customers through the publication of the NMP.

4.5 Network strategy in organisational context

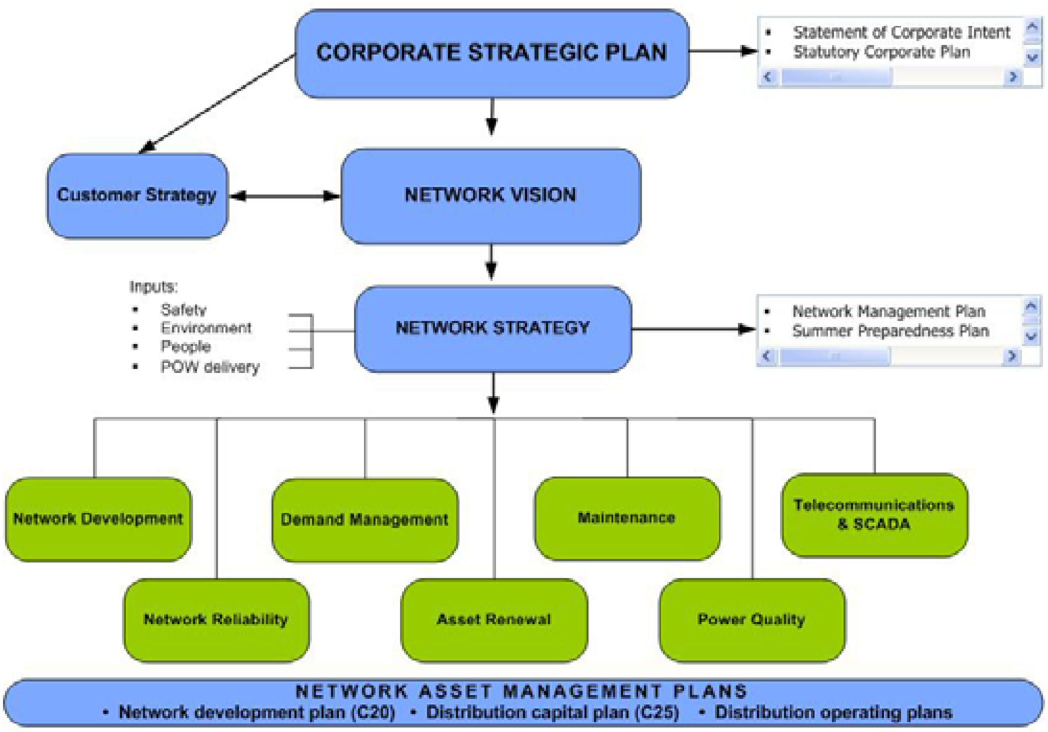
ENERGEX's Network Strategy identifies priorities and outlines strategies for the network business and provides fundamental guidance for decisions over the *2010-15 regulatory control period*.

ENERGEX's Network Strategy deploys the long-term vision for distribution of electricity in SEQ, as articulated in the Network Vision in **Appendix 3.5**. The Network Vision draws on ENERGEX's Corporate Strategy (**Appendix 4.1**).

To achieve the Network Vision, the Network Strategy contains specific initiatives to move ENERGEX towards the distribution system of the future. For example, the Network Strategy responds to the objectives of increasing the proportion of underground network, preparing the distribution network for the connection of distributed generation and ensuring network components meet changing customer expectations for reliability and amenity.

Figure 4.2 shows the hierarchy between the Network Strategy and ENERGEX's Corporate Strategy documents.

Figure 4.2 ENERGEX's strategy hierarchy



Consistent with ENERGEX's Corporate Strategic Plan the business objective of the Network Strategy is for ENERGEX to 'transform into a world class customer-centric organisation providing world class energy solutions'. To achieve this objective ENERGEX will pursue the long-term development of an intelligent connective network that provides customers with choice and capability to participate in managing their energy needs.

ENERGEX's Network Strategy is supported by subordinate documents that take account of the technical standards and engineering needs of the distribution network in the following areas:

- network development;
- network reliability;
- demand management;
- asset renewal;
- maintenance;
- power quality; and
- telecommunications and supervisory control and data acquisition (SCADA).

Key documents which outline how the strategy outcomes are aligned and prioritised are the:

- NDP for the sub-transmission network and distribution backbone capital projects (known internally as the C20 program);
- Distribution Capital Plan including capital projects for customer connections, company initiated and customer driven works (known internally as the C25 program); and
- Distribution Operating Plans including budgets for inspections, planned maintenance, vegetation management, corrective maintenance and storm and emergency response.

4.6 Network strategies

The strategies discussed in this section guide the preparation of the projects and programs that form the basis of the capital and operating expenditure forecasts prepared for this *Regulatory Proposal*. These forecasts also form the basis of ENERGEX's annual budgeting process.

Once the programs are finalised, the elements of risk, customers and sustainability are weighed up and initiatives are reviewed against ENERGEX's corporate objective of a balanced outcome, prior to inclusion in forecast capital and operating expenditure.

4.6.1 Network development

ENERGEX's network development strategy specifically addresses SEQ's growth, peak demand and security challenges.

The Development Strategy is the overarching planning instrument that uses ENERGEX's forecasts and standards and performance data to produce a network-wide plan for the expansion and reinforcement of the SEQ electricity infrastructure.

The key components of the network development process include:

- Development of **network building blocks** that detail the economically efficient standard designs for substations, overhead powerlines and underground cables. The creation of the network building blocks is based on community expectations and the principles contained in the Network Vision.
- Establishment of **Security Planning Guidelines** which reflect the 'N-1' planning approach recommended by the EDSD Review. The guidelines in **Appendix 4.2** and **Appendix 4.3** represent the practical application of the security standard to ENERGEX's major load categories, taking into account load transfers. A review of these guidelines, conducted by Evans & Peck, is in **Appendix 4.4**.
- Preparation of a **Network Strategic Development Plan** which is a schematic representation of the long-term development of the network that maps out the expected pattern of electricity usage for the next 20 years if load densities and land use are maximised.
- Development of **load forecasts** for ENERGEX's bulk supply and zone substations and sub-transmission and distribution feeders. These load forecasts are then reconciled with the overall system-wide load forecast and are also provided to Powerlink to assist with planning of the transmission network.
- Preparation of **area plans**, based on load forecasts, to predict the consequences for the network and identify any locations where security standards may be reduced. Guided by the Network Strategic Development Plan, high-level options and potential projects are identified to overcome network constraints.
- Detailed planning either confirms the high-level option analysis or provides a cost-effective alternative.
- The application of a **risk assessment** to each project to quantify the risk to electricity distribution and supply to customers if the network upgrade does not proceed within the nominated time period.

The Network Risk-Based Framework has been developed in accordance with *AS/NZS 4360:2004 Risk Management* and other appropriate Australian and International Standards and maintains consistency with the ENERGEX Enterprise Risk Management policy and procedure.

Four risk categories are defined by which network-based risks or concerns are assessed:

1. safety;
2. environment;
3. reliability; and
4. capacity (including network security).

Projects are assessed against each of the four risk categories, with a risk consequence determined, followed by an estimation of the likelihood enabling a risk score (1-36). This is compared to a risk tolerability matrix to determine the level of risk, ranging from very low to intolerable. Projects are then prioritised according to their risk.

Co-ordination of proposed projects with other capital projects for asset refurbishment and reliability is undertaken to ensure an optimum network outcome. Following a review for balanced outcomes, the project estimates are then included in the NDP and subsequently in the forecast capital expenditure for the *regulatory control period*.

4.6.2 Network reliability

The purpose of the Reliability Improvement Strategy is to deliver reliability performance in line with customer expectations and to comply with the MSS specified in Queensland's EIC as part of ENERGEX's licence conditions. This strategy responds to ENERGEX's reliability challenges and the distribution of electricity that meets customers' 21st century needs.

In developing this strategy, ENERGEX has been cognisant of the need to ensure improvements are targeted and address poor performing parts of the network on a priority basis.

ENERGEX's predominantly overhead network is prone to damage from storms, high winds, vegetation and wildlife. Performance improvement relies on the identification and elimination of root causes, the minimisation of the number of customers impacted by power outages and the improvement of restoration response times.

In addition the Network Building Blocks, described as part of the Development Strategy, are designed to meet required reliability standards. This strategy is delivered through a series of capital and operating projects.

Reliability analysis quantifies the expected gap to the MSS after taking into account the expected benefits from other network investment streams, such as network growth and security, and the statistical variability of network reliability due to seasonal weather patterns and normal random events.

To address the reliability gap, ENERGEX develops comprehensive localised capital and operating projects and programs, targeted on a feeder by feeder and asset class basis. Improvements expected to be achieved result from:

- a comprehensive vegetation management program to reduce interruptions caused by contact with overhead powerlines, particularly during storms;
- targeting maintenance to reduce root causes of faults, including wildlife proofing on key parts of the distribution network;
- refurbishing poor performing areas of the network to the new building block standards;
- installing automatic circuit reclosers to reduce the number of customers affected by individual outages;
- introducing operational enhancements, such as the more efficient deployment of field crews; and
- the use of technology through the accelerated deployment of SCADA and Distribution System SCADA to improve restoration times by using remote control.

Network performance is regularly monitored and reported quarterly to QME. The success of individual programs is assessed and this knowledge is fed back into the process to refine and continually improve reliability outcomes.

4.6.3 Demand management

Although ENERGEX's DM Strategy will be discussed in detail at Chapter 5, an important aspect of this strategy is its contribution to ENERGEX's consideration of practical non-network alternatives.

The DM Strategy recognises that the construction of electricity infrastructure to manage peak demand at current rates is not financially sustainable over the long term. As such ENERGEX is committed to seeking cost-efficient non-network alternatives that ensure reliability standards can be achieved. ENERGEX's strategy is to implement a suite of concurrent co-ordinated initiatives that will deliver a reduction in peak demand, known as 'bending the forward demand curve'.

In addition to a number of initiatives designed to reduce the peak demand – a key driver for network augmentation – ENERGEX is seeking non-network alternatives through the *Rules* and the application of the *regulatory test*.

ENERGEX has supported the emergence of practical solutions by forming a panel of potential suppliers developing alternatives to network augmentation that have the capacity to meet ENERGEX's reliability and security obligations.

ENERGEX's DM Strategy also contributes to ENERGEX's forecast capital expenditure by incorporating into network planning a target MW reduction in relation to peak demand.

4.6.4 Asset renewal

ENERGEX's Asset Renewal Strategy addresses the optimisation of assets and their efficient operation, in addition to ensuring compliance with reliability and security requirements. This strategy is centred on a CBRM approach. The key point of this approach is that age is not the sole determinant of replacement of assets; rather a combination of factors which describe their condition will determine whether they are replaced.

CBRM is used throughout the world by electricity utilities to deliver effective asset-related risk management. ENERGEX's strategy is based on the British Standard PAS55 and has been developed and deployed within the company with the assistance of an experienced international consultant, EA Technology Consulting. The report by EA Technology Consulting is in **Appendix 4.5**.

The CBRM methodology determines the probability of failure based on the following factors:

- age of asset and expected life;
- actual performance;
- operational experience;

- environmental conditions; and
- manufacturer and specification.

The probability of failure is generally described in terms of a health index. As the probability of failure increases the health index increases. Health indices are derived for different asset groups and calibrated using failure rates. The future health index for individual items of plant is derived from the current health index and operating conditions. This is aggregated and allows future failure rates for asset classes to be calculated.

The risk associated with the failure of each asset class is assessed in accordance with the ENERGEX risk assessment framework and a replacement program is developed. Where practical, in terms of timing, asset replacement work is incorporated in other capital projects to achieve a cost efficient outcome. These projects are then incorporated into the NDP.

4.6.5 Maintenance

ENERGEX develops and implements maintenance plans to provide a safe, reliable network that delivers power quality and legislative compliance whilst achieving an economical asset life. As such, maintenance contributes to the large number of the overall target outcomes of the Network Strategy.

Maintenance requirements for ENERGEX assets are determined by consideration of mechanisms by which equipment can degrade and fail. The safety, environmental, operational and economic consequences of equipment failure, is also assessed.

Asset inspection and maintenance cycles are based on the main cause of equipment failure for that particular asset class. These are:

- time-based inspection i.e. poles and crossarms;
- the number of operations i.e. tap changers; and
- the number of fault operations i.e. circuit breakers.

There are two documents that deploy ENERGEX's asset management policy; the Substation Asset Maintenance Policy (SAMP) and the Mains Asset Maintenance Policy (MAMP) in **Appendixes 4.6 and 4.7**. The SAMP deals with substation-based equipment (within the substation fence) and the MAMP applies to other transmission, sub-transmission and distribution assets such as overhead powerlines, underground cables and distribution transformers. Both the MAMP and the SAMP are subject to continuous review to reflect the latest maintenance strategies.

The two documents define inspection and maintenance periods or cycle times for each type of asset together with an overview of the extent of maintenance to be undertaken. These documents are used as inputs to determine the detailed annual Operating and Maintenance Plan and the five-year operating forecast.

Specific targeted strategies include:

- reducing failure rate of crossarms and overhead equipment to meet MSS SAIFI targets;
- reducing incidence of wire down events in the network to reduce the risk to public safety; and
- reducing corrective repair expenditure in comparison to inspection and planned maintenance budget.

4.6.6 Smart networks – telecommunications and SCADA

A number of network strategies rely on effective telecommunications and SCADA to deliver their outcomes. To deliver these, ENERGEX has developed a Telecommunications and SCADA Strategy that will progressively overlay the distribution network with communications technology.

This strategy has the capacity to deliver outcomes in the areas of efficient operation of assets, reliability, and regulatory compliance in addition to distributing electricity that meets 21^{st} century needs.

As an essential service provider ENERGEX, particularly in times of emergency, needs reliable voice and data communications systems to allow it to respond in an effective and timely fashion. In addition, key power system protection functions are required by the *Rules* to have dual protection circuits.

ENERGEX's Telecommunications and SCADA Strategy provides for the continued use of both internal systems and external service providers to deliver its requirements. The key drivers for the strategy are:

- replacement of ageing technologies that are no longer supported by external providers, such as back up voice communications and leased data lines;
- replacement of obsolete analogue radio and ageing microwave communications networks;
- replacement of the ageing copper pilot cable network;
- compliance with NEMMCO-required protection systems for key plant;
- the ability to significantly increase the number of remote controlled devices and monitoring points on the network; and
- provision of future readiness for Advanced Metering Infrastructure (AMI).

The cost efficient modernisation of the communications network includes:

- replacing the backup voice communications network;
- developing a full digital communications network with built-in redundancy;

- increased network automation and condition monitoring; and
- being prepared to introduce communication to the customer premise level when the details of the AMI solution are available.

This work will be progressively implemented both as individual projects and, where cost-effective, as part of other projects included in the NDP.

4.6.7 Power quality

Power quality is the degree to which the supply system is free from major distortions and fluctuations in supply voltage and frequency. Network power quality, as distinct from reliability, is becoming an increasingly important issue for all classes of customer.

The Power Quality Strategy addresses the dual challenges of optimising assets and their efficient operation, in addition to distributing electricity to meet 21st century needs.

ENERGEX's Power Quality Strategy is currently based on measuring power quality parameters following a power quality complaint from a customer. Measurements are taken and a site-specific solution is identified as a result of engineering analysis.

In the *2010-15 regulatory control period*, ENERGEX intends to establish a power quality monitoring regime at all voltage levels to determine the extent of any power quality problems. The data from the monitoring program will be used to forecast trends and develop appropriate responses to meet power quality standards. The advent of low cost multi-function metering technology allows the installation of meters to monitor voltage levels. The meters also measure unbalance and harmonic distortion at both zone substation and distribution substation levels and in some cases to individual customers.

This will enable early identification of declining power quality and ideally a low cost solution to rectify issues before they become noticeable to customers.

The installation of monitoring equipment is being addressed by including metering in the standard building blocks for new distribution and zone substations and the development of a program to progressively retro-fit existing equipment with the new metering devices. This program is included in the capital expenditure forecast for the *2010-15 regulatory control period*.

4.6.8 Additional plans and inputs

4.6.8.1 Environment

ENERGEX's Environment Strategy included as **Appendix 4.8** is an overarching corporate document that addresses environmental sustainability from an organisational perspective, in addition to incorporating network responses that are specific to the distribution of electricity.

The objective of ENERGEX's Environment Strategy is to deliver a sustainable environmental position through compliance and business practices that minimise harm to the environment. Input from environmental initiatives is key to achieving the Network Strategy outcome of environmental sustainability.

ENERGEX's network-focused business practices include:

- **Obligation compliance** – Compliance with the Environmental Protection Act 1994 and more than fifty other legislative instruments is achieved through deployment and monitoring of the Environment Compliance Plan.
- **Waste management** – ENERGEX has targeted progressive programs to remove polychlorinated biphenyls from transformers and capacitors. Sulphur hexafluoride gas is also recovered during asset maintenance or de-commissioning. ENERGEX disposes of these wastes in accordance with regulatory requirements.
- **Site decontamination** – ENERGEX investigates and takes remedial action to ensure existing sites and prospective sites are suitable for their intended use, in accordance with the National Environment Protection Measures – Assessment of Site Contamination.
- **Land remediation** – In addition to offsetting carbon emissions, ENERGEX also provides vegetation, koala and biodiversity offsets for infrastructure programs which impact on these values.
- **Training** – ENERGEX provides field-based staff with environmental training to ensure procedural understanding and personal awareness of environmental issues.

4.6.8.2 Summer preparedness plan

The SPP is developed annually in accordance with the requirements of the EIC.

Although the SPP is more of a short-term operational instrument as opposed to a strategy, it makes an important contribution to addressing the challenging SEQ's operating environment.

Capital and operating expenditure forecasts for regulatory purposes are based on long-term assumptions over a five year *regulatory control period*. The SPP provides details of preparations ENERGEX will undertake for the upcoming summer. It is based on the current state of the network, planned commission dates for current projects and short-term forecasts of load and weather conditions. It describes the targeted use of capital and operating funds in the six months leading up to the summer period.

The Plan provides details of specific capital and operating works as well as operational responses, system preparations and planned communication activities.

Preparations for summer 2009-10 had four major areas of focus to ensure:

1. the capacity and security of the network was sufficiently increased to meet high summer energy demand;
2. ENERGEX continued to improve the resilience of the network in times of severe weather;

3. ENERGEX's operational response to network emergencies continued to improve; and
4. timely and accurate communication in relation to network outages would be provided to customers and the media.

ENERGEX develops the SPP as part of its long-term continuous improvement approach and is on target to further improve the resilience of the network to withstand severe weather events, enhance operational response to such events and keep customers and the media better informed of progress in restoring supply.

4.7 Governance of network development and maintenance framework

4.7.1 Approval of expenditure

ENERGEX has a three-tier governance process to oversee future planning and expenditure on the distribution network.

Central to ENERGEX's governance process is legislative compliance. The *GOC Act* requires the submission of a Statutory Corporate Plan (SCP) and Statement of Corporate Intent (SCI) while the EIC requires preparation of the NMP.

The three tiers include:

1. high level targets and forecasts approved by the ENERGEX Board as part of the five year SCP and the SCI;
2. endorsement of the five year rolling expenditure programs by the ENERGEX Board and the 12-month detailed programs of work as part of the NMP; and
3. annual budgets and delivery plans approved by the ENERGEX Board.

4.7.2 Preparation of expenditure programs

ENERGEX's Network Strategy together with a range of internal procedures, plans, standards and policy documents, collectively form ENERGEX's network development and management framework. The outcomes of the network development and management framework are overseen by ENERGEX's Network Technical Committee (NTC).

The Committee, comprising three ENERGEX directors, is charged with assisting the ENERGEX Board in relation to innovation, maintenance and improvement of technical and network standards for the delivery of electricity in a manner that meets reasonable expectations of the community. The Committee oversees the fulfilment of ENERGEX's commitments under the NMP.

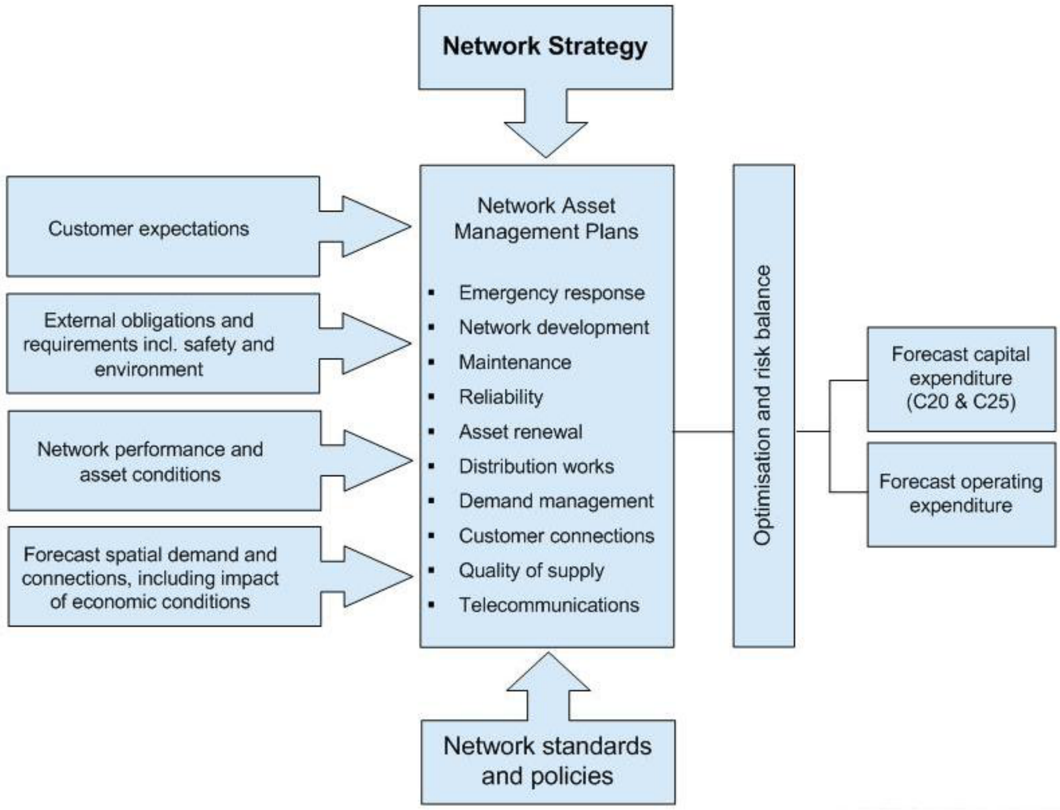
The network development and management framework translates ENERGEX's network strategies into the projects and programs that result in the development of the capital and operating expenditure forecasts.

From an operational perspective the development of projects and programs is undertaken in compliance with the relevant ENERGEX policy and Business Management System (BMS). These process documents are maintained and available to all staff through the ENERGEX intranet.

A summary of the main policies and BMS documents that govern the compilation of forecast capital and operating expenditure is available in pro forma 2.3.6 in **Attachment 1**. Compliance with BMS is monitored annually through external audits.

The network development framework in Figure 4.3 summarises the integration of ENERGEX's strategies and operational plans.

Figure 4.3 ENERGEX's development and management framework



4.7.3 Monitoring program and expenditure outcomes

Approval of variance to program and monitoring of outcomes of the program is overseen by executive management through the Program of Work (PoW) Governance Committee.

The PoW Governance Committee, with a membership that includes the Chief Financial Officer and the three network General Managers, has been established to enable optimal performance outcomes in the governance of variations to the approved PoW, including C20, C25 and operating expenditure.

5 Demand management strategy

5.1 Summary

Demand Management (DM), coupled with effective supply-side management, is necessary for sustainable business operations and capital investment. ENERGEX has identified the moderation of peak demand required by customers as key to the ongoing physical and financial efficiency of the distribution network. Implementation of DM will ultimately result in an improved economic outcome for customers.

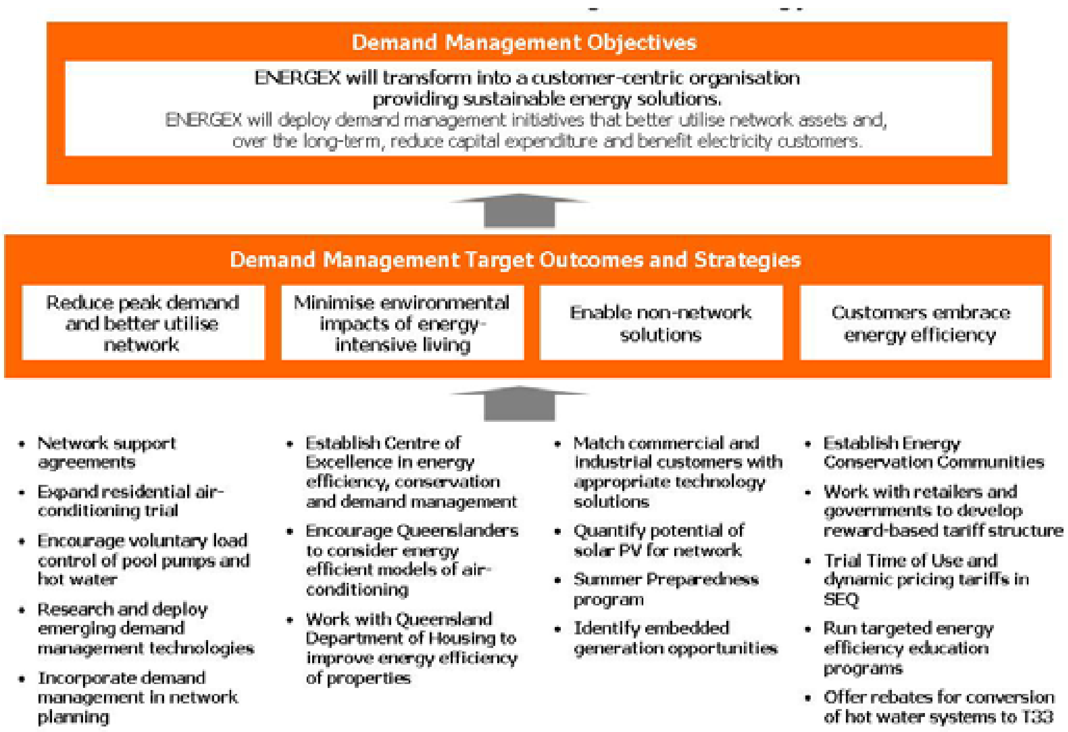
ENERGEX's load duration curve demonstrates the poor utilisation of the network assets – the top 11 per cent of load occurs for less than one per cent of the year.

ENERGEX's strategy is consistent with the objectives of the AER's DMIS for Queensland and South Australia.

From 1 July 2009, ENERGEX is required to comply with a new *Electricity Amendment Regulation* requiring ENERGEX (for each financial year) to submit to the Regulator for approval, a DM plan that includes a description of the existing and planned programs, including forecast capital and operating expenditure, and performance targets for each initiative.

The DM Strategy, as shown in Figure 5.1 focuses on both broad-based DM initiatives implemented across the ENERGEX network as well as peak DM strategies targeted towards specific network constraints. This strategy is consistent with ENERGEX's DM compliance obligation.

Figure 5.1 ENERGEX's DM strategy



The DM programs that ENERGEX will undertake during the *2010-2015 regulatory control period* are outlined in Section 5.8.

ENERGEX submits that the proposed expenditure on DM over the *2010-15 regulatory control period* is prudent and efficient, comparing favourably to supply-side investment.

5.2 Regulatory information requirements

Clauses 6.5.6(e)(10) and 6.5.7(e)(10) of the *Rules* require the AER to have regard to the extent that ENERGEX has considered and made provision for efficient non-network alternatives in ENERGEX's total forecast operating and capital expenditures.

Clause 2.3.9 of the RIN requires information regarding the extent to which ENERGEX has considered and made provision for efficient non-network alternatives in developing its forecast operating and capital expenditures for the *2010-15 regulatory control period*.

5.3 ENERGEX's demand management challenge

Strong economic growth in SEQ, together with growing population numbers and ever-increasing use of electrical appliances such as air-conditioners, computers and large screen televisions, is resulting in increased electricity consumption and higher peak demand.

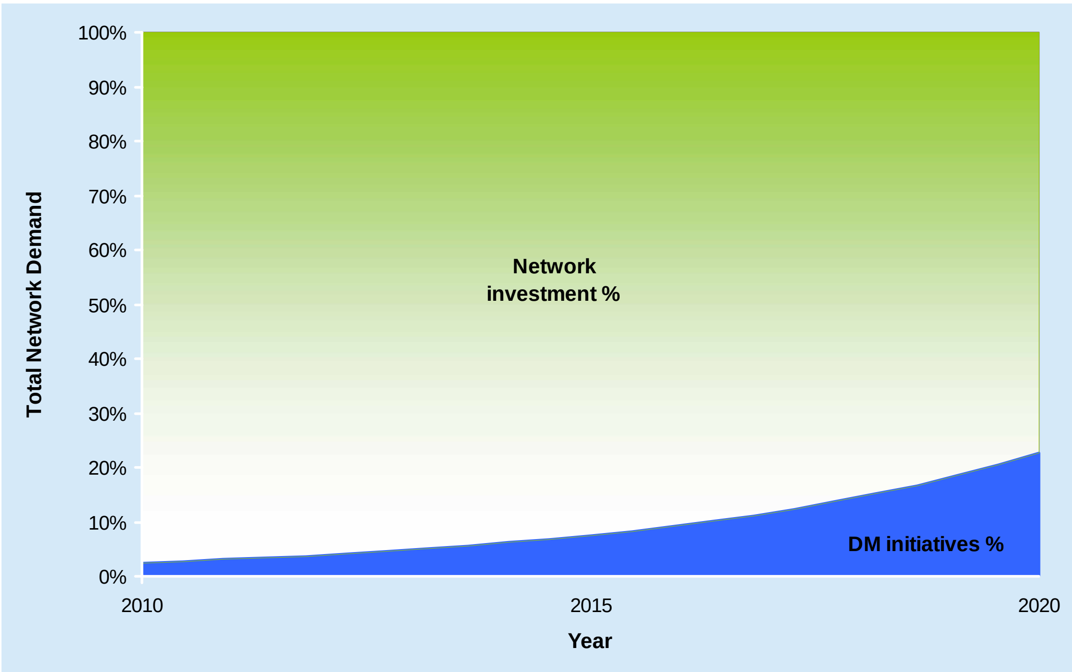
The rise in electricity demand results in high capital expenditure on electricity infrastructure while additional energy usage impacts the environment.

Based on historical weather patterns and usage trends, ENERGEX estimates peak demand in SEQ will rise by 71 per cent over the next decade from 4,367 MW in 2007 to an estimated 7,454 MW by 2018[20]. Electricity customers expect that ENERGEX will plan, build and maintain an electricity distribution system to meet demand at times of peak load.

ENERGEX is pursuing the DM strategy to encourage and support the development of a broader range of initiatives, developed both internally through business driven activities and externally through the encouragement of a competitive market. The electricity network of the future, similar to the generation sector, must be a hybrid of base capacity (supply-side investment) components and peaking capacity (DM initiatives) components. ENERGEX along with a number of counterparts is promoting the development of the hybrid approach to meet the challenges of increasing network demand.

Figure 5.2 analyses electricity investment over the longer term and seeks to highlight the potential for increasing effective DM solutions.

Figure 5.2 Hybrid solutions to customer demand



ENERGEX's position is that to encourage and develop DM options for long-term infrastructure sustainability it is necessary to maintain investment through supply-side solutions while making a material investment in the progression of a real market for DM options. This is the DM challenge that will be faced over the next 10 years.

20 Source: ENERGEX, *Network Management Plan 2008-09 to 2012-13*, excluding the effects of the CPRS and the GFC.

For the past three years ENERGEX has been steadily building its network DM capability to respond to this peak demand challenge.

The need for a successful DM Strategy is underscored by ENERGEX's experience since 2004, where the maximum demand growth rate increased an average of five to seven per cent[21].

ENERGEX's DM Strategy recognises three key factors, namely:

1. peaking network demand drives poor utilisation of electricity assets and sub-optimal use of capital investment as electricity infrastructure is built to meet peak demand used for relatively short periods;
2. the link between the impacts of peak demand on electricity infrastructure costs and how these translate to customer electricity bills needs to be more explicit to allow customers to make informed choices; and
3. based on current growth rates, the construction of electricity infrastructure to manage peak demand is not financially sustainable over the long term.

ENERGEX is committed to DM as a critical strategy to assist in the mitigation of future peak demand. Delivering the benefits of DM requires a commitment and material investment in the *2010-15 regulatory control period*. ENERGEX has recognised its importance to achieving a sustainable future and has aligned the outcomes of the DM Strategy directly with ENERGEX's overall Corporate Strategic Plan.

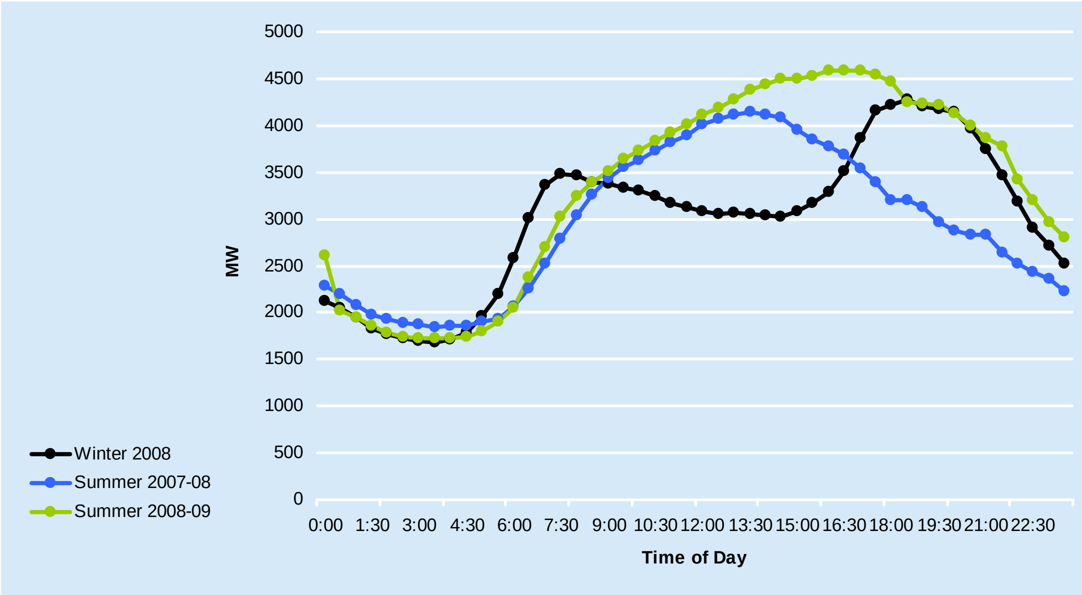
5.4 Changing daily load profile

As discussed in Chapter 3.10, ENERGEX's network changed from winter peaking to summer peaking in the early 2000s. Summer peaking demand has a compound effect on the distribution network as network components such as transformers and cables have lower capacity ratings on hot days, reducing their ability to carry high loads.

Figure 5.3 shows the daily load curve of the peak demand days of summer 2007-08, winter 2008 and summer 2008-09.

21 Source: ENERGEX, *Network Management Plan 2008-09 to 2012-13*, page 31.

Figure 5.3 ENERGEX's daily load profile



Growth in ENERGEX's peak demand continues season upon season. The peak recorded demand of 4,142 MW in summer 2007-08 was exceeded by the winter 2008 demand of 4,270 MW, mainly due to the extremely mild summer season and cold winter. This peak was subsequently exceeded in summer 2008-09 (4,593 MW) despite the relatively mild summer of 2008-09.

A key component of influencing growth in peak demand and its timing is the intensity of the summer. As typical summer conditions return to SEQ bringing humid and hot weather, ENERGEX anticipates that its network will continue to display year-on-year summer peaks.

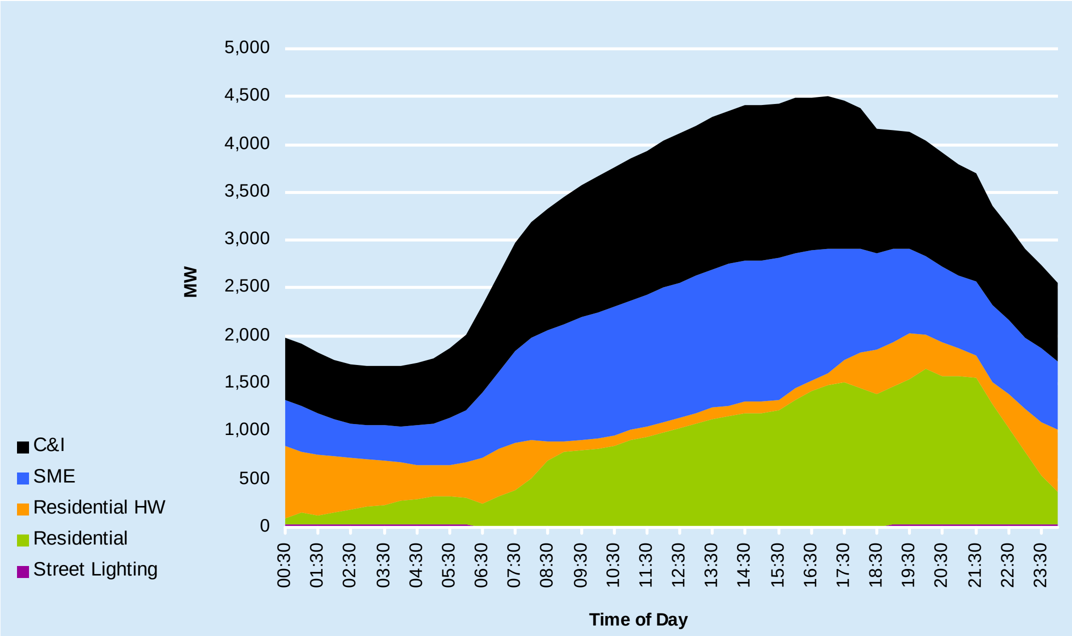
The record winter peak demand of 2008 shown in Figure 5.3 includes tariff 31 and 33 load under control (particularly hot water). It is estimated that the evening peak would have been a further 450MW higher if this load was not curtailed. ENERGEX's challenge is to develop DM capability to address the summer peak in the same way that we have successfully addressed winter peaks for decades.

5.5 Composition of peak demand

Understanding customers' electricity usage and demand patterns is fundamental to devising initiatives to manage peak demand. A breakdown of the composition of the peak demand by customer class identifies the different usage patterns of each of the customer segments and how each contributes to the peak profile in SEQ from 4.30 pm as a result of diminishing C&I loads.

Figure 5.4 shows the composition of system peak demand on ENERGEX's network for the 2008-09 summer, which occurred on Monday, 9 February 2009. The recorded peak demand was 4,593 MW, which occurred at 4.30 pm, as increasing demand in the residential sector added to the relatively flat midday loads of the C&I sector and SME sector. Although the residential demand kept rising until around 8.00 pm, overall system peak demand declined from 4.30 pm as a result of diminishing C&I loads.

Figure 5.4 ENERGEX's load segmentation



ENERGEX's DM Strategy must include tailored initiatives for each of the customer segments and classes.

5.6 Load duration analysis

An analysis of peak demand in ENERGEX's network reveals the impact that short high peaks have on electricity assets.

In simple terms ENERGEX's system peak demand usually occurs when there are consecutive days of extreme hot and humid weather. In some years such weather conditions can impact demand for as few as three days. Reduction of such infrequent peak demand as well as the appropriate use of limited capital resources is the major target for DM.

The load duration curve in Figure 5.5 demonstrates the poor utilisation of the network assets, with the top 11 per cent of load occurring for less than one per cent of the year. Meeting this peak is driving approximately 50 per cent of the capital program network investment.

Figure 5.5 ENERGEX's load duration curve (2007-08)

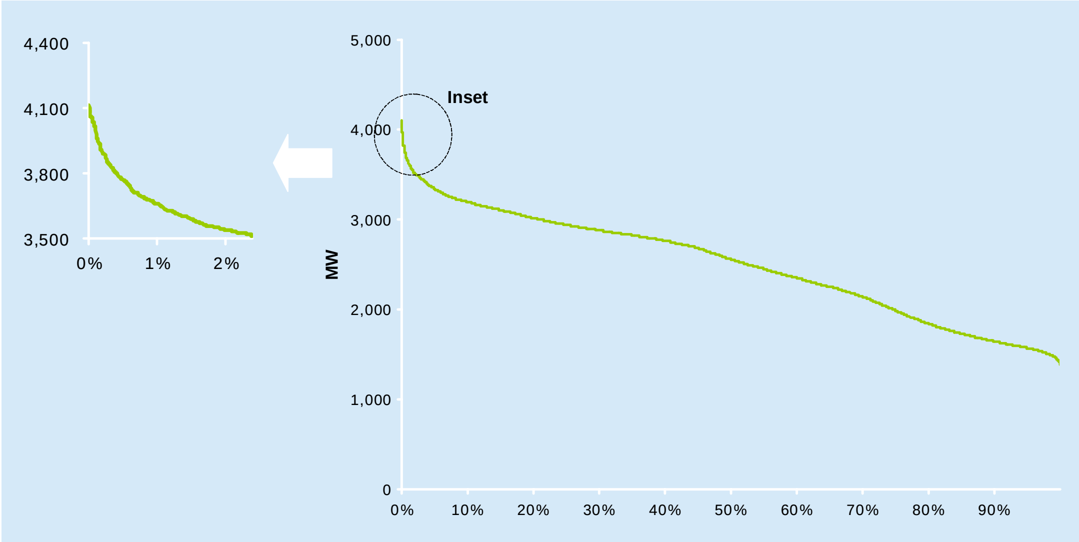
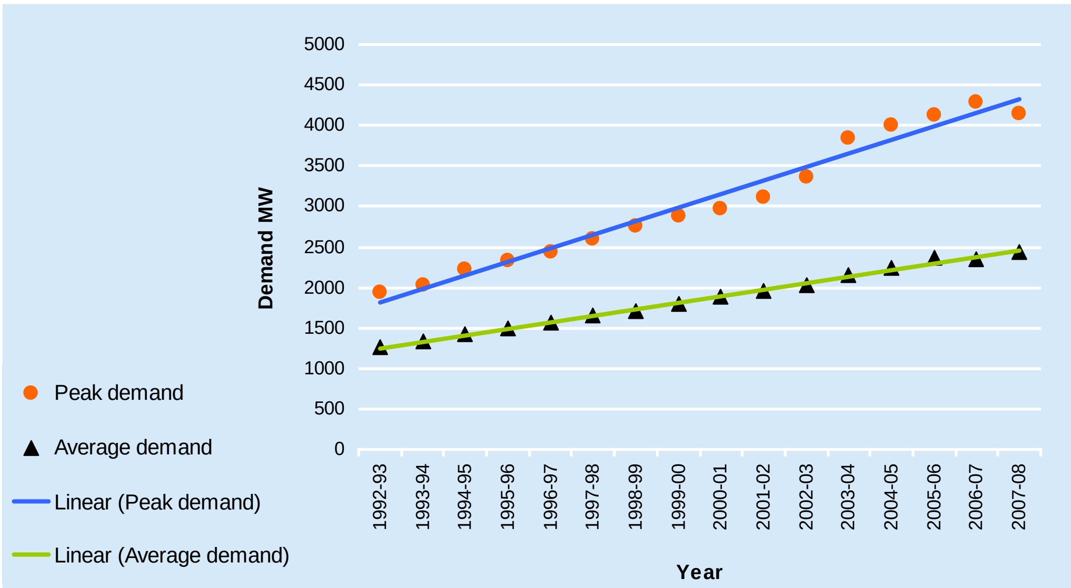


Figure 5.6 depicts the growing divergence between the peak and average load demand on the ENERGEX network. This ongoing trend demonstrates the need for real options to meet or reduce the demand requirements of customers that are not limited to network augmentation, particularly when such network capacity has the potential to be underutilised for the majority of the year.

Figure 5.6 ENERGEX's average and peak demand trends



ENERGEX's analysis indicates that air-conditioning and other peak summer type loads (e.g. pool filters) are the most significant drivers of the divergence between peak and average network demand. It is for this reason that ENERGEX has focused on customer usage of these appliances when identifying DM initiatives.

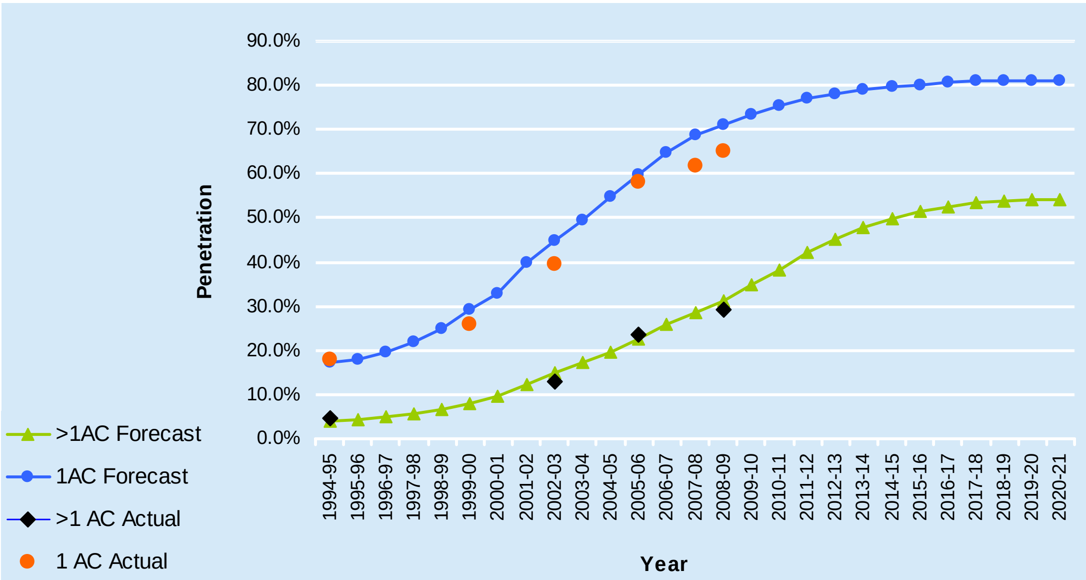
5.7 Air-conditioning use – a major driver of the peak

Increasing temperature sensitivity of the ENERGEX customer base is another major driver of network demand. This is reflected in the ongoing and increasing penetration of air-conditioners in SEQ.

Survey estimates of air-conditioning penetration in SEQ in 2007-08 show that 65.2 per cent of households have an air-conditioner and 29.5 per cent of customers have multiple air-conditioning units.

Figure 5.7 highlights the growth in air-conditioning over the last 14 years. Also provided is the forecast of the increasing penetration of air-conditioning units, particularly as it becomes more affordable and desirable.

Figure 5.7 Air-conditioning penetration in SEQ 2008-2020[22]



Overall the number of air-conditioners is increasing due to the compounding effect of a growing population, increasing numbers of SEQ households installing units and the rise in the number of units per household.

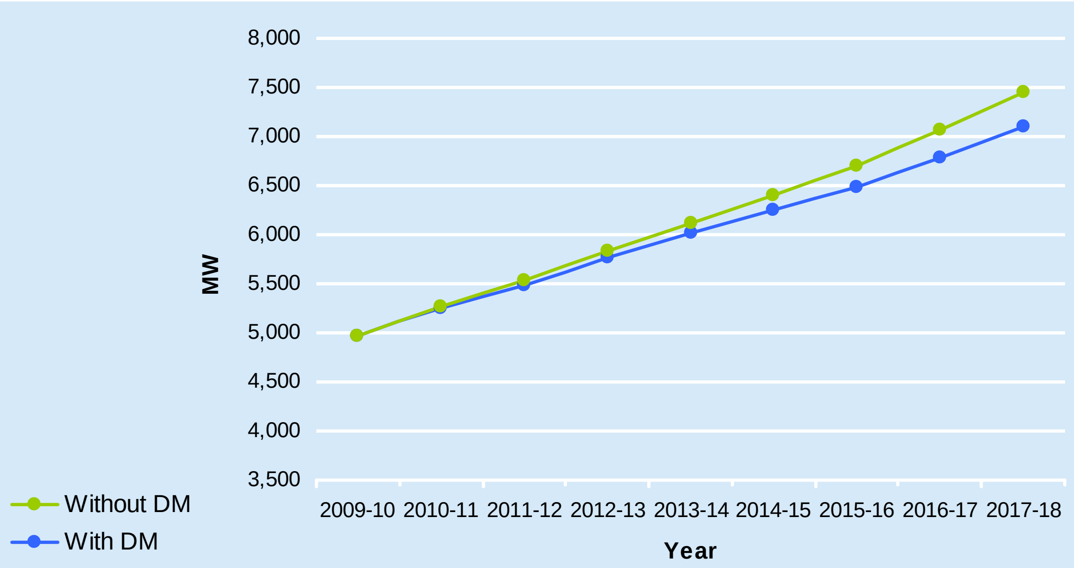
22 Source: *Queensland Household Survey – May 2007* (Office of the Government Statistician, incorporated within the Office of Economic and Statistical Research).

5.8 ENERGEX's demand management strategy for the 2010-15 regulatory control period

From an electricity infrastructure point of view, ENERGEX's objective is to achieve better utilisation of network assets so that ultimately this benefit can be passed on to electricity customers, through efficient network prices that reflect the real cost of customer demand.

In order to achieve this objective, ENERGEX's strategy is to implement a suite of concurrent, co-ordinated initiatives and to encourage DM capability that will deliver a reduction in future peak demand, known as 'bending the forward demand curve', illustrated in Figure 5.8.

Figure 5.8 Results of DM initiatives



The programs and initiatives that ENERGEX has developed and included in this strategy target real peak demand reduction over the next five years in conjunction with the development of capability to deliver further options in the longer term. The forecast progressive reduction in peak demand through broad-based programs is set out in Table 5.1.

Table 5.1 Anticipated demand reductions arising from application of strategy

Year	Annual MW reduction from broad-based DM	Cumulative MW reduction
2010-11	18	18
2011-12	22	40
2012-13	27	67
2013-14	34	101
2014-15	43	144
Total	**144**	**144**

The demand reduction forecasts arising from the DM initiatives exclude benefits achieved from existing DM programs such as the hot water load control capability which is approximately 450 MW in winter and up to 100 MW in summer.

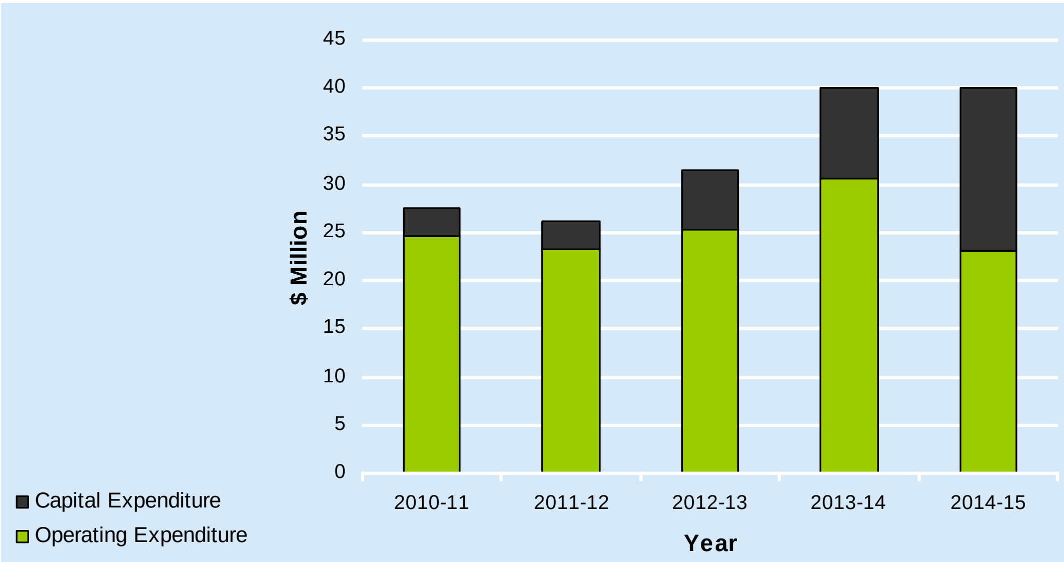
ENERGEX's integrated response to the DM challenge is contained in the Network DM Strategy 2010-2015 in **Appendix 5.1**.

ENERGEX's DM Strategy delivery comprises three elements:

1. broad-based DM programs that also provide reductions in energy consumption;
2. peak DM programs that are targeted towards specific constraints in the network; and
3. initiatives funded from the Demand Management Innovation Allowance (DMIA) under the DMIS discussed at Chapter 17.

Figure 5.9 illustrates the proposed expenditure on DM for the *2010-15 regulatory control period*.

Figure 5.9 Proposed expenditure on DM for the *2010-2015 regulatory control period*



ENERGEX submits that the proposed expenditure on DM to deliver a peak demand reduction of 144 MW over the *2010-15 regulatory control period* is prudent and efficient, comparing favourably to supply-side investment.

ENERGEX's broad-based and peak DM programs for the *2010-15 regulatory control period* are discussed in the following sections.

5.8.1 Broad-based programs

ENERGEX will undertake broad-based DM programs that aim to reduce demand across the SEQ network, rather than at specific points on the network. These programs are targeted at both residential and C&I customer segments and will include energy conservation (energy efficiency) programs.

5.8.1.1 kV.A -based tariffs

During the past three years, ENERGEX has undertaken an extensive consultation process around a proposed change to its network tariffs to incorporate a kV.A tariff element for very large customers. KV.A is considered to more accurately measure a customer's impact on the network compared with kW and, as a result, is more cost reflective.

Following this consultation, ENERGEX has concluded that it will seek to introduce kV.A pricing to its tariff structure for large customers, as it will better encourage these customers to manage their power factor, reducing the need for ENERGEX to build additional network capacity. ENERGEX is proposing to introduce kV.A tariffs from 1 July 2010, subject to regulatory approval.

5.8.1.2 Enhance interruptible loads

Load may be interrupted without loss of utility benefits to customers or where customers volunteer to sacrifice utility benefit for a financial and/or environmental reward.

Over the past five years ENERGEX has successfully employed both tactics to foster DM practices and continues to tailor incentives to meet the specific needs of different customer groups.

<u>Air-conditioning direct load control</u>

Domestic and commercial air-conditioning load continues to be a significant contributor to peak demand. During the *2010-15 regulatory control period*, ENERGEX will build on the early success of its 'time for a cool change' (Cool Change) trials, by rolling out the technique of air-conditioning compressor 'cycling' more widely across SEQ.

The Cool Change trials, undertaken in the northern suburbs of Brisbane from December 2007 and continuing to 2011, involve more than 2000 residential volunteers. Results demonstrate a capability to reduce peak demand by 17 per cent without affecting customer comfort.

The next phase of the Cool Change program will focus on how to achieve the most cost-effective method of deployment in SEQ. This will:

- further investigate the most efficient technology for direct load control in SEQ;
- identify best channels for deployment (e.g. pre-installed air conditioned units prior to sale or electrician installation); and
- determine the customer value proposition and undertake a full cost benefit analysis of direct load control.

<u>Pool pump direct load control</u>

The Queensland government's Household Survey 2007 indicates that 24 per cent of SEQ households have a swimming pool. Energy consultant Charles River Associates (CRA) estimates that pool pumps contribute to ENERGEX's system peak demand and confirm that there is benefit in shifting pool pumps from peak use time.

In addition to continuing to offer and promote a better rate for electricity used by pool pumps at non-peak times through tariff 33, ENERGEX will be conducting further trials in 2009 to leverage off the learnings of the Cool Change air-conditioning trials. This pool pump trial will utilise a new generation of audio frequency load control technology similar to that employed in the Cool Change air-conditioning trials. More than 500 households have already subscribed.

In the *2010-15 regulatory control period* ENERGEX will build on the learnings of this trial by making pool pump technology available to customers across SEQ in addition to the existing tariff 33 arrangements.

5.8.1.3 Hot water program optimisation

ENERGEX's hot water load control system was developed at a time when the network was winter peaking. With the advent of a summer peak, there is an opportunity to review and optimise the switching times to identify and ensure network benefits whilst maintaining customer satisfaction.

ENERGEX will analyse the optimum number of hours in a day for switching hot water loads to off-peak. Under the existing tariff arrangements, electricity supply is made available for a minimum of eight hours per day on tariff 31 and 18 hours per day on tariff 33. Preliminary analysis suggests that optimisation of the existing hot water switching program (through the optimisation of the hours of supply) may increase the load under control over the peak periods.

5.8.1.4 Ongoing conversion of tariff 11 hot water to off-peak

ENERGEX will conduct a campaign across SEQ to offer an incentive to householders to convert from a continuous supply tariff (tariff 11) to a cheaper off-peak tariff that provides supply for a minimum of eight hours per day (tariff 31) or 18 hours per day (tariff 33).

5.8.1.5 Reward-based tariff trials and policy development

ENERGEX is committed to tariff reform as a means of encouraging more efficient use of the network as customers switch non-essential electricity use to off-peak periods, reducing peak demand and ultimately benefiting the community through reduced capital infrastructure expenditure.

This project will conduct pricing trials in SEQ and identify the benefits from Time of Use and Dynamic Pricing tariffs. In addition to research and analysis on load limiter technology (a device used to limit the maximum demand per household), these trials will provide understanding of customer acceptance and behaviour towards tariffs of this nature and develop ENERGEX's understanding of the effectiveness of such tariffs. These learnings will feed into future tariff policy development.

The trials and research are a necessary precursor to the potential of widespread deployment of reward-based tariffs amongst residential customers in SEQ.

5.8.1.6 Centre of excellence for customer electricity demand

To provide a single authoritative reference point for DM and energy conservation (energy efficiency), ENERGEX will work with the Queensland government and key electricity industry bodies to establish a Centre of excellence (Centre). The rationale for the Centre is to:

- facilitate customer confidence in adopting DM initiatives through credible information;
- consolidate DM information and advice;
- address the often referred to barrier for customers not implementing DM initiatives of 'lack of public information'; and
- provide a single reference point for consistent data and advice for Queensland.

The Centre will provide energy users and stakeholders with Queensland specific data and analysis on issues including energy efficient lighting, hot water systems, house wiring for off-peak tariffs and solar PV purchase and connection. This information will be available in an easy-to-access one-stop central resource, supported by government and the energy industry. Customers could access this information without needing to search through various government and industry websites to locate information.

The Centre would:

- reduce duplication of resources;
- champion DM and energy savings for customers;
- publish key sources of advice relevant to Queensland;
- establish a research library; and
- steward new information.

5.8.1.7 DM for C&I customers

DM for C&I customers comprises energy conservation (energy efficiency) and DM programs across ENERGEX's network that match C&I customers with appropriate technology solutions.

These projects are not necessarily located in specific points on the network and focus on identifying DM solutions of the SME and large C&I customer segments within SEQ.

This initiative will leverage off SME and C&I customer willingness to participate in DM solutions and will initially focus on industry segments such as refrigeration, hospitals, food manufacturing plants etc. through a targeted broad-based campaign. The learning from each customer and industry segment will continue to build capability both internally through business driven activities and externally through the encouragement of a competitive market – leading to the development of a business-as-usual model for non-residential DM solutions.

The technology solutions may include distributed generation, load control and shifting, improving building energy management systems, power factor correction, fuel substitution and improving energy conservation through an appropriate commercial delivery model. The model relates to customer arrangements such as:

- build, own and operate;
- design, build and operate;
- owner-funded upgrades; or
- developer-funded upgrades.

5.8.1.8 Energy conservation communities

An energy conservation community is a geographic group of energy users who are willing participants in an energy conservation program.

In addition to the residential and C&I DM programs described above, it is acknowledged that there are a range of other products that may be deployed in a community-based campaign. For example, compact fluorescent light change-out, fuel substitution, home energy assessments and second fridge buy-back programs using the principles of community-based social marketing.

This initiative involves establishing energy conservation communities in SEQ, enabling the deployment of residential and C&I energy conservation and DM policy initiatives in focused community areas, working with key community stakeholders and varying in accordance with the particular demographics and characteristics of each community.

As a demonstrated effective tool for deployment of DM programs, ENERGEX will develop and expand the number of energy conservation communities in SEQ during the *2010-15 regulatory control period*.

5.8.1.9 Demand and energy data capture and analysis

Improved energy demand and consumption data is essential for understanding changing customer energy needs and usage behaviour. It also leads to the development of sound DM policy and allows the accurate modelling of DM potential initiatives.

The data collected as part of this project will allow analysis by industry segments, socio-economic groups, climatic region, building/residence types, and feeder categories and will be used to develop future DM programs and strategies.

Under this project ENERGEX will capture energy and demand data at the customer premises and align this information with the characteristics of the community to identify target areas for DM programs to provide improved outcomes for the network and customers.

5.8.2 Peak demand management programs

As opposed to the broad-based programs discussed above, ENERGEX will undertake specific programs that aim to address specific network constraints by reducing demand on the network at the location and time of the constraint.

5.8.2.1 Summer preparedness plan

During the *2010-15 regulatory control period*, ENERGEX will continue its short lead time tactical response to managing demand through its effective SPP.

Commenced in 2006-07, this initiative sees ENERGEX engage in network support agreements with customers who during the high peak summer season are located in areas where ENERGEX has identified network constraints. The resulting agreements have supplied 16 MV.A in 2006-07, 17 MV.A in 2007-08 and an estimated 37 MV.A in 2008-09.

To be effective the SPP requires commercial agreements with customers with suitable load profiles that offset peaks during extreme hot weather conditions. Agreements are negotiated with customers who have shiftable load, private generation that can be made available to the network or the capacity to locate generators onsite to provide network support.

5.8.2.2 Regulatory test outcomes

ENERGEX is committed to seeking cost-efficient non-network alternatives that ensure reliability standards can be achieved.

Through compliance with the *Rules* and the application of the *regulatory test*, ENERGEX identifies new network investments or non-network alternative options that maximise the net economic benefit to electricity market participants or minimise the present value of the costs in meeting mandated technical requirements.

To enhance the *regulatory test* process ENERGEX is fostering non-network solutions by forming a list of preferred suppliers to provide non-network options.

5.9 Impact of demand management on expenditure forecasts

ENERGEX's objective is to achieve improved utilisation of network assets, ultimately resulting in a better economic outcome for our customers.

ENERGEX has targeted a system peak demand reduction of 144 MW for the *2010-15 regulatory control period*. The nature of the broad-based initiatives to be deployed in this period delivers a whole of network benefit.

In light of the nature of the whole of network benefit to be derived, ENERGEX excluded DM impacts from the baseline forecasts relied on to produce the forecast expenditure for this *Regulatory Proposal.* The forecast benefits have been captured in the adjustments to the capital program as discussed in Chapter 11.

Over the long term, ENERGEX's DM strategy will seek to curtail peak demand and reduce the need for intensive network investment. This *Regulatory Proposal* recognises that, while DM practices will assist in ameliorating the impact of customers' demands on the network, significant supply-side solutions will be required for the *2010-15 regulatory control period* to meet the forecast capital and operating expenditure objectives.

A further benefit of ENERGEX's DM program in the *2010-15 regulatory control period* will be improved security that will assist the progression toward meeting ENERGEX's security obligations.

ENERGEX is confident that over time its continued commitment to DM will deliver a reduction in capital expenditure leading to benefits to customers.

6 Classification of services proposal and control mechanism

A *Regulatory Proposal* must include the DNSP's proposed classification of distribution services. If the proposed classification differs from that suggested in the AER's Stage 1: Framework and approach paper, the DNSP must outline those differences and the reasons for them. If the DNSP proposes negotiated distribution services, the *Regulatory Proposal* must include a proposed negotiating framework.

For *standard control services*, the *Regulatory Proposal* must be a *building block proposal*. A demonstration of the application of the control mechanism, as set out in the Stage 1: Framework and approach paper is required for *alternative control services*.

This chapter outlines ENERGEX's proposal in regard to the classification of services and control mechanisms. Part 1 of this *Regulatory Proposal* details the required *building block proposal* for *standard control services* and Part 2 covers *alternative control services*.

6.1 Summary

This *Regulatory Proposal* has been prepared in accordance with the Stage 1: Framework and approach paper in relation to:

- grouping of distribution services;
- classification of services; and
- forms of control mechanisms.

6.2 Regulatory information requirements

A distribution determination is predicated on decisions by the AER on the following:

- Clause 6.12.1(1) – a decision on the classification of services to be provided by ENERGEX during the course of the *regulatory control period*.
- Clause 6.12.1(11) – a decision on the control mechanism (including the X factor) for *standard control services* (to be in accordance with the relevant framework and approach paper).
- Clause 6.12.1(12) – a decision on the control mechanism for *alternative control services* (to be in accordance with the relevant framework and approach paper).

Clause 6.8.2(c)(1) states that a *regulatory proposal* must include a proposal for the classification of the services to be provided by ENERGEX, which includes reasons for any departure from the classification suggested in the relevant framework and approach paper.

Clause 6.8.2(c)(2) states that for direct control services classified as *standard control services*, the *regulatory proposal* must include a *building block proposal*.

Clause 6.8.2(c)(3) states that, for direct control services classified as *alternative control services*, the *regulatory proposal* must include a demonstration of the application of the control mechanism as set out in the framework and approach paper and the necessary supporting information.

Clause 6.8.2(c)(4) states that, for direct control services, the *regulatory proposal* must include the indicative prices for each year of the *regulatory control period*.

Clause 6.8.2(c)(5) states that, for services classified as negotiated distribution services, the *regulatory proposal* must include the proposed negotiating framework.

Schedule 6.1.3(6) requires that the *building block proposal* provides information in relation to revenues or prices.

Pro forma 2.2.5 of the RIN requires ENERGEX to provide details of its services and the indicative prices.

RIN 2.4.6 sets out the required information relating to street lighting services.

RIN 2.4.7 sets out the required information relating to *alternative control services* other than street lighting services.

6.3 Framework and approach paper – classification of services and control mechanisms

On 27 August 2008 and in accordance with Clause 11.16.6 and Clause 6.8.1 of the *Rules*, the AER released its final decision in relation to the classification of services and control mechanisms in the Stage 1: Framework and approach paper.

ENERGEX's proposal in response to the AER's Stage 1: Framework and approach paper is discussed further in the following sections.

6.4 Grouping of distribution services

In Stage 1: Framework and approach paper, the AER decided on the following groupings of distribution services:

- **Network services** – Network services relate to the 'shared' network used to service all network users connected to ENERGEX's distribution network. Network services are delivered through the operation of assets such as substations, power lines, communication and control systems, and involve activities such as repairs, maintenance, vegetation clearing, asset replacement/refurbishment and construction of new assets.
- **Connection services** – Connection services relate to building connection assets at the customer's premises as well as connecting those connection assets to the distribution network. Connection services are usually dedicated to a particular customer, and not shared with other customers. The connection services cover a broad range of works from establishing a simple service line connection for a small domestic customer to connection for a small to medium commercial or industrial customer with dedicated transformers.
- **Metering services** – Metering services relate to Type 5-7 metering activities including scheduled meter reading, non-chargeable unscheduled meter reading, meter investigation, maintenance and repair of metering and/or control equipment, provision of metering data to minimum requirements and all activities related to ENERGEX's role as the Responsible Person.
- **Street lighting services** – Street lighting services relate to activities of construction and maintenance of street light assets owned by ENERGEX.
- **Fee-based services** – Services relating to activities undertaken by ENERGEX at the request of customers or their agents (e.g. retailers or contractors). The costs for these activities can be directly attributed to customers and service-specific charges can therefore be levied.
- **Quoted services** – Services for which the nature and scope cannot be known in advance irrespective of whether it is customer requested or an external event that triggers the need (e.g. price on application or compensable).
- **Unregulated services** – Unregulated services relate to activities that are not distribution services or are distribution services provided in a competitive market.

This *Regulatory Proposal* is in accordance with the AER's decision on the grouping of services. **Appendix 6.1** provides details of the activities under each grouping.

6.5 Classification of services

Clause 6.2.1 requires that the AER classify a distribution service as a direct control service or a negotiated distribution service.

Under Clause 6.2.2, the AER must classify direct control services as either *standard control services* or *alternative control services*.

6.5.1 Standard control services

In the Stage 1: Framework and approach paper, the AER classified network services, connection services and metering services as *standard control services*. This *Regulatory Proposal* is in accordance with the AER's decision.

In accordance with Clause 6.8.2(c)(2) of the *Rules*, ENERGEX's *standard control services* proposal is prepared using the building block approach and is discussed in detail from Chapters 8 to 20.

6.5.2 Alternative control services – street lighting services

The AER's position as outlined in the Stage 1: Framework and approach paper is that the provision, construction and maintenance of street lighting assets is a distribution service and an *alternative control service* classification will apply.

The AER further proposed that a limited building block approach be applied to street lighting services. ENERGEX's *Regulatory Proposal* for street lighting services is in accordance with the AER's position and is discussed in detail in Chapter 21.

6.5.3 Alternative control services – fee-based services and quoted services

In the Stage 1: Framework and approach paper, the AER classified the fee-based services and quoted services as *alternative control services*. Services included under these groupings included the QCA's classified excluded services and the design and construction of large connection assets.

ENERGEX's *Regulatory Proposal* for fee-based services and quoted services are in accordance with the AER's decision and are discussed further in Chapter 22.

6.5.4 Negotiated distribution services

In accordance with the AER's decision in the Stage 1: Framework and approach paper, ENERGEX is not proposing any services as negotiated distribution services. A negotiating framework is therefore not required under this *Regulatory Proposal.*

6.6 Form of control mechanisms

Clause 6.12.3(c) of the *Rules* states that, in making a distribution determination, the AER must adopt the control mechanisms that are set out in the AER's Stage 1: Framework and approach paper. The AER's decision on control mechanisms for ENERGEX is set out in Table 6.1.

Table 6.1 Summary of AER's decision on classification and control mechanisms

Distribution service group	AER service classification	Control mechanism
Network services	*Standard control services*	Revenue Cap
Connection services	*Standard control services*	
Metering services	*Standard control services*	
Street lighting services	*Alternative control services*	Price Cap
Fee-based services	*Alternative control services*	
Quoted services	*Alternative control services*	

6.6.1 Revenue cap – standard control services

The AER's decision is to apply a fixed revenue cap control mechanism to ENERGEX's *standard control services* for the *2010-15 regulatory control period*. In accordance with Clause S6.1.3(6) of the *Rules*, ENERGEX's revenues and prices are modelled on the basis of a revenue cap using the AER's PTRM as discussed in detail in Chapter 18.

Further, consistent with Clause 6.8.2(c)(4) of the *Rules* and RIN 2.2.5, indicative prices are provided at aggregated customer class levels and discussed in Chapter 18.

6.6.2 Price cap – alternative control services – street lighting services

The AER's decision in the Stage 1: Framework and approach paper is to apply a price cap control mechanism to ENERGEX's *alternative control services* for the *2010-15 regulatory control period*.

The AER stated that it 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 year of the *regulatory control period* and establish a price path for the remaining years of the period. Further, the AER provided some guidance on simplified building block assumptions for the application of the price cap control mechanism to street lighting services.

ENERGEX has prepared this *Regulatory Proposal* in accordance with the AER's simplified building block approach and using the AER's PTRM modelled on the basis of price cap regulation. Chapter 21 of this *Regulatory Proposal* describes ENERGEX's street lighting services, demonstrates the application of the control mechanism, and provides indicative prices in accordance with Clause 6.8.2(c)(3) of the *Rules*, RIN 2.2.5 and RIN 2.4.6.

6.6.3 Price cap – alternative control services – fee-based services and quoted services

For fee-based services and quoted services, the AER will apply a formula based approach (a non-building block approach) to determine the efficient costs of providing these services under a price cap form of control in the first year of the *regulatory control period* and establish a price path for the remaining years of the period.

Fee-based services and quoted services are discussed in detail in Chapter 22 of this *Regulatory Proposal*. In that chapter, ENERGEX demonstrates the application of the price cap control mechanism in accordance with Clause 6.8.2(c) (3) of the *Rules* and RIN 2.4.7. In addition and in accordance with RIN 2.2.5, the indicative prices for fee-based services and a representative sample of quoted services are also provided.

7 Transitional arrangements

The *National Electricity (Economic Regulation of Distribution Services) Amendment Rules 2007* which were made on 16 December 2007 replaced the then Chapter 6 of the *Rules*. Following this amendment, the responsibility for economic regulation of distribution services was transferred to the national AER, effective 1 January 2008.

In addition to the amendments to Chapter 6, the Ministerial Council on Energy (MCE) also established *Transitional Rules* to preserve specific arrangements in the various jurisdictions. These *Transitional Rules*, applicable to the first distribution determination under the AER, are required to facilitate an orderly transition from the jurisdictional arrangements to the national framework.

The transitional arrangements for the first distribution determination for Queensland DNSPs are outlined in Chapter 11 Division 3 (Clause 11.16) of the *Rules*. These transitional arrangements will apply to ENERGEX and Ergon Energy for the *2010-15 regulatory control period*.

In addition to the specific issues identified in Clause 11.16, ENERGEX considers that there are other issues that should be addressed by the AER in the 2010-15 distribution determination.

This chapter sets out ENERGEX's transitional issues for the 2010-15 distribution determination.

7.1 Summary

Clause 11.16 sets out the transitional arrangements for the first distribution determination for Queensland DNSPs as follows:

- Clause 11.16.3 Treatment of the Regulatory Asset Base;
- Clause 11.16.4 *Efficiency Benefit Sharing Scheme*;
- Clause 11.16.5 *Service Target Performance Incentive Scheme*;
- Clause 11.16.6 Framework and Approach;
- Clause 11.16.7 *Regulatory Proposal*;
- Clause 11.16.8 Side Constraints;
- Clause 11.16.9 Cost Pass Throughs; and
- Clause 11.16.10 Capital Contributions Policy.

In addition, ENERGEX considers that the following issues under the QCA's existing arrangements will have a material impact on it in the transition to the *2010-15 regulatory control period* and need to be addressed by the AER in its distribution determination:

- unders and overs of the revenue cap;
- unders and overs of tax;
- treatment of TUOS cost; and
- contributed street lighting assets.

7.2 Regulatory information requirements

Clause 2.4.1 of the RIN requires ENERGEX to provide information on existing or potential transitional issues (expressly identified in the Rules or otherwise) which ENERGEX expects will have a material impact on it and should be considered by the AER in making its distribution determination.

7.3 Treatment of the regulatory asset base

The Regulatory Asset Base (RAB) for ENERGEX includes some non-system assets used to provide *alternative control services*. To ensure that there are no cross subsidies between *standard control services* and *alternative control services*, ENERGEX proposes that the PTRM for *standard control services* be adjusted to account for the portion of assets from the RAB that is used to deliver *alternative control services*. This approach is consistent with the approach adopted by the QCA following the reclassification of the non-distribution use of system (DUOS) services as excluded services.

Further details of the proposed approach are outlined in Chapters 14 and 18.

7.4 Efficiency benefit sharing scheme

The AER's decision, as outlined in its Stage 2: Framework and approach paper, is to apply the national distribution EBSS to ENERGEX.

Clause 11.16.4(a) of the *Rules* states that the EBSS for ENERGEX must not cover efficiency gains and losses relating to capital expenditure. The national distribution EBSS does not include efficiency gains and losses that relate to capital expenditure and therefore this Clause is not relevant.

Clause 11.16.4(b) states that the AER must also have regard to the continuing obligations on ENERGEX throughout the *2010-15 regulatory control period* to implement the recommendations from the EDSD Review adopted by the Queensland government.

There are no specific operating expenditure-related recommendations in the EDSD Review. The operating expenditure-related recommendations in the review are general in nature and require ENERGEX to ensure that sufficient funding is made available to carry out an effective preventative maintenance program on its assets, in particular the overhead network. Whilst ENERGEX will not nominate any specific operating expenditure for exclusion from the EBSS, ENERGEX believes that the AER should take these general operating expenditure-related recommendations in the EDSD Report into consideration in its assessment of ENERGEX's operating expenditure.

ENERGEX's operating costs are outlined in Chapter 12 and details of the application of the EBSS to ENERGEX for the *2010-15 regulatory control period* are provided in Chapter 17.

7.5 Service target performance incentive scheme

The AER's decision, as outlined in Stage 2: Framework and approach paper, states that its likely approach is to apply the national distribution STPIS with ± 2 per cent of revenue at risk.

Clause 11.16.5 of the *Rules* requires the AER to take into account the continuing obligations on ENERGEX throughout the *2010-15 regulatory control period* to implement the recommendations from the EDSD Review adopted by the Queensland government and the impact of severe weather events on service performance and consider whether a lower power incentive is appropriate.

Details of the application of STPIS to ENERGEX, including the proposed targets for the *2010-15 regulatory control period,* are provided in Chapter 17.

7.6 Framework and approach

The *Rules* require the AER to publish a framework and approach paper in anticipation of every distribution determination.

Clause 11.16.6 of the *Rules* allowed ENERGEX to submit proposals to the AER in relation to the classification of services and control mechanisms by 31 March 2008 and required the AER to publish its 'Framework and approach paper – Classification of services and control mechanisms' within five months of receiving the proposals.

ENERGEX submitted a proposal to the AER on the classification of services and control mechanisms for the *2010-15 regulatory control period* on 31 March 2008. The AER published its '*Final framework and approach paper – Classification of services and control mechanisms'* (Stage 1: Framework and approach paper) on 27 August 2008. This *Regulatory Proposal* is consistent with the AER's decision as discussed in Chapter 6.

Stage 2: Framework and approach paper, which covers the application of schemes, concluded with the release of the AER's '*Final framework and approach paper – Application of schemes'* on 27 November 2008. Details of the application of the schemes to ENERGEX for the *2010-15 regulatory control period* are outlined in Chapter 17.

7.7 Regulatory proposal

Clause 11.16.7 of the *Rules* provides ENERGEX, for the purposes of calculating indicative prices and X factors, the option of using the proposed *statement of regulatory intent (SoRI)* in lieu of the final *SoRI*.

ENERGEX has not invoked Clause 11.16.7 as this *Regulatory Proposal* has been prepared based on the AER's final *statement of regulatory intent* published on 1 May 2009.

7.8 Side constraints

Clause 11.16.8 of the *Rules* allows ENERGEX to continue to implement any price paths approved by the QCA. ENERGEX does not have any specific price paths approved by the QCA that carry into the *2010-15 regulatory control period*.

7.9 Cost pass throughs

Clause 11.16.9 of the *Rules* provides for ENERGEX to apply to the AER for cost pass throughs for events that occur before 1 July 2010 which would constitute a pass through event under the *QCA's 2005 final determination*.

At the time of this *Regulatory Proposal*, ENERGEX has not identified any such events. If an event occurs between 1 July 2009 and 30 June 2010 that constitutes a pass through event under the *QCA's 2005 final determination*, ENERGEX will make an application to the AER as allowed for under Clause 11.16.9.

7.10 Capital contributions policy

Clause 11.16.10 of the *Rules* relates to the application of a capital contributions policy. ENERGEX will continue to apply the QCA's approach to the treatment of capital contributions as regards to determining the revenue stream and RAB.

The transitional provision requires ENERGEX to publish its capital contributions policy as approved by the QCA. The capital contributions policy relates to the application of capital contributions to customers connecting to ENERGEX's network. ENERGEX does not intend to change its capital contributions policy for the *2010-15 regulatory control period*.

Treatment of capital contributions as regards to determining the RAB and revenue stream is a separate issue and is discussed further in Chapters 14 and 18.

7.11 Unders and overs of the revenue cap

Under the revenue cap control mechanism outlined in the *QCA's 2005 final determination*, the surplus or shortfall of actual revenue compared to the revenue target each year will need to be adjusted. The balance of the unders and overs account is assessed after the end of each financial year. Depending on the size of the variance, the balance in the account is generally cleared at two years after its occurrence.

Adjustments to determine the revenue to be collected in 2010-11 and 2011-12 to account for any under or over recoveries in 2008-09 and 2009-10 will be required. ENERGEX proposes that a similar treatment to the unders and overs for 2008-09 and 2009-10 revenue be adopted. These adjustments are incorporated into the revenue requirement as outlined in Chapter 18.

For the *2010-15 regulatory control period*, ENERGEX's *standard control services* will continue to be under a revenue cap form of control mechanism. Subject to the variation in capital contributions revenue, as discussed in Section 18.8, ENERGEX proposes that the QCA's approach to unders and overs recovery be adopted for the *2010-15 regulatory control period*.

7.11.1 Operation of the unders and overs mechanisms

The proposed operation of unders and overs of the revenue cap control mechanism will include an adjustment for the WACC allowance. The earliest practical timing of the adjustment is a two year lag to reflect the timing of the annual reporting and price approval process. The adjustment for the WACC allowance is to ensure an NPV neutral position for both ENERGEX and its customers.

The proposed adjustment process will involve an assessment of the actual revenue recovery at the end of each financial year. A comparison to the allowed revenue for that year is made to assess the variance.

The action taken will depend on the tolerance limit as detailed in Table 7.1.

Table 7.1 Revenue recovery tolerance limits and actions

Variance	Action required
Less than 2%	Where the under or over recovery is less than 2%, the under or over recovery will be cleared within one regulatory year.
Between 2% and 5%	Where the under or over recovery is greater than 2% but less than 5% the under or over recovery can be spread over two regulatory years.
Greater than 5%	Where the recovery variance is greater than 5% ENERGEX will submit a plan to the AER detailing how it proposes to clear the balance.

7.12 Unders and overs of tax

In the *QCA's 2005 final determination*, the QCA adopted the approach of including the forecast cost of tax in ENERGEX's revenue requirement, with any differences between forecast and actual tax paid being subject to an unders and overs process on an annual basis.

Adjustments for tax for 2005-06, 2006-07 and 2007-08 have been cleared from the unders and overs account. Forecast of the tax position for 2008-09 has been incorporated into the calculation of the ARR as set out in Chapter 18 and the tax position for 2009-10 has yet to be determined. Adjustments for actual tax paid in 2008-09 and 2009-10 will need to be made in the revenue for 2010-11 and 2011-12 respectively.

ENERGEX proposes that a similar treatment to the unders and overs for actual tax paid in 2008-09 and 2009-10 be adopted. These adjustments are incorporated into the revenue requirement as outlined in Chapter 18.

The PTRM model from the AER accounts for tax in a different manner. In adopting the AER's PTRM, this issue will no longer be relevant in the *2010-15 regulatory control period*.

7.13 TUOS cost

ENERGEX connects to the Powerlink network at multiple connection points. Powerlink, as a regulated transmission NSP, recovers its revenue from directly connected customers and DNSPs connected to its network.

In accordance with the connection agreement with Powerlink, ENERGEX is required to pay TUOS charges to Powerlink on a monthly basis. The TUOS charges comprise fixed charges and variable components based on metered energy at the connection points. A forecast of the TUOS charges is provided by Powerlink in March of each year to allow ENERGEX to develop network prices (DUOS and TUOS) for the annual approval by the QCA. Actual TUOS payment is based on metered energy at the connection points.

ENERGEX network charges to customers, billed via the retailers, include a TUOS component. The actual recovery of TUOS is separately identified in invoices to retailers and is also reported in the Regulatory Reporting Statement (RRS) to the QCA.

Under the QCA, TUOS cost and revenue are specifically identified and reported, with a reconciliation undertaken annually as part of a separate unders and overs process. ENERGEX proposes that this approach be adopted in the *2010-15 regulatory control period*.

7.14 Contributed street lighting assets

In March 2008, as provided under Clause 11.16.6, ENERGEX made an application to the AER in relation to classification of its distribution services. In the application ENERGEX proposed that street lighting services should not be classified as a distribution service. The AER in its final decision classified street lighting services as an *alternative control service* under a price cap control mechanism.

ENERGEX has adopted the classification and control mechanism for street lighting services as decided by the AER in its Stage 1: Framework and approach paper. However, the change in classification and control mechanism for street lighting services from prescribed distribution service under a revenue cap to an *alternative control service* under a price cap will require a transitional arrangement on the treatment of street light contributed assets.

In the *current regulatory control period*, some street light assets are constructed by customers or their agents, with the capital cost paid upfront, and then gifted to ENERGEX following construction and upon commissioning. These gifted assets are treated as a capital contribution under the revenue cap in accordance with the QCA approved methodology, whereby the assets are included in the RAB with an equivalent amount taken off the revenue cap in that year.

Due to the change in classification and control mechanism in the *2010-15 regulatory control period,* a different treatment in relation to the gifted assets is required. ENERGEX proposes to recognise gifted assets as contributed assets and record these assets at zero value in the street light asset base. Consequently, there is no requirement to adjust the revenue and ENERGEX will not seek to recover any asset-related costs from the customer. The customer will receive an ongoing charge for the maintenance of the street light asset.

A transitional arrangement is required on the gifted street light assets that have been included in the RAB prior to 1 July 2010. ENERGEX has adjusted the annual allowable revenue for the value of contributions received, and is therefore entitled to recover an annual Return on Asset (ROA) and depreciation charge over the life of the assets. In light of the change to the regulatory framework for street lighting services ENERGEX proposes to account for the residual value of contributed street light assets (prior to 1 July 2010) within the RAB for *standard control services* and allocate these costs to the standard asset customer (SAC) group. This is discussed further in Section 21.4.3.

ENERGEX submits that the proposed approach for treatment of street lighting assets, contributed and non-contributed, will satisfy Rule requirements and deliver network charges which directly correlate with the level of service provided and account for the change in regulatory framework.

Part One – Building Block Proposal

8 Current performance scorecard

The RIN seeks information on ENERGEX's current performance in relation to network reliability, growth in peak demand, energy consumption and customer numbers and capital and operating expenditure. Whilst the RIN requires the capital and operating expenditure for the current regulatory period to be consistent with the CAM approved by the AER, the data presented and discussed in this chapter is in accordance with audited regulatory accounts as reported to the QCA.

This information is to assist the AER in assessing ENERGEX's *Regulatory Proposal* for the *2010-15 regulatory control period*. This chapter outlines ENERGEX's performance during the *current regulatory control period*.

8.1 Summary

In the *current regulatory control period* ENERGEX has significantly increased its resourcing capabilities to undertake the capital and operating investment programs for security compliance and service standards as detailed in the EDSD Review. Compared to the previous *regulatory control period*, ENERGEX's operating expenditure will, on average, increase by 120 per cent while its annual capital expenditure will be up by 132 per cent.

In summary, the first three years of the *current regulatory control period* have seen ENERGEX:

- exceed the QCA allowed capital expenditure by 2.4 per cent;
- exceed the QCA allowed operating expenditure by 1.9 per cent;
- outperform the MSS CBD and urban feeders SAIDI and SAIFI targets;
- deliver slightly worse than the MSS rural feeders SAIDI target in 2005-06 and MSS rural feeders SAIFI targets in 2005-06 and 2007-08;
- increase the installed capacity at bulk supply points and zone substations by 33 per cent;
- experience demand and energy growth that is below forecast due to milder summer weather; and
- provide new connections to customers as forecast.

8.2 Regulatory information requirements

Clauses 6.5.6(e)(5) and 6.5.7(e)(5) of the *Rules* requires the AER, when assessing forecast operating and capital expenditures, to have regard to actual and expected expenditure during the preceding *regulatory control periods*.

Clause S6.1.1(6) of the *Rules* requires ENERGEX to provide the capital expenditure for each of the past regulatory years of the previous and *current regulatory control period*s, and the expected capital expenditure for each of the last two regulatory years of the *current regulatory control period*, categorised in the same way as for the capital expenditure forecast.

Clause S6.1.2(7) of the *Rules* requires ENERGEX to provide the operating expenditure for each of the past regulatory years of the previous and *current regulatory control period*s, and the expected operating expenditure for each of the last two regulatory years of the *current regulatory control period*, categorised in the same way as for the operating expenditure forecast.

Clause 2.3.7(a)(5) of the RIN requires an explanation of historic network capacity or performance levels and their impact on service levels at key points in the network.

Clause 2.3.7(a)(7) of the RIN requires an explanation of how network capacity in the *current regulatory control period* met actual demand relative to the demand forecasted for each period.

8.3 Network reliability performance

This section outlines ENERGEX's network reliability performance in the *current regulatory control period*.

As noted in Section 3.11.2, ENERGEX is subject to MSS in relation to its reliability performance under the EIC. ENERGEX's reliability performance against the MSS targets is provided in Table 8.1.

Table 8.1 SAIDI and SAIFI reliability achievements against MSS[23]

SAIDI	Urban		Rural		CBD	
Year	**MSS**	**Actual**	**MSS**	**Actual**	**MSS**	**Actual**
2005-06	155	104	265	306	20	4.1
2006-07	145	80	255	203	20	0.0
2007-08	134	85	244	242	20	4.0
SAIFI	**Urban**		**Rural**		**CBD**	
Year	**MSS**	**Actual**	**MSS**	**Actual**	**MSS**	**Actual**
2005-06	1.73	1.41	2.77	3.29	0.33	0.02
2006-07	1.64	1.00	2.70	2.33	0.33	0.00
2007-08	1.54	1.05	2.63	2.71	0.33	0.04

The MSS reflect unplanned and planned SAIDI and SAIFI. Reliability performance is impacted by a number of factors. These include:

- efforts to improved unplanned 'non-storm' (e.g. car hit pole) SAIDI and SAIFI;
- probabilistic events, such as equipment failure, third party interference or weather influences; and
- the amount of planned events.

In recent years, unplanned 'non-storm' SAIDI and SAIFI have shown an improving trend on both the urban and rural networks. ENERGEX considers that this is largely due to both a concentrated reliability improvement effort (e.g. vegetation clearing) and splitting up of the 11 kV network in demand driven projects.

However, planned SAIDI and SAIFI have shown an increase over recent years, due to higher volumes of planned work on the network, as well as improvements in reporting of planned outages in the Network Outage system.

Historically, ENERGEX's reliability performance is closely linked to seasonal changes in weather patterns. This can lead to significant variations to unplanned SAIDI and SAIFI for a given year due to the impact of storms on the network. This variation is especially prevalent on the short rural network due to the predominant overhead network which is heavily exposed to the vagaries and volatility of the environment. The urban network also experiences variations due to weather conditions but not to the same extent as for the rural network.

23 Source: ENERGEX, *Network Management Plan 2008-09 to 2012-13*.

An analysis of weather patterns over the past few years indicates:

- 2005-06 delivered an extremely severe storm season with 29 severe weather events, compared to only 16 in the previous year. Also, this was one of the hottest years on record (most hot days occurred on weekends);
- 2006-07 saw a relatively mild storm season for SEQ; and
- 2007-08 saw the impact of strong winds and heavy rain in the rural areas.

The EIC allows for the removal of major events (including the impact of severe weather) from MSS using the 2.5 Beta method. Whilst excluding these events does remove some of the variation due to seasonal changes in weather patterns, it tends to be less sensitive to events affecting the rural network due to its lower contribution to system SAIDI. In any given year, it is typical for ENERGEX to exclude around two days as major event days. In recent years this has varied between zero and six major event days per annum.

ENERGEX's reliability performance over the duration of the *current regulatory control period* reflects these factors. In summary,

- **urban performance** – strong SAIDI and SAIFI performance against the MSS throughout the period. Improvements across the years reflect improvement programs as well as the milder storm impacts over the past few years. These improvements have been offset slightly by increases in planned SAIDI and SAIFI;
- **rural performance** – since 2005-06, SAIDI has been better than MSS (only marginally better in 2007-08), but rural SAIFI was slightly worse than MSS in 2007-08. In 2006-07, a mild storm season, there was an improvement in rural SAIDI performance of 33 per cent compared to the previous year. However, in the following year, this improvement was offset by the contribution of strong winds and heavy rain and several significant substation outages. The increases in planned SAIDI and SAIFI have also had an effect on rural performance; and
- **CBD** – strong SAIDI and SAIFI performance against the MSS throughout the period. ENERGEX's CBD network is completely underground, resulting in a high performance and is not typically influenced by seasonal weather variations. The 'meshed' CBD network also means that any unplanned events which do occur will typically impact only on a small number of customers. The outage causes which have had the highest impact on CBD SAIDI and SAIFI over the last three years are equipment failure (such as distribution transformers or cables), accidental excavation of cables and overloading of distribution transformers.

8.4 Network capacity performance

The EDSD Review recommended that ENERGEX reduce the utilisation of its network to 60-65 per cent – a level generally accepted as good practice. More than 3,000 MV.A has been added to the installed capacity of the network in the first three years of the *current regulatory control period*; an increase of 34 per cent.

ENERGEX's bulk supply point network utilisation based on the load in 2007-08 is 61 per cent while the zone substation utilisation is 56 per cent. These utilisation levels are likely to be understated due to the low maximum demand recorded in recent years as a result of mild weather conditions. Based on a 50 PoE weather adjusted demand, the 2007-08 utilisation levels at bulk supply points and zone substations are calculated to be 69 per cent and 63 per cent respectively.

The network utilisation and installed capacity of the bulk supply points and zone substations are summarised in Table 8.2.

Table 8.2 Network utilisation and installed capacity

	Actual			Projected	
	2005-06	**2006-07**	**2007-08**	**2008-09**	**2009-10**
Bulk supply point network utilisation	71.2%	63.0%	61.2%	61.3%	N/A
Bulk supply point installed capacity (MV.A)	4,795	5,155	5,815	5,935	6,155
Zone substation network utilisation	64.6%	59.6%	56.2%	56.6%	N/A
Zone substation installed capacity (MV.A)	7,307	8,155	8,680	9,180	9,435

Utilisation targets were set as part of the EDSD report. While utilisation is a useful measure of the outcome of plans, it is not used as a specific policy for bulk supply and zone substation capacity. Rather, capacity planning targets for major lines and substations are in accordance with system normal and contingency planning policies as described in Chapter 13. Adherence to these policies will result in appropriate utilisation outcomes.

In addition, ENERGEX monitors and reports on the status of load and capacity at key points in the network. The status for bulk supply points and zone substations, 132/110 kV feeders and 33 kV feeders are provided in Table 8.3, Table 8.4 and Table 8.5[24].

24 Source: ENERGEX, *Network Management Plan 2008-09 to 2012-13*.

Table 8.3 Bulk supply and zone substation capacity

Substation type	Substation loading	2005-06	2006-07	2007-08
Bulk supply	Demand > Normal Cyclic Capacity (NCC)*	0	0	1
	Demand > N-1*	20	14	15
	Total substations	**34**	**35**	**37**
Zone	Demand > Normal Cyclic Capacity (NCC)*	6	3	1
	Demand > N-1*	135	117	109
	Total substations	**200**	**206**	**213**

** Based on actual demands. Minor overloads (<1 MV.A) that can be covered by transfers are excluded.*

Table 8.4 132 kV and 110 kV feeder utilisation

System configuration	132 kV and 110 kV feeder loading	2005-06	2006-07	2007-08
Normal	Demand > 1.0 Normal Cyclic Capacity (NCC)*	0	0	0
N-1	Demand > 1.0 Emergency Cyclic Capacity (ECC)**	8	4	11
	Total feeders	**92**	**95**	**96**

** Based on actual demands. Minor overloads (<1 MV.A) that can be covered by transfers are excluded.*

*** Based on actual demands. Minor overloads (<2 MV.A) that can be covered by transfers are excluded.*

Table 8.5 33 kV feeder utilisation

System configuration	33 kV feeder loading	2005-06	2006-07	2007-08
Normal	Demand > 1.0 Normal Cyclic Capacity (NCC)*	5	12	14
N-1	Demand > 1.0 Emergency Cyclic Capacity (ECC)*	103	114	124
	Total feeders	**304**	**322**	**334**

** Based on actual demands. Minor overloads (<5 A) that can be covered by transfers are excluded.*

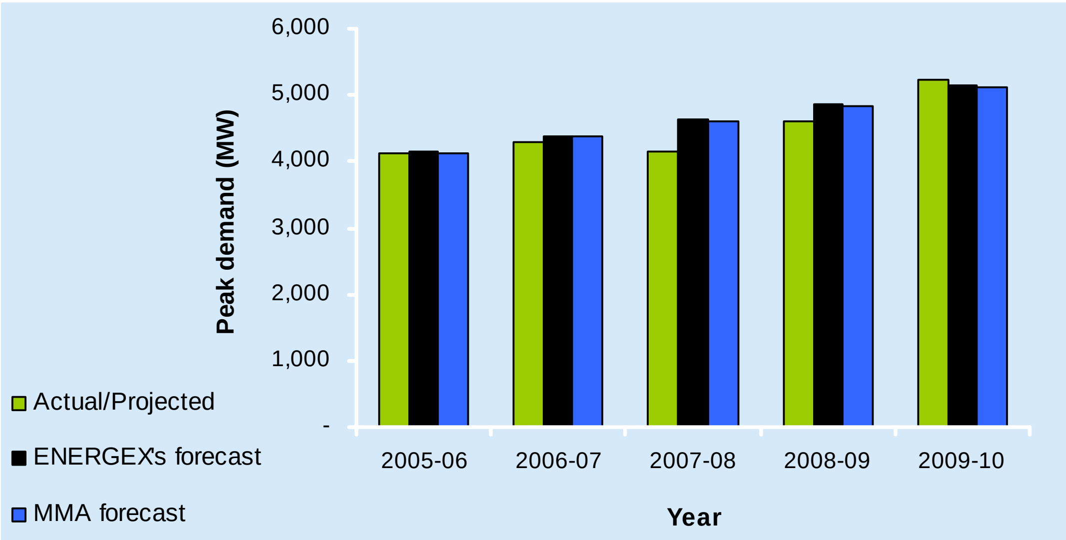
8.5 Growth over the current regulatory control period

For the first three years of the *current regulatory control period*, actual growth in demand, customer numbers and energy consumption has been impacted by the mild summer seasons and continued strong migration trends.

8.5.1 System peak demand during the current regulatory control period

The recorded system peak demand compared to forecast is provided in Figure 8.1.

Figure 8.1 System peak demand



Since the hot summer of 2003-04, SEQ summers have been relatively mild. Whilst the summer of 2005-06 was hot, the high temperature days mostly occurred during the weekends.

The recorded peak demands for the first three years of the *current regulatory control period* were below forecast.

Summer of 2007-08 is on record as the coolest summer since 1940[25]. ENERGEX's system maximum demand peaked on a Saturday in February 2008 at 4,142 MW, almost 500 MW below forecast. The week day maximum demand occurred on Friday 22 February 2008 and was recorded at 4,120 MW. This demand is almost 4 per cent below the previous summer maximum demand of 4,289 MW and more than 10 per cent below the figure forecasted for the 2005 distribution determination.

25 Source: NIEIR, *Electricity consumption and maximum demand projections for the ENERGEX region to 2018*, October 2008.

To determine the underlying growth rate, the recorded maximum demands are weather corrected to a 50 PoE day to account for temperature sensitive loads.

Table 8.6 summarises the actual and temperature corrected (50 PoE) demands.

Table 8.6 Actual and weather corrected maximum demand (MW)

	2005-06	2006-07	2007-08
Actual recorded demand	4,131	4,289	4,142
Weather corrected 50 PoE demand	4,363	4,716	4,673

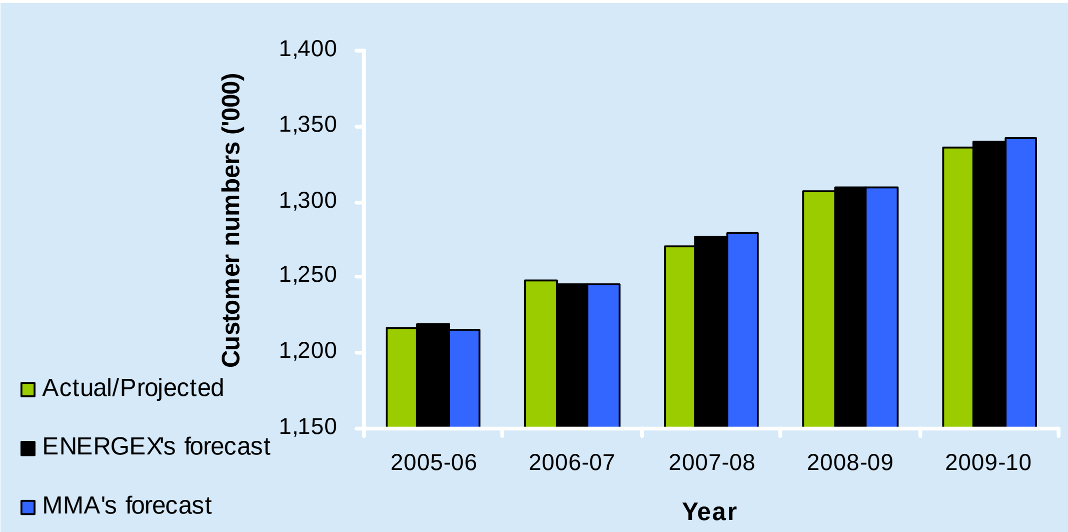
The projected maximum demand for the remaining two years of the *current regulatory control period* is based on a temperature corrected maximum demand of 4,673 MW for 2007-08. Temperature adjusted to 50 PoE day on maximum demand is the basis of ENERGEX's demand forecast methodology. The average annual growth rate for the *regulatory control period* is expected to be 5.5 per cent, just below the forecast of 5.6 per cent used in the 2005 distribution determination.

Demand forecasts are discussed further in Chapter 10.

8.5.2 Customer numbers during the current regulatory control period

Customer numbers for the *current regulatory control period* are provided in Figure 8.2.

Figure 8.2 Customer number growth

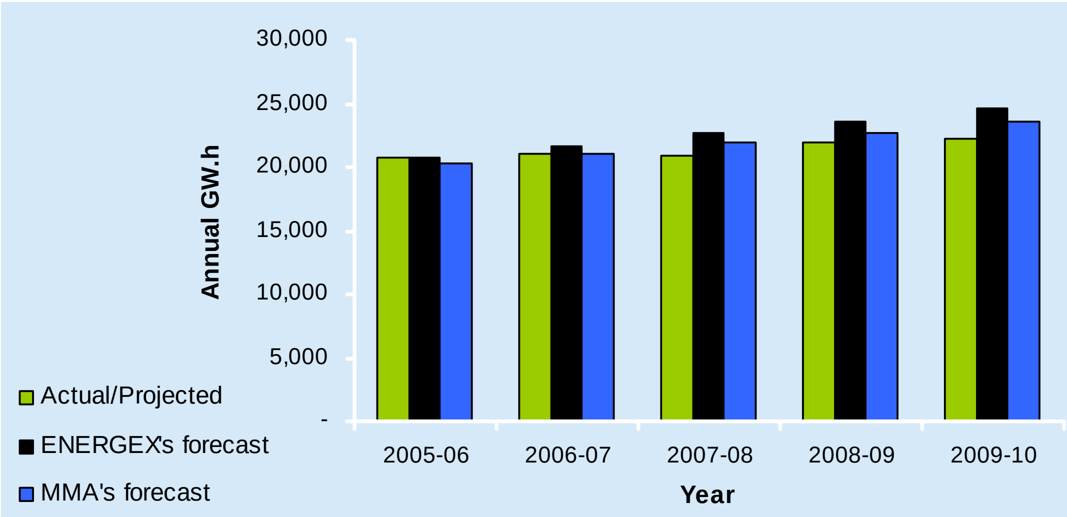


In the first three years of the *current regulatory control period*, ENERGEX has made over 81,000 new connections to its network. This is consistent with the forecast used in the 2005 distribution determination.

8.5.3 Energy consumption during the current regulatory control period

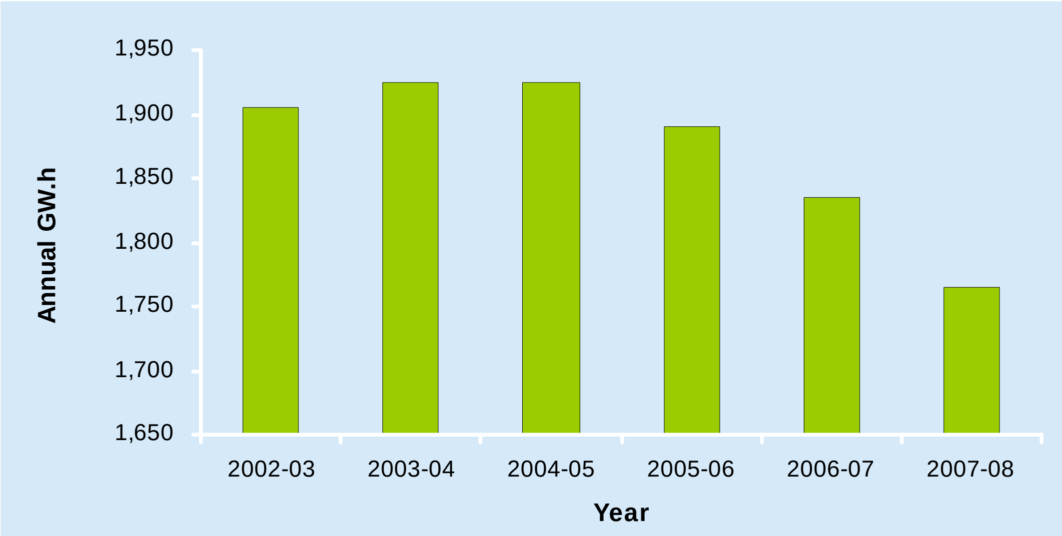
The energy consumption growth during the *current regulatory control period* is provided in Figure 8.3.

Figure 8.3 Energy consumption growth



Following strong growth in 2004-05, driven by hot summer conditions and strong economic growth, the growth trend in energy consumption appears to be slowing as demonstrated by constrained growth of 1.6 per cent in 2006-07 and negative growth in 2007-08. The lower than forecast energy consumption is primarily driven by low air-conditioning use as a result of the mild summer seasons. In addition, the Queensland government's directive for installation of solar, gas and heat pump hot water heating in all new dwellings, which came into effect on 1 March 2006, has impacted on the energy growth of the controlled load tariff as shown in Figure 8.4.

Figure 8.4 Controlled load



8.6 Capital expenditure trends

In the *QCA's 2005 final determination*, the QCA approved a $2.7 billion (real $2004-05) capital expenditure allowance for the current regulatory period. ENERGEX subsequently successfully applied to the QCA for an additional $720 million (real $2004-05) capital expenditure related to the EDSD Review and capital expenditure excluded by the QCA's consultant Burns Roe Worley at the time of the *QCA's 2005 final determination*.

Consistent with the NEL objectives, ENERGEX is committed to promoting the efficient investment in its network for the long-term interests of its customers. Despite the QCA's concerns in relation to ENERGEX's ability to undertake the 2005-10 forecast capital program, ENERGEX has demonstrated its capability through the timely delivery of its capital program.

ENERGEX has conducted analysis of its capital expenditure based on the available audited RRSs submitted annually to the QCA for the first three years of the *current regulatory control period*.

Table 8.7 shows that actual capital expenditure for the first three years of the *current regulatory control period* is $2.1 billion or an average of $709 million per annum. This is 106 per cent higher than the capital expenditure incurred in the previous regulatory period (average $345 million per annum).

Table 8.7 Capital expenditure

	Actual			Projected		
Nominal $M	**2005-06**	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**Total**
System capex						
QCA allowance	537.4	618.3	738.4	778.6	819.1	**3,491.8**
Actual/projected	603.9	624.2	632.6	796.9	921.5	**3,579.1**
Non system capex						
QCA allowance	72.1	49.3	60.9	41.2	41.7	**265.2**
Actual/projected	121.0	94.6	50.4	72.2	99.1	**437.3**
Total capex						
QCA allowance*	609.5	667.6	799.3	819.8	860.8	**3,757.0**
Actual/projected**	725.0	718.9	683.0	869.1	1,020.5	**4,016.5**

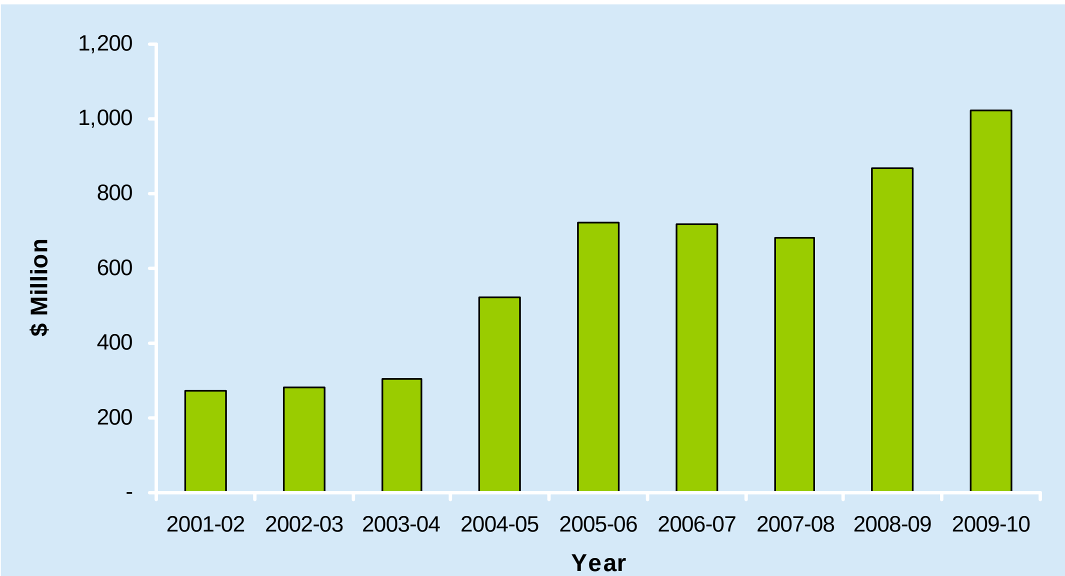
** ENERGEX Annual Regulatory Reporting Statements, Schedule P2. The 2005-06 RRS was subsequently adjusted following approval of off-ramp application.*

*** Schedule P of RRS 2007-08.*

ENERGEX's non-system capital expenditure is significantly above QCA's allowance. Non-system capital expenditure is integral to investment in the electricity distribution network as it supports the provision of system capital expenditure and operating and maintenance activities. The key expenditures under non-system are in fleet (vehicles), tools and equipment and property; all of which are related to the additional resources employed to deliver network services.

Figure 8.5 provides the trend of ENERGEX's historical and projected capital expenditure.

Figure 8.5 Capital expenditure



Total capital expenditure is projected to exceed $4.0 billion over the *current regulatory control period*, representing a total expenditure that is approximately 2.4 per cent above the level allowed in *QCA's 2005 final determination* and approved capital expenditure pass through application[26].

The major projects undertaken by ENERGEX in the *current regulatory control period* include:

- Completion of the CityGrid project – establishment of additional substations and reinforcement of the underground network in and around the CBD;
- Algester – establish 110/33/11 kV substation;
- Currumbin to Burleigh Heads – establish two 33 kV underground feeders;
- Sumner – establish 110/11 kV substation;
- Goodna – establish 110/33 kV substation;
- Loganlea – replace switchgear and establish new zone substation;
- Merrimac to Broadbeach – uprate 110 kV underground cables;
- Upper Mt Gravatt – install second module (15/25 MV.A transformer);
- Surfers Paradise – install third transformer;
- Crestmead to Browns Plains – install two 33 kV underground cables;
- Tugun to Currumbin – install two 33 kV underground cables;
- Scrub Road to Belmont – install two 33kV underground cables;
- Nudgee and Lomandra Drive – construct two 33 kV underground feeders;
- Robina – replace two 110/33 kV transformers; and
- Browns Plains – install transformers and switchgears to increase network capacity.

8.7 Operating expenditure trends

Table 8.8 shows that actual operating expenditure for the first three years of the *current regulatory control period* is $816 million or $272 million per annum. This is 86 per cent higher than the operating expenditure incurred in the previous regulatory period (average $146 million per annum).

26 Source: QCA, *Final Decision – ENERGEX Application for Capital Expenditure Cost pass through*, March 2007.

Table 8.8 Operating expenditure

	Actual			Projected		
Nominal $M	**2005-06**	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**Total**
QCA allowance*	225.9	270.5	311.2	328.3	335.7	**1,471.6**
Actual/projected**	234.1	274.5	307.3	362.0	431.6	**1,609.5**

** Total of allowance provided in the QCA's 2005 final determination, adjusted for QCA levy (full five years) and FRC cost pass through (in 2007-08, 2008-09 and 2009-10).*

*** Schedule O of RRS 2007-08.*

Figure 8.6 provides the trend of ENERGEX's historical and projected operating expenditure.

Figure 8.6 Operating expenditure

The total operating expenditure is projected to be $1.6 billion over the *current regulatory control period*. In the first three years of the *current regulatory control period*, ENERGEX's actual operating expenditure is 1.9 per cent above the level allowed by the QCA.

The increased operating expenditure contributes towards maintaining and improving the reliability performance of ENERGEX's network. Delivery of effective vegetation management and improved maintenance programs will be required to ensure enhanced reliability performance.

8.8 Customer service performance

ENERGEX's customer-centric vision continues to focus on meeting our customers' needs and delivering balanced commercial returns. Understanding the differing needs of our customers is essential to delivering on this business vision. Retail energy companies are both customers and strategic partners in delivering excellent services to our industrial, commercial and residential customers.

In addition to performance improvements associated with the introduction of EDSD initiatives, ENERGEX has:

- successfully transitioned staff and the business following the completion of the sale of ENERGEX's gas and retail arms and the introduction of FRC;
- achieved high performance levels in the Network Contact Centre;
- engaged the community in its activities; and
- achieved high levels of customer satisfaction.

8.8.1 Full retail competition and trade sale

In 2006-07 ENERGEX successfully managed the Queensland government-initiated trade sales of its retail and gas network businesses and continued to support the Transition Service Agreements with Origin Energy, Australian Gas Light (AGL) and Australian Pipeline Trust (APT).

Introduction of FRC in July 2007 and the trade sale of the retail business was a significant challenge for ENERGEX. A significant number of new legislative and market obligations that impact on ENERGEX were introduced. In preparation for FRC, ENERGEX had to enhance existing ICT systems, implement new systems and review associated processes across the business. As a result of a significant effort, all systems and processes were in place to be compliant with the new legislative and market obligations prior to 1 July 2007.

ENERGEX's Transition Services Agreements with Origin, AGL and APT were progressively phased out and completed in March 2008. Subsequently, ENERGEX's Contact Centre was restructured and now operates in a distribution network only capacity. Customers now deal with their electricity retailer for account and billing enquiries, but continue to deal directly with ENERGEX for network enquiries, including faults and supply interruptions.

In the first year of FRC in Queensland, a record number of customers (347,751) were transferred onto market contracts offered by energy retailers. This number is almost three times the number processed in the first 12 months of FRC in NSW.

As a distribution network business only, ENERGEX is reliant on retailers to provide updates on customer information in accordance with a national standard set by NEMMCO, giving ENERGEX limited ability to control the quality of customer information resulting in difficulties with communicating directly with customers.

8.8.2 Network contact centre

The Network Contact Centre has an internal target of answering 70 per cent of calls within 20 seconds. In 2007-08, staff excelled in the delivery of customer service, answering more than 80 per cent of the 2.3 million calls within 20 seconds.

Speech recognition technology was introduced in 2005-06 to provide customers with the opportunity to update their contact numbers on the Loss of Supply (13 62 62) and General IVR (13 12 53) telephone numbers. These systems were implemented prior to the start of the 2006-07 summer season to enhance the telephone service experience.

8.8.3 Community

ENERGEX understands that its maintenance and construction activities can have an impact on the nearby community. Hence, there is a detailed communication framework to engage, consult and inform the community.

There are community reference groups for specific projects, community information days, speakers supplied to community organisations and schools and personal contact with stakeholders including homeowners, business owners and elected representatives. These activities are supported through the media, community flyers, stakeholder letters, local advertisements and ENERGEX's website.

8.8.4 Customer satisfaction

Independent research is conducted annually to survey customer satisfaction. The research considers the performance of ENERGEX's Network Contact Centre, service delivery and brand value within the community. Since the changes in the energy industry and the sale of ENERGEX's retail and gas business, ENERGEX has maintained a significantly high level of customer support in comparison to Australian and international utilities.

In 2007-08, ENERGEX recorded a Corporate Reputation Index score of 66 for the year, indicating positive regard in the home market. In addition, 99.9 per cent of complaints were resolved internally.

8.8.5 Guaranteed service levels

In January 2005, as a result of EDSD recommendations, the Queensland government introduced a range of GSLs. Prescribed in the EIC, these GSLs describe the standards for the delivery of customer service for Queensland electricity distributors. They relate to the quality of service received by individual customers in regard to new connections, de-energisations, re-energisations[27], loss of hot water, scheduled appointments, notice of planned interruptions and reliability (frequency and duration). ENERGEX must compensate the customer in the form of a financial rebate if the required service levels are not met.

27 The term 'de-energisation' and 're-energisation' are used in the national market and correspond to the terms 'disconnection' and 'reconnection' in the EIC.

Since the introduction of this scheme, ENERGEX has achieved better than 99 per cent performance to the required standard on connections, de-energisations, re-energisations, loss of hot water and appointments. However there was a significant increase in rebates in the 2007-08 year largely associated with timely completion of connections. Operational issues in relation to transferring customer data (subsequent to the retail separation in March 2008) resulted in delays to a number of customer power connections.

9 Service obligations and performance standards

The obligations outlined in this chapter relate to the provision of direct control services as outlined in the AER's Stage 2: Framework and approach paper.

A large number of Commonwealth and State legislative regulatory instruments, detailed in pro forma 2.3.4 in **Attachment 1** and discussed in Chapter 3, define the framework under which ENERGEX operates as a DNSP in the provision of direct control services. These instruments drive ENERGEX's service and performance obligations which in turn influence internal standards and practices. ENERGEX's forecast capital and operating expenditures reflect these obligations and derived internal standards and practices.

This chapter identifies the main obligations and service performance standards for ENERGEX as a DNSP.

9.1 Summary

ENERGEX's primary distribution performance obligations as an NSP are outlined in national electricity legislations (e.g. NEL and the *Rules*) and Queensland jurisdictional legislations (e.g. *Electricity Act 1994*, *Electrical Safety Act 2002*, relevant subordinate legislations, the EIC and the Energy Ombudsman Act 2006).

ENERGEX has developed its capital and operating programs to comply with these obligations and the associated standards and targets. Chapters 12 and 13 outline the forecast operating and capital expenditure programs, developed to deliver performance consistent with obligations and standards discussed in this chapter.

ENERGEX has also identified future legislative obligations associated with the following:

- review of MSSs and GSLs under the EIC;
- the Demand Management plans under *Electricity Amendment Regulation (No1) 2009*;
- feed-in tariffs;
- smart metering;
- CPRS;
- national review into model occupational health and safety (OH&S) laws;
- Henry Review on tax;
- AER's *Regulatory Information Order* (RIO);
- National Energy Customer Framework (NECF);

- National Broadband Network (NBN); and
- customer claims for GSLs.

The QCA has recently finalised the MSS and GSL arrangements to apply from 1 July 2010[28]. The decision has resulted in changes to the MSS limits and the GSL payment amounts as discussed further in this chapter. Demand Management plans under *Electricity Amendment Regulation (No1) 2009* are discussed in Chapter 5.

The scope, timing and cost impacts of the remaining obligations cannot be reasonably forecast at the time of submitting this *Regulatory Proposal*. Therefore ENERGEX is nominating these obligations as specific pass through events as discussed in Chapter 20.

9.2 Regulatory information requirements

Clauses 6.5.6(a)(2) and 6.5.7(a)(2) of the *Rules* require ENERGEX to include in its *Regulatory Proposal* the total forecast operating and capital expenditure that it considers is required to achieve its regulatory obligations or requirements associated with the provision of *standard control services*.

Clause 2.3.5 of the RIN requires ENERGEX to provide information related to its service standard obligations. This includes external obligations and internally imposed service performance standards that assist in satisfying externally imposed standards. Pro forma 2.3.5 in **Attachment 1** contains this information. In addition, ENERGEX is required to provide information regarding programs/projects/initiatives associated with achieving these internal and external obligations and the respective impact on capital and operating expenditure for the *2010-15 regulatory control period*.

9.3 Overview of legislation, obligations, expenditure and performance

Electricity industry-specific legislation largely defines ENERGEX's obligations as regards to the provision of connection and supply services to customers in an efficient, economic, safe, reliable and environmentally sound manner. In addition to economic regulation, the NEL and the *Rules* also prescribe obligations relating to power system security, network connections and metering.

ENERGEX's key obligations are outlined in Chapters 4, 5 and 7 of the *Rules* and relate to the following:

28 Source: QCA, *Final Decision –.Review of Electricity Distribution Network Minimum Service Standards and Guaranteed Service Levels to apply in Queensland from 1 July 2010*, April 2009.

- Chapter 4 includes planning and operating the distribution system, recognition of NEMMCO's responsibility for power system security and compliance with NEMMCO's power system security guidelines;
- Chapter 5 includes connection enquiries, planning and development of the network, inspection and testing, commissioning, de-energisations and re-energisations. ENERGEX must also comply with relevant schedules which specify: planning, design and operating criteria; system standards; conditions for connection of generators, connection of customers, and connection of market network services; and terms and conditions of connection agreements; and
- Chapter 7 includes metering obligations. As the Responsible Person, Local Network Service Provider (LNSP) and Metering Provider, ENERGEX must comply with rules relating to metering installations, accreditation and registration as a metering provider, metering data and metrology procedures.

The jurisdictional electricity legislation complements the national legislation. The *National Electricity (Queensland) Law 1997* governs Queensland's participation in the NEM. As discussed in Chapter 3, key state electricity legislative instruments are the:

- *Electricity Act 1994* and its subordinate legislation;
- *Electrical Safety Act 2002* and its subordinate legislation;
- *Electricity Industry Code 4th Edition 2008*; and
- *Energy Ombudsman Act 2006*.

The EDSD Review, initiated in March 2004 by the Queensland government, had a wide-ranging impact on the regulatory arrangements for ENERGEX. As a consequence of the review, the EIC was formulated to encapsulate many of the recommended service standard requirements. The EIC prescribes the condition of ENERGEX's distribution authority and is directed at efficient investment in and utilisation of the electricity system in the long-term interests of Queensland customers.

The service standards derived from these national and state obligations underpin the development of ENERGEX's forecast capital and operating expenditure. These obligations can be identified in association with:

- day-to-day operational service requirements;
- annual business requirements;
- customer service and reporting obligations; and
- electrical safety obligations.

Pro forma 2.3.4 in **Attachment 1** provides a summary of ENERGEX's major regulatory obligations and requirements.

9.4 Day-to-day operational service obligations

Queensland electricity legislations impose obligations on ENERGEX as regards its day-to-day operations. These obligations largely relate to:

- connections and supply;
- metering;
- MSSs; and
- customer and retailer relationships.

9.4.1 Connection and supply obligations

Under the *Electricity Act 1994*, ENERGEX's connection obligation is to provide customers with connection services. These services are supplied under a Standard Connection Contract (SCC) in accordance with Section 3.3.1 and Annexure A of the EIC, or a negotiated Customer Connection Contract. In addition to specifying the terms of the SCC, Chapter 3 of the EIC outlines liability associated with negotiated connection contracts with small customers. It also requires ENERGEX to make available a customer charter and comply with obligations associated with disconnections and billing.

9.4.2 Metering

In addition to Chapter 7 of the *Rules*, ENERGEX's metering obligations (including Meter Types 5-7) are further described in more detail in:

- the National Metrology Procedure Parts A and B;
- the NEMMCO service level agreements for:
  - Metering Data Collection, Processing and Delivery Services for Metering Data Providers Category Installation Types 5-7;
  - Metering Provision Services for the Provision, Installation and Maintenance of Metering Installation Types 1-6;
- a Metering Asset Management Plan approved by NEMMCO outlining the statistical sampling inspection and testing of metering installations and equipment necessary to demonstrate the initial and ongoing accuracy of metering data in accordance with Schedule S7.3.1(c)(2) of the *Rules* and with NEMMCO's Metering Asset Management Plan: Information Paper; and
- the Queensland EIC.

ENERGEX is accredited by NEMMCO for the following functions:

- as a Meter Data Agent and Meter Data Provider covering the collection, processing, validation, substitution and delivery of metering data for installation types 5-7; and
- as a Metering Provider Category B covering the provision, installation and maintenance of type 6 metering installations.

To provide a fundamental basis for the accuracy of metering data and to provide traceability to Australian national standards of measurement, the above organisational units are also independently accredited by the National Association of Testing Authorities for activities associated with:

- the laboratory and field testing of metering equipment accuracy; and
- inspection of metering installations in accordance with the *Rules*.

Chapter 9 of the EIC includes obligations for types 5-7 metering installations not covered by the *Rules* and relate to responsibility for meter provision and energy data services.

9.4.3 Minimum service standards

Section 2.4 of the EIC outlines ENERGEX's MSS for average reliability thresholds and includes defined limits for the duration (SAIDI) and frequency (SAIFI) of outages experienced by the average customer in a year. The MSS is inclusive of both planned and unplanned outages and is differentiated by CBD, Urban and Short Rural[29] feeder categories. ENERGEX must target performance levels below the MSS limits to reduce the risk of non-compliance and to limit the risk to the 90th percentile. Hence, there are internal targets to operate at the 10 PoE level as in pro forma 2.3.5 in **Attachment 1**. Customer Average Interruption Duration Index (CAIDI) limits are also included in the EIC for interpretative purposes only, given they are derived from the MSS for SAIDI and SAIFI limits.

MSS limits for the *2010-15 regulatory control period* have been finalised by the QCA (**Appendix 9.1**) and require ENERGEX to continue to improve its performance over the next *regulatory control period,* as per pro forma 2.3.5 in **Attachment 1**. The QCA has indicated that it will investigate the introduction of additional MSS prior to the next review.

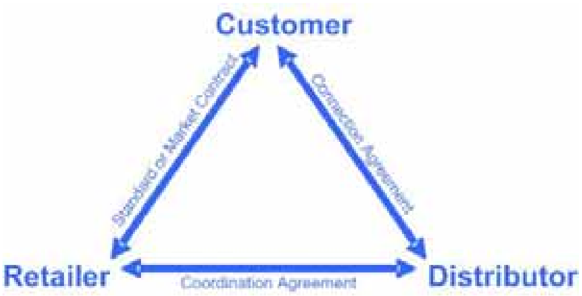
Failure to meet the MSS is a breach of the EIC. In the event of a contravention (or likely contravention), the *Electricity Act 1994* (QLD) provides for the QCA to issue warning notices, Code contravention notices or institute Supreme Court proceedings. The Electricity Act also permits the QCA to refer the matter to the entity responsible for ENERGEX's distribution authority.

29 ENERGEX does not apply the classification of Long Rural as only three feeders potentially fall into this category. The QCA has endorsed ENERGEX's approach that these three feeders should not be included in a separate category; hence they are included in the Short Rural Feeder category.

9.4.4 Customer and retailer relationships

ENERGEX's distribution network is utilised by retailers to transport electricity from connection points with the Powerlink transmission network to customers' connection points. As shown in Figure 9.1, and as required under the EIC, ENERGEX currently operates in a tripartite contractual relationship with its customers and retailers.

Figure 9.1 ENERGEX customer/retailer relationship model



As discussed in Section 9.4.1 above, the relationship between ENERGEX and its customers is as outlined in Chapter 3 of the EIC and managed through the SCC (Annexure A) and negotiated connection contracts.

Chapter 5 of the EIC and the standard co-ordination agreement (Annexure C) sets out the framework under which ENERGEX and retailers interact and their obligations to ensure their joint customers' needs, such as service order requests, are met.

Further, Section 4.2.10(b) of the EIC requires ENERGEX to inform the customer of the standard retail contract. Chapter 6 of the EIC outlines ENERGEX's obligations in relation to market transfers and ENERGEX's role as the DNSP.

The *Energy Ombudsman Act 2006*, supported by the *Electricity Act 1994*, provides an independent investigation and resolution mechanism for customer disputes with energy entities.

9.5 Annual business requirements

Section 1.1.2(a) of the EIC requires the preparation of annual management plans relating to ENERGEX's supply network. ENERGEX's NMP for the following five year period must be submitted annually in accordance with Section 2.3 of the EIC.

Summer preparedness plans must be submitted if requested by the QCA in accordance with Section 2.2 of the EIC and have been submitted each year since EDSD.

9.5.1 Network management plan

Sections 1.1.2 and 2.3.1(a) of the EIC require ENERGEX to develop and publish an annual NMP in **Appendix 9.2** that details how ENERGEX will manage and develop its supply network. The NMP is directed toward delivery of an adequate, economic and reliable electricity supply with safe connection to customers for the following five financial years and must include the following:

- the background and purpose of the NMP;
- general information about ENERGEX's supply network and the operating environment (including growth forecasts);
- statements of, and assessment of compliance with, ENERGEX's planning policy and asset management policy;
- development of a DM Strategy including existing and planned programs for demand-side participation;
- analysis of historical reliability performance, a five year forecast of the reliability targets and a description of improvement programs and expenditure initiatives;
- performance evaluation against the NMP in the previous financial year;
- risk assessment and management strategies in relation to the major constraints in ENERGEX's network;
- definition and analysis of the performance of worst performing feeders; and
- various certifications.

Security of supply is a cornerstone of ENERGEX's NMP and capital and operating programs. Network security (or security of supply) relates to how failure or failures of elements (e.g. transformers, feeders, etc) within the distribution system impact on the continuity of supply of electricity to customers (i.e. the capability of the distribution network to maintain supply in the event of an outage of one or more elements). In the distribution context, this is normally described as 'N' or 'N-1' supply. An 'N' level of security would result in an outage following a failure of a single element while an 'N-1' level of security would require the failure of at least two elements to result in an outage.

The EDSD Review imposes a jurisdictional regulatory requirement that fits the meaning of regulatory obligation or requirement under Section 2D(1)(b)(v) of the NEL. The requirement to ensure the level of security of supply is outlined in the EDSD Review (recommendations 17 and 18).

ENERGEX's security planning criteria are published as part of the NMP which is approved under the EIC on an annual basis. The standards were developed in response to the EDSD recommendation and assessed against a balanced outcome. This assessment considered customer and community expectations, willingness to pay for service delivery and the management of network risk. In 2008 a review of the security standards was conducted by ENERGEX. The resulting revised standards were independently reviewed by engineering consultants Evans & Peck who concluded that, with the implementation of identified safeguards, the revised standards were in accord with the 'N-1' philosophy envisaged by the EDSD Review. These revised standards, as detailed in pro forma 2.3.5 in **Attachment 1** and **Appendix 4.2** and **Appendix 4.3** will be published in ENERGEX's 2009-10 NMP.

On its' *Application for Additional Capital Expenditure* – October 2006 (**Appendix 9.3**), ENERGEX notified the QCA that significant funding in capital expenditure would be required to meet the EDSD targets and these would not be achieved by June 2010. ENERGEX's capital program for the *2010-15 regulatory control period* has been prepared to continue delivery of the EDSD security requirements.

9.5.2 Summer preparedness plan

Section 2.2 of the EIC requires ENERGEX to prepare and submit an annual SPP if requested by the QCA. The intent of the SPP is to ensure the network's preparedness for the upcoming summer and to minimise adverse impacts on customers' electricity supply. The SPP must include:

- a timetable outlining the specific activities to be undertaken prior to the start of summer, including programs and initiatives requiring capital, operational or maintenance expenditure; and
- information about ENERGEX's capacity to manage and respond to extreme weather events and emergencies including emergency response programs, the capacity of telephone and customer information systems over the summer, the public communications strategy and staffing levels.

9.6 Customer service and reporting obligations

In addition to MSS, ENERGEX's customer service standard obligations include GSLs, conditions for completion of standard service orders, reporting on service quality, and market obligations. These are outlined in the following sections.

9.6.1 Guaranteed service levels

Section 2.5 of the EIC prescribes the GSL regime including parameters and associated financial penalties. ENERGEX is required to pay rebates (or GSLs) to customers when targeted performance levels are not achieved. GSL obligations relate to wrongful de-energisations, timeliness of connections and re-energisations, supply of hot water, timeliness of appointments, notice of planned interruptions and reliability (frequency and duration of interruptions). These are included in pro forma 2.3.5 in **Attachment 1**.

There are limits on the number of GSL payments an individual customer may receive as well as a cap on the total value of the payments for any financial year. This cap does not apply to GSL payments for wrongful de-energisations. Failure to comply with the GSL is considered to be a contravention of the EIC and the enforcement options are the same as those discussed as regards to failure to meet MSS. GSL payment amounts will increase by 30 per cent from 1 July 2010[30], and apply for the duration of the *2010-15 regulatory control period.* The annual cap on the amount an individual may receive has also increased by 30 per cent.

The QCA has recently released a paper on further amendments to the *EIC* in regards to claims for GSL payments.[31] The outcome of this consultation may require new obligations in relation to processing of payments. At the time of submitting this *regulatory proposal* ENERGEX is unable to forecast the cost impact as the scope and timing of the changes is unclear. ENERGEX is seeking a cost pass through if the costs to comply with these obligations are material.

9.6.2 Standard service orders

Section 5.7.2 of the EIC prescribes the requirements, preconditions and timeframes for completion of standard service orders. These apply to new connections, re-energisations, de-energisations, special reads, additions and alterations, meter reconfigurations, meter investigation, supply abolishment and miscellaneous services.

9.6.3 Reporting

ENERGEX has reporting obligations to the QCA prescribed by the EIC (Section 2.6.2) as well as those for reporting to the Shareholding Minsters. These are outlined below:

- **QCA** – *The Electricity Distribution: Service Quality Reporting Guidelines* (**Appendix 9.5**) require quarterly and annual reporting on reliability, quality of supply and customer service data. These obligations are summarised in pro forma 2.3.5 in **Attachment 1**;

30 Source: QCA, *Final Decision –.Review of Electricity Distribution Network Minimum Service Standards and Guaranteed Service Levels to apply in Queensland from 1 July 2010*, April 2009.

31 Source: QCA, *Proposed Amendments to the Electricity Industry Code regarding customer claims for Guaranteed Service Levels (GSL) payments*, May 2009.

- **QCA –** Under the *Rules***,** ENERGEX is required to comply with ring-fencing obligations as regards its regulated and non-regulated business activities. The QCA monitors compliance with ring-fencing requirements and requires ENERGEX to submit an annual ring-fencing compliance report in accordance with QCA's electricity distribution ring-fencing guidelines;
- **QME** – In accordance with the *Electricity Act 1994*, as the holder of a Distribution Authority licence, ENERGEX is required to submit an annual report (**Appendix 9.6**) on its operations, as directed by the (technical) Regulator and ENERGEX is required to report on specified information, including registration issues, breaches, enforcement action against ENERGEX, injuries, events reported to the ESO and/or Workplace Health and Safety, reporting to the QCA under Clause 2.6.2 of the EIC and general information about customers, energy and the network.; and
- **QME** – *The Minimum Service Standards, Guaranteed Service Levels, Service Quality and Operations Reporting Guidelines for Distribution Networks Connected to the Main Grid* (**Appendix 9.7**) require quarterly reporting on reliability performance, compliance with GSLs, Network Contact Centre performance and other data deemed to be pertinent. These guidelines also require progress reporting against the recommendations made in the EDSD Review.

9.6.4 Market obligations

As a registered LNSP in the NEM, ENERGEX must ensure that all systems and processes are compliant with legislative and market obligations including:

- Queensland Jurisdictional Market Rules for electricity;
- procedures governing the use of market systems including Market Settlement and Transfer Solution (MSATS), Consumer Administration and Transfer Solution and Metering Data Management; and
- NEMMCO Accreditation for full Meter Provider and Meter Data Provider.

Regulatory obligations under FRC require:

- publishing Standing Data for electricity consumers to MSATS;
- maintaining the Standing Data once it is published;
- transferring network customers from and to the Host Retailer, and between retailers;
- accepting and completing service orders (eg special meter read) from retailers;
- managing consumption data for all network customers;
- preparing and issuing network bills at NMI and retailer level;
- establishing and maintaining Co-ordination Agreements; and
- installation and data management of remotely read interval sample meters to enable the calculation of controlled load peel off.

9.7 Electrical safety obligations

The *Electrical Safety Act 2002* and associated Regulation require ENERGEX to ensure that all electricity inspections, testing and maintenance works are conducted in an electrically safe manner. There is an obligation in regard to Safety Management Systems. ENERGEX discharges this obligation through its Safety Management System (SMS) in **Appendix 9.8** (BMS 01983), which describes ENERGEX's obligations under workplace health and safety and electrical safety legislation. The system is directed at achieving ENERGEX's core safety value – **safety must always come first**. The SMS reflects ENERGEX's corporate compliance standards and operating work practices/instructions.

In addition to prescribing the safety framework (including safe work methods, risk management, emergency preparedness, communications), the SMS identifies specific safety objectives and associated targets for design, construction, operation and maintenance of the network. These include:

- equipment failure – causing wires down;
- competency of new electrical employees;
- working live – LV;
- vegetation – causing mains down;
- Zero Incident Program – behavioural change;
- exposed live parts – near point of entry;
- weather/wind effects causing wires down;
- failed neutral connections – network-related shocks; and
- ring main unit (RMU) failure.

9.8 New and anticipated regulatory obligations

The following are the known new or anticipated regulatory obligations for the *2010-15 regulatory control period*:

- review of MSSs and GSLs under the EIC;
- the Demand Management plans under *Electricity Amendment Regulation (No1) 2009*;
- feed-in tariffs;
- smart metering;
- CPRS;
- OH&S Laws;
- Henry Review on tax;
- RIO;
- NECF;

- NBN; and
- Customer claims for GSLs.

The QCA's review of the MSS and GSL arrangements to apply from the beginning of the regulatory period commencing on 1 July 2010 have resulted in changes to the MSS limits and the GSL payment amounts. The costs associated with these obligations have been included in this *Regulatory Proposal*.

The *Electricity Regulation* has been amended to include a requirement for ENERGEX to prepare demand management plans as a condition of its distribution authority. This requirement, to apply from 1 July 2009, places a positive obligation on ENERGEX to ensure that demand management initiatives are implemented. The costs associated with this obligation have been included in this *Regulatory Proposal*.

ENERGEX is seeking a cost pass through on the remaining new or anticipated obligations as discussed in Chapter 20.

10 Demand forecasts

This chapter outlines ENERGEX's approach to forecasting peak maximum demand, customer numbers and energy consumption used to prepare expenditure forecasts for the *2010-15 regulatory control period*.

The demand and customer number forecasts underpin ENERGEX's forecast capital expenditure, discussed at Chapter 13. Forecasts inform the DM Strategy at Chapter 5. The assessment of ENERGEX's current performance against forecasts for the *current regulatory control period* is discussed at Chapter 8.

The demand and customer forecasts were developed prior to the Federal government's CPRS and the onset of the GFC. ENERGEX adopted the baseline energy forecasts developed by NIEIR as they incorporated a preliminary assessment of the impact of CPRS.

The next forecast, due post summer 2008-09, is still under development and will not be available in time for the preparation of expenditure forecasts for this *Regulatory Proposal*. ENERGEX has sought to incorporate an updated view of the anticipated effect of a reduction of network demand growth resulting from the GFC as discussed at Chapter 11.

10.1 Summary of forecasts

Peak demand for electricity and the number of new customers connecting to the ENERGEX network are among the key drivers of ENERGEX's forecast capital expenditure program. Additional network assets arising from the capital program drives an increase in forecast operating expenditure.

To ensure ENERGEX's network capacity meets the growing and changing needs of its customers, ENERGEX prepares on an annual basis:

- area-wide forecasts of peak demand, customer connections and energy consumption; and
- spatial forecasts of peak demand growth for zone substations and feeders to identify network capacity constraints and triggers to capital investment or risk management decisions.

ENERGEX's approach to forecasting has been recently reviewed with the assistance of an industry experienced consultant, ACIL Tasman, to ensure it represents leading industry practice.

A particular focus for ENERGEX in the *2010-15 regulatory control period* is the increasing sensitivity of demand to temperature. This sensitivity poses a compound issue for ENERGEX in that the peak demand places increased pressure on network capacity at the same time as the capacity of the network assets is constrained by the reduced ratings arising from the higher ambient temperature. Further to this, experience during recent summers demonstrates that once demand does increase, the load remains at elevated levels until such time as the temperature cools.

The analysis which underpins the forecasts in this *Regulatory Proposal* considered actual results, weather corrected results and relevant demographic and socio-economic factors and trends. ENERGEX's baseline forecast system maximum demand, customer numbers and energy consumption for the *2010-15 regulatory control period* are shown in Table 10.1.

Table 10.1 Forecasts for the *2010-15 regulatory control period* (prior to adjustments)

	2010-11	2011-12	2012-13	2013-14	2014-15	Avg annual growth*
50 PoE peak demand (MW) (baseline) **	5,486	5,767	6,023	6,250	6,490	
50 PoE peak demand (growth p.a.) (baseline)	4.63%	5.12%	4.44%	3.77%	3.84%	4.36%
Customer numbers ('000)	1,363	1,389	1,417	1,448	1,480	
Customer numbers (growth p.a.)	2.02%	1.91%	2.02%	2.19%	2.21%	2.07%
Total energy consumption (GW.h)	22,416	23,139	24,042	24,794	25,845	
Total energy consumption (growth p.a.)	0.49%	3.23%	3.9%	3.13%	4.24%	2.99%

** Average annual growth rate from year 2009-10.*

*** Prior to adjustment for the GFC.*

The baseline forecasts used in the preparation of forecast capital and operating expenditures and included in this *Regulatory Proposal* were developed as part of ENERGEX's annual planning processes, prior to an understanding of the wide-reaching impact of the GFC and the Federal government's CPRS. However, ENERGEX continues to monitor the impact of these issues on its forecasts and resulting expenditure programs.

ENERGEX's approach in this *Regulatory Proposal* is to set the 2008 forecasts as a baseline and adjust the demand forecast for the GFC impacts as well as DM initiatives. A full review of all forecasts will be conducted during 2009 as part of ENERGEX's annual planning and reporting processes.

ENERGEX validated its baseline 2008 demand, customer numbers and energy forecasts by engaging NIEIR to produce independent forecasts. ENERGEX's own forecasts compared well with NIEIR's forecasts. However, ENERGEX adopted NIEIR's lower October 2008 baseline energy forecasts for the pricing outcomes included in this *Regulatory Proposal*, due to NIEIR's accommodation of a preliminary CPRS scenario and the timely availability of that assessment.

Adjustment for the GFC and DM initiatives included in this *Regulatory Proposal* are outlined in Chapter 11.

10.2 Regulatory information requirements

Clauses 6.5.6(a)(1) and 6.5.7(a)(1) of the *Rules* require that a *building block proposal* include the total forecast operating and capital expenditure for the *regulatory control period*, which ENERGEX considers is required to meet or manage the expected demand for *standard control services* over the *2010-15 regulatory control period*.

Schedules 6.1.1 and 6.1.2 list information and matters relating to capital expenditure and operating expenditure respectively which must be contained in a *building block proposal*. These include the forecasts of load growth relied upon to derive the capital expenditure forecasts and the method used for developing those forecasts of load growth.

Clause 2.3.8 of the RIN requires ENERGEX to provide information regarding the demand forecasts that ENERGEX has used to develop its capital and operating expenditure forecasts, key drivers that impact on the forecasts, methodology used, key assumptions and description of the model.

10.3 ENERGEX's customer usage characteristics and implications

Several factors relating to the ENERGEX network's operating environment have been used to forecast demand, customer numbers and energy consumption. The factors considered in the development of ENERGEX's demand forecasts are:

- customer growth and distribution patterns;
- SEQ economy;
- climatic considerations;
- impact of air-conditioning use; and
- projected impact of demand management strategies.

10.3.1 Customer growth and distribution patterns

Population growth has been significant in recent years and Queensland remains among the fastest growing states in Australia. Queensland's population grew by 2.4 per cent in 2005-06, by 2.2 per cent in 2006-07 and continued to increase by 2.5 per cent for the year ended 31 December 2008[32]. SEQ accommodates about 60 per cent of new arrivals to the state. ENERGEX's supply area includes two of Australia's fastest growing statistical divisions, being the Gold Coast and the Sunshine Coast.

Interstate and overseas migration is a major contributor to population growth in Queensland. Tightening conditions in the Australian labour market have also seen a switch from domestic to international migration as the major contributor to growth.

Over the past decade sustained population growth has contributed to an average growth in summer peak demand of between five to seven per cent. Population growth drives the construction of new dwellings and new connections to the network. At the peak, in October 2007, ENERGEX was performing a record 4,060 connections a month.

Population growth is projected to moderate slightly over the next few years as the Queensland economy and employment growth slows. Nevertheless, Queensland's population is still expected to continue to grow by around 2.1 per cent per annum.

The energy carried by the ENERGEX network is dominated by supply to the residential and business customer sectors. In 2006-07 electricity distributed to residential customers accounted for 39 per cent of electricity sales, while commercial customers comprised 44 per cent and industrial customers 15 per cent of electricity sold. The remainder of sales were made up by the rural, traction and street lighting sectors[33].

Higher levels of residential load growth are occurring in the Brisbane suburbs, particularly those areas subject to medium density renewal and new land releases near Ipswich, north of Brisbane, and the Sunshine Coast and Gold Coast suburbs.

Commercial loads have become more prevalent in Brisbane's western corridor, the Sunshine Coast coastal strip and the northern Gold Coast, while the greatest proportion of electricity distributed around Fisherman's Island and the Trade Coast is comprised of industrial load.

Customer growth and distribution patterns are therefore a key consideration in ENERGEX's development of forecasts for the *2010-15 regulatory control period*.

---

32 Source: Australian Bureau of Statistics, *3101.0 Australian Demographic Statistics*, December 2008.

33 Source: ACIL Tasman, *System Energy – An evaluation of ENERGEX's System Energy Forecasting Methodology*, November 2008.

10.3.2 South East Queensland economy

Overall demand for electricity is driven by economic activity and the rate at which demographic variables such as population grow. As the economy expands, the demand for electricity tends to rise across all sectors. In addition, real wage increases are driving up spending capacity and resulting in a greater uptake of energy intensive appliances such as air-conditioning, as well as increases in the number and size of dwellings. All these factors combine to primarily increase demand for network capacity and as a secondary outcome, increase energy use.

As set out in the ACIL Tasman report, the Queensland economy has been consistently growing as indicated by an average growth of Gross State Product (GSP) in real terms of about 4.9 per cent per annum since 1993-94. In the past 20 years the Queensland economy has outpaced the rest of Australia in all but two years[34].

In their October 2008 report, NIEIR included the prediction that Queensland's GSP would slow to 2.6 per cent in 2010-11 and rally to 4.9 per cent in 2011-12. The slower growth reflected national factors such as the impact of higher interest rates on private consumption and housing construction. At that time it was expected Queensland's GSP would be cushioned from national events due to expenditure associated with resource and infrastructure development. However, this expectation has subsequently been revealed to be optimistic due to the impact of the GFC on growth prospects. The impact of the GFC is discussed in more detail in Chapter 11.

The *SEQ* economy has been a key consideration in ENERGEX's development of forecasts for the *2010-15 regulatory control period*.

10.3.3 Climatic considerations

Variable weather conditions add a level of complexity to forecasting electricity demand and energy use in SEQ, particularly due to the sensitivity of network demand to high temperatures.

In line with the recommendations of the EDSD Review, ENERGEX's forecasting methodology incorporates a high degree of sensitivity to severe weather events by forecasting on a 50 PoE for the planning and construction of new network. ENERGEX relies on a 10 PoE assumption to ensure that system normal configurations of the network have the capacity to meet peak demand. A forecast based on a 50 PoE assumption centres on a daily temperature with a probability of occurring once every two years, while the 10 PoE assumption has a probability of occurrence once every 10 years.

34 Source: Office of Economic and Statistical Research, *Queensland State Accounts*, December Quarter 2008 – Economic growth, Queensland, Rest of Australia and Australia, 1986-87 to 2007-08 (a).

The climate of SEQ has been a key consideration in ENERGEX's development of forecasts for the *2010-15 regulatory control period*.

10.3.4 Temperature sensitive load

Temperature sensitivity poses a compound issue for ENERGEX in that peak demand places increased pressure on network capacity at the same time that capacity of network assets is constrained by reduced ratings arising from the higher ambient temperature.

The sensitivity of electricity demand to warmer weather has increased over time due to the increasing market penetration of air-conditioning systems.

NIEIR noted that ENERGEX's share of temperature sensitive load rose from 49 per cent in 1991-92 to 61 per cent in 2007-08, reflecting the very rapid growth in air-conditioning sales, particularly since the mid-1990s.

NIEIR has commented that variability in Queensland's temperature makes identification of base load more complex[35].

The installation and use of air-conditioning was a major contributing factor to the record high system demand growth rates of five to seven per cent experienced by ENERGEX in 2004-05 and 2005-06. These higher growth rates are expected to continue until the SEQ air-conditioning market saturates.

Air-conditioning growth and use is closely correlated to high temperatures. Extended periods of hot and humid conditions drive extraordinarily high demand for air-cooling. This will result in high loading on the ENERGEX network on hot summer days, when distribution assets are constrained to their lowest capacity ratings.

Due to variability in temperatures and particularly the recent mild summer conditions, ENERGEX recorded lower actual peak demand than predicted in 2007-08 and 2008-09. ENERGEX anticipates that there is a significant amount of latent demand arising from the installation of air-conditioning that will be realised when normal summer conditions return.

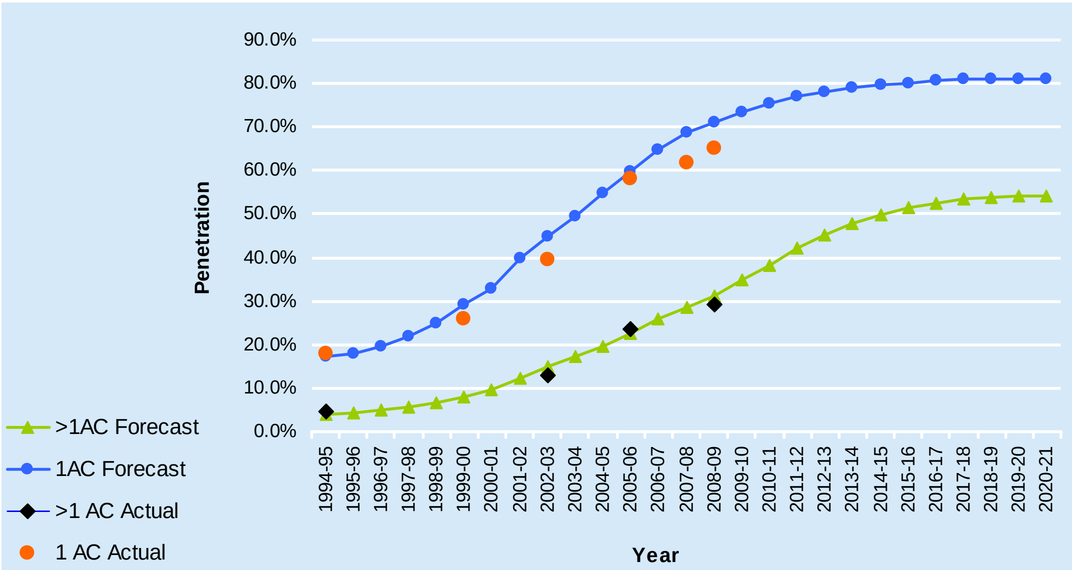
A key determinant of temperature sensitive loads is the level of penetration of air-conditioning systems. Indications from manufacturers and installers are that air-conditioner sales have continued over this period, albeit at a slower rate than would be expected in normal summer conditions. The magnitude of temperature sensitive loads is expected to have a significant and immediate impact on the SEQ network during hot conditions.

35 Source: NIEIR, *Electricity consumption and maximum demand projections for the ENERGEX region to 2018*, October 2008.

Historically SEQ has lagged behind southern states in the uptake of air-conditioning. There is a significant potential for growth with current penetration rates for single air-conditioning unit homes at just 65.2 per cent and multiple air-conditioning unit homes at 29.5 per cent. South Australia currently has the nation's highest penetration rate of air-conditioning at 90 per cent.

Air-conditioner penetration in *SEQ* has been growing at approximately three per cent per annum for the past three years. With the expected slower GSP growth over the next three to four years, a more conservative prediction is that penetration of air-conditioners will grow at between 2-3 per cent per annum. Slowing of the growth, as illustrated at Figure 10.1, means saturation in the domestic sector is unlikely to occur before 2017, after the *2010-15 regulatory control period*.

Figure 10.1 Air-conditioning penetration SEQ 2008-2020[36]



The impact of the demand for air-conditioning on the network has been included in the development of ENERGEX's forecasts for the *2010-15 regulatory control period*.

36 Based on research including the *Queensland Household Survey – May 2007* (Office of the Government Statistician, incorporated within the Office of Economic and Statistical Research).

10.3.5 Projected impact of demand management strategies

ENERGEX anticipates that, in the long term, future growth will slow due to the uptake of more efficient appliances and the impact of environmental regulations. The quantum of the impact is difficult to predict given variables such as:

- the GFC;
- the CPRS; and
- customer behaviour to upward pressure on energy tariffs.

In preparation of the DM Strategy, ENERGEX has considered energy efficiency gains in a number of areas including improved appliances, the impact of government policy initiatives and the implications on the peak system demand.

ENERGEX's DM Strategy has targeted a system peak demand reduction of 144 MW by 2015.

It is anticipated that the nature of the broad-based DM initiatives to be deployed in the *2010-15 regulatory control period* will deliver a whole of network benefit, which is difficult to align with a specific area and result in no immediate deferral of identified capital projects.

For this reason, along with the requirement on ENERGEX to move towards 'N-1' security standards, the benefits of peak demand management come through an overall reduction in system demand and risk to electricity assets.

ENERGEX has made adjustment to the baseline demand forecast for demand management benefits as discussed in Chapter 11.

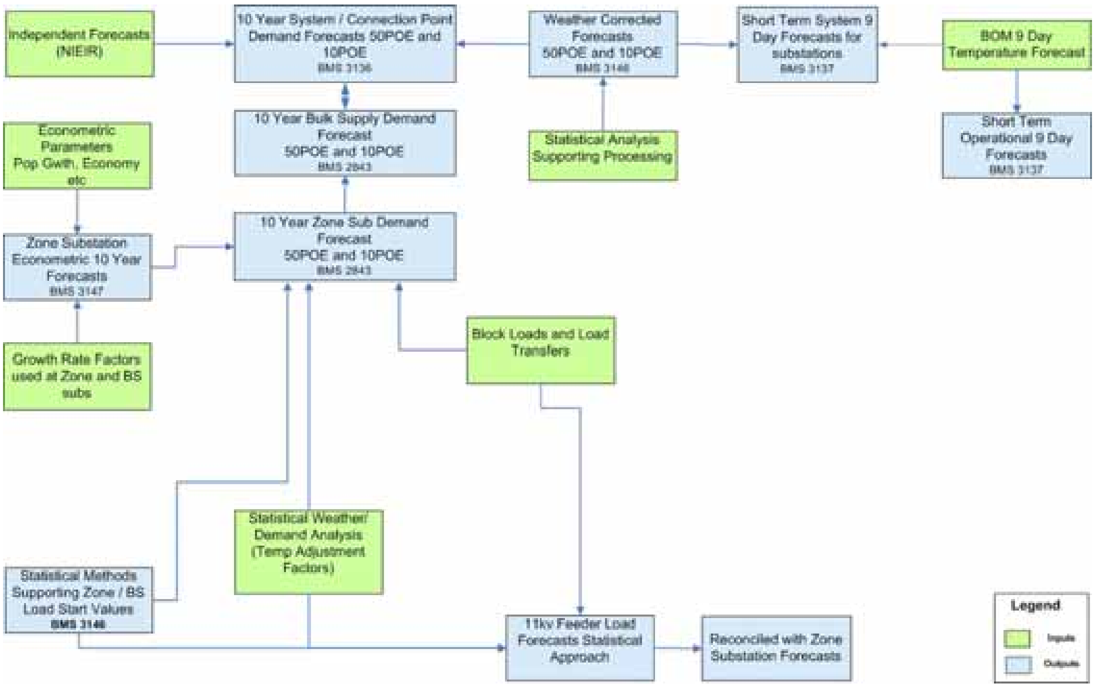
10.4 Forecasting methodology and assumptions

Peak demand and the number of new customers connecting to the ENERGEX network are among the key drivers of ENERGEX's forecast capital expenditure programs.

Forecasts for demand and customer numbers are also drivers of forecast operating expenditure through the expansion and utilisation of the network to deliver customer requirements.

ENERGEX's forecasting methodology and assumptions for the *2010-15 regulatory control period* are summarised in Figure 10.2 and detailed in **Appendix 10.1**.

Figure 10.2 ENERGEX's forecasting process



Validation of ENERGEX's forecasts for the *2010-15 regulatory control period* was achieved by benchmarking against forecasts independently produced by specialists NIEIR.

ENERGEX's own forecasts compare favourably with the NIEIR forecasts, providing overall validation of the assumptions and techniques applied by ENERGEX. The volatility of the economy and the lack of certainty in relation to government environmental policy, however, resulted in ENERGEX adopting NIEIR's October 2008 energy forecasts in **Appendix 10.2** for this *Regulatory Proposal*, given NIEIR's accommodation of a preliminary CPRS scenario.

In conjunction with the commissioning of independent forecasts, a review of ENERGEX's approach to forecasting long-term 10 year forecasts was undertaken by industry experienced consultant, ACIL Tasman.

ACIL Tasman assisted ENERGEX in revising its methodology for improved sensitivity to temperature and statistical rigour to ensure year-on-year consistency. ENERGEX has improved its forecasting methods and will progressively make enhancements in line with ACIL Tasman's recommendations for implementation through the annual 2009 forecasting process.

ACIL Tasman endorsed ENERGEX's approach to forecasting in relation to energy consumption. ACIL Tasman confirmed ENERGEX's method for extrapolating trends using the data and applying regression analysis. ACIL Tasman's report is available in **Appendix 10.3**.

10.5 Forecasts for the 2010-15 regulatory control period

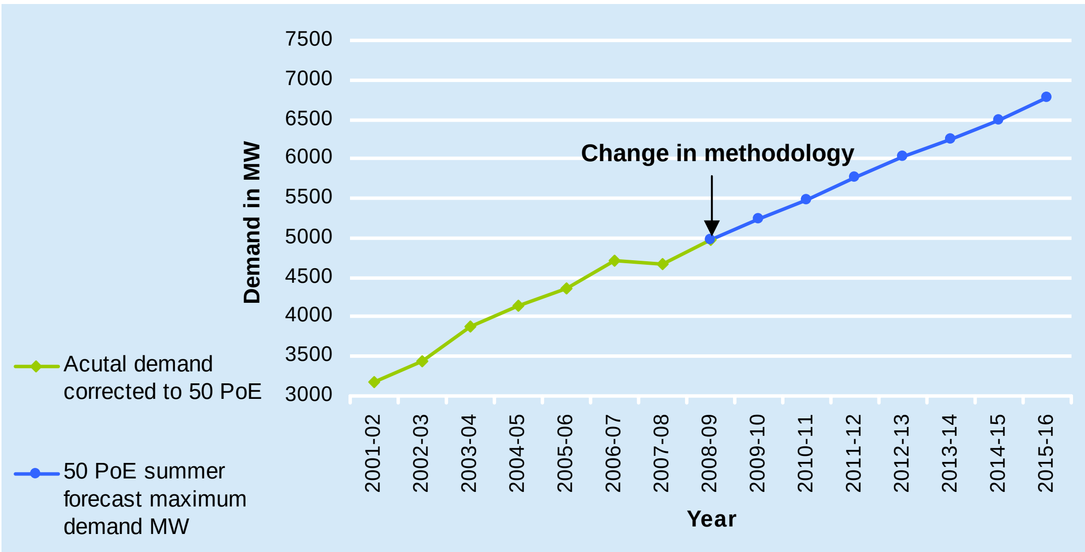
A comprehensive breakdown of the baseline forecasts developed by ENERGEX for the *2010-15 regulatory control period* are available in the pro forma 2.3.8 in **Attachment 1** and summarised in the following sections.

10.5.1 Peak demand forecast

ENERGEX's baseline peak maximum demand forecast is anticipated to grow from 5,486 MW in 2010-11 to 6,490 MW in 2014-15, representing an average annual growth rate of 4.36 per cent over the *2010-15 regulatory control period* as illustrated in Figure 10.3. ENERGEX is predominantly a summer peaking network and this is predicted to continue during the *2010-15 regulatory control period.*

Demand and customer forecasts were produced prior to the CPRS and the onset of the GFC.

Figure 10.3 ENERGEX maximum demand for summer 2001-02 to 2015-16[37]



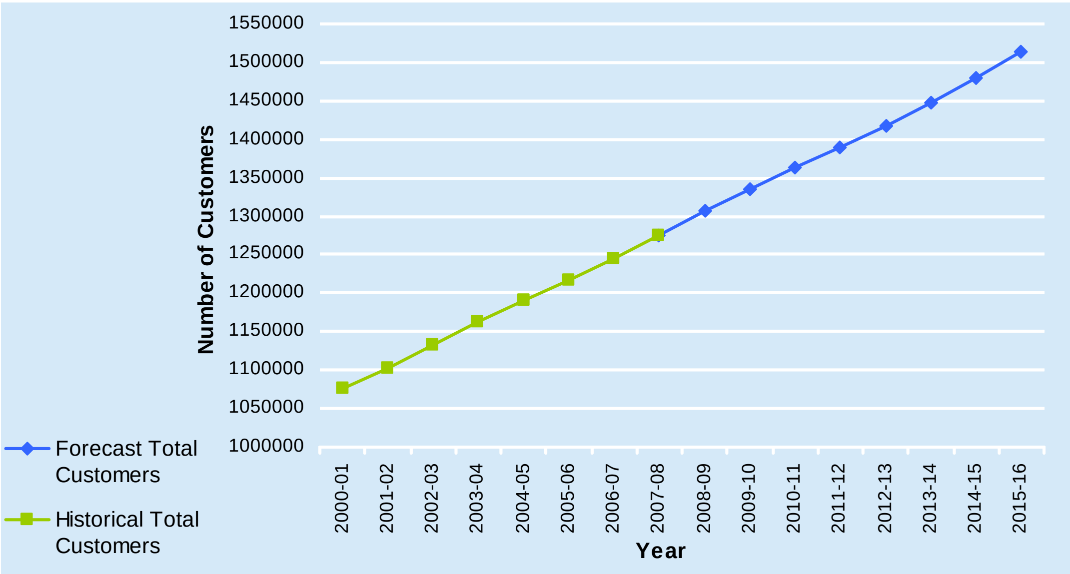
The 50 PoE demand represents the load on the ENERGEX network with a probability of being exceeded once in two years. ENERGEX also develops a 10 PoE demand to ensure the network at normal configuration has the capability to withstand a one in ten year event.

37 Source: ACIL Tasman's *System maximum demand – an evaluation of ENERGEX's system maximum demand forecasting methodology*, April 2008.

10.5.2 Customer numbers forecast

Customer numbers for the ENERGEX network are forecast to grow from 1.36 million connections in 2010-11 to 1.48 million connections in 2014-15, representing an average compound growth rate of 2.07 per cent over the *2010-15 regulatory control period* as illustrated in Figure 10.4.

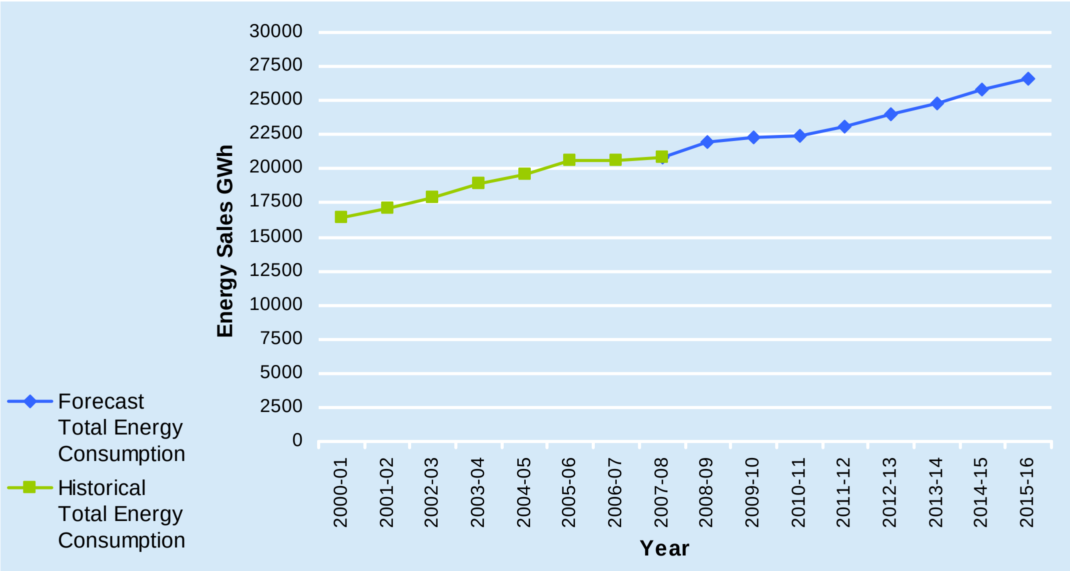
Figure 10.4 ENERGEX customer numbers 2001-02 to 2015-16



10.5.3 Energy consumption forecast

Energy sales on the ENERGEX network are forecast to grow from 22,416 GW.h in 2010-11 to 25,845 GW.h in 2014-15, representing an average annual growth rate of approximately three per cent over the *2010-15 regulatory control period* as illustrated at Figure 10.5.

Figure 10.5 ENERGEX energy consumption 2001-02 to 2015-16*



*The energy forecasts, relied upon for the revenue and price modelling contained in this *Regulatory Proposal*, were prepared taking account of a preliminary view of the impact of CPRS but not the effects of the GFC.

10.5.4 Forecast annual growth rates

The forecast annual growth rates for demand, energy and customer numbers for the *2010-15 regulatory control period* are summarised in Table 10.2.

Table 10.2 Forecasts for the *2010-15 regulatory control period* (prior to adjustments)

	2010-11	2011-12	2012-13	2013-14	2014-15	Avg annual growth*
50 PoE peak demand (MW) (baseline) **	5,486	5,767	6,023	6,250	6,490	
50 PoE peak demand (growth p.a.) (baseline)	4.63%	5.12%	4.44%	3.77%	3.84%	4.36%
Customer numbers ('000)	1,363	1,389	1,417	1,448	1,480	
Customer numbers (growth p.a.)	2.02%	1.91%	2.02%	2.19%	2.21%	2.07%
Total energy consumption (GW.h)	22,416	23,139	24,042	24,794	25,845	
Total energy consumption (growth p.a.)	0.49%	3.23%	3.9%	3.13%	4.24%	2.99%

** Average annual growth rate from year 2009-10.*
*** Prior to adjustment for the GFC.*

As peak demand on the ENERGEX network continues to increase – driving a significant part of ENERGEX's capital program to both supply the load and to provide for the required level of network security – the duration of the demand peak period is increasingly temperature sensitive. This trend means that the demand increases during periods of heat drive network expenditure to meet demand and ensure network security is maintained at an appropriate level when high summer temperatures are recorded. This need for continued high capital expenditure places upward pressure on electricity prices.

ENERGEX has sought to accommodate the updated understanding of the impacts of the GFC and the introduction of CPRS in our forecasts for the next seven years. The anticipated effect of this reduction of network demand growth on ENERGEX's forecast capital and operating programs is discussed at Chapter 11.

11 Forecast adjustments

This chapter outlines the anticipated impact of national and international events based on currently available information as well as the expected benefits of ENERGEX's DM initiatives on ENERGEX's forecast capital expenditure for the *2010-15 regulatory control period*.

ENERGEX's *Regulatory Proposal* is based on a capital expenditure program that is necessary to maintain the quality, reliability and security of supply of *standard control services* and to maintain the reliability, safety and security of the distribution system. Due to the timing of recent external events including the GFC, ENERGEX has made a specific adjustment to the necessary capital expenditure program. The baseline and adjusted capital expenditure projections are discussed in Chapter 13.

ENERGEX submits that the adjusted forecast capital expenditure is necessary to meet the capital expenditure objective set out in Clause 6.5.7(a)(1) of the *Rules* and is therefore used to calculate ENERGEX's Annual Revenue Requirements (ARR) as discussed at Chapter 18.

11.1 Summary

In developing this *Regulatory Proposal*, ENERGEX has made a preliminary assessment of the impact and influences of recent national and international events and influences as these events affect ENERGEX's objective of submitting a *Regulatory Proposal* that balances risk, business sustainability and value to customers.

The baseline capital expenditure forecast included in Chapter 13 was developed using the network demand forecasts prepared in July 2008 and published in the NMP in September 2008, as discussed in Chapter 10. Due to the cyclical nature of the forecast development program, the capital program which forms ENERGEX's baseline forecast does not include the likely impact and effects of recent events such as the broader and ongoing impacts of the GFC. Further, due to the timing of the baseline forecast it does not incorporate the delivery of ENERGEX's DM initiatives.

ENERGEX's load forecasting review is an annual process which takes approximately three months to complete and which subsequently informs the development of the capital expenditure forecasts. The review is a data intensive process and involves the gathering, analysis, correlation and validation of data prior to the completion of the forward load forecasts. The recent events of the CPRS implementation and GFC impacts will be taken into account in the development of the 2009 forecasts, which are expected to be finalised in July 2009, after the required lodgement date for this *Regulatory Proposal*.

The GFC and delivery of DM initiatives have the strongest impact on the peak demand forecasts and consequently the forecast capital expenditure. The GFC is also expected to have some impact on customer connections, however, due to continued construction activity in SEQ, the GFC influence is difficult to isolate.

The adjustments to the forward program are linked to the impact of the GFC and the outcomes of the DM initiatives. Initial analysis indicates that the majority of market shrinkage or down turn is likely to occur in the *current regulatory control period* and during the early months of the *2010-15 regulatory control period,* prior to economic recovery towards the later part of the period.

ENERGEX had completed preliminary modelling based on a range of possible scenarios using the latest available information to identify the impact of the CPRS and the GFC as well as the delivery of DM initiatives on the forward demand forecast. ENERGEX is using the most recent NIEIR forecast (April 2009) as the basis of this modelling. Our response is to reduce the demand driven component of the capital expenditure program by an amount that is proportional to the anticipated demand reduction arising from these factors. ENERGEX has reduced the baseline capital expenditure by around $45 million ($2009-10) per annum for each year of the *2010-15 regulatory control period*.

ENERGEX is not able to reliably form a view or predict the impact of recent national and international events on the operating expenditure forecast that forms part of this *building block proposal*. The baseline capital expenditure program does inform the operating expenditure forecast and the forecast reliability improvement. This preliminary adjustment, predominantly for the GFC, has not been extended to operating expenditure impacts or reliability and service performance outcomes.

A comparison of ENERGEX's revised capital expenditure forecast against the baseline forecast is set out in Table 11.1.

Table 11.1 Forecast capital expenditure comparison

Year	Baseline data 2009-10 $M	Forecast capex after adjustment 2009-10 $M
2010-11	1,283.0	1,239.5
2011-12	1,313.7	1,269.7
2012-13	1,346.8	1,301.9
2013-14	1,338.2	1,292.4
2014-15	1,407.9	1,362.5
Total	**6,689.6**	**6,466.0**

11.2 Regulatory information requirements

Clause 6.5.7(c)(3) of the *Rules* states, inter alia, that the AER must accept the capital operating expenditure, including in a *building block proposal*, if satisfied that the total forecast capital expenditure reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

The adjusted capital expenditure has been provided in pro forma 2.2.1 in **Attachment 1** and reflected in pro formas 2.2.3 and 2.2.4.

11.3 Global financial crisis

The system demand forecast used for the baseline capital expenditure forecast was published in September 2008 when economic conditions in Queensland were positive and growth was expected to continue on the back of a resources boom. SEQ population growth was forecast to continue to grow at approximately 2 per cent to 2.4 per cent each year for the next 10 years. Queensland GSP growth was expected to continue at 3.5 per cent to 4.5 per cent for the next 10 years.

In late 2008 a significant change occurred with reductions in the availability of funds and the global demand for products and services, which led to international trade slowing down significantly. The International Monetary Fund downgraded global growth forecasts to less than one per cent for 2009. A mid year review of the Queensland GSP in December resulted in a reduction of the growth forecast to three per cent. The expected downturn in the Queensland economy was being countered by state government expenditure on infrastructure and the federal response through the stimulus package. The Queensland government confirmed its commitment to an $18 billion infrastructure program in the State Budget 2009-10[38].

The GFC is an unprecedented event that will have a material but as yet unquantified impact on ENERGEX's forecast capital expenditure, particularly through the impact on customer behaviour both in terms of demand and consumption, as well as new connections. It is not prudent to make any binding assessment at this time and therefore ENERGEX proposes this adjustment approach.

A more comprehensive assessment of the impact of the GFC on ENERGEX's demand forecast and capital expenditure program is currently under way as part of the annual forecast process. ENERGEX anticipates that the level of growth used in the 2008 forecasts will be downgraded in the 2009 forecasts, with a flow-on impact to demand and growth driven capital expenditure.

38 Source: *Queensland Government State Budget 2009-10*, Budget Highlights.

From the information currently available on the timing and extent of the slowdown and the forecast recovery, as well as the continued infrastructure, and residential and commercial development in SEQ, ENERGEX is not able to assess the effect of the GFC beyond investment/expenditure on the sub-transmission network.

11.4 Carbon pollution reduction scheme

The Federal government has signalled the introduction of the CPRS, with the objective to reduce the carbon dioxide equivalent emissions in Australia. This scheme, expected to be introduced in 2011, will have a material effect on the price of electricity in Queensland.

Electricity consumption after the introduction of CPRS is expected to be tempered by two factors. Firstly, through the upward pressure on retail electricity prices, and secondly, by customer responses to the CPRS target of ongoing reductions to the volume of CO_2 gases emitted into the atmosphere. Both of these factors are expected to drive energy efficiency responses and lead to reduced energy consumption. ENERGEX's forecasts for energy consumption incorporated a preliminary view of the impacts of CPRS based on the scheme prior to the May 2009 changes. ENERGEX expects that while CPRS will impact on forecast energy consumption, peak demand growth will not be materially impacted in the short to medium term. The temperature sensitivity of ENERGEX's peak demand indicates that customers will continue to draw a high demand during periods of extreme weather. For these reasons the CPRS impact has been limited to the electricity consumption forecasts which inform only the average network price outcomes. There is no assessment in this section of the input cost impacts and flow through to the capital expenditure and operational expenditure programs of the CPRS introduction.

ACIL Tasman has been engaged by ENERGEX to assist in further analysis of the likely impact of higher electricity prices on energy consumption in SEQ. The analysis will be incorporated as part of the NMP to be published in September 2009.

ENERGEX has included in its baseline forecasts a preliminary view of the impact of the CPRS on energy consumption determined prior to the intended changes announced by the Federal government in May 2009.

11.5 Demand management

ENERGEX has finalised the development of the DM Strategy (included as Chapter 5) and the initiatives that are planned for implementation before or during the *2010-15 regulatory control period* to deliver this strategy. Consistent with Table 5.1 in Chapter 5, ENERGEX is targeting a reduction in the system level demand as a result of these initiatives. These demand reductions were not available at the time the baseline forecast was developed and therefore have been included in this adjustment.

The early stages of the DM initiatives are not anticipated to result in identified deferral of specific capital works projects. Due to the nature of the programs, the demand reduction will be experienced more globally. Compensation for DM expectations has been included in the adjusted overall system level demand forecasts reflective of the broader benefits of the initiatives.

11.6 Methodology for adjustment

The basis for the adjustment of the baseline demand forecast and resultant capital expenditure forecast to accommodate the latest available information in relation to the GFC and its impact on demand and growth driven capital expenditure, as well as the DM initiatives, is outlined below.

The adjustment takes account of:

- long lead times for capital projects and the works currently commenced or programmed for commencement in the forthcoming financial year;
- the lag between the economic slowdown and demand driven capital expenditure and the latent network demand driving ENERGEX's growth program;
- the need to continue the progress toward 'N-1' security standards;
- a balanced risk profile for distribution network assets;
- the need to maintain a smooth investment path in the asset base to ensure ENERGEX is prepared to meet the expected demand when the economic outlook improves;
- 11 kV and LV network growth expenditure is primarily driven by new connections and localised load increases, both of which are expected to return to long-term average levels in 2010-11; and
- the slowdown in the demand forecasts from the baseline position that ENERGEX has calculated to be 549 MW of demand (in excess of one year of the demand driven growth investment in the sub-transmission network).

Based on the above factors, ENERGEX estimates on a preliminary basis that the economic slowdown and the application of the DM initiatives will result in the deferral of a total of approximately $225 million in capital expenditure over five years or around $45 million reduction for each year of the *2010-15 regulatory control period*.

11.7 Impact on baseline network demand forecast

The baseline network demand forecast, discussed at Chapter 10, has been compared with the adjusted forecast for each year of the *2010-15 regulatory control period* as shown in Table 11.2.

Table 11.2 Adjustments to demand forecast (MW)

	2010-11	2011-12	2012-13	2013-14	2014-15
50 PoE peak demand (Table 10.1) (baseline)	5,486	5,767	6,023	6,250	6,490
50 PoE NIEIR April 2009	5,144	5,378	5,700	5,945	6,085
50 PoE demand reductions arising from DM initiatives (Table 5.1)	(18)	(40)	(67)	(101)	(144)
50 PoE adjusted peak demand forecast	5,126	5,338	5,633	5,844	5,941
50 PoE nett reduction in forecast demand	**360**	**429**	**390**	**406**	**549**

The impact of the adjustment is expected to reduce the growth and demand driven capital expenditure, contained in ENERGEX's sub-transmission capital program as discussed in the relevant sections. As yet it is not clear to what extent the GFC will affect customer connections as well as customer initiated work. ENERGEX will continue to monitor and assess the impact on its projects and programs and address this during 2009.

ENERGEX has assessed the impact of the adjusted forecast capital expenditure on the risk profile of the network and is confident the adjusted forecast will meet the capital expenditure objective, namely Clause 6.5.7(a)(1) of the *Rules*. The adjusted forecast capital expenditure also ensures that a smooth investment profile is maintained so that ENERGEX can continue its progress toward 'N-1' security requirements.

ENERGEX will review the capital expenditure forecasts against the updated demand forecast data that will be finalised in July 2009, and quantify the impact on future programs and projects. ENERGEX will address the impact of the 2009 forecasts on capital and operating expenditure forecasts and include relevant information as part of the response to the AER's draft decision.

The adjustments to the demand forecast and the resultant impact on the capital expenditure forecast are set out in Chapter 13.

12 Forecast operating expenditure

The forecast operating expenditure in this *Regulatory Proposal* is required to manage expected demand for *standard control services*, maintain the quality, reliability and security of supply of *standard control services* and maintain the reliability, safety and security of the distribution system. This forecast operating expenditure is also necessary to comply with the applicable regulatory obligations and requirements, including security and reliability obligations arising from the EDSD Review.

This chapter sets out ENERGEX's forecast operating expenditure for the *2010-15 regulatory control period*.

As outlined in the AER's *Final Framework and Approach Paper: Application of Schemes: ENERGEX and Ergon Energy 2010-15*, an EBSS will apply to operating expenditure in the *2010-15 regulatory control period*. The EBSS is discussed at Chapter 17.

12.1 Summary

ENERGEX's forecast operating expenditure has been prepared to:

- efficiently meet or manage the expected demand for *standard control services*;
- maintain the quality, reliability and security of supply of those services;
- maintain the reliability, safety and security of the distribution system; and
- comply with the applicable regulatory obligations and requirements associated with the provision of those services.

The forecast operating expenditure also recognises that ENERGEX's operating environment is heavily influenced by the summer storm season.

ENERGEX's forecast operating expenditure program is $1,843.1 million for the *2010-15 regulatory control period*. This program has been prepared to efficiently deliver the obligations and address the challenges facing the business in the current and future operating environment.

ENERGEX has assessed the high level efficiency of the operating expenditure forecasts in this *Regulatory Proposal* by utilising the revised methodology developed by AER consultant Wilson Cook[39] and accepted by the AER in its final determination of NSW's DNSPs[40].

39 Source: Wilson Cook & Co report, *Review of proposed expenditure of ACT & NSW electricity DNSPs*: Energy Australia's submission of January and February 2009 (March 2009).

40 Source: AER, *Final decision New South Wales distribution determination 2009-10 to 2013-14*, 28 April 2009.

ENERGEX also participated in industry benchmarking undertaken by SAHA International (SAHA), including 10 other NEM DNSPs. In addition to analysis of ENERGEX's performance at the macro level, the SAHA benchmarking provided an assessment of the efficiency of operations related to individual asset categories.

Based on the results of this combination of high level and individual program analysis, ENERGEX submits that the operating expenditure forecasts in this *Regulatory Proposal* compare favourably with the industry benchmark and are therefore efficient.

The breakdown of the proposed operating expenditure program is provided in Table 12.1.

Table 12.1 Operating expenditure forecast for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Network operating costs	25.5	26.8	27.4	28.3	28.9	**137.0**
Network maintenance costs	211.0	215.4	221.0	225.1	228.6	**1,101.0**
Other costs	90.8	90.9	95.1	101.4	94.7	**473.0**
Subtotal operating expenditure	**327.3**	**333.0**	**343.5**	**354.8**	**352.2**	**1,710.9**
Debt raising allowance	7.2	8.1	9.0	9.9	10.7	**44.8**
Equity raising allowance	20.6	19.8	18.8	15.7	12.6	**87.4**
Total operating expenditure	**355.1**	**360.9**	**371.3**	**380.4**	**375.5**	**1,843.1**

Expenditure includes overheads.
Total may not add due to rounding.

The operating expenditure forecasts have been developed based on ENERGEX's historical expenditure, forecast maintenance requirements, proactive improvement of vegetation control, the introduction of broader network demand initiatives and the delivery of the more stringent reliability targets required by the EIC through the MSS.

ENERGEX's forecast maintenance expenditure is based on a detailed knowledge of equipment condition, taking into account an analysis of the risks and consequences of equipment failure.

Self insurance costs have specifically been included in the operating expenditure forecast. These forecasts are supported by detailed actuarial advice.

12.2 Regulatory information requirements

In accordance with Clause 6.12.1(4), a distribution determination is predicated on a decision on operating expenditure in which the AER either accepts the total of the forecast operating expenditure for the *regulatory control period* that is included in the *building block proposal* or does not accept the total of the forecast operating expenditure for the *regulatory control period* that is included in the *building block proposal*, in which case the AER must set out its reasons for that decision and an estimate of the total of ENERGEX's required operating expenditure for the *regulatory control period* that the AER is satisfied reasonably reflects the operating expenditure criteria, taking into account the operating expenditure factors.

Clause 6.5.6(a) of the *Rules* requires a *building block proposal* to include total forecast operating expenditure for the *2010-15 regulatory control period*. This forecast must achieve the operating expenditure objectives in relation to *standard control services* namely to:

- meet or manage the expected demand for those services over the period;
- comply with all applicable regulatory obligations or requirements associated with the provision of the services;
- maintain the quality, reliability and security of supply of the services; and
- maintain the reliability, safety and security of the distribution system through the supply of the services.

In line with Clause 6.5.6(b) ENERGEX's operating expenditure forecast for the *2010-15 regulatory control period* must be prepared to:

- comply with the RIN requirements;
- be for expenditure that is properly allocated to *standard control services* in accordance with the principles and policies set out in ENERGEX's CAM; and
- include both the total and the year-by-year operating expenditure forecasts.

Clause 6.5.6(e) lists 10 operating expenditure factors that the AER must have regard to when assessing ENERGEX's operating expenditure forecasts.

Clause 2.2.2 of the RIN requires ENERGEX to provide the operating expenditure forecasts on a basis consistent with the AER approved CAM.

Clause 2.3.3 of the RIN requires information regarding the key assumptions used by ENERGEX to develop its operating forecasts.

Clause 2.3.11 of the RIN seeks details of self insurance including the reason for self insuring, the value of each insured event, the annual self insurance premium and confirmation of the ENERGEX Board approval.

Clauses 2.3.4 and 2.3.5 of the RIN require ENERGEX to provide information in relation to regulatory obligations and service performance obligations. The operating expenditure forecast takes account of ENERGEX's regulatory obligations and service performance obligations.

Clause 2.3.10 of the RIN requires ENERGEX to detail the cost estimation process, particularly the unit rates and escalators that have been applied to the forecast operating expenditure.

12.3 Key assumptions and other factors

ENERGEX's key assumptions and other factors that underpin its operating expenditure forecasts and details of the independent review of those assumptions and factors are summarised in Table 12.2 and Table 12.3.

Table 12.2 Key assumptions underpinning operating expenditure forecasts

Key assumptions*	Use	External review
Forecast growth for additional network assets and customer numbers	Direct operating expenditure reflects increases in the asset population and customer service costs.	Independently reviewed by Evans & Peck.
Input cost escalation rates (labour, contractor and materials)	Operating costs have been adjusted to reflect cost escalation.	Labour, material and contractor rates were recommended by KPMG and adopted by the ENERGEX Board.
Self insurance costs	The operating expenditure forecasts include an allowance for self insurance costs.	Finity Consulting Pty Ltd recommended certain risks which the ENERGEX Board has resolved to insure.
Forecast resource availability and capability	To ensure ENERGEX has the capability to deliver the operating program.	ENERGEX has developed a resource forecast based on the KPMG Contractor Strategy and internal workforce plans.

** Key assumptions relating to ENERGEX's operating expenditure forecasts are detailed in pro forma 2.3.3 in **Attachment 1**.*

Table 12.3 Other factors underpinning operating expenditure forecasts

Other factors	Use	External review
ENERGEX's 2007-08 operating expenditure is efficient	To demonstrate 2007-08 operating expenditure is an appropriate base year for developing the operating expenditure forecasts.	Independently reviewed by Evans & Peck. Analysis conducted based on Wilson Cook methodology and SAHA benchmarking.
Indirect costs	Operating forecasts include overheads allocated according to ENERGEX's capitalisation policy and the AER approved CAM.	The AER approved ENERGEX's CAM in March 2009.
Debt and equity raising costs	The operating expenditure forecasts include an allowance for debt and equity raising costs.	Debt and equity raising costs recommended by Synergies Economic Consulting (Synergies) have been adopted by ENERGEX.

12.4 Service standards and regulatory obligations

The operating expenditure forecasts in this *Regulatory Proposal* reflect the historical trends and growth in assets resulting from capital investment. They also include the expenditure necessary to ensure the ongoing operation and maintenance of the assets and ensure compliance with regulatory obligations and service standards.

As discussed at Chapters 3 and 9, ENERGEX is subject to various acts and regulations.

The more significant of these relating to operating expenditure include the:

- *Electricity Act 1994;*
- *Electricity Regulation 2006;*
- *Electricity Industry Code 4th Edition 2008;*
- *Electrical Safety Act 2002;* and
- *Electrical Safety Regulation 2002.*

In broad terms the *Electricity Act 1994* and Regulations together with the *Electrical Safety Act 2002* and Regulations set the technical parameters for the safe operation of the ENERGEX network.

The lead document for annual reporting of compliance to the Queensland government in relation to these mandatory requirements is the NMP. The Plan is supported by the Substation Asset Management Policy (SAMP) and the Mains Asset Management Policy (MAMP). These operational documents integrate ENERGEX's mandatory obligations and internal policies to programs and initiatives that ensure ENERGEX meets its regulatory obligations in maintaining the quality, reliability and security of supply of *standard control services*, in addition to maintaining the reliability, safety and security of the distribution system.

ENERGEX's operating and maintenance forecasts are directed by the maintenance strategies and programs detailed in ENERGEX's Network Strategy and summarised in Chapter 4.

ENERGEX has estimated the impact of satisfying new, proposed or incremental externally imposed obligations on the forecast operating expenditures, such as incremental improvement under the MSS, administrative compliance involved with the STPIS, EBSS and the recently gazetted change to electricity regulations to include demand management obligations.

In accord with Clause 3.2.1 of the STPIS, the development of ENERGEX's STPIS reliability targets has considered forecast material improvements in reliability associated with forecast expenditure included in this *Regulatory Proposal*. The incentive schemes to be introduced in the *2010-15 regulatory control period* are discussed in Chapter 17.

Modifications to this funding proposal that impact on forecast reliability will require an associated adjustment to STPIS targets. Hence, ENERGEX will need to recast its STPIS targets to accommodate any adjustments resulting from the AER's final determination of this *Regulatory Proposal*.

12.5 Operating expenditure forecasting methodology

ENERGEX has used a two part process for the development of forecast operating expenditure for the *2010-15 regulatory control period*. This involves building the operating expenditure program using a bottom-up approach and then assessing the resulting forecast against industry accepted efficiency benchmarks as a top down review.

ENERGEX has incorporated the updated methodology used by Wilson Cook in its assessment of the efficiency of operating expenditure forecasts.

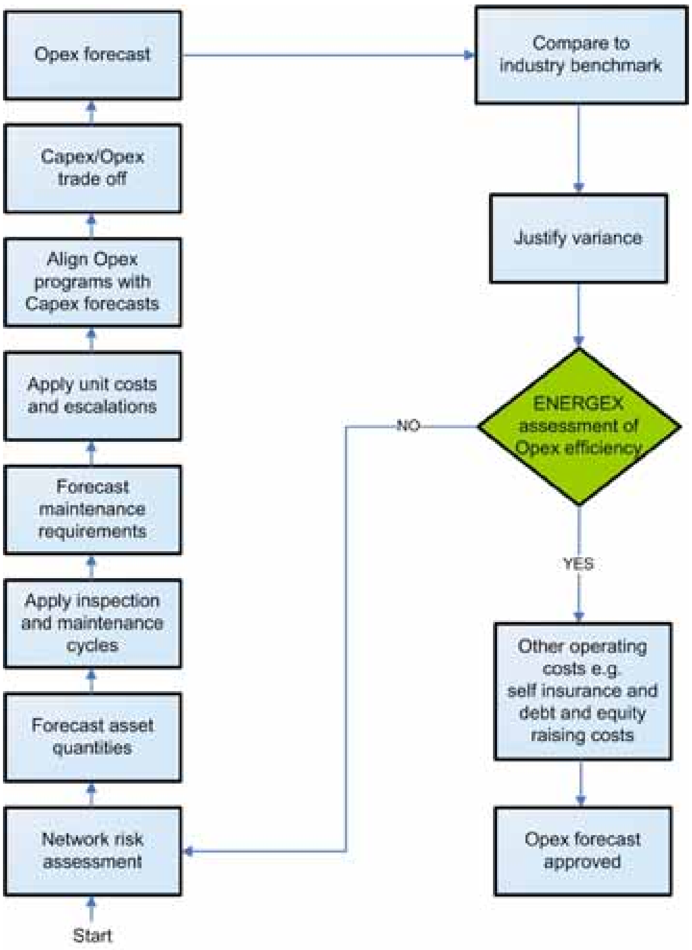
That methodology found a composite size variable comprising customer numbers and line length compared with operational spend provided the best correlation.

Wilson Cook concluded that forecast operating expenditure above the efficiency line indicated an opportunity for improvement.

In addition ENERGEX regularly participates in industry benchmarking studies to ensure its expenditure is comparable with industry efficiency benchmarks. In addition to benchmarking with Australian peers, ENERGEX has also examined international practices with EA Technologies, specifically in the United Kingdom, which has similar networks to ENERGEX. The review of ENERGEX's maintenance policy undertaken by EA Technology Consulting is in **Appendix 12.1**.

The process ENERGEX used to develop its forecast operating expenditure is summarised in Figure 12.1.

Figure 12.1 ENERGEX's operating expenditure forecasting methodology



12.5.1 Process for forecasting operating expenditure

An overview of the key components of the forecast operating expenditure process includes:

<u>Part One – Build operating expenditure program and develop forecast spend</u>

Components of the first part of this process include:

- Preparation of a **network risk assessment** to identify assets and services that require expenditure;
- An analysis of the asset base over the five year period is undertaken to **forecast asset quantities** taking account of the condition of current assets and forecast capital program;
- Apply **inspection and maintenance cycles** in respect to each asset class;
- Calculate an **estimate of maintenance requirements** based on historical equipment failure rates;

- Calculate and estimate **unit costs** for materials, labour and contractors and incorporate escalations as required for the five year period;
- Align **capital and operating programs** of work;
- Identify opportunities for **capital expenditure/operating expenditure trade-offs**; and
- Calculate **operating forecast expenditure** for the *2010-15 regulatory control period*.

Part Two – Assess efficiency of forecast operating expenditure

Components of the second part of this process include:

- Compare expenditure program against **industry benchmarks**;
- Determine the **efficiency of operating expenditure**;
- Investigate and justify any **variance**;
- If the program fails to meet the objectives of the NER at Clause 6.5.6(a) or does not satisfy the efficiency test or has unexplained variance, the program is **resubmitted** for network risk assessment and a re-run of part one of the process; and
- If the forecast operating expenditure is found to be efficient with any variance justified, the program including other operating costs is submitted to the NTC of the ENERGEX Board for endorsement and ultimately to the ENERGEX Board for **approval** as part of the NMP.

ENERGEX's process for development of forecast operating expenditure, based on ENERGEX's Network Strategy, is summarised in Chapter 4. The key internal documents that ensure compliance with our legislative obligations and are used to develop the forecast are the SAMP and the MAMP. These internal documents are relied upon in preparing the NMP, which is the lead document for ENERGEX's annual compliance reporting.

The SAMP and the MAMP define inspection and maintenance periods or cycle times for each type of asset based on legal compliance, manufacturer's recommendations and ENERGEX's CBRM methodology. These policies are used to determine the maintenance work to be carried out each year and are the basis for building up the operating and maintenance works program and budget.

The assets included in the SAMP include:

- 11 kV and 33 kV circuit breakers, reclosers and switches;
- 110/132 kV switchgear;
- transformers and on load tap changers;
- protection systems;
- audio frequency load control equipment;

- RMUs;
- substation property assets; and
- ancillary equipment (including battery systems, emergency back-up and SCCs).

The assets included in the MAMP include:

- 132/110 kV overhead transmission assets;
- 110 kV/33 kV underground transmission assets;
- 33 kV/11 kV/LV overhead distribution assets; and
- 11 kV/LV underground distribution assets.

The forecasts take into account a growing asset base by using projected quantities of assets that will require inspection and maintenance in the *2010-15 regulatory control period.*

ENERGEX's inspection and maintenance programs are based around policies that are documented in both the MAMP and the SAMP.

Both these documents detail the inspection and maintenance programs required for each asset class. As new assets are added to the asset base and older assets refurbished or replaced, the quantities of assets to be inspected or maintained for each program will change. Also, as new assets are installed, different inspection or maintenance programs may be appropriate.

Methods for calculation of asset quantities differ depending on asset type. In the case of large assets such as power transformers the method takes account of the life of individual assets and the assets to be added as part of the annual capital program. For smaller and more numerous assets such as poles and pillars etc, quantities are forecast on the basis of "number of units" or a percentage increase. These forecasts rely on historical trending and are adjusted for significant changes as a result of capital programs.

Cost estimates have also been adjusted for expected real cost increases over the *2010-15 regulatory control period* as discussed in Section 12.9.

Forecast costs are either built up from standard jobs or based on historical costs. Standard jobs are developed for units to be inspected or maintained and are built up from an estimate of the labour and materials required to do this work. The standard jobs are then adjusted based on historical rates, which include average travelling time and efficiencies derived through maintaining multiple assets at a particular site. Examples of standard jobs are inspection of poles, circuit breaker maintenance and cross-arm replacement. The cost for individual categories of work is obtained by multiplying the unit cost by the quantity of assets to be inspected or maintained.

Where a unit cost build up is not applicable to the type of work being undertaken, historical costs for that particular category are obtained and then adjusted for forecast changes. Examples of categories determined from historical costs are corrective repair and storm and emergency repair forecasts.

The actual unit rates for labour used by ENERGEX are built up for different categories of labour based on a fully costed labour rate. Contractor costs are based on tendered rates for the different categories assigned to contractors. Material costs are based on the current average stores cost for the stock item.

The operating and maintenance work is itemised under various budget activity codes and includes the activities of inspection, planned maintenance, corrective repair, network operating costs, emergency response/storms, vegetation, metering, customer services, DM initiatives, levies and other operating costs. These components of the forecast operating expenditure, together with indirect costs, are discussed in the following section.

12.6 System operating expenditure by category

Table 12.4 System operating expenditure forecast for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Network operating costs	25.5	26.8	27.4	28.3	28.9	**137.0**
Inspection	19.2	20.8	22.5	23.3	25.0	**110.8**
Planned maintenance	66.0	65.0	66.9	68.5	69.6	**336.0**
Corrective repair	39.9	41.1	41.4	41.9	42.1	**206.4**
Emergency response/storms	8.6	8.9	9.1	9.3	9.4	**45.2**
Vegetation	77.2	79.5	81.1	82.2	82.5	**402.6**
Metering	14.6	15.2	15.8	16.5	17.1	**79.2**
Customer services (inc. call centre)	21.0	21.9	22.4	23.1	23.6	**111.9**
DM initiatives	24.6	23.2	25.3	30.6	23.2	**126.9**
Total system operating expenditure	**296.7**	**302.4**	**311.9**	**323.5**	**321.5**	**1,556.0**

Total may not add due to rounding.

12.6.1 Network operating costs

ENERGEX's forecast operating expenditure for network operations in the *2010-15 regulatory control period* includes activities required to configure, monitor and operate the network such as:

- high voltage access and isolation switching;
- update and maintain operating panel drawings;
- prepare contingency planning;

- evaluate network incidents;
- manage emergency response;
- reliability of supply investigations;
- power quality investigations;
- Electro Magnetic Field (EMF) investigations; and
- load control investigations.

Network operations expenditure is based on historical quantities and unit costs.

12.6.2 Inspection

ENERGEX's inspection program detects potential defects requiring remedial response as part of the planned maintenance program.

The MAMP and SAMP are the two key internal documents used to develop operating forecasts and set the requirements for ENERGEX's inspection cycles.

The MAMP sets the inspection requirements for ENERGEX's distribution and sub-transmission mains assets. The SAMP sets the intervals, linked to equipment class, for ENERGEX's 250 zone and bulk supply substations and high voltage sub-transmission equipment to be inspected.

In summary, the routine inspection periods for different assets are:

- bulk, zone and urban C&I substations every six months;
- all poles and associated equipment of more than 10 years of age are inspected on a five year cycle;
- pre-storm season patrols by vehicle or helicopter of overhead 33 kV and 11 kV powerlines occur each year;
- thermographic inspection of 33 kV lines is undertaken on a two year cycle with 11 kV lines subject to a five year cycle; and
- LV service pillars on a five year cycle.

In addition, post fault feeder patrols are conducted to ensure safety, reliability targets and obligations are achieved.

Inspection costs for each category of plant and equipment are developed using forecast quantities based on unit costs and inspection cycles.

12.6.3 Planned maintenance

ENERGEX has a pro-active approach to maintenance based on its CBRM methodology. This approach seeks to identify potential defects prior to equipment failure. Planned maintenance is a direct and forecast outcome of the inspection program and key to delivery of supply, reliability, security and safety objectives.

In 2004 the EDSD Review identified vegetation management and cross-arm replacement as areas where underspending had resulted in greater incidences of outages during the storm period than otherwise would be the case.

Planned maintenance costs are built by category as follows:

- forecast quantities based on historical failure rates per units inspected;
- application of unit costs; and
- operating expenditure and capital expenditure trade-offs are considered.

Planned maintenance costs for each category of plant and equipment are developed using forecast quantities based on unit costs and maintenance cycles.

12.6.4 Corrective repair

Corrective repairs are works undertaken after a failure of an asset to either restore the network to a state in which it can perform its required function or render the installation safe to allow planned maintenance or replacement.

The corrective repair is considered complete when the network area has been made safe or returned to service, enabling the restoration of supply.

Forecast expenditure on corrective maintenance has been based on historical costs.

12.6.5 Vegetation

Compliance with safety obligations requires ENERGEX to ensure that clearance zones around powerlines are maintained to prevent contact with electrical equipment likely to result in injury to any person or damage to property.

Vegetation management is a preventative measure that forms a key part of ENERGEX's reliability strategy. The probability of vegetation-related outages increases in sub-tropical regions where foliage is dense and growth rates are high.

The MAMP seeks to minimise the impact of vegetation on public safety, network reliability, quality of supply and network operating costs through a combination of a planned trimming cycle, planned vegetation management to target areas and unplanned vegetation management to manage events triggered by customer requests or network events. To maximise public safety and minimise the risk associated with vegetation around overhead powerlines and poles, ENERGEX has undertaken a successful vegetation management program, which it plans to extend further to the low voltage network in the *2010-15 regulatory control period*.

ENERGEX's vegetation management program attempts to balance the reliability impacts of vegetation growth with community views about acceptable levels of tree clearance. The EDSD Review identified vegetation management as an area where underspending had resulted in greater incidences of outages during the storm period than otherwise would be the case.

ENERGEX committed to ensuring more resources were devoted to this area and a Vegetation Management Plan was implemented to address the entire network with a maximum 2.5 year cycle time.

The MAMP requires the following initiatives:

- pre-storm season asset inspections of 33 kV/11 kV/LV powerlines conducted on an annual basis to identify high priority risk areas in terms of safety and reliability for response;
- planned vegetation programs set a 15-month trimming cycle for high voltage powerlines in urban areas;
- a reduction of the cycle time from 30 months to 15 months for LV spurs in urban areas following a reassessment of re-growth and safety implications;
- a 30-month trimming cycle for rural areas;
- targeted vegetation programs determined by region, to identified high risk areas or as a direct result of post fault feeder patrols; and
- the introduction of a visual tree assessment program to remove potentially dangerous vegetation, outside the normal tree trimming profile, with a high probability of impacting powerlines during storm events.

12.6.6 Emergency response/storms

Emergency response involves repair of damaged equipment and all storm-related repairs.

Because of the unpredictable nature of the initiating events, a long-term historical average number of storm events is used to estimate forecast expenditure in this area.

Costs above this level are then managed through the self insurance and pass through arrangements. Costs covered by ENERGEX's self insurance allowance are discussed in Section 12.7.3. Storm events on the scale of a natural disaster, not covered under the self insurance allowance, will be considered as a specific nominated pass through event as discussed in Chapter 20.

12.6.7 Metering

As part of its *standard control services* ENERGEX undertakes meter reading, network billing and associated data processing for more than 1.3 million residential and small to medium business metered connections to the SEQ network.

The forecast operating expenditure incorporates the following metering activities:

- **Meter reading** – This work includes physical visits to customer premises every three months in most cases and monthly for high usage customers. ENERGEX's meter reading activities are subject to a periodic tendering process to ensure efficient service levels are maintained. ENERGEX's operating expenditure forecasts include costs associated with *standard control services* such as scheduled cycle and final meter reads. Costs associated with *alternative control services*, including other non-cyclic meter reads, relate to fee-based services covered in Chapter 22. ENERGEX's operating expenditure forecasts in relation to meter reading have been based on contractor unit costs and customer number forecasts.
- **Data processing and warehousing** – This work involves the collection of interval data for type 5-7 customers and the conversion of data to consumption reads for network billing. Consumption data collected from the meter reads is uploaded, validated and published to retailers and the market in accordance with NEMMCO requirements. The operating expenditure forecast for metering only includes the proportion relevant to the provision of *standard control services*. Other metering services are provided under other *alternative control services*.
- **Network billing** – The Network Billing group within ENERGEX utilises validated meter and consumption data to generate invoices against National Metering Identifiers, providing a monthly statement to retailers. The metering forecast for this *standard control service* is based on forecast customer numbers.

12.6.8 Customer service

The customer service category of ENERGEX's forecast operating expenditure includes costs arising from the provision of customer services, directly related to the planning, management and operation of the distribution network. It includes ENERGEX's Network Contact Centre as well as customer initiated activities classified as *standard control services*.

12.6.8.1 Network contact centre

In summary, the Network Contact Centre:

- provides services to customers, contractors, retailers and other bodies on distribution-related enquiries and storm and major event responses;
- manages the administration of GSLs;
- provides telephone services to other parts of the business (e.g. access and departure times of contractors and crews to substations for safety audit purposes); and
- manages customer compliments and complaints.

The Network Contact Centre has operated in its present form since April 2008, after the completion of transition arrangements associated with the sale of ENERGEX's retail and gas network businesses. The Network Contact Centre maintains three separate telephone lines for customers to maximise service quality and provide effective communication to incoming callers. They are:

- The general enquiries line relating to general calls such as metering, service order status of retailer initiated services (e.g. new connections and meter reads), tree trimming, high load escorts and compliments/complaints;
- The Loss of Supply (LOS) line is a 24 hour service covering calls about damage to the network, including poles or cross-arms, and customers' loss of supply; and
- The 24 hour emergency line covers emergency and life-threatening calls such as electric shock, fallen powerlines and quality of supply issues such as dim/flickering lights.

Both the general enquiries and LOS lines are answered in the first instance by interactive voice recognition (IVR) and then by a service operator if required.

Emergency calls are routed direct to an experienced officer. To ensure priority service for emergency calls ENERGEX plans to improve this service through the introduction of IVR on this line during peak times to filter non-emergency calls.

The Network Contact Centre also provides separate support lines for electrical contractors and for retailers.

In the year to 30 March 2009, ENERGEX's Network Contact Centre received more than 729,000 calls. The majority of telephone calls or 48 per cent were received on the LOS line. The general enquiries line handled 36 per cent, the emergency line five per cent, while electricity contractors account for one per cent and the retailers 10 per cent.

Outbound communication is effectively delivered through various channels including phone, facsimile, email, IVR, letter, ENERGEX's website and media broadcasts during storm and other outage events.

12.6.8.2 Other customer services

ENERGEX provides services that are initiated by customers and are not generated through retailers. These enquiries relate to the following network services:

- servicing existing customers;
- LOS;
- loss of hot water supply; and
- meter queries.

Customer service costs are based on historical expenditure and, where applicable, on forecast quantities and unit costs.

12.6.9 Demand management

As an organisation, ENERGEX's ultimate goal is to improve the balance between supply-side management involving meeting demand through building capacity into the system and demand-side solutions that focus on reducing demand or the provision of alternative energy solutions.

Key to meeting this goal is the forecast operating expenditure to enable development of practical DM initiatives that maintain required levels of network reliability.

ENERGEX has developed an integrated DM Strategy with the objective to reduce overall system demand by 144 MW over the *2010-15 regulatory control period*.

The initiatives included in the forecast operating expenditure are discussed in detail in Chapter 5.

12.7 Non-system operating expenditure by category

12.7.1 Levies

The major part of ENERGEX's levy forecast is the electrical safety contribution payable under the *Electrical Safety Act 2002*.

The ESO develops and implements legislative compliance and enforcement frameworks to improve electrical safety in Queensland. The ESO also enforces standards for electrical safety and promotes strategies for improved electrical safety performance across the community.

Queensland distributors of electricity are required to make an annual contribution towards the ESO.

ENERGEX's levy forecast for the *2010-15 regulatory control period* has been calculated using the methodology published by the Department of Employment and Industrial Relations in February 2009.

In addition the forecast includes provision for a levy payable under the *Queensland Competition Authority Amendment Regulation (No. 1) 2003.*

12.7.2 Other operating costs

Other operating costs include support costs such as:

- advertising and marketing;
- sponsorships;
- property and operating costs;
- seminar and training expenses; and
- other general expenses.

ENERGEX's advertising and public information is safety focused. As an electricity distributor and as required under the *Electrical Safety Act 2002*, ENERGEX has a responsibility to promote electrical safety. A significant part of this involves educating the community about the dangers of fallen powerlines and ensuring awareness of ENERGEX's emergency telephone contact numbers.

ENERGEX also contributes to the SEQ region by providing sponsorship programs that reinforce the safety message and positively contribute to local communities. There are four main areas that ENERGEX supports through its sponsorship programs:

- safety;
- education;
- energy efficiency; and
- environment.

Property operating and maintenance expenditure includes costs incurred in the management of properties including general maintenance of offices, hubs and depots.

Operating costs include seminar and training services delivered through Esitrain to ENERGEX staff. Esitrain is recognised as an electricity industry leader in technical training and provides certified training programs and specialist trade and post trade technical training in the competencies of:

- high voltage and substations;
- line work and cable jointing;
- metering;
- live line work; and
- safety training.

Other support costs, shown in Table 12.5 include stationery costs, postage and courier costs and audit fees. These costs have been forecast based on historic trends and will remain constant over the *2010-15 regulatory control period*.

Table 12.5 Other support costs forecast for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Other support costs	19.2	18.8	19.3	18.6	17.9	**93.8**

12.7.3 Self insurance allowances

ENERGEX's operating forecasts for the category of other operating costs also include self insurance allowances.

ENERGEX retains the risk and self insures for below deductible risks threshold (i.e. risks below the $1 million policy excess) and for risks where external insurance is not available and/or the insurance premiums are prohibitively expensive.

The specific risks the ENERGEX Board has resolved to self insure, as required under Clause 2.3.11(b) (3) of the RIN, include:

- storm catastrophe – property damage caused by an event that goes beyond the level of ENERGEX's forecast emergency response but is not a declared disaster event;
- public liability – liability claims between $0.1 million and $1.0 million (policy deductible); and; and
- retailer credit risk – insurance in the event of a retailer's failure to meet ENERGEX network charges to a total of $5 million (pass through threshold).

ENERGEX engaged Synergies in partnership with Finity Consulting Pty Ltd to undertake an actuarial assessment of the above risks and to determine the corresponding self insurance premium. Self insurance costs have only been quantified where adequate historical loss data for ENERGEX exists. The review of ENERGEX's self insurance program is provided in **Appendix 12.2** and advice on retailer credit risk in **Appendix 12.3**.

ENERGEX's forecast self insurance costs are summarised in Table 12.6. Supporting information required by the RIN, including the copy of the ENERGEX Board resolutions to self insure, is available in **Appendix 12.4**. The Finity reports, provided in compliance with RIN Clause 2.3.11(b), includes full details of the amounts, inputs, methodology and calculations used to determine these proposed allowances.

Table 12.6 Self insurance costs forecast for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Self insurance	2.8	2.9	3.1	3.2	3.0	**15.1**

12.7.4 Debt raising allowance

Raising debt involves paying finance costs and transaction costs over and above the debt margin allowed in the cost of capital. Such costs are dependent on market conditions.

ENERGEX engaged Synergies to advise on the appropriate forecast for the transaction costs expected to be incurred when raising debt and equity capital. Synergies' report is provided in **Appendix 12.5**.

ENERGEX's debt raising costs included in the forecast operating expenditure for the *2010-15 regulatory control period* are limited to debt raising relating to *standard control services*.

The debt raising cost forecasts proposed by ENERGEX represent the transaction costs for a benchmark gearing ratio of 60 per cent of the value of ENERGEX's RAB. Debt raising costs include both the direct fee charged by an underwriter and the indirect costs associated with issuing debt at a discount in the market in order to sell.

An analysis of infrastructure firms undertaken by Synergies, on behalf of ENERGEX, shows that there is a variety of debt financing options with the pricing of these options differentiated. Consistent with regulatory precedent and information available to the market, Synergies recommended a conservative debt raising cost estimate of 15.5 basis points.

Based on this advice, ENERGEX 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 PTRM results in the debt raising cost forecast is detailed in Table 12.7.

Table 12.7 Debt raising allowance forecast for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Debt raising allowance	7.2	8.1	9.0	9.9	10.7	**44.8**

12.7.5 Debt hedging costs

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 ENERGEX'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 the date of submission of this *Regulatory Proposal* and when the hedging program is likely to be implemented, a forecast of these costs is not included in this *Regulatory Proposal*. ENERGEX will continue to review the costs of a prudent hedging program.

12.7.6 Equity raising allowance

Raising equity incurs costs including direct accounting, legal and broker fees, as well as indirect costs such as underpricing required to ensure the raising of the required level of funds.

ENERGEX engaged Synergies to advise on appropriate equity raising costs. Synergies' recommendation and report detailing the methodology for deriving the cost is in **Appendix 12.5.**

The equity raising cost forecast proposed by ENERGEX represents the transaction cost to maintain the benchmark equity proportion of 40 per cent of the value of ENERGEX's RAB.

Modelling indicates that a corporation with benchmark financing arrangements and with ENERGEX's capital expenditure program would need to raise an amount of $1,030.5 million from external sources to fund capital expenditure required during the *2010-15 regulatory control period*. The cost of raising this additional equity is estimated at $87.4 million.

ENERGEX has included this as an operating expenditure allowance as shown in Table 12.8.

Table 12.8 Equity raising allowance forecast for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Equity raising allowance	20.6	19.8	18.8	15.7	12.6	**87.4**

12.7.7 Insurance costs

ENERGEX has insurance policies with external providers for specified risks. ENERGEX's current insurance program includes a general insurance policy for items including public liability, motor vehicle, personal accident and corporate travel. The excess payable on this policy is $1 million.

ENERGEX's forecast self insurance allowance includes public liability below-deductible claims between $0.1 million and $1 million. ENERGEX still carries a residual risk for claims below $0.1 million (attritional claims) and has forecast these costs as part of network operating expenditure. Forecast costs associated with attritional claims expected to be paid during the *2010-15 regulatory control period* are outlined in Table 12.9.

Table 12.9 Insurance allowance forecast for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
General insurance premium	2.0	2.0	2.0	2.0	1.9	**9.8**
Attritional claims	1.9	1.9	1.9	1.8	1.8	**9.2**
Total	**3.8**	**3.8**	**3.8**	**3.8**	**3.7**	**19.0**

Total may not add due to rounding.

12.8 Substitution between capital and operating program

The efficient use of electrical equipment is key to ENERGEX's prudent and efficient investment asset management practice and central to the assessment of options for expenditure.

The benefits that flow from capital expenditure such as the addition of a modern asset with commensurate performance and low maintenance costs must be balanced against the benefits of operational expenditure including reduced short-term cost by undertaking additional maintenance to extend the life of an existing asset.

ENERGEX has incorporated consideration of the trade-off between capital and operating expenditure in the following ways:

Design and maintenance standards – The building block approach that ENERGEX uses to develop its network has been designed to minimise the whole of life cost of the assets. High maintenance items have been removed from the network by limiting their inclusion at the design stage or by using low maintenance alternatives. Enhanced network outcomes are achieved by the implementation of new equipment designs resulting from advances in technology, such as the use of vacuum switches and tap changers. Overhead power line design has been improved with the use of low maintenance synthetic insulators. Designs have been modified to replace timber cross-arms with steel or light weight poly-composite alternatives or removed altogether with the use of a bundled LV conductor.

Renew, replace or maintain assets – The decision to replace or maintain an asset is supported by the comprehensive CBRM methodology that ENERGEX has implemented. This methodology uses an NPV analysis to determine the optimum time to replace an asset.

This approach has been applied to individual classes of assets including transformers, overhead powerlines and underground cables. It has also been applied to whole sections of the distribution network containing a number of different asset classes.

For example, CBRM methodology has been applied to LV powerlines where detailed analysis shows that rebuilding the overhead lines using a bundled conductor provides better reliability and quality of supply to customers while reducing costs associated with tree clearing and other maintenance.

Equipment specification and purchasing – A key specification for purchase of assets is a requirement to minimise whole of life costs. This assessment criterion is incorporated into ENERGEX's procurement process for evaluating plant and equipment purchases.

12.9 Relative cost inputs

In early 2008, ENERGEX commissioned KPMG to provide an independent and systematic assessment of the escalation rates to be applied in the development of ENERGEX's operating and capital programs for the *2010-15 regulatory control period*.

Costs associated with the operating expenditure forecast have been developed using bottom-up estimates of expenditure in 2007-08 dollars, escalated by the relevant rates as described in more detail in this section and RIN supporting document 2.3.10.

The unprecedented events in the global financial markets have impacted escalation estimates. As this *Regulatory Proposal* was being prepared the Reserve Bank of Australia stated in its *Statement of Monetary Policy*[41] that due to 'the extraordinary circumstances at present, the uncertainty surrounding the forecasts is significant'.

ENERGEX has considered a review of the March 2008 escalation rates against current economic forecasts and adopted escalation rates, based on national indicators of the economic environment that recognise investment in electricity infrastructure requires long-term sustainability and smoothed price path outcomes for customers.

The same overall process has been applied to the development of the forecast capital expenditure requirement discussed in Chapter 13.

12.9.1 Labour escalation rates

In March 2008 KPMG considered the Enterprise Bargaining Agreement negotiations and statistical analysis on available information. KPMG recommended an escalation rate of 5.5 per cent nominal be applied for the *2010-15 regulatory control period*. The rationale underpinning the recommendation is detailed in KPMG's report, detailed in **Appendix 12.6**.

Major factors considered by KPMG were economic forecasts as at March 2008 and ENERGEX's commitment to the ENERGEX Union Collective Agreement 2008.

41 Source: Reserve Bank of Australia, *Statement of Monetary Policy*, February 2009, page 67.

12.9.2 Contractor escalation rates

KPMG recommended that the escalation rates for contractors align with the escalation rate for labour at 5.5 per cent (nominal) reflecting the close alignment between the rates as a key consideration in the finalisation of the ENERGEX Union Collective Agreement 2008.

The KPMG forecast accommodates the remuneration equivalency between members of the contractor workforce and ENERGEX employees, based on the similar skills and experiences required to complete work on the electricity network.

Even though financial market conditions have materially impacted the resource and general labour markets, the availability of skilled labour resources and capability that ENERGEX requires is not expected to improve.

It is further anticipated that capital and operating programs implemented by NSW and other interstate distribution businesses, in addition to ongoing infrastructure development in SEQ, will continue to place pressure on the demand for skilled resources and capability in Queensland's electricity industry.

12.9.3 Material escalation rates

Given the requirement for the long-term sustainability of investment in electricity infrastructure together with the need to retain a smooth path for network charges as ultimately passed through to customers, ENERGEX adopted classes of escalation rates based on known and nationally accepted indicators of the economic environment.

In March 2008 KPMG recommended that ENERGEX adopt an escalation rate of 4.5 per cent nominal for each year of the *2010-15 regulatory control period*.

In light of the uncertainty of current economic conditions and the possible impact of CPRS, ENERGEX sought the advice of KPMG in February 2009. KPMG recommended that, given the fundamental change in economic circumstances and its impact on the commodity cycle, a downward revision of the rate was warranted. This has resulted in an overall reduction in the material escalation rate from 4.5 per cent to Consumer Price Index (CPI) of 2.45 per cent for materials, motor vehicles and plant and equipment.

ENERGEX's escalation rate of 12.65 per cent for construction is based on data from the Australian Bureau of Statistics (ABS) Engineering Construction Activity, Australia, September 2008 with specific reference to the chain volume measures for value of work done in Queensland during the June quarter from 1988-2008. ENERGEX's escalation rate for land is based on data from the ABS Queensland annual land value estimates for residential, commercial and rural from 1989-2007. Further details in relation to the calculation of escalators for construction and land are outlined in KPMG's report in **Appendix 12.7**.

Table 12.10 summarises the forecast material cost escalations that ENERGEX has applied to forecast operating expenditure.

Table 12.10 Material cost escalators by category forecast for the *2010-15 regulatory control period*

Forecast cost	Escalation (nominal)
Materials	2.45%
Construction	12.65%
Land	4.45%
Motor vehicles	2.45%
Plant and equipment	2.45%

ENERGEX will continue to monitor the input data over 2009 and will consider any need for revision of material escalation rates in response to the AER's draft determination.

12.10 Benchmark efficiency

Wilson Cook, as part of their review of the proposed expenditure of the ACT and NSW electricity DNSPs for the revenue determination to be applied from 1 July 2009 to 30 June 2014, developed a methodology to compare different DNSPs based on size. In their report, *ACT & NSW DNSPs Expenditure Review* - *Main Report FINAL, October 2008*, they compared operating expenditure between DNSPs using a number of different measures. The composite size measure based on customer numbers, total network line length and maximum demand gave the best correlation.

Wilson Cook subsequently reviewed its methodology, limiting the composite size variable to customer numbers and line length as well as reviewing its assumptions.

ENERGEX notes that Wilson Cook found that the application of the new method produced results that were not materially different from that used in the original analysis[42].

ENERGEX has used this revised methodology to determine if its forecast operating expenditure is comparable with the industry benchmark. As shown in Figure 12.2 ENERGEX's forecast operating expenditure is efficient when compared with the industry benchmark.

ENERGEX's reported operating expenditure in 2006-07 of $274.5 million included $27.1 million in recoverable work. This work, undertaken for external parties, involves the relocation of ENERGEX assets with costs recovered from the customer.

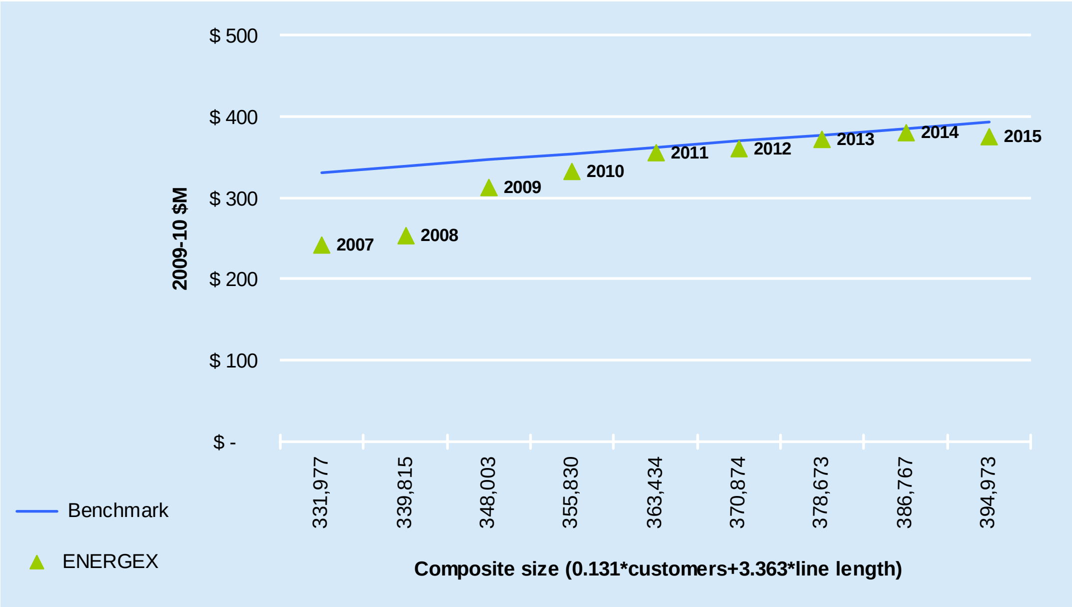
In preparation of its benchmarking findings for electricity distributors, Wilson Cook used ENERGEX's reported operating expenditure, inclusive of recoverable work, and rated ENERGEX on the industry benchmark line.

42 Source: AER, *Final Decision New South Wales distribution determination 2009-10 to 2013-14*, 28 April 2009, page 175.

ENERGEX believes that the nature of recoverable work arrangements place this category of work outside expenditure related to operation and maintenance of the network and has therefore excluded recoverable work costs from its efficiency calculation.

Modelling by ENERGEX using the Wilson Cook methodology and excluding recoverable work costs places ENERGEX below the industry benchmark line for 2006-07.

Figure 12.2 Industry comparison of ENERGEX's forecast operating expenditure



Note: For the purposes of comparison the Wilson Cook benchmark operating expenditure has been escalated from $2008-09 to $2009-10 by CPI of 2.45 per cent. This comparison uses the information provided in pro forma 2.2.2 in ***Attachment 1****.*

Figure 12.2 shows that ENERGEX's operating expenditure is moving toward the industry benchmark as forecast operating expenditure increases to more closely align management of the network with ENERGEX's obligations and EDSD commitment. The operating expenditure also includes a necessary and significant commitment to ongoing environmental sustainability through demand management.

In addition ENERGEX has undertaken a more detailed benchmarking study with the assistance of SAHA, resulting in the report titled *ENERGEX Electricity Distribution Business Operational Expenditure Review* (9 June 2009) in **Appendix 12.8**.

At the macro level SAHA concluded that ENERGEX is achieving operating expenditure performance similar to that of participating DNSPs that were similar in nature[43].

[43] Source: SAHA, *ENERGEX Electricity Distribution Business Operational Expenditure Review*, 9 June 2009, page 19.

SAHA further commented that 'Those areas where ENERGEX has focused expenditure over the period – for example overhead network maintenance – the results in terms of favourable failure rates and increased reliability demonstrate a high level of success of those deliberate programs[44].

The analysis also included benchmarking of operating expenditure for component categories of maintenance, given the major contribution maintenance has to forecast operating expenditure.

SAHA's asset maintenance findings in relation to the two component categories of underground and overhead maintenance were as follows:

- **Underground asset maintenance** – On a raw cost basis ENERGEX was found to have the lowest maintenance cost per kilometre of all participating DNSPs. SAHA noted that analysis of this one indicator of efficiency needed to consider the maintenance regime undertaken by each DNSP[45].
- **Overhead asset maintenance** – SAHA concluded the wide-ranging variability between DNSP costs of maintenance procedures for overhead networks resulted from different expenditure drivers including access and travel times to pole locations, traffic management costs and inspection frequencies. SAHA noted that ENERGEX's significant unit cost increases over the review were the result of deliberate programs of maintenance to rectify an identified deficiency, such as cross-arm replacement. This increased focus on the overhead network resulted in ENERGEX's unit costs rising from a position much lower than the other participants to a position equivalent with the others[46].

Based on the results of this combination of high-level and individual program analysis, ENERGEX believes the operating expenditure forecasts in this *Regulatory Proposal* compare favourably with the industry benchmark and are therefore efficient.

ENERGEX has also undertaken a benchmarking exercise against distribution practices in the United Kingdom, with the assistance of EA Technology Consulting. ENERGEX has adopted the opportunities identified by EA Technology Consulting for improvements of ENERGEX's maintenance policies through CBRM.

44 Ibid, page 19.

45 Ibid, page 36.

46 Ibid, page 38.

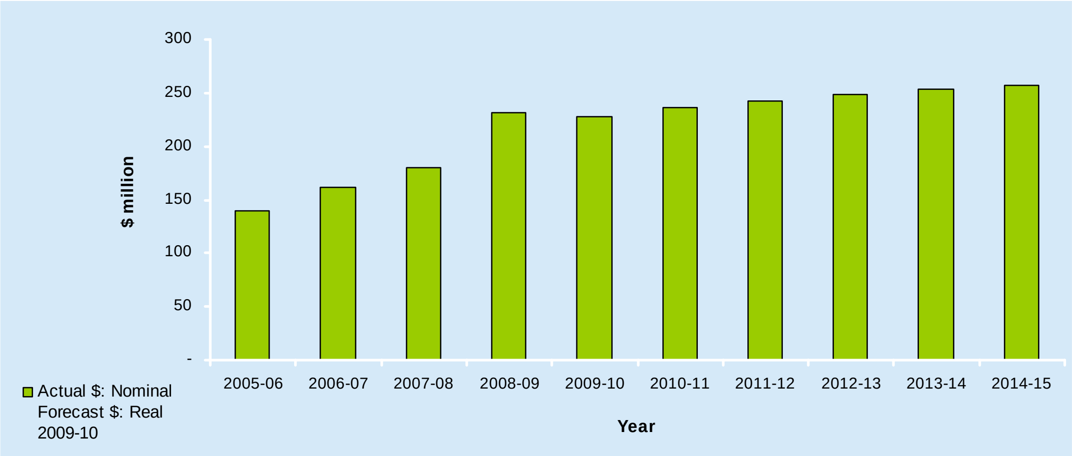
12.11 2007-08 base year

Over the *current regulatory control period* ENERGEX has significantly increased expenditure to deliver the EDSD recommendations. In the operations and maintenance area, this has been achieved by developing programs aimed at improving distribution reliability, developing an effective preventative maintenance program and improving the management of vegetation.

Delivery of these programs has been achieved through deploying ENERGEX's contracting strategy and implementation of a resource strategy that has increased the field workforce to an optimum level. Expenditure in the *current regulatory control period* reflects this ramp up in capability and is in line with that provided for in the *QCA's 2005 final determination* and supplemented by ENERGEX's application for expenditure cost pass through in relation to FRC. ENERGEX's current performance and achievements in respect to this investment are discussed in detail in Chapter 8.

The 2007-08 year represents expenditure that builds a foundation to enable ENERGEX to further increase its capability and progress toward EDSD compliance. As shown in Figure 12.3 the steady build-up in expenditure in the early years of the *current regulatory control period* has been a precursor that places ENERGEX in a position to deliver a 2009-10 operating expenditure outcome that more closely aligns with the forecast operating expenditure included in this *Regulatory Proposal*.

Figure 12.3 Network operating expenditure



Overall, any assessment of variances against the 2007-08 base year needs to be cognisant of significant increases allowed by the QCA to provide the foundation for ENERGEX's progress toward achieving the EDSD obligations. As a requirement of the RIN Section 2.2.4, variances of the 2007-08 base year to the five year average of the *2010-15 regulatory control period* are explained in the following section.

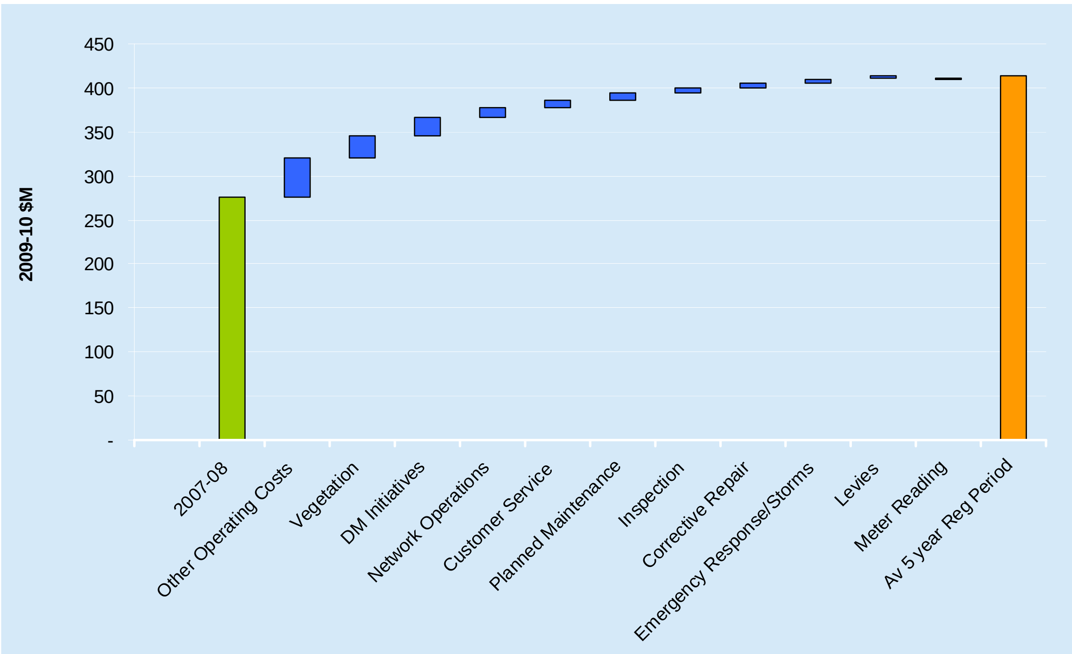
12.12 Variation in expenditure forecasts

The yearly average forecast expenditure for each category in the *2010-15 regulatory control period* has been compared to the 2007-08 base year and variances are have been identified and justified.

This section has relied on the categories identified in the RIN, resulting in the inclusion of some activities that will be *alternative control services* from 1 July 2010.

These variations are shown in Figure 12.4.

Figure 12.4 Variations in operating expenditure from 2007-08 to five year average 2009-10 to 2014-15*



** The five year average includes some alternative control services.*

To calculate the variance ENERGEX has taken the actual expenditure in 2007-08, escalated to 2009-10 dollars, and back cast figures to align with the AER's CAM as approved in February 2009.

A contributing factor to the overall increase in operating expenditure is the real increases incurred in cost terms between the 2007-08 base year and the forecast operating expenditure included in this *regulatory proposal*.

For the purposes of this comparison actual expenditure in 2007-08 has been escalated by CPI but has not incorporated the additional real costs, particularly in labour and contractor costs experienced by ENERGEX to the commencement of 2009-10 and forecast over the *2010-15 regulatory control period*.

These real cost increases have, however, been reflected in the escalation rates used in the development of the forecasts for this *Regulatory Proposal* as discussed in section 12.9.

The main variations in forecast operating expenditure when compared with the 2007-08 base year are itemised in pro-forma 2.2.4 in **Attachment 1**.

In summary, the reasons for variances in system operating expenditure include:

- new programs to progress toward EDSD and legislative compliance;
- maintenance and management of an expanding asset base;
- increased inspection and maintenance programs resulting from the introduction of a condition based risk management approach to asset renewal and refurbishment; and
- forecast customer growth.

The RIN requires major variations to be explained by expense category, other operating expenditure and cost category. ENERGEX's headline explanation focuses on the expense and other operating categories, recognising the flow on effect to the cost category.

12.12.1 Other operating costs

Other operating expenditure included recoverable works which will be an *alternative control service* for the *2010-15 regulatory control period*. The variation is included in this chapter in compliance with the requirement for its incorporation in pro-forma 2.2.4.

While *alternative control service* forecasts are discussed in Chapter 22, ENERGEX advises a forecast increase of $44.9 million is mainly due to relocation of assets for the large number of infrastructure projects ($18.2 million), foreshadowed by local and state authorities, and anticipated to flow from the South East Queensland Regional Plan.

Recoverable works expenditure has a neutral cost impact on the customer base, with project costs funded by the entities that request the work.

A further contributing factor to the variation from the 2007-08 base year in relation to other operating costs is the provision made for a debt raising allowance ($ 8.9 million) and equity costs ($17.5 million) in the forecast operating expenditure for the *2010-15 regulatory control period*.

12.12.2 Vegetation

The variation in the network operating expenditure program of $24 million a year relates to ENERGEX’s vegetation management program.

The increase can be attributed to a revised program to counter re-growth in urban areas following the end of the drought in SEQ, together with the introduction of a visual tree assessment program in the *2010-15 regulatory control period*.

After the return of more typical rainfall patterns in 2008, a review of the 2.5 year cyclic vegetation management program identified safety issues arising from vegetation re-growth in urban areas.

In response ENERGEX has reduced the trimming cycle from 30 months to 15 months for LV urban lines. This program will improve the safety profile of electricity infrastructure in urban areas while at the same time improving reliability for customers serviced by LV lines.

In addition ENERGEX will introduce methods for improved assessment and removal of vegetation, located beyond the nominal clearance zone to improve reliability by targeting vegetation that poses a risk to the network during high wind and storm events.

Vegetation management is undertaken by contractors, subject to competitive tendering arrangements, with operating costs subject to market conditions.

12.12.3 Demand management initiatives

Forecast operating expenditure on demand management also represents a significant variation of $21 million from the 2007-08 base year.

ENERGEX has made a significant commitment to demand management in the *2010-15 regulatory control period*. ENERGEX's ultimate goal is to improve the balance between supply-side management, involving meeting demand through building capacity into the system, and demand-side solutions that focus on reducing demand.

Any alternative must continue to serve the long term interests of consumers in terms of price, quality, safety, reliability and security of electricity supply. ENERGEX has proposed operating expenditure on DM initiatives that provide an overall system reduction in demand and provide a platform for future initiatives that will redress the balance between supply and demand-side response.

Increases in this area against the 2007-08 base year are a direct result of the implementation of key DM programs including:

- k.VA based tariffs;
- enhancement of interruptible load programs (air-conditions and pool pump direct load control);
- hot water optimisation;
- ongoing conversion of tariff 11 hot water to off peak;
- reward based trials and policy development;
- centre for excellence for customer electricity demand;
- demand management for C&I customers;
- energy conservation communities; and
- demand and energy data capture analysis.

A business case has been prepared for each of the DM intiatives.

12.12.4 Network operations

Forecast expenditure on network operations is predicted to increase by $11 million when compared with the 2007-08 base year.

The steady build up in overall operating expenditure from 2007-08 to 2009-10, placing ENERGEX in position to deliver the required outcomes for 2010, has resulted in increased network operating expenditure.

A significant contributor to the increase in expenditure on network operations is the rise in network control costs, resulting from a high loaded network that requires additional maintenance, extensive switching and increased after hours access.

The *Electrical Safety Act 2002* places restrictions on working on live equipment. While this requirement has been in place since 2002, a more rigorous application of the requirement has developed as a result of practical experience with the legislation. The result is a greater requirement to work de-energised and hence an increase in switching and network access costs.

Costs associated with the increased utilisation of mobile generators with larger capacity as a contingency measure for security and reliability compliance during peak load conditions, have also increased when compared to the mild conditions experienced during the 2007-08 base year.

A further reason for the increase is the introduction of a new program to balance the load on LV mains. The program resulted from a review that an imbalance between the three phases on a large number of LV mains was a significant contributor to poor voltage quality. This program is required to ensure compliance with power quality standards.

12.12.5 Customer service

Expenses in the customer service area relate to the contact centre and field response, resulting from customer requests in relation to Loss of Supply, cold water concerns and network related meter queries which result in a yearly average variation of $8.8 million against the base year.

Direct costs savings in the contact centre as a result of the retail sale have been largely offset by the loss of synergies that were previously in place when the costs of the service were shared with the gas and retail businesses.

There are seasonal variations that impact the volume of customer requests in relation to Loss of Supply, cold water concerns and network related meter queries, with cold winters and hot summers incurring increased field costs.

ENERGEX has based its forecast on requests resulting from a more typical weather pattern, than that which occurred in 2007-08 resulting in a variation from the base year.

The forecast for customer service operating expenditure also makes provision for GSL payments. It includes the 30 per cent increase to apply from 1 July 2010, determined by the QCA to preserve their real deterrent value by accounting for the effects of inflation[47].

12.12.6 Planned maintenance and inspection

In the past two *regulatory control periods* ENERGEX concentrated resources on meeting demand for electricity driven by high growth. In the *2010-15 regulatory control period* ENERGEX will increase focus on preventative initiatives in relation to assets that pose potential safety hazards, while continuing toward the security and reliability compliance requirements arising from the EDSD.

The review commissioned by ENERGEX and undertaken by EA Technology Consulting compared the inspection and maintenance intervals and tasks for each asset class against those of other distributors, principally in the UK.

In addition EA Technology Consulting examined recent failure rates with a view to reduce safety risk associated with particular asset classes.

The introduction of CBRM will result in increased expenditure on maintenance and inspections. The adoption of CBRM will result in more frequent inspection schedules and an anticipated increase in maintenance in order to achieve the overall objective of improved asset management and reliability.

Additional initiatives relating to network assets include:

- The introduction of a new compliance-driven program to test substation earth mats on a five-year cyclic program;
- Provision for inspection and maintenance of additional network automation assets installed as part of the move toward a ‘smart network’;
- The extension of ENERGEX’s Thermoscan inspection program, for overhead feeders to LV switch boards, based on increased failure rates;
- A program with renewed focus on testing of protection equipment to achieve compliance after a sustained period where testing and commissioning new assets installed to meet demand received priority;
- The introduction of a targeted program for live line pole topping to improve overhead safety and reduce current cross arm failure rates;
- More rigorous inspections procedures with increased regularity for LV pillars and streetlight panels. Initially samples of the population of both assets will be conducted to ascertain a likely defect occurrence rate;

47 Source: QCA, *Final decision on the Review of Minimum Service Standards and Guaranteed Service levels to apply from July 2010*, April 2009.

- Introduction of a new capital refurbishment option for air break switches, which will see their replacement with metal clad switches that incorporates an opex/capex trade off benefit; and
- Additional funding for diagnostic sampling, testing and analysis to provide key input into the CBRM approach in relation to key asset classes.

The increase in planned maintenance of an average $7.8 million year inspections of $6.3 million, against the 2007-08 base year, is also driven by the growth in the number of assets built in the *current regulatory period.*

12.12.7 Corrective repair

The increase from the 2007-08 base year represents a refinement of internal policy to collate costs previously allocated to storms and emergency to corrective repair.

The average yearly forecast for corrective repair increases by $5.5 million.

ENERGEX recognises that a slow down in the response to meet sustained SEQ growth, presents an opportunity to focus on more cost effective preventative measures rather than corrective repair work.

ENERGEX anticipates that the progressive implementation of CBRM, in combination with the addition of a significant number of new assets as part of the capital program, will result in a reduction in expenditure on corrective repair.

12.12.8 Emergency response/storms

The average yearly forecast for emergency response/storms is $9 million. The actual costs can be volatile depending on the severity of the storm season. The storm season experienced during the 2007-08 base year was an exceptionally mild year with the actual cost for emergency and storm response $4.5 million. By comparison the storm season in 2008-09 was more severe resulting in an actual to date cost of $19.8 million.

ENERGEX's operating expenditure forecast for the *2010-15 regulatory control* period incorporates an average cost for emergency response based on historical actual performance over the last eight seasons and adjusted for transfer of cost to corrective repair.

12.12.9 Levies

The average yearly forecast for levies is $9.2 million. The variation from the 2007-08 base year of $2.8 million results from changes in the methodology mandated for calculation of the ESO and attaining a higher threshold in relation to QCA levies.

The formula for calculation of the ESO levy was amended in the 2008-09 financial year. The impact of this amendment was a step increase of 30 per cent in 2008-09, and then a six per cent annual increase. The increases resulting from the change in methodology have been incorporated into the 2010-15 operating expenditure forecast.

The QCA methodology for calculating the annual levy is based on revenue on a two year lag, with the 2009-10 levy based on revenue reported for 2007-08. ENERGEX exceeded the previous revenue threshold resulting in a 21 per cent increase in the QCA levy in 2009-10. ENERGEX has calculated the future QCA levy requirement using the annual revenue contained in this *Regulatory Proposal*.

12.12.10 Meter reading

Although an explanation for this increase is not required by the RIN, an increase in meter reading expenditure does contribute to the overall variation from the 2007-08 base year.

Meter reading is undertaken by contractors with operating costs subject to market conditions.

An increase in meter reading expenditure also reflects the increase in customer numbers expected over the *2010-15 regulatory control period*.

12.13 Indirect costs

Indirect costs are those costs that are necessarily incurred to support the construction, maintenance and operation of the distribution network and therefore are a component of the provision of distribution and other services. These costs are not directly attributed to a specific activity or service and are therefore allocated on a methodological basis, consistent with previous practice and the AER approved CAM.

For ENERGEX, these costs include common or shared functions that support all distribution services such as:

- corporate support costs including the CEO, Executive Management, Finance, Regulatory Management, Human Resources, Legal and Business Support Services;
- customer services including business support services, customer advocacy, government relations and energy market services;
- environmental, safety management, regulatory and legal compliance;
- information and communication technology (ICT);
- regulatory and legal compliance; and
- training, occupancy, leasing and communications and community activities.

As a distribution only network business, the majority of ENERGEX's indirect costs are allocated to *standard control services*, limiting comparative analysis, particularly with those network businesses that have an associated business (either retail business or gas network business). ENERGEX's indirect costs definition and methodology has remained consistent from the current period to the next *regulatory control period* and therefore comparison with the 2007-08 base year is reasonable.

Indirect costs are allocated to services based on direct spend in accordance with ENERGEX's CAM as approved by the AER.

12.13.1 ICT services

The most material contributor to ENERGEX's indirect costs is the provision of ICT services performed by SPARQ, which is jointly owned by ENERGEX and Ergon Energy and provides ICT services to both businesses. SPARQ is considered a related party under the NEL and ENERGEX has included this nomination in the pro forma 2.3.2 in **Attachment 1.**

SPARQ was launched in 2004 with the amalgamation of the ICT services of both ENERGEX and Ergon Energy with the aim of delivering improvements through economies of scale and integration and co-ordination of ICT services to both distribution businesses.

The three businesses (being ENERGEX, Ergon Energy and SPARQ) jointly developed an ICT investment plan for years 2010-15 (**Appendix 12.9**). This co-ordination is part of the long-term objective of having both ENERGEX and Ergon Energy utilising a common ICT platform with complementary systems that delivers increased benefits. Both distribution businesses developed the ICT program based on specific business needs. Separate ICT regulatory forecasts for ENERGEX and Ergon Energy were developed based on investment initiatives forecast within the joint plan.

In 2008 ENERGEX, in co-ordination with Ergon Energy, commissioned KPMG to perform a review of the efficiency of the ICT services delivered by SPARQ and assess the prudency of the programs and initiatives included in the ICT forecast for the *2010-15 regulatory control period*. KPMG performed these reviews taking into consideration the objectives, factors and criteria outlined in Clauses 6.5.6 and 6.5.7 of the *Rules*.

In relation to the efficiency component of the review, KPMG found SPARQ to be an efficient ICT service provider, with SPARQ outperforming its peers in many of the efficiency indicators. This benchmarking exercise is performed and reviewed annually by the SPARQ Board and the ENERGEX Board.

KPMG concluded, as a result of the prudential component of the review, that:

- a reasonable process was followed to develop the Joint ICT Plan;
- the initiatives in the plan aligned to business needs and broader industry direction; and
- the resulting regulatory forecasts were prudent.

These findings are further detailed in **Appendix 12.10.**

Table 12.11 shows ENERGEX's ICT forecast (in indirect costs) for the *2010-15 regulatory control period*.

Table 12.11 ICT forecast for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Service level agreement	24.9	25.5	26.4	26.9	28.4	**132.2**
Telecommunications	7.0	7.2	7.4	7.7	7.9	**37.3**
Asset usage	43.1	54.7	59.9	56.7	53.4	**267.8**
Project costs	3.7	3.8	3.9	4.1	4.2	**19.7**
Total	**78.8**	**91.3**	**97.7**	**95.4**	**93.9**	**457.0**

Total may not add due to rounding.

12.13.2 Key ICT programs and initiatives

ENERGEX's ICT delivery program for the next *regulatory control period* is based on a five year Joint ICT Investment Roadmap for 2010-15, developed in conjunction with SPARQ and Ergon Energy.

ENERGEX co-ordinates its ICT investments to ensure alignment with the key business objectives and risks through SPARQ. SPARQ provides the vehicle to manage ICT investments jointly through the governance arrangements that are in place between ENERGEX and Ergon Energy to deliver optimal outcomes for their shareholders, the Queensland government.

Key drivers of the development of the capital program are to:

- ensure ENERGEX's ICT capability supports critical and operational business processes and activities through a regular cycle of system upgrades and replacement;
- achieve continuous improvement through managing system changes by facilitating business improvements identified over the course of the year;
- target strategic initiatives that would enhance and improve ENERGEX's business capability; and
- provide and promote ICT investment decisions that assist business alignment initiatives between ENERGEX and Ergon Energy that lead to improved business efficiency.

ENERGEX's core ICT systems have been grouped into a number of high-level business categories in the Joint ICT Investment Roadmap. Investments in the Joint ICT Roadmap are governed by an internal Information Management Steering Committee.

Capital expenditure for ENERGEX's ICT over the *2010-15 regulatory control period* will focus on upgrades/replacements, continuous improvements/enhancements and strategic initiatives underpinning the network vision. These three expenditure areas are discussed below:

- **Upgrades and replacements** – These are directed at refreshing and renewing existing software and hardware platforms. This is non-discretionary expenditure that includes lifecycle costs, patches and ensuring compatibility with other technology environments. Of the $198.9 million SPARQ capital expenditure program, approximately 60 per cent is directed at upgrades and replacements. This work was deferred in the *current regulatory control period* as resources were concentrated on achieving FRC and the Trade Sale requirements and a significant amount of upgrade/replacement.

- **Continuous improvement/enhancements** – These initiatives are directed at advanced capability, reflecting the cyclic nature of software changes and provide additional capability to existing programs. Approximately 23 per cent of the SPARQ capital expenditure program has been allocated for these initiatives over the *2010-15 regulatory control period*. An example of one of these initiatives is the proposed asset inspection upgrade to provide additional functionality in conducting condition analysis of assets such as poles and transformers. It supports ENERGEX's CBRM methodology and is a key part of the inspection, planned maintenance and asset refurbishment programs.
- **Strategic change initiatives critical to the network vision** – These initiatives are directed at achieving the network vision of an automated, remotely managed and maintained network. Key initiatives include the DM foundation platform (to improve ENERGEX's network response capability), a customer relationship management foundation program (to better inform ENERGEX's future network investment decisions) and business intelligence (to improve financial and asset data underpinning network decision-making). Approximately 17 per cent of the SPARQ capital expenditure program across the *2010-15 regulatory control period* has been allocated for these initiatives.

Funding from this *Regulatory Proposal* will support the initiatives detailed in **Appendix 12.9**.

13 Forecast capital expenditure

The forecast capital expenditure in this *Regulatory Proposal* is required to meet or manage expected demand for *standard control services*, maintain the quality, reliability and security of supply of those services, and maintain reliability, safety and security of the distribution system. This forecast capital expenditure is also necessary to comply with applicable regulatory obligations and meet the security and reliability obligations arising from the EDSD Review.

To comply with the timeframe of the regulatory determination process ENERGEX prepared its baseline capital program using 2008 demand and other forecasts. Uncertain economic conditions arising from the GFC and the introduction of CPRS prompted ENERGEX to make a preliminary adjustment to its demand forecast and amend its capital expenditure forecast.

The 2008 forecasts used to develop the capital works program are discussed in Chapter 10, while the methodology used to calculate the adjustment is discussed in Chapter 11.

This chapter identifies the major drivers underpinning this *Regulatory Proposal* and outlines ENERGEX's forecast capital expenditure, including the associated works program, for the *2010-15 regulatory control period*.

13.1 Summary

In compliance with its obligations and in response to network demand, ENERGEX has developed a capital expenditure program for the *2010-15 regulatory control period*. There are four fundamental considerations behind the capital expenditure forecast, namely:

- meeting the growth in customer demand and network connections;
- meeting ENERGEX’s obligations and responsibilities as a distribution business (specifically in terms of security and reliability);
- replacing aged and underperforming network assets; and
- delivery of reliability and power quality obligations.

ENERGEX’s system capital expenditure program has been developed through our network investment process which is governed by the following hierarchy of planning instruments:

- Network Vision (20 year view);
- Network Strategy (five to 10 year view); and
- Network Asset Management Plans as reported annually in the NMP.

Further to this, the capital expenditure factors outlined in the *Rules* are addressed through demonstration of alignment of the proposed program with those objectives, factors and criteria.

To account for an expected reduction in demand as a result of developments in finance and energy markets, ENERGEX adjusted the growth category of the program, resulting in a total forecast capital expenditure of $6,466 million.

A summary of ENERGEX's forecast capital expenditure forecast for the *2010-15 regulatory control period* is included in Table 13.1.

Table 13.1 Capital expenditure forecasts for the *2010-15 regulatory control period*

2009-10 $M	Baseline	Adjustments	Revised
Growth	2,854.9	(241.7)	2,613.2
Asset replacement/renewal	1,154.0	11.4	1,165.3
Reliability and quality of service enhancement	303.3	3.0	306.3
Security compliance	1,815.8	1.6	1,817.4
Total system	**6,128.0**	**(225.8)**	**5,902.3**
End-use computing assets	12.8	-	12.8
Land and buildings	296.2	2.1	298.4
Fleet	196.3	-	196.3
Tools and equipment	56.2	-	56.2
Total capital expenditure	**6,689.6**	**(223.6)**	**6,466.0**

Total may not add up due to rounding.

Expenditure on the categories of growth, security compliance, replacement and refurbishment of assets and reliability account for 90 per cent of ENERGEX's capital expenditure forecast.

Funding is considered annually as part of the Queensland government required SCI (12-month view) and SCP (five year view) process. These documents in **Appendix 13.1** and **Appendix 13.2**, receive the approval of the ENERGEX Board and the endorsement of shareholders. The SCP and SCI ensure adequate funding for the forecast capital expenditure.

ENERGEX's proposed forecast capital expenditure focuses on a continuation of the current response to electricity demand through constructing and renewing assets. It also ensures investment in accepted technologies that modernise the existing infrastructure to provide a smart network and establish capability for effective demand-side responses for the future.

A number of strategic projects have been included to demonstrate the link between the capital program and the communities of the regions that will benefit from their completion.

13.2 Regulatory information requirements

In accordance with Clause 6.12.1(3), a distribution determination is predicated on a decision on capital expenditure in which the AER either accepts the total of the forecast capital expenditure for the *regulatory control period* that is included in the *building block proposal* or does not accept the total of the forecast capital expenditure for the *regulatory control period* that is included in the *building block proposal*, in which case the AER must set out its reasons for that decision and an estimate of the total of ENERGEX's required capital expenditure for the *regulatory control period* that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors.

Clause 6.5.7(a) of the *Rules* requires a *building block proposal* to include total forecast capital expenditure for the *2010-15 regulatory control period*. This forecast must achieve the capital expenditure objectives in relation to *standard control services* namely to:

- meet or manage the expected demand for those services over the period;
- comply with all applicable regulatory obligations or requirements associated with the provision of the services;
- maintain the quality, reliability and security of supply of the services; and
- maintain the reliability, safety and security of the distribution system through the supply of the services.

In line with Clause 6.5.7(b) ENERGEX's capital expenditure forecast for the *2010-15 regulatory control period* must be prepared to:

- comply with the RIN requirements;
- be for expenditure that is properly allocated to *standard control services* in accordance with the principles and policies set out in ENERGEX's CAM; and
- include both the total and the year-by-year capital expenditure forecasts.

Clause 6.5.7(b)(4) requires ENERGEX to identify forecast capital expenditure that is for an option that has satisfied the *regulatory test*.

Clause 6.5.7(e) lists 10 capital expenditure factors that the AER must have regard to when assessing ENERGEX's capital expenditure forecasts.

Clause 2.2.1 of the RIN requires ENERGEX to provide the capital expenditure forecasts on a basis consistent with the AER approved CAM.

Clause 2.2.3 of the RIN requires ENERGEX to provide information on material projects or programs that have been or are expected to be undertaken in the current regulatory period and/or forecast to be taken in the next regulatory period.

Clause 2.2.4 of the RIN requires ENERGEX to identify and explain significant variations in the forecast expenditure.

Clause 2.3.3 of the RIN requires information regarding the key assumptions used by ENERGEX to develop its capital forecasts.

13.3 Key assumptions and forecasting method

ENERGEX's key assumptions and other factors that underpin the capital expenditure forecasts and independent review of those assumptions and factors are summarised in Table 13.2 and Table 13.3.

Table 13.2 Key assumptions underpinning capital expenditure forecasts, requiring directors' certification

Key assumptions	Use	External review
Forecast growth for demand and customer numbers	Used in the development of the capital expenditure forecasts.	Demand forecasts validated by independent forecasts prepared by NIEIR. Customer numbers recommended by NIEIR.
Input cost escalation rates (labour, contractor and materials)	Capital costs have been adjusted to reflect cost escalation.	Labour, material and contractor rates were reviewed by KPMG.
Forecast resource availability and capability	Ensures ENERGEX has the capability to deliver the operating program.	Internal expertise and contract resources reviewed by KPMG.

** Key assumptions relating to ENERGEX's capital expenditure forecasts are detailed in pro forma 2.3.3 in **Attachment 1**.*

Table 13.3 Other factors underpinning capital expenditure forecasts

Other factors	Use	External review
Age and condition of assets	Used as a key input to develop asset and renewal and replacement forecasts.	Review of CBRM methodology by EA Technology Consulting.
Unit rates reflective of efficient costs and derived from competitive tendering	Used in formulating capital expenditure forecasts.	Independently reviewed by Evans & Peck.

13.4 Security compliance, service standards and other regulatory obligations

As discussed at Chapter 9, ENERGEX is subject to various acts and regulations.

The more significant of these relating to capital expenditure include the:

- *Electricity Act 1994;*
- *Electricity Regulation 2006;*
- *Electricity Industry Code 4th Edition 2008;*
- *Electrical Safety Act 2002; and*
- *Electrical Safety Regulation 2002.*

In broad terms the *Electricity Act* and Regulations together with the *Electrical Safety Act* and Regulations set the technical parameters for the safe operation of the ENERGEX network.

The lead document for annual reporting of compliance with the EIC in relation to these mandatory requirements is the NMP.

ENERGEX also has an obligation to meet and manage demand. The component of forecast capital expenditure that ensures ENERGEX has the capacity to meet the demand for supply over the *2010-15 regulatory control period* is discussed in Section 13.7.1.

ENERGEX's forecast capital expenditure has also been developed to move toward security compliance, a requirement arising from the EDSD Review, discussed in more detail in Chapters 3 and 9.

In summary the EDSD Review recommended ENERGEX adopt planning processes that apply a deterministic 'N-1' planning philosophy to sub-transmission feeders and bulk supply and zone substations. A revision of the security planning guidelines for the practical application of the 'N-1' approach is currently being considered by the technical regulator. ENERGEX has based the capital expenditure forecast included in this *Regulatory Proposal* on the revised security planning guidelines.

The security planning guidelines used to develop ENERGEX's forecast capital expenditure for the *2010-15 regulatory control period* are available in **Appendix 4.2** and **Appendix 4.3**, while the category of security compliance is discussed in Section 13.7.2.

Fundamental to maintaining services at the required standard is a cost efficient asset refurbishment and replacement program. The detail of its contribution to ENERGEX's forecast capital expenditure is considered in Section 13.7.3.

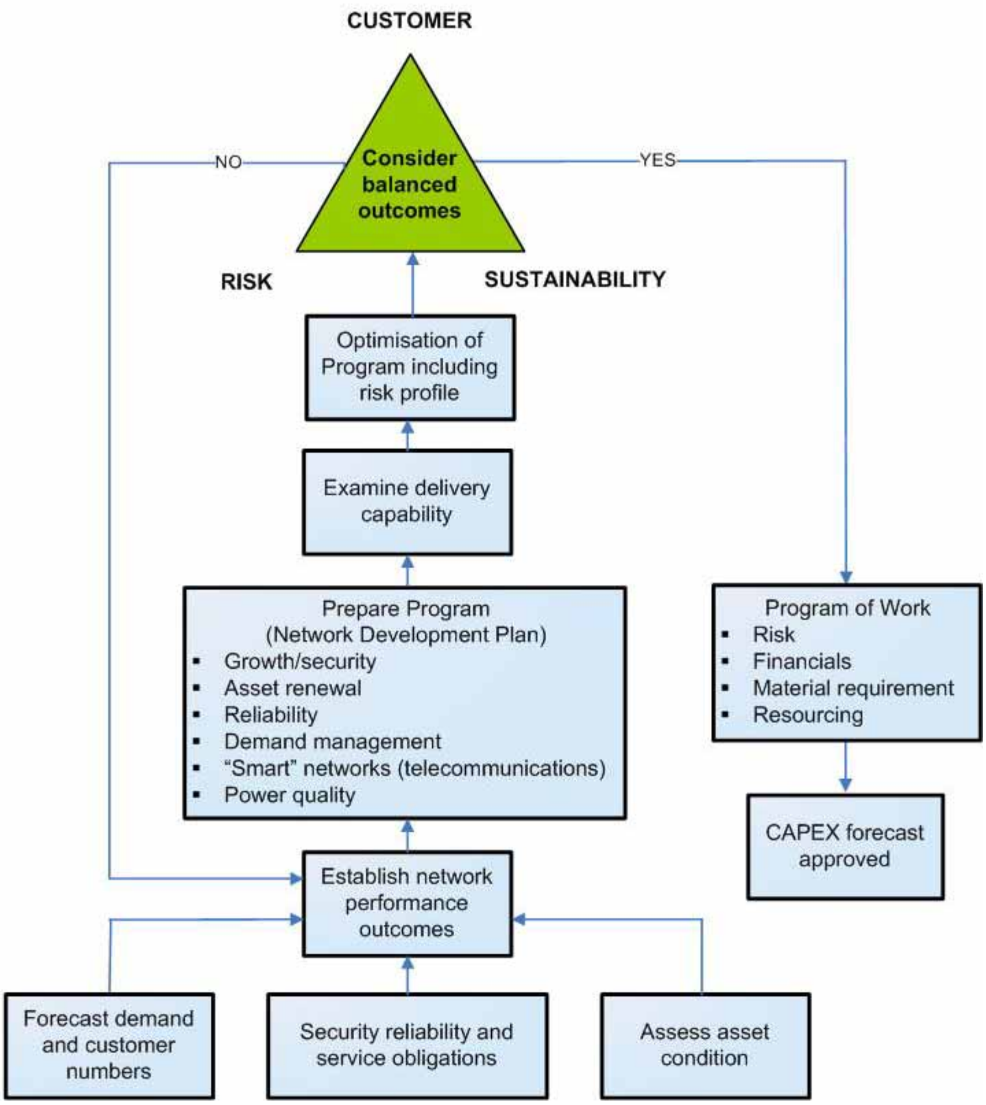
Included in the forecast capital expenditure are a number of reliability projects and programs to ensure ENERGEX meets the MSS under the EIC. These standards are discussed in detail in Chapter 9 and examples of the programs and projects included in the expenditure category are detailed in Section 13.7.4.

Specifically ENERGEX's forecast capital expenditure has been developed to meet the capital expenditure objectives in the *Rules*, factors and criteria.

13.5 Capital expenditure forecasting methodology

ENERGEX's capital expenditure forecasting methodology takes a 'bottom up' approach, developing a program on a project basis that meets demand, security compliance, and reliability obligations, taking account of asset condition. The process, as shown in Figure 13.1, incorporates ENERGEX's balanced outcomes decision model to ensure the forecast capital expenditure also delivers to the organisation's objectives.

Figure 13.1 Process for forecasting capital expenditure



An overview of the key components of the forecast capital expenditure process includes:

- Preparation and consideration of the **major inputs** to development of the works program being:
  - forecast demand and customer numbers;
  - security and reliability obligations; and
  - loads and condition of current assets.
- **Establish network performance outcomes** to deliver security standards and reliability, in addition to the key result areas reported to government as part of the SCP. These organisational targets include areas such as safety performance, responsibilities to the environment, financial outcomes and commitments to customers as well as obligations to the community.
- **Prepare program** though the application of ENERGEX's network strategies to build a Network Development Plan that addresses the drivers of growth, security, asset renewal, reliability, demand management, modernisation of the network and power quality. At this stage a strategic estimate is prepared (the full estimation process is outlined at Section 13.5.1) and capital and operating expenditure trade-offs are considered. The costing of a high-level estimate for the program includes application of unit costs, escalations and consideration of the cost of financing. The program is then consolidated into a seven year PoW.
- **Delivery capability** is examined with resources needed for the program reviewed to ensure outcomes are deliverable in the required time-frames.
- **Optimisation of the program** to achieve target outcomes including evaluation of the risk profile.
- The organisation then considers the program against the **balanced outcomes** decision model, weighing up customer expectations and the risk profile against sustainable financial imperatives.
- If the program fails to satisfy the legislative requirement and balanced outcomes model, the program is **resubmitted** to review the network performance outcomes.
- If the program provides a balanced outcome and meets the objectives of the NEL in terms of Clause 6.5.7(a), a detailed works program is developed. At this stage network risk is revisited, the material and resourcing requirements are identified and financials are finalised.
- The forecast capital expenditure is submitted to the NTC of the ENERGEX Board for endorsement and ultimately to the ENERGEX Board for **approval** as part of the NMP.

13.5.1 Estimation process for capital projects

ENERGEX's estimation process for individual projects provides the platform for the development of forecast capital expenditure. Project estimates are considered at key stages in the planning, design and construction process.

ENERGEX uses an estimating computer program that is part of its Ellipse ERP package. Ellipse has an integrated suite of products that includes finance, works management, human resource management, purchasing, inventory management and estimation capability.

Following more than 50 years experience in management and construction of electricity infrastructure, ENERGEX has developed economically efficient standard designs for substations, overhead powerlines and underground cables. These designs are the building blocks used in the construction of the network and are periodically tested and reviewed against market and industry development.

Individual components (i.e. civil works, isolators etc.) are assembled to form compatible units (i.e. transformer bays), which in turn are built up into standard building network blocks (i.e. zone substations). This bottom-up approach ensures all labour, material and contract work is included in the compatible units.

A project scope is developed by selecting the appropriate building blocks to deliver the required network solution and the project estimate is developed from the building block estimates.

The Ellipse estimation system is used to prepare specific estimates for various stages in the planning, design and construction process. Strategic estimates are prepared at the outset of the program, a project approval estimate is undertaken and a further estimate is undertaken if variation from the approved estimate is required.

Strategic estimates are used to compare potential project options that overcome network constraints. Risk factors such as site conditions for substation civil work and rock in trenching for underground cables are accommodated by allowing for the most likely scenario based on previous experience. Strategic estimates are used to produce forecast capital requirements in the three to 10 year timeframe.

Project approval estimates are developed from detailed planning analysis of individual network limitations and they are used for formal approval of capital expenditure. Risk factors are managed by detailed site investigation into soil condition or the amount of rock in the underground cable route. Project approval estimates are used to forecast capital requirements in the zero to three year timeframe.

Variation estimates are used to seek re-approval for current projects where known factors make it likely that the original approval will be exceeded. Variation estimates are used to forecast capital requirements in the zero to one year timeframe.

Projects are programmed and managed and progress is monitored in the Primavera project management system. The Primavera system consolidates individual projects and estimates into the works program that contributes to the overall capital expenditure forecast.

13.6 Capital expenditure asset categories

A brief description of ENERGEX's capital expenditure categories is provided below.

Categories for capital expenditure related to system assets are:

- **Growth (demand-related projects) –** capital expenditure with the primary purpose of meeting the increase in demand or additional load within the network, prior to security compliance becoming binding.
- **Security compliance** – capital expenditure with the primary purpose of meeting 'N-1' security standards. Projects in this category address network limitations that breach security standards at the time of preparation of the capital forecast.
- **Asset renewal and replacement –** capital expenditure with the primary purpose of maintaining the existing level of supply and standard of service by replacement or renewal of assets that are no longer capable of delivering their designed purpose or where the net present cost of maintaining the asset exceeds the replacement cost.
- **Reliability enhancement –** capital expenditure with the primary purpose of addressing network reliability requirements.

The non-system capital expenditure category includes capital expenditure not directly related to the construction or replacement of system assets but which supports the operation of the regulated network business. Non-system assets include vehicles, offices and depots, land, and buildings.

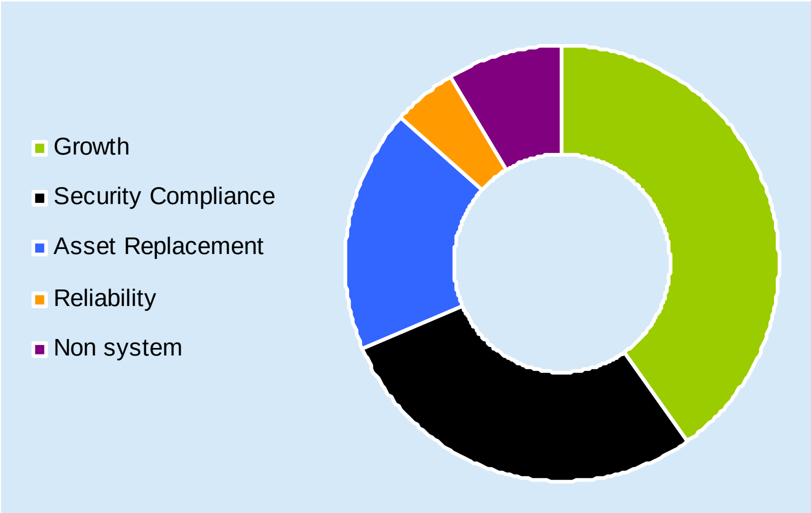
End-use computing assets capital expenditure includes lap tops and end-user personal computers. Mainframe and infrastructure costs are included in ICT expenditure by SPARQ, which is discussed at Chapter 12.

Irrespective of the primary driver for a project, the interconnectivity of the electricity network results in flow-on benefits for the whole system. For example the commissioning of a new substation in response to growth will typically provide down-stream benefits for the system in terms of security compliance and reliability. Similarly the provision of new infrastructure prompted by asset replacement is likely to have benefits for reliability, while at the same time provide supply switching capability that provides flexibility to cater to growth on the network.

For the purpose of this *Regulatory Proposal* ENERGEX has nominated a primary driver for expenditure for each project. However, the overall benefits that a particular project provides have been incorporated into network planning, with particular reference to the security and reliability plans.

The main components of the proposed capital program for the *2010-15 regulatory control period* are illustrated in Figure 13.2.

Figure 13.2 Forecast capital expenditure by category for the *2010-15 regulatory control period*



Growth accounts for 40 per cent of the program, while security compliance contributes 28 per cent. Expenditure on replacing and refurbishing assets accounts for 18 per cent and reliability expenditure five per cent. The remaining nine per cent consists of non-system capital expenditure to support the operation of the business.

Growth, security compliance, replacement and refurbishment of assets and reliability expenditure account for 90 per cent of ENERGEX's capital expenditure forecast.

13.7 Drivers for capital expenditure by category

Drivers for network expenditure are considered in line with each of ENERGEX's relevant network strategies including:

- network development;
- network reliability;
- demand management;
- asset renewal;
- maintenance;
- power quality; and
- smart networks – telecommunications and SCADA.

The integrated nature of electricity infrastructure results in programs that fall into two or more expenditure categories. For example, the smart network program has expenditure elements in growth, compliance, asset renewal/replacement and reliability.

13.7.1 Meeting growth in demand

The total growth capital in the forecast comprises augmentation works resulting from demand growth and customer connection capital is $2,854.9 million.

ENERGEX's Network Development Strategy sets out how the network is planned to meet or manage forecast demand growth. The growth in forecast demand drives augmentation works and the resulting capital expenditure forecast.

The baseline forecast capital expenditure related to demand growth comprises:

- bulk supply and zone substations – $508 million;
- 110 kV and 33 kV overhead lines and underground cables – $300 million;
- 11 kV lines and distribution equipment – $911 million; and
- communication and other works – $52 million.

This forecast has been adjusted, as outlined in Chapter 11, to address the anticipated reduction in demand arising from recent finance and energy market developments. Changes to the timing of specific projects will be prepared as part of ENERGEX's annual planning process and is expected to be reflected in its 2009-10 NMP in September 2009. The adjusted forecast capital expenditure used to prepare this *Regulatory Proposal* (exclusive of design and construction of large customer connections) is $1,519 million.

ENERGEX expects to continue to connect over 25,000 customers each year. Domestic customers are connected to new underground subdivisions in urban areas and by extending the overhead network in rural and semi-rural areas. The design and construction of connection assets for larger C&I customers is an *alternative control service* and this has been excluded from this forecast. However, design and construction of connection assets for most C&I customers and the connection to the network of all C&I customers is classified as a *standard control service*. The capital to design and construct connection assets and connect customers including providing services and metering is forecast at $1,094 million.

If ENERGEX is not funded to meet this growth, deferral of these nominated projects will impede ENERGEX's progression toward security compliance.

The adjusted total growth forecast for the *2010-15 regulatory control period* is $2,613.2 million.

Major projects are discussed in Section 13.16.

13.7.2 Security compliance

ENERGEX has identified network infrastructure (bulk supply and zone substations, sub-transmission lines and cables and 11 kV feeders) that did not meet security compliance standards at the time the capital program was prepared.

Forecast capital expenditure in this category is based on projects to augment the network and reduce loading on lines and substations to a level such that failure of one component does not result in a sustained outage to customers. The total security compliance forecast for the *2010-15 regulatory control period* is $1,817.4 million. This comprises:

- bulk supply and zone substations $652 million;
- 110 kV and 33 kV overhead lines and underground cables $499 million;
- 11 kV lines and distribution equipment $656 million; and
- communication and other works $10 million.

These works are required to address security compliance and cannot be scaled back to accommodate any reduced demand forecast. Security compliance-based projects must proceed to ensure progress continues toward the 'N-1' planning philosophy put in place through the EDSD and reported to the technical regulator through the NMP.

13.7.3 Renewal and replacement of ageing asset base

This section describes the capital expenditure required to address the age profile of ENERGEX's infrastructure and modernise the network to meet 21st century electricity needs.

ENERGEX has a significant number of assets that were installed in the 1960s and are approaching the end of their forecast life. In addition, large quantities of assets installed in the 1980s are moving into the latter part of their forecast life and, depending on service conditions such as the need for high loading during periods of peak demand, require refurbishment or replacement.

In accordance with its Asset Renewal Strategy, ENERGEX undertakes detailed analysis of the network assets using the CBRM methodology. The results of the analysis lead to the development of a comprehensive program to replace higher risk assets prior to anticipated failure.

Asset renewal is co-ordinated with the growth and security compliance program and assets that are not addressed through these programs are included in the asset replacement and refurbishment program.

Forecast capital expenditure in the asset renewal and refurbishment category also includes projects that not only meet the core challenges facing our electricity infrastructure but also position ENERGEX to better respond to its emerging challenges.

An effective, fully-integrated, secure, and reliable communications infrastructure is an essential network component. The creation of a high-speed, two-way communications channel is the first step in developing an ICT enabled participative and connective network.

Currently serviced by multiple systems, ENERGEX has identified capital projects to progressively update its communications capability by overlaying the existing network with proven and interactive telecommunications technology and developing a smart network.

The forecast capital expenditure component dedicated to asset renewal and replacement is $1,165.3 million.

A summary of the key components of this work includes:

- Compliance with the Code of Practice - Works provisions relating to maintenance of supporting structures for powerlines that require a pole failure rate of less than one in 10,000 per annum. ENERGEX has developed a comprehensive inspection and testing program to identify poles that are likely to fail. Depending on condition, poles are either refurbished by nailing or rebutting to extend life or replaced – $234 million.
- Programs targeting equipment on the distribution network including 11 kV RMUs, air break switches, pole mounted plant and replacement of timber cross-arms with wide trident steel supports. In addition a replacement program has been developed to address the unacceptable failure rate at the tee joint to the service pillar of LV Consac cable. Low voltage open wire mains on timber cross-arms are also being replaced as part of a capital expenditure/operating expenditure trade-off that also improves safety and reliability – $292 million.
- Refurbishment of identified 11 kV feeders – $131 million.
- Replacement and refurbishment of 11 kV circuit breakers, feeder protection, reclosers and regulators to modernise the network as part of the smart network program – $37 million.
- A program targeting aged C&I substations – $16 million.
- Replacement and refurbishment of sub-transmission 33 kV and 110 kV lines – $161 million.
- A program focused on bulk supply and zone substation plant, including transformers, switchgear and ancillary equipment – $159 million.
- Refurbishment and replacement of obsolete and ageing telecommunications and SCADA equipment – $135 million.

13.7.4 Reliability enhancement

This section describes the capital expenditure required to ensure that the average and individual feeder reliability performance remains within the levels mandated in the MSS.

The programs included in the expenditure forecast have been developed in line with ENERGEX's Reliability Improvement Strategy, as discussed in Chapter 4, and total $306.3 million over the *2010-15 regulatory control period*.

A summary of the key components of this work includes:

- Improved 11 kV distribution network reliability by upgrading existing feeders and building new feeders to improve performance and reduce the number of customers affected by an outage – $171 million.

- Targeted programs directed at installing short sections of poorly performing overhead feeders underground; extending underground sections to achieve a reduction in the number of overhead to underground transition points, causing failures; improvement of reliability to critical infrastructure such as hospitals and sewerage pumping stations – $32 million.
- Installation of nine new rural substations to divide the rural distribution network into smaller sections, improving rural reliability by the provision of additional power switching options. This program has added benefits of providing additional capacity and improving power quality on the rural network – $39 million.
- Installation of additional switches on rural 11 kV feeders to reduce the number of customers affected during an interruption, allowing faster restoration where transfer capacity is available. Included in this work is the installation of communication systems as part of the smart network program to enable remote control of these field devices – $36 million.
- Other works such as the installation of distance-to-fault relays on 33 kV rural feeders, wildlife proofing of the 11 kV network and older exposed busbar rural substations and replacement of unreliable sub-transmission assets – $28 million.

13.7.5 Non-system capital expenditure

The non-system capital expenditure forecasts for the *2010-15 regulatory control period* provides for investment in:

- property assets;
- vehicle fleet and associated plant;
- field response tools, equipment and plant; and
- End-use computing assets.

For the *2010-15 regulatory control period*, ENERGEX will be adopting a Property Strategy which includes expansion, upgrade or replacement of existing facilities to meet operational needs, alleviate overcrowding and improve field response capability.

The strategy recognises that in a 10-year period, even though the number of employees has increased, the number of depots has decreased from 28 in 1997 to 18 in 2009.

ENERGEX's proposed capital expenditure on property will address the following major concerns:

- extensive use of temporary accommodation;
- increased safety risks resulting from multidisciplinary uses of existing depot and office facilities; and
- restricted office and depot facilities, and aged equipment.

In summary the forecast capital expenditure on property for the *2010-15 regulatory control period* takes account of the long-term forecasts outlined in the Queensland government's South East Queensland Regional Plan 2009-31 and includes:

- replacement of three major amenities including logistics and warehousing, training and pole depot facilities;
- construction of a centrally located new purpose-built facility, providing accommodation that minimises health and safety risks with improved field response capability to ENERGEX's south west regions;
- construction of five new regional administration centres to reduce pressure on current regional field response facilities due to expanded multidisciplinary utilisation and to minimise health and safety risks;
- acquisition of land and construction of seven unmanned sites for secure storage of critical spare parts and heavy machinery in close proximity to customers in remote locations or with high service level requirements to improve operational efficiency and response time;
- replacement of three smaller depots; and
- upgrading existing sites.

This has contributed to an increase in the non-system capital requirement. Other elements of the non-system capital requirement include fleet, plant, tools and equipment. The forecast for fleet is limited to the replacement of existing vehicles, consistent with the forecast staff requirements.

Forecast expenditure on tools and equipment is derived from equipment testing and inspection management systems and includes the acquisition and replacement of hand-held tools and safety equipment.

Forecast expenditure on computing assets is based on the objective of maintenance of software and hardware technologies at supported versions to ensure service sustainability, application stability and reduction in servicing costs.

The non-system capital expenditure for the *2010-15 regulatory control period* is limited to asset replacement based on compliance with ENERGEX's ICT asset renewal guidelines and principles for laptop, desktop and toughbook computers.

The major expenditure in relation to ICT is incorporated in ENERGEX's arrangements with SPARQ, which is discussed Section 12.13.1.

13.8 Security compliance status

Progression toward security compliance is non-discretionary expenditure accounting for 28 per cent of forecast capital expenditure for the *2010-15 regulatory control period*.

In the course of the development of the NDP, ENERGEX analysed the risk profile associated with the program.

In line with the supply security standards, ENERGEX considered the risk based on two scenarios for each year of the *2010-15 regulatory control period*:

- the Emergency Cyclic Capacity (ECC) load at risk, which is essentially the raw load at risk measured in MV.A, if a fault were to occur in a component on the sub-transmission network; and
- the residual ECC load at risk, which is the load that cannot be supplied after transfers of load are affected in line with the timeframes contained within the revised supply security standards.

ENERGEX's risk analysis takes into account projects scheduled in the remainder of the *current regulatory control period* and the additional transfer capacity those upgrades of the network provide. ENERGEX has also considered the security program being undertaken at bulk supply points by Queensland transmission company Powerlink.

The forecast capital expenditure contained in this *Regulatory Proposal* will substantially improve ENERGEX's network risk profile. Risks have been calculated using September 2008 demand forecasts and documented contingency plans. The risk profile is discussed in relation to:

- bulk supply substations;
- zone substations; and
- 110/132 kV and 33 kV feeders.

Bulk supply substations – The proposed capital program is expected to reduce the raw ECC load at risk at bulk supply substations from 571 MV.A in 2010-11 to around 302 MV.A in 2014-15. Load at risk, taking account of allowable transfers, reduces from 135 MV.A to 7 MV.A.

Zone substations – The proposed capital program is expected to reduce the raw ECC MV.A at risk from 982 in 2010-11 to 580 in 2014-15. Load at risk, taking into account load transfers, will effectively halve (444 MV.A to 213 MV.A).

Feeders – Feeders have an improving risk profile with the majority of risk managed through operational strategies. The proposed capital program is expected to reduce the residual ECC load at risk on 33 kV feeders from 636 in 2010-11 to 241 in 2014-15.

The risk analysis is based on significantly reducing the number of bulk supply substations, zone substations and sub-transmission feeders that are not compliant with the 'N-1' security standard.

In assessing ENERGEX's expenditure program on behalf of the Queensland Competition Authority (QCA), in 2006 consultants WorleyParsons found that 'the ENERGEX's network fell short of meeting the standards detailed in the EDSD Review' and comments that even with the additional funds provided under the capital expenditure pass through, the network was unlikely to achieve the full suite of EDSD outcomes by 2010.

Due to the continued need to meet and manage demand and growth, ENERGEX is not yet in a position of full EDSD compliance. This forecast capital expenditure is needed, irrespective of forecasts for demand and growth, in order to progress toward security compliance.

13.9 Forecast capital expenditure program

In the course of the development of this *Regulatory Proposal* ENERGEX recognised that uncertainty in relation to the impact of the GFC and to a lesser extent the introduction of CPRS would affect ENERGEX's forecast capital expenditure.

ENERGEX has made a preliminary assessment of the impact of these events based on current information and adjusted the forecast capital expenditure using the methodology outlined in Chapter 11.

ENERGEX developed the baseline capital expenditure forecast using the network demand forecasts prepared in July 2008 and published in the NMP in September 2008.

ENERGEX's baseline forecast capital expenditure is summarised in Table 13.4.

Table 13.4 Capital expenditure (baseline) forecast for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Growth	463.7	504.7	581.2	618.9	686.4	**2,854.9**
Asset replacement/ renewal	159.0	253.2	210.8	277.4	253.6	**1,154.0**
Reliability and quality of service enhancement	85.0	50.1	71.9	51.1	45.3	**303.3**
Security compliance	383.9	381.5	384.9	327.7	337.9	**1,815.8**
Total system*	**1,091.6**	**1,189.4**	**1,248.8**	**1,275.1**	**1,323.2**	**6,128.0**
End-use computing assets	3.2	4.3	1.3	1.8	2.2	**12.8**
Land and buildings	142.1	67.3	44.0	18.4	24.5	**296.2**
Fleet	32.8	41.8	42.0	32.3	47.4	**196.3**
Tools and equipment	13.3	10.9	10.7	10.6	10.7	**56.2**
Total capital expenditure**	**1,283.0**	**1,313.7**	**1,346.8**	**1,338.2**	**1,407.9**	**6,689.6**

** Includes capital contributions for assets in the RAB.*
*** Expenditure on ICT is discussed in Chapter 12.*
Total may not add up due to rounding.

Due to the lead time required to develop the works program, ENERGEX was unable to revise the entire program using the adjusted demand forecasts.

Based on information in May this year, ENERGEX's view was that the GFC would have an impact on growth expenditure, which is contained in ENERGEX's sub-transmission program. Subsequently, forecast expenditure in the growth expenditure category has been adjusted.

As a result ENERGEX has adjusted forecast capital expenditure to defer a total of approximately $225 million capital over five years or a reduction of about $45 million for each year of the *2010-15 regulatory control period*.

ENERGEX will consider the capacity requirement and timing for individual projects based on actual localised demand for electricity as part of its annual planning process, which is reported in the NMP.

The adjustment to growth expenditure impacted the distribution of indirect costs. Costs have been reallocated to the adjusted figures in line with the AER approved CAM.

The forecast capital expenditure used in the PTRM for this *Regulatory Proposal* is summarised in Table 13.5.

Table 13.5 Capital expenditure (post adjustment) forecast for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Growth	416.7	457.0	533.0	569.3	637.2	**2,613.2**
Asset replacement/renewal	160.5	255.7	212.9	280.2	256.0	**1,165.3**
Reliability and quality of service enhancement	85.8	50.6	72.6	51.6	45.7	**306.3**
Security compliance	384.0	381.6	385.0	328.1	338.6	**1,817.4**
Total system*	**1,047.1**	**1,144.9**	**1,203.6**	**1,229.2**	**1,277.5**	**5,902.3**
End-use computing assets	3.2	4.3	1.3	1.8	2.2	**12.8**
Land and buildings	143.0	67.8	44.4	18.5	24.7	**298.4**
Fleet	32.8	41.8	42.0	32.3	47.4	**196.3**
Tools and equipment	13.3	10.9	10.7	10.6	10.7	**56.2**
Total capital expenditure**	**1,239.5**	**1,269.7**	**1,301.9**	**1,292.4**	**1,362.5**	**6,466.0**

** Includes capital contributions for assets in the RAB.*

*** Expenditure on ICT is discussed in Chapter 12.*

Total may not add up due to rounding.

ENERGEX's proposed capital expenditure program of $6,466 million for the *2010-15 regulatory control period* has been developed to meet the key network challenges of growth, security compliance, refurbishment/replacement of assets and reliability.

It has been prepared in accordance with the robust network planning and governance processes to ensure a prudent and efficient capital spend.

An external review and verification of the capital program has been carried out by Evans & Peck.

ENERGEX has assessed the impact of the adjusted forecast capital expenditure on the risk profile of the network and is confident the adjusted forecast will meet the capital expenditure objective, namely Clause 6.5.7(a)(1) of the *Rules*. The adjusted forecast capital expenditure also ensures that a smooth investment profile is maintained so that ENERGEX can maintain progress toward 'N-1' security requirements.

13.10 Delivery capability

ENERGEX has responded to historical and ongoing growth in addition to increasing regulatory and security obligations through the application of forecast capital and operating expenditure as part of this *Regulatory Proposal* for the *2010-15 regulatory control period*.

ENERGEX's demonstrated performance over the *current regulatory control period* reflects its ability to implement strategies that will deliver record capital and operating programs. These outcomes were achieved through integrating strategies including the management of ENERGEX's people, contracts, procurement and design standardisation.

Designs for new transmission lines and substations are highly standardised and ENERGEX has incorporated these into its network building block. This has delivered benefits in regards to design resources, construction and project commissioning as well as for procurement (standard equipment contracts able to be negotiated at efficient market prices).

The introduction of FFA, in addition to improved despatch processes, has further enabled the capacity of ENERGEX's field resources.

A continuation of ENERGEX's integrated, multi-faceted approach will be instrumental in delivering the 2010-15 works program and ENERGEX intends to consolidate and refine these strategies to capitalise on previous success.

13.10.1 People strategy

The availability and capability of resources is fundamental to delivery of these programs. ENERGEX is well aware of the challenges of recruiting and retaining a skilled workforce in the current economic climate, having undertaken significant recruitment programs both nationally and internationally over the past five years. ENERGEX's People Strategy (2005-10) supported this recruitment program and the development of the internal workforce.

More than 400 additional tradespersons have been recruited since 2004 as a result of the accelerated tradesperson recruitment program, an increase in tradespersons of approximately 85 per cent. Further, ENERGEX recruits approximately 100 new apprentices annually and has about 330 apprentices undergoing training at any one time[48]. ENERGEX considers that the size of its current internal workforce is optimal for a business of this size and, supported by appropriate contract resources and supplementary processes, will be able to deliver on the forecast PoW. Hence, over the *2010-15 regulatory control period*, ENERGEX has forecast internal staff numbers to stabilise with slight increases in 2010-11 and 2011-12 while the contracting strategy is expanded.

ENERGEX's People Strategy for 2010-15 will focus on maintaining this capacity as well as support increased capability. Ongoing workforce programs such as the tradesperson recruitment program and the apprentice program as well as para professional traineeship programs, graduate programs and technical skills programs will continue to be directed at the retention and development of the required staffing capability. Strategic support from external contracting resources will enable ENERGEX to efficiently deploy its internal resources into critical technical areas, e.g. cabling, substation design and control and protection systems, whilst maintaining service levels across the business.

ENERGEX has used contract labour in a number of areas over the *current regulatory control period* to support delivery of the PoW. These contracting arrangements allow appropriate deployment of internal resources to maximise benefit from the internal skill and capacity base. These contractors are allocated batch work that can be clearly defined, is independent of daily operational activities and is largely autonomous.

Examples of work categories with identified lead times that are suitable for batching of work include:

- vegetation;
- street lighting (*alternative control services*);
- design and construction of substations;
- design and construction of overhead lines;
- design and construction of underground cables; and
- inspection of assets.

48 Apprentice training averages 3.5 years and numbers vary between 280 and 350 apprentices dependent on the recruitment/graduation cycle.

13.10.2 Contracting strategy

In preparation for the *2010-15 regulatory control period*, ENERGEX engaged KPMG to review the existing Contracting Strategy (developed in 2005) and conduct an assessment against the forthcoming works program. KPMG's report is included in **Appendix 13.3**. Supported by the delivery of the 2005 Contract Strategy, ENERGEX has made significant progress with the expansion of both its internal and external resources. After its review, KPMG concluded that ENERGEX is able to secure the resource capability and capacity necessary to deliver the forecast works program through the adoption of the initiatives and action set out in the Contracting Strategy.

ENERGEX's revised contracting framework:

- builds on the strengths of the current arrangements through consolidation of the supplier base and resultant long-term efficiencies;
- focuses on skills gaps and future resource needs;
- targets 'on-time and to standard' contracting services; and
- aligns service contract performance to ENERGEX's business objectives.

These overarching strategies focus on the capacity of current contracts, the availability of specialist skills and the deployment of existing internal resources. A key initiative to support these strategies is the refinement of internal processes, particularly in regards to scheduling, despatch of work and the ENERGEX/contractor interface.

13.10.3 Strategic procurement

As part of the contract review process, ENERGEX has reviewed the operation of current contracts to improve efficiency by providing longer term forecasts of work requirements and batching individual jobs into larger programs.

The objective of the Contracting Strategy is to ensure ENERGEX is able to attract and retain contractors, achieve the best possible contract rates and ensure quality of work.

Consistent with KPMG's previous and recent recommendations, ENERGEX is transitioning from short-term contracts in existing service areas to longer term arrangements that apply to a broader number of services and provide balanced, common outcomes which are alliance-based.

The longer term view of the work program is to provide for greater certainty and transparency of work to contractors.

ENERGEX has been an industry leader in establishing a Performance Management Framework that ensures ENERGEX and the supplier receive value from the contract.

This Performance Management Framework is being enhanced to cover the broader range of contracts in place and those planned for the future.

ENERGEX also has an established contractor management framework, supported by legal arrangements, for the engagement of suppliers that meet qualifications in relation to factors such as safety, quality, environment, skills competency and authorisations. An enhancement to the framework will be the inclusion of a 'pre-qualification' step in its procurement process to streamline the engagement of reliable resource providers.

ENERGEX applies its strategic procurement methodology to materials and service contracts. This approach includes the assessment of the market and commodity type, and applies the most appropriate procurement strategy to achieve best market value for ENERGEX.

13.11 Relative cost inputs

In developing the forecast capital expenditure ENERGEX applied the same escalation rates for labour, contractor and materials as were used to prepare the forecast operating expenditure.

These rates are summarised in Table 13.6.

Table 13.6 Escalation rates used to forecast capital expenditure for the *2010-15 regulatory control period*

Category	Escalation (nominal)
Labour	5.5%
Contractor	5.5%
Materials:	
– Materials	2.45%
– Motor vehicles	2.45%
– Plant and equipment	2.45%
– Construction	12.65%
– Land	4.45%

13.12 Funding the forecast capital expenditure

ENERGEX as a Queensland government owned corporation is required to comply with a number of policies codes and guidelines issued by Queensland Treasury (Office of Government Owned Corporations).

In compliance with the Code of Practice for Government Owned Corporations' Financial Arrangements, ENERGEX seeks a requested allocation of funds annually under the State Borrowing Program. This requested allocation is consistent with the SCI, submitted to the Shareholding Ministers on an annual basis and accompanied by the SCP.

ENERGEX's SCI sets out the matters for the current and following financial year while the SCP covers the next five financial years.

The forecast operating and capital expenditure included in the SCP 2009-10 to 2013-14, is consistent with this *Regulatory Proposal*. The SCP includes forecasts of borrowings and equity injections in line with the relevant policies, codes and guidelines. The Shareholding Ministers will continue to assess the capital funding requirements on an annual basis to determine the appropriate capital requirements for the annual SCI.

The Queensland Treasurer will now assess the reasonableness of ENERGEX's and other requests made under the State Borrowing Program and inform ENERGEX of any borrowing limits prior to the commencement of the 2009-10 financial year.

13.13 Variation in expenditure forecasts

13.13.1 2007-08 base year

Over the *current regulatory control period* ENERGEX has significantly increased expenditure to deliver the EDSD recommendations. In the capital works area, this has been achieved by developing programs aimed at meeting network demand, complying with security and reliability obligations and replacing assets.

Expenditure in the *current regulatory control period* reflects this ramp up in ENERGEX's capital program and is in line with that provided for in the *QCA's 2005 final determination* and supplemented by its final decision on ENERGEX's application for capital expenditure cost pass through in March 2007. ENERGEX's current performance and achievements in respect to this investment are discussed in detail in Chapter 8.

The 2007-08 year represents expenditure that builds a foundation to enable ENERGEX to further increase its capability and progress toward its network objectives.

As shown in Figure 13.3 the steady build-up in expenditure in the early years of the *current regulatory control period* has been a precursor to placing ENERGEX in a position to deliver a 2009-10 capital expenditure outcome that more closely aligns with the forecast capital expenditure included in this *Regulatory Proposal*.

Figure 13.3 Network capital expenditure

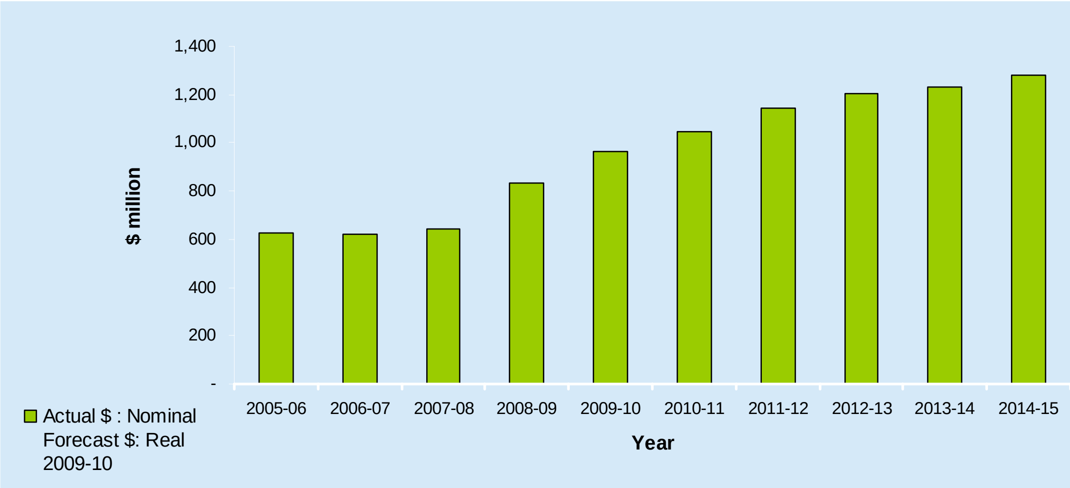


Figure 13.3 shows that ENERGEX's capital expenditure is increasing to meet its network requirements and progress toward security compliance, as outlined in Section 13.8.

Overall, any assessment of variances against the 2007-08 base year needs to be cognisant of significant increases allowed by the QCA to provide the foundation for ENERGEX's expenditure to meet demand growth and progress toward EDSD compliance. As a requirement of the RIN pro forma 2.2.4, individual variances arising from comparison with the 2007-08 base year are explained in the following section.

13.13.2 Alignment of categories to allow comparison with the 2007-08 base year

To enable like-for-like comparison of past expenditure with future expenditure, ENERGEX has mapped the categories used to describe forecast capital expenditure in this *Regulatory Proposal* with the categories formerly used by the QCA.

Table 13.7 shows the mapping between the categories.

Table 13.7 Alignment of QCA and ENERGEX capital expenditure categories

QCA category	ENERGEX category
Asset replacement	Asset replacement/refurbishment
Customer initiated capital works	Growth
Corporate initiated capital works (part)	Growth
Corporate initiated capital works (part)	Security compliance
Reliability/quality improvement	Reliability
Other	Other
Non-system assets	Non-system assets

13.14 Variations by expenditure category

The RIN requires variation from the 2007-08 base year to be explained by:

- asset category;
- expenditure purpose; and
- cost category.

ENERGEX's headline explanation focuses on the expense purpose category, recognising the flow on effect to the asset and cost categories. To ensure consistency with current regulatory arrangements ENERGEX has explained the variation aligning the QCA categories as outlined in Table 13.7.

13.14.1 Asset replacement/refurbishment

Asset replacement capital expenditure has substantially increased based on the *current regulatory control period*. High demand growth experienced in SEQ for a number of years has resulted in capital expenditure programs primarily focused on meeting demand.

ENERGEX has now increased focus on the condition of its population of 1960s' assets approaching the end of their forecast life. In addition large quantities of assets installed in the 1980s are moving into the latter period of their forecast life and require refurbishment or replacement, depending on service conditions such as high loading.

After detailed analysis of the network assets using the CBRM methodology, a comprehensive program of replacing higher risk assets prior to anticipated failure has been developed.

This has resulted in an average $164 million per annum increase in asset replacement and renewal.

Forecast capital expenditure over the *2010-15 regulatory control period* will allow the replacement of many assets of poor condition and also those that have a nameplate age of more than 30 years. In this regard the forecast capital expenditure program provides for the replacement of:

- more than 62 power transformers;
- in excess of 7,533 kV underground cables;
- approximately 1,800 kilometres of overhead conductor;
- more than 580 circuit breakers;
- about 220 protection relays; and
- over 14,000 LV and 7,000 11 kV poles.

13.14.2 Corporate initiated augmentation

The growth in the corporate initiated augmentation capital expenditure category in 2007-08 is driven by growth to meet network demand and security compliance. ENERGEX has scaled back forecast capital expenditure on demand growth by $242 million as a result of the revised demand forecast using the methodology outlined in Chapter 11.

Security compliance work, however, is forecast to increase to an average of $363 million each year of the *2010-15 regulatory control period*. ENERGEX considers this category is non-discretionary expenditure required to ensure continued progress toward the EDSD 'N-1' security standard.

The annual average expenditure for corporate initiated capital works is up $308 million from the 2007-08 base year, mainly as a result of the security compliance work.

13.14.3 Reliability

Reliability capital expenditure in the *current regulatory control period* has also been overshadowed by the need to spend on demand growth.

For the *current regulatory control period* reliability improvements have been achieved mainly through improved maintenance and vegetation management expenditure. However, to continue to meet the improving MSS targets, capital expenditure is required to improve reliability by installing fault isolating devices in the network, building small rural substations and rebuilding rural overhead lines. These projects improve reliability and reduce the number of customers affected by a single fault.

Reliability expenditure increases on average by $41 million per annum when measured against the 2007-08 base year as a result of additional focus in this area.

13.14.4 Non-system assets

The $62 million increase over the 2007-08 base year in this category is mainly due to expenditure increases for programs and projects summarised in Section 13.7.5.

The additional expenditure will ensure the replacement of aged equipment, address the extensive use of temporary accommodation and manage and mitigate safety and health risks in the workplace that have arisen from the rapid increase in the workforce to deliver the required record programs of work.

Overall the non-system asset expenditure increase is mainly to align non-system assets to a standard so as to continue to support the delivery of record levels of capital and operating expenditure.

13.15 Efficient non-network alternatives

ENERGEX has a program to promote growth in non-network alternatives as part of its DM Strategy.

Over time expenditure on demand management will allow growth in the range of economically efficient alternatives available to defer network augmentation and reduce capital expenditure. ENERGEX is also committed to the regulatory arrangements that promote non-network alternatives.

In compliance with Clause 5.6.5A of the *Rules*, ENERGEX's planning process includes application of the *regulatory test*.

The *regulatory test* is an important planning and consultative tool that promotes economically efficient investment in the electricity grid and provides a framework whereby the economic contribution or feasibility of network augmentation proposals can be assessed. It also ensures that non-network solutions are considered.

13.16 Material projects/programs

Major projects represent 52 per cent of the total proposed capital program. In summary, the planning of capital expenditure projects takes into account the varying characteristics of each region and their development.

The following section provides examples of major projects included in forecast capital expenditure for the *2010-15 regulatory control period*. ENERGEX considers the requirement for individual projects based on actual localised demand for electricity as part of the annual planning process, with the outcome reported in the NMP. This analysis determines the commencement date for projects based on updated network requirements.

ENERGEX manages the distribution network by dividing SEQ into six hubs which include:

- Central West;
- Metro North;
- Metro South;
- South Coast;
- North Coast; and
- Western.

13.16.1 Central west hub

The Central West hub encompasses Brisbane CBD and the inner city suburbs, stretching from Mount Glorious in the north, to Ellen Grove in the south and to the CBD in the east.

The culmination of steady growth in the economy, stimulating business enterprise and rises in residential demand, spurring inner city renewal and urban infill have led to a requirement to reinforce the backbone of the network that services Brisbane CBD and surrounding suburbs.

To address this increased demand ENERGEX embarked on a program in the early 2000s to steadily replace the 33 kV network in the city area. The network was initially constructed to transform electricity from 110 kV bulk supply points to 33 kV and then to 11 kV, prior to distribution on the LV network.

To meet growth in demand ENERGEX has developed a series of projects that will provide a direct high capacity in-feed to the CBD and surrounding suburbs by transforming electricity from 110 kV directly to 11 kV. This work involved construction of new 110-11 kV substations, installation of 110-11 kV transformers and connecting feeders to complete the network circuit.

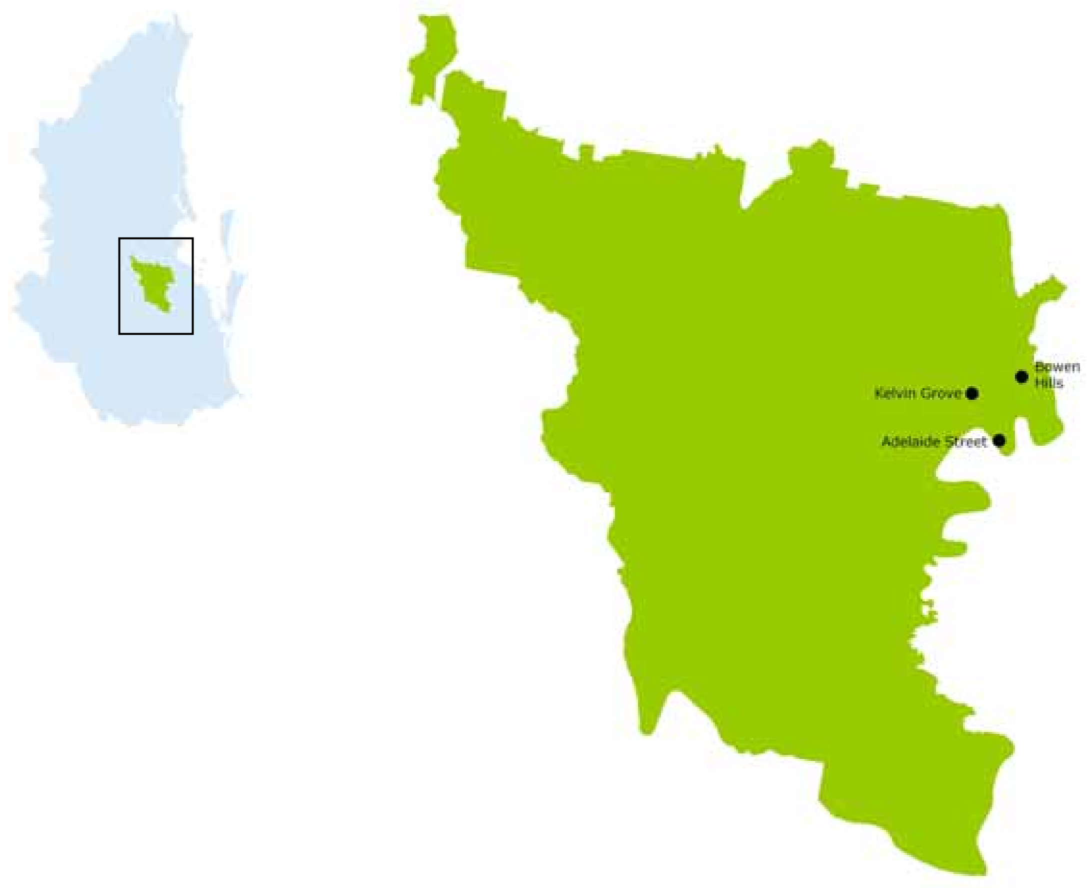
The interrelated projects, included in the 2010-15 forecast capital expenditure, to reinforce the CBD and surrounding suburbs occur across three hub areas.

Examples of major projects in the Central West hub are summarised in Figure 13.4 and include:

- construction of a 110-11 kV substation at Kelvin Grove cut into one of the 110 kV feeders to Milton; and
- construction of a new city 110-11 kV substation in Adelaide Street.

Additionally, ENERGEX has included a project to construct a new substation at Bowen Hills to cater to the commercial and residential renewal of the area.

Figure 13.4 Major projects planned for central west hub



13.16.2 Metro north hub

The Metro North hub encompasses Brisbane's suburbs north of the river from Brisbane airport to Moggill, stretching as far north as Jimna, and east to Donnybrook and Bribie Island.

This region has experienced ongoing high growth with a large number of residential land releases resulting in a sustained requirement for increased capacity and renewal of the distribution network.

ENERGEX has responded by including projects in forecast capital expenditure that extend and develop the 33 kV network to cater to the increased demand requirement resulting from the urban sprawl.

Examples of major projects in the Metro North hub are summarised in Figure 13.5 and include:

- construction of a 110-33 kV new bulk supply substation at Griffin;
- construction of a new 33-33 kV bulk supply substation at Aspley;

- installation of 110 kV powerlines connecting Powerlink's Southpine substation to Hays Inlet;
- construction of a 33-11 kV substation at Burpengary;
- hub area construction of 11-33 kV bulk supply substation at Tingalpa; and
- construction of a 110-11 kV substation at Strathpine West.

Additionally, ENERGEX has included a project to construct a new substation at Fisherman Islands north to ensure the electricity demands of an upgraded Port of Brisbane are met.

Figure 13.5 Major projects planned for metro north hub

13.16.3 Metro south hub

The Metro South hub encompasses Brisbane suburbs south of the river, west to Greenbank and east to Fisherman Islands, Redland Bay and Bay Islands such as North Stradbroke.

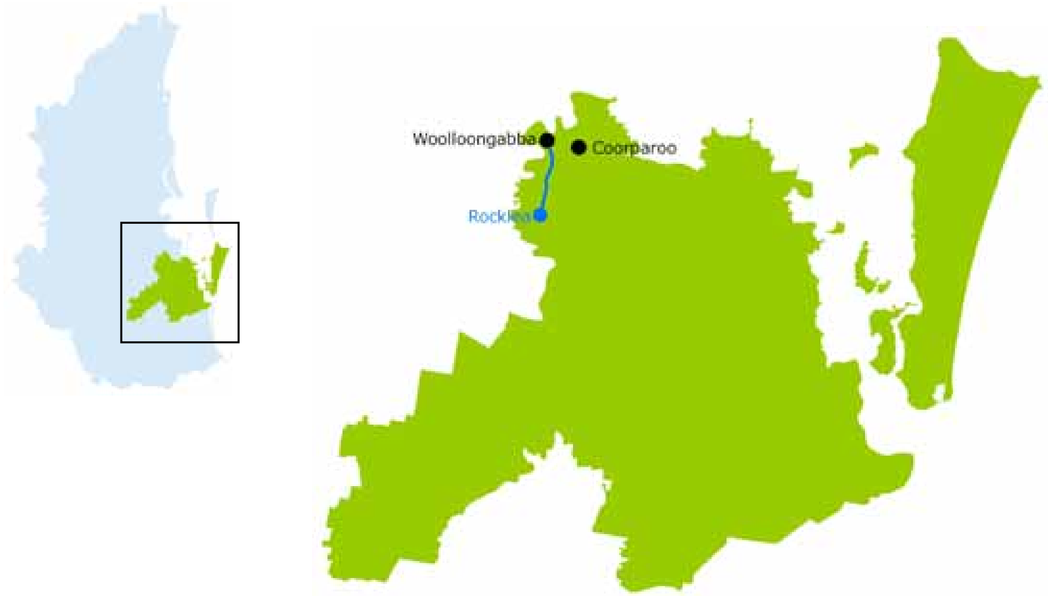
This region was originally planned to support a typically suburban area. A shift to higher densities of residential development has resulted in a need to refurbish much of the existing network.

Some of the projects located in the Metro South hub form part of the series of projects developed to provide a direct high capacity in-feed to the CBD and surrounding suburbs by transforming electricity from 110 kV directly to 11 kV.

Projects planned for the Metro South hub are summarised in Figure 13.6 and include:

- installation of a 110 kV double circuit feeder from Rocklea to Woolloongabba;
- construction of a 110-11 kV substation at Woolloongabba; and
- construction of a 110-33 kV substation at Coorparoo in response to increased densities in the area.

Figure 13.6 Major projects planned for metro south hub



13.16.4 South coast hub

The South Coast hub is centred on the Gold Coast and stretches from Logan in the north to Coolangatta in the south and west to Mount Barney. Growth in summer peaking load, in combination with an ageing network and population increases, particularly on the northern Gold Coast, is driving the need to reinforce the capacity of this region.

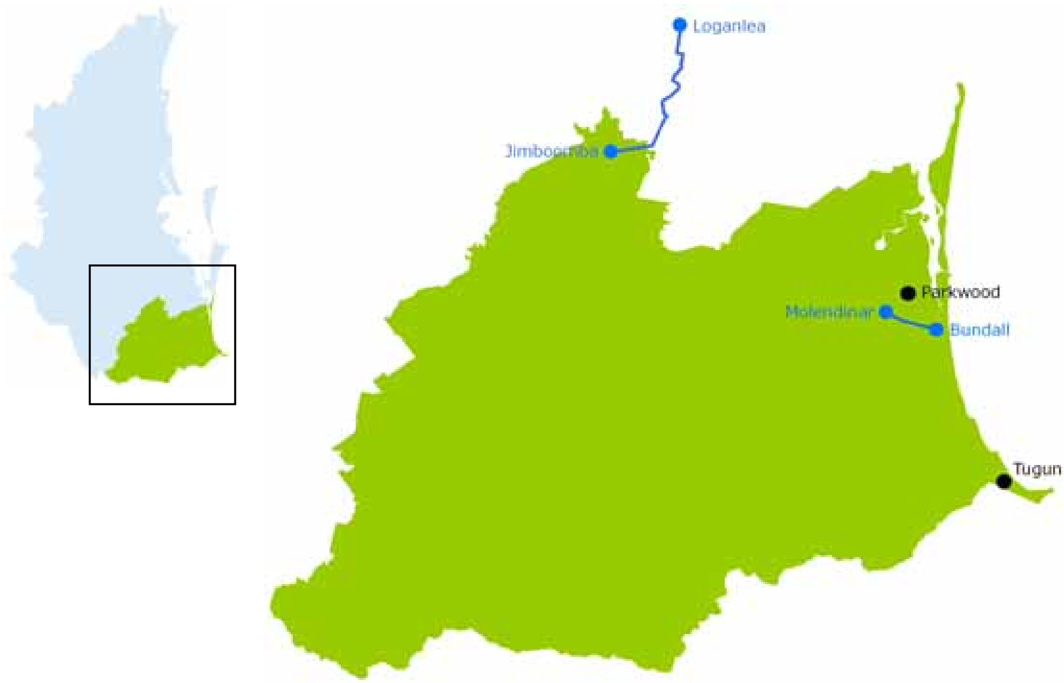
Similar to the long-term solution to growth in Brisbane's CBD and surrounding suburbs, ENERGEX also embarked on a program to replace the 33 kV network on the Gold Coast and provide high capacity in-feeds from 110-11 kV in response to high densities.

Examples of major projects planned to upgrade and reinforce the South Coast hub are summarised in Figure 13.7 and include:

- installation of a 110 kV transmission line between Bundall and Molendinar; and
- construction of a 33-11 kV zone substation at Parkwood, earmarked for a future upgrade to 110-11 kV.

Additionally ENERGEX has planned the construction of a 110-33 kV substation at Tugun in response to commercial load increases and the installation of a 110 kV transmission line connecting Jimboomba to Loganlea in response to development in the district.

Figure 13.7 Major projects planned for south coast hub



13.16.5 North coast hub

The North Coast hub encompasses the electricity network from Rainbow Beach and Gympie in the north to Caloundra and the Glass House Mountains in the south. Over the past 10 years the demands on a network, initially built to support a rural lifestyle with seasonal tourism, have changed. The electricity demand of the commercial and residential growth sector is aligned with the requirements expected of one of Australia's fastest growing regions.

The network on the Sunshine Coast was initially constructed to support a rural community with an influx of people during tourist seasons. The use of 132 kV on the Sunshine Coast was a product of the historical development of the network from a time when the SEQ network was run by a combination of private enterprise and local councils.

ENERGEX has responded to the high development in this region with forecast capital expenditure that continues to transform the previous 132-33 kV network into a sub-transmission system with high capacity in-feeds directly from 132-11 kV.

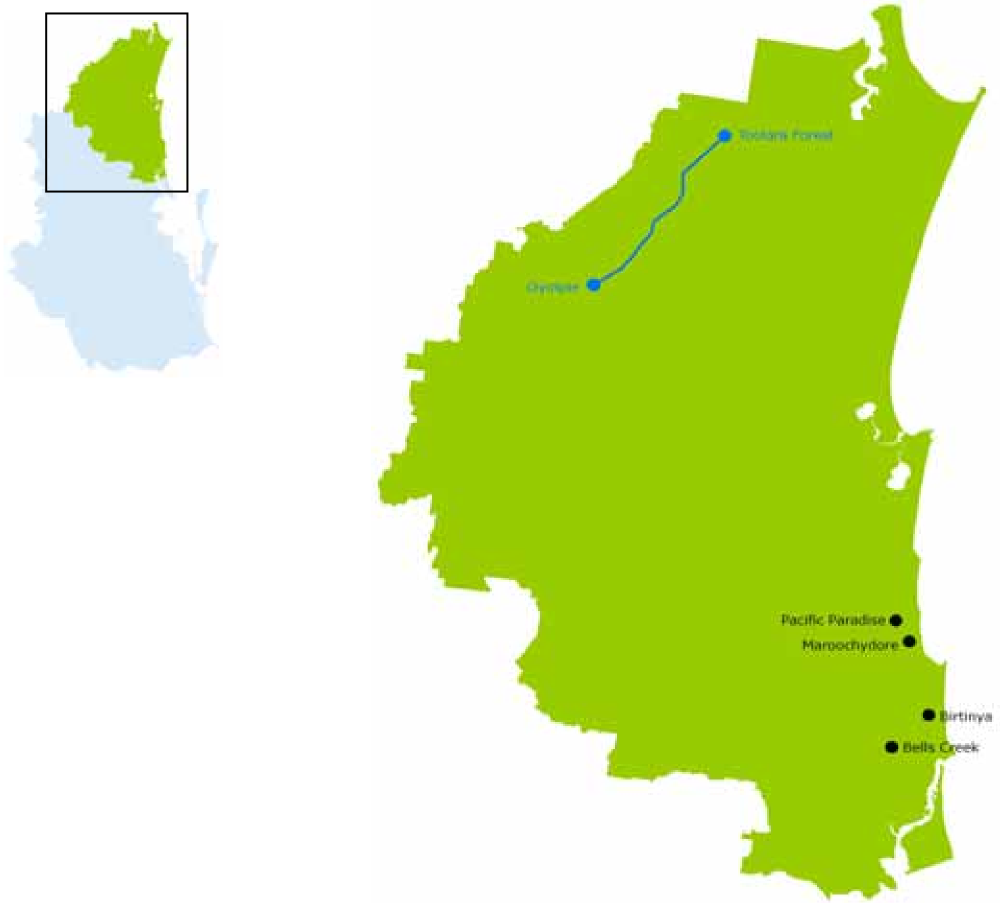
Examples of major projects to boost capacity within the North Coast hub are summarised in Figure 13.8 and include:

- construction of a 132-11 kV substation at Pacific Paradise;

- construction of a 132-11 kV substation at Maroochydore;
- construction of a 132-11 kV substation at Bells Creek; and
- construction of a 132-11 kV substation at Birtinya.

In addition ENERGEX plans to install an additional 33 kV feeder from Gympie to the Toolara Forest to address population growth, increased primary industry manufacturing and an increasing market in tourism.

Figure 13.8 Major projects planned for north coast hub



13.16.6 Western hub

The Western hub encompasses the region from Esk Shire in the north, Boonah in the south, Gatton in the west and as far east as Inala.

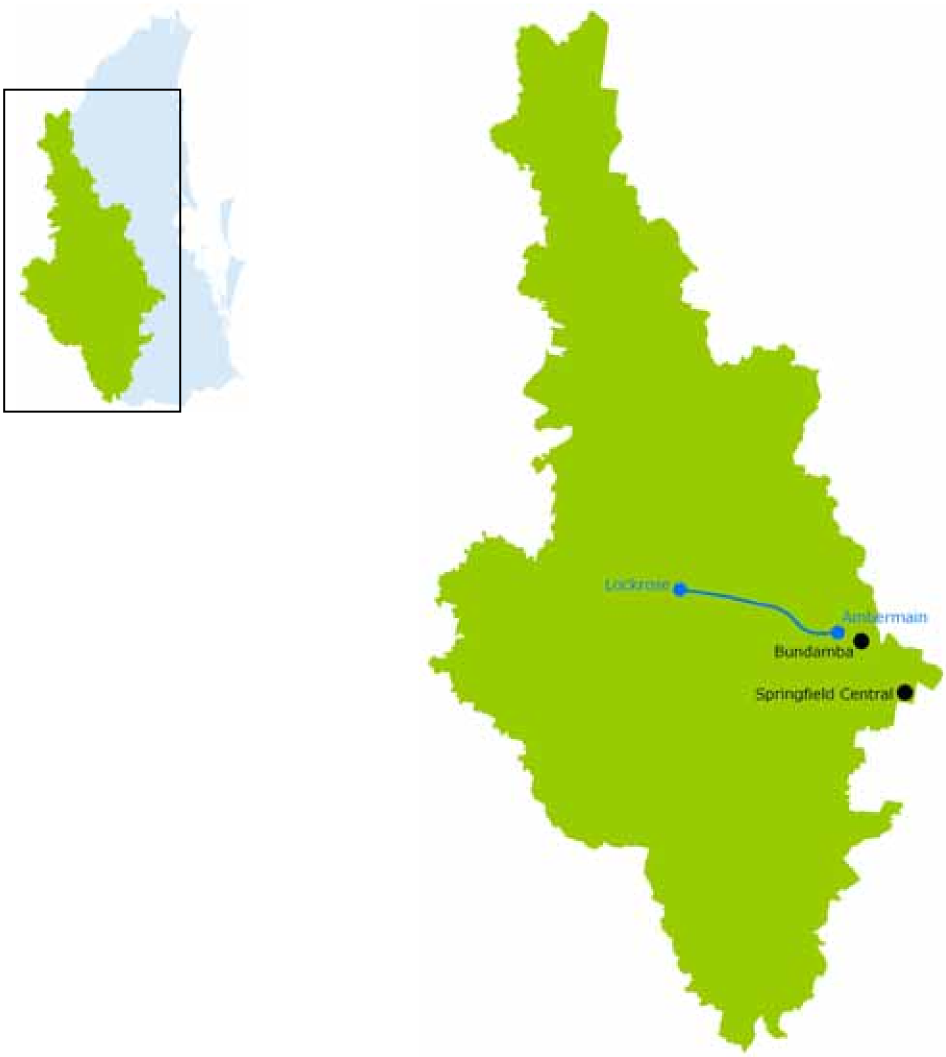
The western corridor is identified in the SEQ Regional Plan as an area that will play a significant role in the future development of the region. This corridor has land available for new housing and industry and has been earmarked by the State government for employment opportunities associated with economic growth.

Electricity infrastructure was designed in the 1960s to support a rural-based community but as population has increased and land use changed, demand for electricity in many areas has risen to levels comparable to sections of the urban network. ENERGEX also recognises that expectations for reliability in rural areas have increased commensurate with reliance on computer-based communications and the emergence of the 'digital age' via the internet.

Major projects to cater for development in the Western hub are summarised in Figure 13.9 and include:

- construction of a second 33-11 kV substation for the satellite city of Springfield with subsequent upgrading of assets to 110-11 kV to coincide with earmarked future commercial development;
- reconstruction of the overhead transmission feeder between Powerlink's Abermain substation and ENERGEX's Lockrose bulk supply point; and
- upgrade the existing 110-11 kV substation at Bundamba to cater for increased residential and commercial growth.

Figure 13.9 Major projects planned for western hub



14 Regulatory asset base

The *Rules* require that ENERGEX establish the RAB at the commencement of the *regulatory control period* (1 July 2010) and then roll forward that RAB consistent with the AER's RFM.

This chapter outlines the methodology used by ENERGEX to roll forward its RAB. Information is also provided on forecast capital expenditure and disposals. Details of the establishment of the RAB value as at 1 July 2010 and summaries of the roll forward value of the asset base over the *2010-15 regulatory control period* are also provided.

14.1 Summary

The nominal opening RAB (as at 1 July 2010) value of $7.9 billion is based on:

- the *QCA's 2005 final determination*;
- adjustments as provided by the *Rules*;
- depreciation during the *current regulatory control period*;
- actual capital expenditure during the *current regulatory control period*;
- actual disposals (based on written down book value) during the *current regulatory control period*;
- actual inflation during the *current regulatory control period*; and
- estimates of capital expenditure and disposals for the 2008-09 and 2009-10 financial years.

Clause 11.16.3 allows ENERGEX to include in its RAB, as a transitional arrangement, assets used to provide services which are not *standard control services*. The transitional arrangement further requires an adjustment to revenue derived from the PTRM for the assets not used to provide *standard control services*.

Table 14.1 summarises ENERGEX's forecast of the RAB over the *2010-15 regulatory control period*.

Table 14.1 RAB over the *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Opening RAB – 1 July	7,887.4	9,099.7	10,367.4	11,691.1	13,011.9
Forecast capital expenditure/additions	1,312.7	1,377.3	1,446.6	1,469.7	1,588.3
Forecast regulatory depreciation	(87.1)	(96.4)	(108.0)	(119.5)	(120.6)
Forecast disposals	(13.3)	(13.2)	(14.9)	(29.4)	(13.3)
Closing balance	9,099.7	10,367.4	11,691.1	13,011.9	14,466.3
Forecast inflation rate	2.45%	2.45%	2.45%	2.45%	2.45%

14.2 Regulatory information requirements

In accordance with Clause 6.12.1(6), a distribution determination is predicated on the AER's decision on ENERGEX's RAB at the commencement of the regulatory period.

ENERGEX is required to determine the RAB value for the *2010-15 regulatory control period* in accordance with the following Clauses of the *Rules*:

- Clause 6.5.1(e) – specifies that the RFM must include the methodology for rolling forward the RAB.
- Clause S6.2 – specifies the methodology for calculating the opening value of the RAB for a *regulatory control period* by using the RFM (Clause S6.2.1); and for rolling forward the RAB within the same *regulatory control period* (Clause S6.2.3).
- Clause S6.1.3(7) – requires ENERGEX to provide details of all amounts, values and other inputs used to calculate the RAB; a demonstration that these inputs comply with the relevant requirements of Part C of Chapter 6 of the *Rules*; and an explanation of the calculation of the RAB for each regulatory year in the regulatory period.
- Clause S6.1.3(10) – requires the PTRM and the RFM to be completed as part of ENERGEX's *building block proposal*.
- Under Queensland transitional arrangements, Clause 11.16.3 allows ENERGEX to propose an approach to the treatment of the RAB that must be accepted by the AER if it is consistent with the approach in the *QCA's 2005 final determination.*

14.3 Transitional arrangements

ENERGEX proposes that no change to the RAB value be made in relation to non-system assets used in the provision of both standard control and *alternative control services*. Non-system assets are predominantly used by ENERGEX in the provision of *standard control services* and are only used to a lesser extent to provide *alternative control services*.

As provided for in the transitional arrangements, ENERGEX has retained all of its non-system assets in its RAB. An adjustment to the revenue as calculated by the PTRM for *standard control services* has been made to account for the portion of non-system assets used in the provision of *alternative control services*.

14.4 Methodology used in rolling forward the RAB

In rolling forward the RAB, ENERGEX has used:

- the methodology specified in Clauses S6.2.1 and S6.2.3 of the *Rules*; and
- the AER's DNSP RFM and RFM Handbook.

The completed RFM for ENERGEX is provided in **Attachment 2**.

14.5 Establishing the RAB value as at 1 July 2010

The opening RAB value for 1 July 2010 has been calculated by rolling forward the opening RAB value as at 1 July 2005 (as approved by the QCA) and using the AER's published RFM for DNSPs. ENERGEX has rolled forward its RAB over the *current regulatory control period* as one total RAB to derive a closing RAB as at 30 June 2010. The opening RAB for 1 July 2010 will then be split into two values to represent ENERGEX's two asset bases; one for *standard control services* and one for the street lighting component of *alternative control services*.

14.5.1 RAB value as at 1 July 2005

The opening RAB value as at 1 July 2005 was approved by the QCA to be $4,345 million[49]. This was calculated from the $4,308.1 million as specified in Clause S6.2.1(c)(1) of the *Rules* and an incremental adjustment by the QCA for the financial year ending 30 June 2005 in accordance with Clause S6.2.1(c)(2).

---

[49] Source: Attachment A, *QCA letter to ENERGEX CEO*, dated 23 March 2006.

The value of $4,345 million is comprised of:

- the independent valuation conducted by Sinclair Knight Merz of $3,833.8 million as at 31 December 2003 plus the actual capital expenditure, depreciation and inflation in the six months to 30 June 2004 of $129.9 million;
- the approved forecast capital expenditure, depreciation and inflation for the period between 1 July 2004 to 30 June 2005 of $344.3 million[50]; and
- a $37 million[51] adjustment for QCA allowed actual capital expenditure, depreciation and inflation during the 2004-05 year in accordance with Clause S6.2.1(c)(2).

The QCA approved adjustment of $37 million reflects some of the variance between the actual capital expenditure of $541.75 million and the estimated capital expenditure of $448.4 million.

14.5.2 RAB value at 1 July 2010

The opening RAB value for 1 July 2010 is derived using:

- RAB value as at 1 July 2005 of $4,345 million;
- actual results to 30 June 2008;
- estimated figures for the final two years of the *current regulatory control period* for which actual amounts were not available at the time of preparation of ENERGEX's *Regulatory Proposal*; and
- inflation.

The following method has been used to determine the value of the RAB as at 1 July 2008:

- rolling forward the 1 July 2005 RAB to 30 June 2008 on the basis of actual capital expenditure (inclusive of contributed assets) over this period (Clause S6.2.1(e)(1));
- increasing the value of the RAB by including the value of assets that were not previously recovered but which are now used to provide *standard control services* (Clause S6.2.1(e)(8)). ENERGEX is not proposing to include any additional value of assets in the *current regulatory control period*;
- reducing the value of the RAB by the value of assets that were previously used to provide *standard control services* but are no longer to be used for that purpose for the *2010-15 regulatory control period* (Clause S6.2.1(e)(7)). ENERGEX is not proposing to make any adjustment to the value of its assets for the *current regulatory control period*;

50 Source: QCA, *Final Determination – Regulation of Electricity Distribution*, April 2005, page 68.

51 Source: Attachment A, *QCA letter to ENERGEX CEO*, dated 23 March 2006.

- deducting depreciation calculated in accordance with the method used in the *QCA's 2005 final determination* for the *current regulatory control period* (Clause S6.2.1(e)(5)). ENERGEX has calculated depreciation on a straight line basis in accordance with the AER's RFM as discussed in Chapter 15;
- deducting actual disposals, based on written down book value as per ENERGEX's regulatory accounts, for the period from 1 July 2005 to 30 June 2008 (Clause S6.2.1(e)(6)); and
- indexing the annual opening RAB for actual inflation for the respective years (Clause 6.5.1(e)(3)). The RFM specifies that the actual inflation should be applied, consistent with the annual adjustments to form of price control. ENERGEX's current regulatory arrangements see the form of price control indexed by the inflation rate forecast in the *QCA's 2005 final determination*, not actual inflation. ENERGEX therefore sought AER approval to use actual inflation and, as the *Rules* do not specify a particular methodology to be applied, ENERGEX elected to use CPI consistent with the annual indexation of its asset base for regulatory reporting requirements. The actual inflation rate used is obtained from the ABS weighted average of eight capital cities, March to March annual CPI. The AER has endorsed this rate of indexation.

For the period from 1 July 2008 to 30 June 2010 for which actual amounts are not available, ENERGEX, in complying with the *Rules*, has estimated capital expenditure based on the latest available information.

The following methodology has been used to roll forward the RAB from 30 June 2008 to 1 July 2010:

- adding estimated capital expenditure (inclusive of contributed assets) as forecast by ENERGEX for the two year period (Clause S6.2.1(e)(2));
- deducting the amount of forecast depreciation calculated in accordance with the method used in the *QCA's 2005 final determination* for the *current regulatory control period* (Clause S6.2.1(e)(5)). ENERGEX has calculated depreciation on a straight line basis in accordance with the AER's RFM as discussed in Chapter 15;
- deducting estimated disposals for the two year period based on estimated written down book value (Clause S6.2.1(e)(6)); and
- indexing the annual opening RAB for forecast inflation for the respective years (Clause 6.5.1(e)(3)), based on independent advice as outlined in Chapter 16.

14.5.3 Summary of RAB value at 1 July 2010

Pursuant to Clauses S6.2.1(c) and S6.2.1(e)(1) of the *Rules*, the opening RAB on 1 July 2005 has been rolled forward to 1 July 2010 by:

- adding $2,174 million, which is the total of the actual capital expenditure (net of disposals and inclusive of contributed assets) to 30 June 2008;
- adding $1,939 million of estimated capital expenditure (net of disposals and inclusive of contributed assets) for the final two years to 30 June 2010;

- deducting $554 million, representing depreciation calculated on a straight line basis in accordance with the AER's RFM;
- indexing the annual opening RAB for inflation; and
- adding an $80 million adjustment for the actual to forecast variance for 2004-05 and return on variance as per the AER's RFM model.

Details of these adjustments are shown in Table 14.2.

Table 14.2 Establishing RAB at 1 July 2010

	Actual			Estimated	
Nominal $M	**2005-06**	**2006-07**	**2007-08**	**2008-09**	**2009-10**
Opening RAB – 1 July	4,345.2	4,996.7	5,596.7	6,248.6	7,003.4
Actual/estimated net capital expenditure	744.7	734.7	694.4	890.5	1,048.0
Actual/estimated regulatory depreciation	(93.2)	(134.7)	(42.5)	(135.7)	(148.2)
Variance between forecast and actual 2004-05	-	-	-	-	53.1
Adjustment for return on variance	-	-	-	-	27.3
Closing balance 30 June	4,996.7	5,596.7	6,248.6	7,003.4	7,983.6
Actual/estimated contributed assets	38.8	47.2	49.3	44.1	70.6
Actual/estimated inflation rate	2.98%	2.44%	4.24%	2.47%[52]	2.45%

Details of the calculation, including amounts, values and inputs used by ENERGEX are shown in the RFM in **Attachment 2**.

14.6 Resulting RAB values over the 2010-15 regulatory control period

ENERGEX has applied the method described above in Section 14.5 to determine the closing RAB value as at 30 June 2010. For the *2010-15 regulatory control period* the RAB will be split into two values, one for *alternative control services* and one for *standard control services*. The opening RAB value as at 1 July 2010 of $7,984 million will be split as follows:

52 Source: KPMG, *Advice on Inflation Rates Final Report*, April 2009, page 3.

- $7,887.4 million for the *Standard Control Services* RAB; and
- $96.4 million for the *Alternative Control Services* asset base (street lighting assets).

For the *Standard Control Services* RAB, this amount is then rolled forward over the *2010-15 regulatory control period* using the methodology and assumptions described in Section 14.6.1 and the AER PTRM, to arrive at the forecast closing RAB value of $14,466 million as at 30 June 2015.

The *Alternative Control Services* asset base is discussed in more detail in Part 2 of this *Regulatory Proposal*.

14.6.1 Roll forward methodology and assumption

ENERGEX has rolled forward the RAB for each year of the forthcoming *2010-15 regulatory control period* using the following methodology and assumptions:

- adding forecast efficient prudent capital expenditure (inclusive of contributed assets);
- deducting regulatory depreciation calculated as per the AER PTRM;
- deducting forecast disposals for each year; and
- indexing the annual closing RAB with forecast inflation.

Table 14.3 summarises ENERGEX's forecast of the *Standard Control Services* RAB value over the *2010-15 regulatory control period*.

Table 14.3 RAB over the *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Opening RAB – 1 July	7,887.4	9,099.7	10,367.4	11,691.1	13,011.9
Forecast capital expenditure/additions	1,312.7	1,377.3	1,446.6	1,469.7	1,588.3
Forecast regulatory depreciation	(87.1)	(96.4)	(108.0)	(119.5)	(120.6)
Forecast disposals	(13.3)	(13.2)	(14.9)	(29.4)	(13.3)
Closing balance	9,099.7	10,367.4	11,691.1	13,011.9	14,466.3
Forecast inflation rate	2.45%	2.45%	2.45%	2.45%	2.45%

Details of the calculation, including amounts, values and inputs used by ENERGEX in completing its PTRM are in **Attachment 3**.

15 Depreciation

The *Rules* require that ENERGEX provide a schedule of depreciation (return of capital) for the assets included in the RAB.

This chapter provides an overview of ENERGEX's approach to calculating depreciation for the *2010-15 regulatory control period*. It sets out the asset lives of ENERGEX's network system and non-system assets and the resulting depreciation allowance included in the building block for ENERGEX.

15.1 Summary

ENERGEX proposes to adopt the straight line depreciation approach consistent with the PTRM and the depreciation profile adopted by the QCA in its 2005 final determination.

For the *2010-15 regulatory control period*, ENERGEX proposes to retain the standard asset lives as adopted by the QCA in its 2005 final determination.

In determining the depreciation schedules, ENERGEX has assessed the remaining asset lives by rolling forward the historical values, adjusting these for actual net capital expenditure and forecast net capital expenditure and depreciation. The results of this approach are consistent with the audited regulatory accounts submitted to the QCA.

Table 15.1 summarises ENERGEX's depreciation forecast for the regulatory assets used to provide direct control services (excluding street lighting assets) over the *2010-15 regulatory control period*.

Table 15.1 Forecast depreciation over the *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Straight line depreciation	280.4	319.3	362.0	406.0	439.4
Inflation on opening RAB	193.2	222.9	254.0	286.4	318.8
Regulatory depreciation	87.1	96.4	108.0	119.5	120.6

15.2 Regulatory information requirements

In accordance with Clause 6.12.1(8), a distribution determination is predicated on the AER's decision on whether or not to approve ENERGEX's depreciation schedules.

ENERGEX must calculate its depreciation in accordance with the *Rules*, specifically:

- Clause 6.5.5(a)(1) states that depreciation for each regulatory year must be calculated on the value of the assets included in the RAB as at the beginning of that regulatory year, for the relevant distribution system.
- Clause 6.5.5(a)(2) requires depreciation to be calculated using the depreciation schedules for each asset or category of assets that are nominated in ENERGEX's *building block proposal*.
- Clause 6.5.5(b)(1) states the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets.
- Clause 6.5.5(b)(2) stipulates that the sum of the real value of the depreciation attributable to any asset or category of assets over the economic life of that asset or category of assets must be equivalent to the value at which that asset or category of assets was first included in the RAB for the relevant distribution system.
- Clause 6.5.5(b)(3) requires that the economic life of the relevant assets and depreciation rates for a given *regulatory control period* be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.

Clause S6.1.3(12) of the *Rules* also requires:

- the depreciation schedules to be based on well accepted asset categories;
- the proposal to include details of all inputs used to calculate the depreciation;
- demonstration that the schedules conform to Clause 6.5.5(b); and
- an explanation of the calculation of the inputs used to calculate the depreciation.

Clause S6.2.1(e)(5) of the *Rules* requires values of the RAB during the previous regulatory period to be depreciated in accordance with the distribution determination for that period.

15.3 Depreciation methodology

The AER's safe harbour approach to calculating the depreciation allowance, as reflected in the PTRM, is to adopt the straight line depreciation method, but this does not limit a business from proposing and justifying an alternative method. The *QCA's 2005 final determination* for the *current regulatory control period* adopted the straight line method. ENERGEX proposes that this method be maintained for the *2010-15 regulatory control period* due to its simplicity, consistency and transparency.

ENERGEX's assets are grouped in asset categories which are made up of a number of assets with different standard lives. A weighted average life is calculated and used for each asset category. In accordance with the requirements set out in Clause 6.5.5 of the *Rules*, ENERGEX has calculated the depreciation allowance using the straight line method over the standard and remaining lives of respective asset categories.

The PTRM calculates the depreciation allowance based on the straight line method. Details of the amounts, values and other inputs used by ENERGEX to compile the depreciation schedules are provided as the input sheet to the AER's PTRM, provided in **Attachment 3**.

15.4 Standard and remaining asset lives

ENERGEX is not proposing to alter asset or asset category standard lives from those applied in the *current regulatory control period*. In determining the standard and remaining asset lives, ENERGEX has considered both the technical and engineering life to assist in determining an appropriate economic life for the relevant assets.

ENERGEX has adopted the standard lives (i.e. the anticipated life of a new asset at the time of commissioning) and the estimated remaining lives as per its fixed asset register. These lives are based on ENERGEX's informed knowledge and understanding of how the assets perform over time and will be used within its distribution system, and the expected life associated with the type of usage.

Table 15.2 shows the standard asset lives and remaining asset lives for system and non-system assets.

Table 15.2 Standard lives for system and non-system assets as at July 2010

Assets categories	Standard life	Remaining life
System assets		
OH sub-transmission lines	51	36
UG sub-transmission cables	45	33
OH distribution lines	45	29
UG distribution cables	60	47
Distribution equipment	35	26
Substation bays	45	32
Substation establishment	58	31
Distribution substation switchgear	45	27
Zone transformers	50	41
Distribution transformers	41	30
Low voltage services	35	30
Metering	25	11
Communication – pilot wires	29	19

Assets categories	Standard life	Remaining life
System buildings	60	59
System easements	Enduring Asset	
System land	Enduring Asset	
Non-system assets		
Communications	7	6
Control centre – SCADA	12	5
ICT systems	5	3
Office equipment and furniture	7	7
Motor vehicles	9	6
Plant and equipment	7	4
Research and development	5	-
Buildings	40	30
Easements	Enduring Asset	
Land	Enduring Asset	

The depreciation allowance included in the building block for the *current regulatory control period* was calculated by the QCA using its internal model which was not available to ENERGEX. In its annual regulatory reporting to the QCA, depreciation is calculated on a straight line method based on the standard and remaining asset lives as recorded in ENERGEX's fixed asset register. ENERGEX has to date submitted three sets of regulatory accounts which have been accepted by the QCA.

In preparing for this *Regulatory Proposal,* the AER provided ENERGEX with the QCA's model that was used to calculate the depreciation for *the current regulatory period*. The QCA's model was based on forecast information for the purposes of the 2005 determination. ENERGEX has assessed the QCA's model and confirms that the model calculates depreciation on a straight line method with similar timing assumptions to those applied by ENERGEX during the *current regulatory control period*. ENERGEX notes there are variances to remaining asset lives between the forecast data in the QCA model and ENERGEX's actual data.

For the *2010-15 regulatory control period,* ENERGEX proposes to roll forward its asset base using the depreciation as calculated by the AER's RFM. The AER's model is based on a straight line method with different timing assumptions to those used by the QCA. ENERGEX proposes to use its fixed asset system calculated standard and remaining asset lives to calculate a weighted average for each of the asset categories in a manner that is consistent with its historical convention and regulatory reporting. This will allow a starting position under the new national regime where the depreciation methodology, timing assumptions and asset lives are clearly outlined in the AER's RFM.

15.5 Forecast regulatory depreciation

ENERGEX has forecast its depreciation schedules for the *2010-15 regulatory control period* using the AER's PTRM and ENERGEX's standard and remaining asset lives, forecast capital expenditure and forecast asset disposals.

ENERGEX has included, in the completed PTRM provided in **Attachment 3,** depreciation schedules by asset category based on the asset categories used to report to the QCA as part of the annual regulatory accounts. These schedules also reflect the asset categories used by the QCA in its 2005 final determination, albeit at a more detailed asset level.

16 Return on capital, inflation and taxation

Return on capital is one of the matters relevant to a building block determination. In addition, the *Rules* require ENERGEX to include an estimated cost of corporate income tax for each regulatory year of the *regulatory control period*. This chapter sets out, in accordance with the *Rules* and RIN requirements, ENERGEX's proposed return on capital, the method that is likely to result in the best estimates of inflation and the estimated cost of corporate income tax over the *2010-15 regulatory control period*.

ENERGEX has calculated its estimated costs of corporate income tax for each year of the *2010-15 regulatory control period* in accordance with the *Rules*. In determining this estimate ENERGEX has adopted as its starting tax asset base the asset base as at 2008 as detailed in **Appendix 16.1**.

16.1 Summary

ENERGEX proposes the departures from the AER's SoRI as set out in Table 16.1.

Table 16.1 Departures from the AER's SoRI

WACC Parameter	AER's SoRI value	Departure
Risk free rate	Moving average of the annualised yield on Commonwealth government bonds with a maturity of 10 years	While ENERGEX has adopted a moving average of the annualised yield on the10-year Commonwealth Government bond to calculate the nominal risk free rate, it does not accept that this rate currently represents an appropriate proxy under the Capital Asset Pricing Model (CAPM) due to the GFC. ENERGEX has therefore proposed a convenience yield adjustment of 79 basis points to the risk free rate to reflect this impact.
Assumed utilisation of imputation credits	0.65	0.2

The proposed return on capital, as measured by the WACC for the *2010-15 regulatory control period*, is 9.49 per cent.

In compliance with the *Rules*, ENERGEX has estimated the costs of corporate income tax for each year of the *2010-15 regulatory control period* through the AER's PTRM. In determining this estimate, ENERGEX has established a starting tax asset base referenced against ENERGEX's 2008 taxation return to the Australian Taxation Office. Details of the derivation of the starting tax asset base are included in **Appendix 16.1**.

ENERGEX's estimate of the costs of corporate income tax for each year of the *2010-15 regulatory control period* is set out in Table 16.5.

16.2 Regulatory information requirements

A distribution determination is predicated on the AER's decisions on the following:

- Clause 6.12.1(5) – a decision in relation to the rate of return on whether to apply or depart from the AER's SoRI published on 1 May 2009.
- Clause 6.12.1(7) – a decision on the estimated cost of corporate income tax for each regulatory year of the *regulatory control period*.

Clause 6.5.2 outlines the methodology for determining the rate of return.

Clauses 6.5.3 requires the corporate income tax to be calculated based on a prescribed methodology.

Clause 6.4.2(b)(1) requires a method that the AER determines is likely to result in the best estimates of expected inflation.

Clause 2.4.5 of the RIN requires ENERGEX to provide information substantiating the value of assets for tax purposes.

16.3 Return on capital

For the purposes of calculating a return on capital for the *2010-15 regulatory control period*, ENERGEX has adopted the WACC formula as specified in Clause 6.5.2(b) of the *Rules*.

ENERGEX has applied the parameters from the AER's SoRI as shown in Table 16.2.

Table 16.2 Parameters adopted from the AER's SoRI

WACC parameter	AER's SoRI value
Equity beta	0.8
Market risk premium (MRP)	6.5%
Value of debt as a proportion of the value of debt and equity	0.60
Credit rating level	BBB+

ENERGEX proposes to depart from the AER's SoRI in respect to the utilisation of imputation credits of 0.65 by using instead a value of 0.2.

While ENERGEX has adopted a moving average of the annualised yield on the 10-year Commonwealth Government bond to calculate the nominal risk free rate, it also proposes an adjustment to compensate for the compression in these yields due to non-risk factors.

16.3.1 Nominal risk free rate

ENERGEX has calculated the nominal risk free rate in accordance with the methodology set out in section 6.5.2(c) of the *Rules* and Clauses 3.2 and 3.3 of the AER's SoRI. The proposed approach to calculating the nominal risk free rate is as follows:

- the rate determined for the *2010-15 regulatory control period* is based on a moving average of the annualised yield on Commonwealth government bonds with a maturity of 10 years, taken over a period of 40 business days;
- the nominal risk free rate is calculated using the indicative mid rates published by the Reserve Bank of Australia (RBA); and
- where there are no Commonwealth government bonds with a maturity of 10 years corresponding to the dates of the averaging period, the nominal risk free rate is calculated by interpolating on a straight line basis from the two relevant bonds closest to the 10-year term and which also straddle the 10-year expiry date.

ENERGEX contends that the GFC has had a significant impact on the market for Commonwealth Government bonds, such that their observed yield cannot be relied upon as an appropriate proxy for the risk free rate under the CAPM. While ENERGEX is of the view that this can be demonstrated by examining the reasonableness of the estimated return on the risk free asset in its own right, it is also highlighted when considering the overall reasonableness of the proposed return on equity, assuming an equity beta of 0.8 and a MRP of 6.5 per cent. The consultant's advice is included in **Appendix 16.2**.

While it is not submitted that nominal Commonwealth Government bond yields are themselves biased, it is maintained that in the current economic climate using the observed yields as a proxy for the nominal risk free rate underestimates the risk free rate within the context of the Sharpe CAPM. The extent of this impact, termed the 'convenience yield', has been estimated to be 79 basis points. ENERGEX has therefore added this amount to the estimated nominal risk free rate, resulting in a nominal risk free rate of 5.08 (inclusive of the convenience yield).

ENERGEX has relied upon expert advice from Competition Economists Group (CEG) on relevant matters relating to the calculation of the nominal risk free rate, including the rationale for an adjustment and the quantum of that adjustment based on current market data. The consultant's advice is included in **Appendix 16.3**.

In compliance with Clause S6.1.3(8) of the *Rules* and section 2.4.3 of the RIN, ENERGEX has nominated a (confidential) commencement date and the length of the period to be used by the AER to calculate the nominal risk free rate for the *2010-15 regulatory control period*, in accordance with Clause 6.5.2(c)(2) of the *Rules*.

ENERGEX proposes an averaging period of 40 business days. For the purpose of this *Regulatory Proposal* an indicative risk free rate has been estimated over the period from 29 January 2009 to 23 March 2009 (inclusive). The proposed averaging period for the *2010-15 regulatory control period* is provided in **Appendix 16.4** of this *Regulatory Proposal*.

16.3.2 Debt risk premium

In establishing the cost of debt for the purposes of calculating the return on capital, a debt risk premium is to be added to the nominal risk free rate, in accordance with Clause 6.5.2(b) of the *Rules*.

ENERGEX has applied the definition set out in Clause 6.5.2(e) of the *Rules* to develop the proposed debt risk premium in accordance with the AER's SoRI, Clause 3.7, based on a benchmark credit rating of BBB+. This includes using an averaging period that is consistent with the period used to estimate the nominal risk free rate.

The other issue that needs to be considered is the data source used to obtain the corporate bond yields, which are then used to estimate the debt risk premium in accordance with the *Rules*. Regulators have historically used both Bloomberg and CBA Spectrum. The AER has referenced Bloomberg in the SoRI and has also used Bloomberg in estimating the debt margin to apply to the NSW distribution businesses.

In recent times, significant issues have been identified with Bloomberg estimates for 10-year BBB+ bonds, which have been driven by the lack of liquidity in the market for long-term, low investment grade debt. These issues have been explored in detail by CEG in **Appendix 16.5**.

CEG's report demonstrates that Bloomberg estimates currently materially under-estimate the debt margin for BBB+ corporate debt, based on criteria that reflect the requirements of the *Rules*. This is particularly the case since the commencement of the GFC although theory and evidence suggest that Bloomberg is likely to under-estimate the cost of issuing benchmark BBB+ corporate debt even under normal market conditions.

CEG also found that CBA Spectrum may overestimate the cost of BBB+ corporate debt. However, on balance, CEG concluded that CBA Spectrum performs better against its criteria (and hence in accordance with the requirements of the *Rules*). A conservative approach would be to take a simple average of the estimates produced by each data service.

Consistent with CEG's recommendation, ENERGEX therefore proposes to estimate the cost of BBB+ corporate debt by calculating a simple average of the AER/Bloomberg and CBA Spectrum BBB+10-year fair value estimates over the same 40 day period that has been used to estimate the risk free rate. The debt premium has then been estimated by taking the difference between this estimate and the risk free rate (inclusive of the convenience yield).

ENERGEX proposes an indicative nominal pre-tax cost of debt of 8.96 per cent for the *2010-15 regulatory control period*, comprising an indicative nominal risk free rate of 5.08 per cent (inclusive of the convenience yield) and an indicative debt risk premium of 3.88 per cent.

16.3.3 Gearing

ENERGEX accepts 0.60 as the value of debt as a proportion of the value of equity and debt (D/V) from the AER's final SoRI and has applied it without modification.

16.3.4 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 in relation to the WACC review, the Joint Industry Associations submitted that the most appropriate estimate for the MRP is 7.0 per cent per annum and provided persuasive evidence to support this proposal. ENERGEX 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, ENERGEX does not have new material to submit to the AER on this parameter and consequently has proposed the market risk premium of 6.5 per cent per annum as set out in the final SoRI.

16.3.5 Value of imputation credits

As noted above, ENERGEX is proposing to depart from the AER's determination of a value of 0.65 in the SoRI. Instead, it submits that a value of 0.2 is more appropriate.

ENERGEX remains of the view that the value of gamma can only be derived from market data and that consideration of a range of recent reputable Australian studies suggests that the value of gamma has fallen considerably and may indeed have no value. These studies have been considered and rejected by the AER in favour of a single study by Beggs and Skeels (2006).

In the final SoRI, the AER has continued to place reliance on tax statistics analysis and this has been central to the proposed increase in the value of gamma compared to regulatory precedent. The evidence the AER has relied upon is a study by Handley and Maheswaran (2008)[53].

Given the reliance the AER has placed on the tax statistics analysis and its material impact on the final outcome, ENERGEX commissioned Synergies to undertake its own analysis as detailed in **Appendix 16.6**. The Synergies study examined available data from 2003 to 2007

53 Source: J.C. Handley and K. Maheswaran, *A Measure of the Efficacy of the Australian Imputation Tax System, Economic Record 2008*, referenced in the AER's Final decision – *Electricity transmission and distribution network service providers review of the weighted average cost of capital (WACC) parameters*, May 2009.

and quantified the amount of the credits created, the amount distributed and the amount claimed by taxpayers. The analysis revealed that:

- if a payout ratio of 100 per cent is applied (although this is not accepted), the maximum upper bound for gamma would be around 0.35; and
- if a payout ratio of 71 per cent is applied (based on Hathaway and Officer's findings), the maximum upper bound for gamma would be 0.23.

These results differ markedly to the results of the Handley and Maheswaran study. Synergies has been unable to reconcile the differences because the data Handley and Maheswaran have used is not published in their study (full details of the data used by Synergies is provided in their report).

As noted previously, this is not considered an appropriate methodology to value theta, particularly given the reported estimates do not reflect the risks borne by shareholders in holding shares to derive franking credits. However, to the extent that the AER is to rely on this methodology to derive an upper bound for theta, the results of the Synergies analysis casts considerable doubt on the evidence it has relied upon, with the difference between the results from the study and estimates produced by Handley and Maheswaran being significant.

ENERGEX does not accept the SoRI value of imputation credits of 0.65 as it is not considered reasonable based on current market evidence. If the AER's assessment framework is applied here, ENERGEX would propose:

- a lower bound of 0, based on the reputable market evidence submitted by the Joint Industry Associations; and
- that if an upper bound is to be set based on tax statistics (and assuming a 100 per cent payout ratio), that upper bound is 0.35. This upper bound is below the regulatory precedent of 0.5 and well below the AER's determined value of 0.65.

Based on this range, a point estimate of 0.2 is considered more appropriate and is included in ENERGEX's proposed WACC parameters.

16.3.6 Equity beta

ENERGEX accepts 0.8 for the value of the equity beta from the AER's final SoRI and has applied it without modification.

16.3.7 Forecast inflation

The *Rules* require that the PTRM include a method that the AER determines is likely to result in the best estimates of expected inflation. This section sets out ENERGEX's proposed methodology for the calculation of the inflation estimate for the *2010-15 regulatory control period*.

Historical inflation and inflation forecasts are used to determine adjustments in the RFM and the PTRM, which form part of this *Regulatory Proposal*.

With regard to the methodology, the AER has discontinued the application of the Fisher equation due to a lack of liquidity in indexed Commonwealth government bonds and has instead expressed a preference to apply a 'general approach'. This general approach involves estimating a simple average of short to medium term forecasts of inflation by the RBA.

KPMG was commissioned by ENERGEX to provide advice on the methodology that would provide estimates of inflation for the *2010-15 regulatory control period*. KPMG in their report titled *Advice on Inflation Rates – Final Report* confirmed historical values and provided an estimate of future values. KPMG calculated the inflation forecasts in accordance with widely accepted regulatory precedent using the general approach. The KPMG report is provided in **Appendix 16.7**.

Table 16.3 shows ENERGEX's inflation estimate over the *2010-15 regulatory control period*. ENERGEX proposes that 2.45 per cent represents the estimate of expected inflation to apply over the regulatory period. These rates are discussed further in **Appendix 16.7**.

Table 16.3 Forecast inflation rates

Financial year	Inflation rates % for use in the WACC calculated using the general approach	Inflation rate % nominal RBA forecast
2008-09	2.45	1.75
2009-10	2.45	2.75
2010-11	2.45	2.00
2011-12	2.45	2.50
2012-13	2.45	2.50
2013-14	2.45	2.50
2014-15	2.45	2.50
2015-16	2.45	2.50
2016-17	2.45	2.50
2017-18	2.45	2.50
2018-19	2.45	2.50
2019-20	2.45	2.50

16.3.8 Historical inflation

Clause 6.5.1(e)(3) of the *Rules* requires the RAB to be adjusted for actual inflation. ENERGEX proposes to use the eight cities inflation observations on a March-to-March quarter basis on the basis of administrative ease and alignment with ENERGEX's statutory accounting approach for indexing the asset base for financial year end statutory reporting.

This approach is also consistent with the roll forward of assets as reported to the QCA in the RRS.

16.3.9 Summary of WACC parameters, variables and outcomes

Based on the requirements of the *Rules* and the RIN and the analysis provided above, ENERGEX proposes the WACC parameters, variables and outcomes in Table 16.4.

Table 16.4 Summary of WACC parameters, variables, outcomes and proposed values

WACC parameters, variables and outcomes	Proposed value
Parameters	
Equity beta	0.8
Market risk premium	6.50%
Proportion of debt to debt plus equity	0.60
Credit rating	BBB+
Proportion of franking credits attributed value by shareholders	0.20
Variables	
Nominal risk free rate (incl. convenience yield)	5.08%
Nominal risk free rate averaging period	40 days
Debt risk premium	3.88%
Inflation	2.45%
Outcomes	
Nominal pre tax cost of debt	8.96%
Nominal post tax cost of equity	10.28%
Vanilla WACC	9.49%

In recognition that applicable market data for two variables required to calculate the return on capital, namely the nominal risk free rate and the debt risk premium, will not be available until nearer the date of the final determination, this *Regulatory Proposal* incorporates the values described previously for these variables for this submission. The return on capital calculated for the final determination may differ depending on future market data for these variables.

ENERGEX engaged SFG Consulting (SFG) to examine the economic reasonableness and plausibility of its proposed return on equity, compared to the estimate implied by the AER's final SoRI and its final determination in relation to electricity distribution in NSW. SFG's report is provided in **Appendix 16.2**.

SFG observed that the return on equity that results from applying the AER's proposed parameters (as is) reduces the premium for systematic risk relative to regulatory precedent. This reduction is not considered reasonable or plausible, particularly given the current economic and financial conditions. This conclusion was reached after comparing the estimates against current market evidence, including dividend yields, debt spreads, option implied volatilities and estimates based on discounted cash flow models.

SFG therefore concludes that the parameters proposed by ENERGEX produce estimates of the required return on equity that are more plausible and economically reasonable than those produced by the AER and ENERGEX estimates these are still considered conservative.

16.4 Taxation allowance

ENERGEX has calculated its estimate of the costs of corporate income tax for each year of the *2010-15 regulatory control period*. The components of this estimate are based on relevant rates and methodologies in accordance with tax law and consistent with the requirements of the PTRM. Also included with this proposal are the basis of the determination of the starting tax asset base (**Appendix 16.1**) and ENERGEX's income tax equivalent return for financial year 2008.

ENERGEX's estimate of the costs of corporate income tax for each year of the *2010-15 regulatory control period* are set out in Table 16.5.

Table 16.5 Forecast corporate income tax over the *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Forecast tax depreciation	140.3	169.9	201.1	232.5	260.4
Tax payable	98.0	109.3	121.1	133.7	143.8
Less value of imputation credits	19.6	21.9	24.2	26.7	28.8
Net tax allowance	78.4	87.4	96.9	107.0	115.0

ENERGEX has estimated nil carried forward tax losses as at 1 July 2010.

16.4.1 Opening tax asset value at 1 July 2010

In establishing the estimate of the costs of corporate income tax for each year of the *2010-15 regulatory control period*, ENERGEX must first establish the opening tax asset value at 1 July 2010. As a result of previous regulatory decisions, ENERGEX has been operating under a post-tax regulatory framework. In their most recent determination for ENERGEX the QCA '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 actual tax paid subject to an unders and overs process on an annual basis'[54]. Therefore, there has been no tax asset value approved by a previous regulator. The establishment of a valid tax asset value is necessary to develop the estimate of the costs of corporate income tax for each year of the *2010-15 regulatory control period*.

The approach taken by ENERGEX to establish the opening tax asset base at 1 July 2010 is:

- the adoption of the regulatory tax asset base from the most recent National Tax Equivalents Regime tax return to the Australian Taxation Office as the reference value (this being for the financial year ending 30 June 2008);
- the separation of the tax value of assets as at 30 June 2008 into RAB and non-RAB assets. Non-system assets were allocated based on the most recent allocation basis used in the preparation of the 2007-08 RRSs; and
- the roll forward to 1 July 2010 of the resultant tax base using the AER's RFM, taking account of relevant tax depreciation rates and methodologies, actual capital expenditure and disposals.

ENERGEX proposes an opening tax asset base as at 1 July 2010 of $3,758.74 million based on the methodology described above and the review of this approach by KPMG. Details of the methodology and review are included in **Appendix 16.1**. ENERGEX submits that the adoption of the most recent National Tax Equivalents Regime tax return to the Australian Taxation Office as the reference value and the roll forward of this value as described in **Appendix 16.1** to 1 July 2010 meets the requirements of the *Rules*. There are other approaches with equal merit, however for administrative efficiency, ENERGEX proposes the recent National Tax Equivalents Regime return is the most appropriate starting point. As ENERGEX changed its general ledger system in 2007 to accommodate enhanced financial ICT software, 2008 has been used as the starting position.

54 Source: QCA, *Final Determination – Regulation of Electricity Distribution*, April 2005.

17 Application of schemes

The EBSS, DMIS and STPIS are incentive schemes developed by the AER in accordance with the *Rules* for DNSPs and are described in Guidelines released by the AER. The final framework and approach paper (Stage 2: Framework and approach paper) sets out the AER's preferred approach to the application of the schemes to ENERGEX. However, this Stage 2: Framework and approach paper was released in November 2008, prior to amendments to the STPIS Guideline (Version 1.1 was finalised in May 2009).

This chapter outlines ENERGEX's approach to the application of the EBSS, DMIS and STPIS.

17.1 Summary

ENERGEX acknowledges the importance of these schemes in ensuring efficient network investment and providing service excellence to customers. Equally, it is recognised that the application of the schemes has the potential to generate revenue volatility resulting in new and additional risks for ENERGEX. ENERGEX has no experience with any of the three schemes (EBSS, DMIS or STPIS) developed by the AER.

In formulating the application for each of these schemes in this *Regulatory Proposal*, ENERGEX has therefore adopted an approach that enables it to extend its knowledge through practical application and assessment of the impacts of the schemes over the *2010-15 regulatory control period*. ENERGEX has sought to embrace the principles of the schemes by adopting the majority of the approaches proposed by the AER in its Stage 2: Framework and approach paper with some modifications to the STPIS application. This modification affects the timing of the introduction of the financial penalty/reward and a parameter for customer service.

17.2 Regulatory information requirements

In accordance with Clause 6.12.1(9), a distribution determination is predicated on the AER's decision on how any applicable EBSS, STPIS or DMIS is to apply to ENERGEX.

Clauses 6.4.3(a)(5) and 6.4.3(b)(5) of the Rules require ENERGEX's *building block proposal* to include the revenue increments or decrements (if any) arising from application of the EBSS, DMIS and STPIS for each year of the *regulatory control period*.

ENERGEX's *building block proposal* must describe the mechanics and provide relevant explanatory material, in relation to its proposed application for the *regulatory control period* of the following matters:

- Clause S6.1.3(3) for matters in relation to the EBSS;

- Clause S6.1.3(4) for matters in relation to the STPIS; and
- Clause S6.1.3(5) for matters in relation to the DMIS.

Under Queensland transitional arrangements, Clause 11.16.4 requires the AER to have regard to the continuing obligations arising from the EDSD Review on ENERGEX under an EBSS. Clause 11.16.5 requires the AER, in formulating the STPIS to apply to ENERGEX, to have regard to the continuing obligations arising from the EDSD Review on ENERGEX, the impact of severe weather and whether the STPIS should be applied by way of a paper trial or a lower powered incentive.

17.3 Efficiency benefit sharing scheme

The purpose of the EBSS is to provide for the sharing, between ENERGEX and its customers, of operating expenditure efficiency gains and losses. These efficiency gains and losses do not relate to capital expenditure (Transitional arrangements, Clause 11.16.4(a) of the *Rules* and EBSS Guideline). The AER's position in its Stage 2: Framework and approach paper is that the national EBSS will apply to ENERGEX.

Under the AER's final decision on the EBSS (June 2008), the following information is required to be provided in this *Regulatory Proposal*:

- capitalisation policy – including proposed changes and their associated impacts on forecast operating expenditure;
- demand growth – the methodology to adjust forecast operating expenditure for outturn demand growth which is to be applied at the end of the *2010-15 regulatory control period*;
- proposed cost category exclusions for uncontrollable costs and an explanation as to why they are uncontrollable; and
- forecast operating expenditure for the *current regulatory control perio*d (including disaggregated forecasts for non-network alternatives and cost categories proposed to be excluded).

17.3.1 Capitalisation policy

ENERGEX's current Capitalisation Policy is included in **Appendix 17.1**. ENERGEX does not envisage any changes to this Capitalisation Policy. However, should there be any changes to it during the *2010-15 regulatory control period,* those changes will be taken into account in the assessment of carryover gains and losses in the *next regulatory control period*.

17.3.2 Demand growth adjustments methodology

ENERGEX has the opportunity in this submission to propose a method for accounting for demand growth to be used at the end of the *2010-15 regulatory control period* to adjust forecast operating expenditure for outturn demand growth.

ENERGEX's operating expenditure forecast, as discussed in Chapter 12, is based on:

- an increase in inspection and maintenance costs based on the growing asset base; and
- a benchmark for its operating expenditure based on the Wilson Cook methodology.

Hence, ENERGEX has not proposed a demand growth adjustment methodology for the *2010-15 regulatory control period*.

17.3.3 Uncontrollable operating expenditure – proposed exclusions

ENERGEX is required to propose in its *Regulatory Proposal* any operating expenditure for uncontrollable cost categories that is to be excluded from the EBSS.

ENERGEX's proposed cost categories for exclusion from the EBSS are discussed in detail in Chapter 12 and are listed below:

- debt and equity raising costs – forecast costs are based on a benchmark firm, not historical data;
- insurance – forecast costs are based on current policies and market premiums and influenced by insurance availability, risk appetite and the unpredictable nature of the events insured;
- self insurance – forecast costs are based on independent external actuarial advice; and
- non-network alternatives – excluded under the AER's final decision on the EBSS Guideline. Forecast costs reflect anticipated network support and are subject to demand and environmental factors.

These are considered to be uncontrollable costs as historical performance data does not provide a suitable basis on which to develop forecasts. These proposed exclusions are consistent with those excluded from EBSS in the NSW final decision with the exception of equity raising costs. ENERGEX proposes that equity raising costs be treated consistently with debt raising costs.

Clause 11.16.4 of the *Rules* provides ENERGEX with the opportunity to exclude costs associated with EDSD from EBSS. ENERGEX does not propose any specific exclusions associated with EDSD recommendations.

17.3.4 Forecast operating expenditure for 2010-15 for EBSS purposes

Table 17.1 outlines the operating expenditure forecasts for EBSS purposes and the forecasts for proposed exclusions referred to in Section 17.3.3.

Table 17.1 Operating expenditure forecasts for the *2010-15 regulatory control period* for EBSS purposes

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15
Total regulated network operating expenditure	**355.1**	**360.9**	**371.3**	**380.4**	**375.5**
Debt raising costs	(7.2)	(8.1)	(9.0)	(9.9)	(10.7)
Equity raising costs	(20.6)	(19.8)	(18.8)	(15.7)	(12.6)
Insurance costs	(3.8)	(3.8)	(3.8)	(3.8)	(3.7)
Self insurance costs	(2.8)	(2.9)	(3.1)	(3.2)	(3.0)
Non-network alternatives*	(3.5)	(3.6)	(3.6)	(3.6)	(3.6)
Total operating expenditure for EBSS purposes	**317.2**	**322.6**	**333.0**	**344.2**	**341.9**

** This is a subset of the total non-network alternative forecast expenditure*

17.4 Demand management incentive scheme

The purpose of the DMIS is to provide incentives to DNSPs to implement efficient non-network alternatives or to manage expected demand for *standard control services* in some other way. The AER's position in its Stage 2: Framework and approach paper is that the DMIS will apply to ENERGEX as a DMIA. The DMIA is in the form of an annual ex ante allowance, provided as an equal and fixed amount of additional revenue at the commencement of each year in the *regulatory control period*. The total amount of the allowance is to be capped although the amount of the allowance that can be spent in any year is not specifically limited.

In accordance with the Stage 2: Framework and approach paper, the DMIA will be in the following form:

- total allowance capped at $5 million, nominally allocated as $1 million annual instalments over each year of the *regulatory control period*;
- the allowance can apply to multiple small scale projects or to a single larger project, subject to these projects meeting criteria prescribed by the AER; and
- the allowance is in addition to funded DM projects included in this *Regulatory Proposal*.

17.4.1 Proposed application of DMIS

ENERGEX recognises the value of DM initiatives as alternatives to traditional solutions and welcomes the opportunity to participate in the scheme.

ENERGEX accepts the proposition of the AER in its Stage 2: Framework and approach paper for application of the DMIS in the form of a DMIA capped at $5 million over the *2010-15 regulatory control period.* The DMIA will be treated as a revenue allowance and is discussed in Chapter 18. ENERGEX is committed to the exploration and development of DM alternatives. Real progress on DM requires a commitment of resources well beyond the DMIA of $5 million. ENERGEX accepts the AER's DMIA position on the basis that the proposed DM strategy and programs outlined in Chapter 5 are accepted.

17.5 Service target performance incentive scheme

The STPIS is intended to maintain the balance between the incentive to reduce expenditure and maintaining or improving service quality.

ENERGEX's STPIS proposition for the *2010-15 regulatory control period* has been developed having regard to the very recent development of the national STPIS and the fact that this financial incentive scheme has not previously been applied to ENERGEX. In light of these circumstances, ENERGEX considers it critical to prudently manage the risks associated with the implementation of the STPIS in order to protect the legitimate interests of its customers as well as its owner.

The key elements of ENERGEX's STPIS proposition are that the scheme should apply to two reliability parameters and a single telephone answering parameter. Proposed upper and lower limits of total revenue at risk are ultimately ±2 per cent, within which the telephone answering limits are equal to ±0.05 per cent. ENERGEX has proposed to adopt VCR values based on the AER's original STPIS Guideline (Version 1.0) with the same value for each of the reliability network segments.

In addition, to mitigate the financial risks associated with the untested STPIS, it is proposed that for the first year of the *regulatory control period*, the STPIS should take the form of a paper trial. After a second transitional year with one per cent of revenue at risk, full implementation of the scheme with two per cent revenue at risk would occur from the third year of the *regulatory control period* onwards and continue for a three year period.

It is further proposed that for the first two years of the *regulatory control period*, the STPIS should exclude the telephone answering parameter. This is because there is a structural break in ENERGEX's historical performance data for the telephone answering parameter caused by the sale of its retail and gas network businesses in 2006-07. Consequently, ENERGEX has less than one year of telephone answering data for its current operations. It is proposed that further performance data should be collected in the first two years of the *regulatory control period* to allow a robust performance target to be set for the final three years of the period.

17.5.1 Key considerations

In addition to *Rules* and AER requirements, the following factors have been critical in shaping the development of ENERGEX's STPIS proposition:

- the application of Queensland MSSs;
- the application of a Queensland GSL scheme;
- ENERGEX network's physical characteristics;
- severe weather impacts;
- the sale of ENERGEX's retail and gas network businesses in 2006-07 and the associated impact on ENERGEX's Network Contact Centre; and
- ENERGEX's guiding principles for its proposed service performance targets and associated revenue at risk under the STPIS.

These factors are discussed below.

Queensland MSS – ENERGEX is required to comply with the MSS (discussed at Chapter 9) outlined in the EIC and to achieve performance levels consistent with a 10 PoE assumption. ENERGEX's CBD and urban networks are currently performing significantly better than the short rural network and they are achieving 10 PoE. In contrast, the rural network performance requires significant improvement to achieve 10 PoE levels. ENERGEX's initial analysis of the interaction between MSS and STPIS identifies the potential for them to operate counter to each other in the *2010-15 regulatory control period*. The higher focus for improvement on the rural feeders under MSS contrasts with the higher reward/penalty associated with performance variation of urban feeders under STPIS[55]. ENERGEX will need to closely monitor and assess the interaction between the two schemes to mitigate against potentially conflicting signals to the operational delivery areas of ENERGEX's business.

Queensland GSL scheme – ENERGEX is required to comply with the GSL scheme (discussed at Chapter 9) outlined in the EIC, which imposes requirements on ENERGEX in relation to service levels received by individual customers. The GSL scheme covers reliability and a range of customer service performance parameters, including activities in relation to connections, de-energisations, re-energisations and appointments. Failure to meet a GSL requirement will result in ENERGEX paying compensation to an individual customer in the form of a specified GSL payment. The STPIS includes a GSL component but under the Guideline it will not apply where, as in ENERGEX's case, there is jurisdictional legislation imposing an obligation on the DNSP. ENERGEX's GSLs are discussed in Chapter 12.

55 The breakdown of energy consumption by network type influences the STPIS reward/penalty. ENERGEX's percentage energy consumption for urban, rural and the CBD is 78 per cent, 17 per cent and 5 per cent respectively. The urban performance has a higher influence.

ENERGEX's network characteristics – ENERGEX currently records and reports its network data by CBD, Urban and Short Rural feeder type. For the purpose of the STPIS, these network categories will be retained. Each of these network segments has very different physical characteristics and associated reliability performance. ENERGEX's CBD segment is a compact and meshed network characterised by multiple feeder connections to provide higher levels of supply security which may only be drawn upon in limited circumstances. In contrast the Short Rural network is a radial system with very limited duplication or parallel connectivity.

Severe weather – SEQ's annual summer storm season can be a significant exogenous factor affecting ENERGEX's reported service quality performance. The summer storm season can adversely affect reliability and customer service performance over a period which usually extends from September to March. There is a large degree of observed variability in the intensity of these storm seasons, which results in an inconsistent impact on reported service performance. While the effect of the worst storm events (major event days) can be removed from reported reliability and customer service data under the STPIS, it is the quantity and severity of storms which do not qualify as a major event day that impact reported service performance data. While ENERGEX has a summer preparedness planning program to mitigate and manage risks associated with storm events, no amount of preparation can remove the variability inherent in the reported reliability and customer service performance as a result of significant weather events.

Sale of ENERGEX's retail and gas network businesses – During 2006-07, ENERGEX's retail and gas network businesses were sold by the Queensland government prior to the introduction of full retail energy competition in Queensland on 1 July 2007. Consequently, the combined Retail/Network Contact Centre was systematically downsized to form a Network Contact Centre, with a reduction of more than 70 per cent in telephone answering staff numbers[56] (reduced from 170 to 47) by April 2008. A smaller team of trained staff is now available to respond to abnormal events (including major event days as well as significant storm events/unplanned outages that are not classified as such). This loss of scale changed the nature of the Network Contact Centre and its performance and this has created a structural break in the performance history of the Network Contact Centre. ENERGEX currently has less than one financial year of telephone answering data associated with its operation as a network only contact centre (July 2008 – present).

Guiding principles for STPIS proposal – ENERGEX's proposed performance targets and associated revenue at risk have been set with regard to the following guiding principles:

- recognition of ENERGEX's physical network characteristics and operating environment, in particular, the events and circumstances that are reasonably controllable;
- consistency with the relevant *Rules* requirements (including Chapter 5 technical standards) and Queensland legislative safety and network performance standards;
- consistency with ENERGEX's own planning and network development standards;

56 Full time equivalents.

- consistency with the capital and operating expenditure submitted as part of this *Regulatory Proposal*;
- consideration of customers' likely willingness to pay for improved service performance; and
- recognition of the quality and variability of the underlying data for the proposed performance parameters and associated targets.

More generally, ENERGEX has not previously been exposed to a service performance incentive scheme in relation to its distribution network[57] and so its STPIS proposition has been carefully structured so as to enable ENERGEX to prudently manage the financial risks associated with the introduction of the AER's STPIS.

17.5.2 AER's proposed STPIS for ENERGEX

The key elements of the AER's proposed STPIS for ENERGEX for the *2010-15 regulatory control period* are set out in the AER's Stage 2: Framework and approach paper. These are summarised in Table 17.2.

Table 17.2 AER's proposed STPIS for ENERGEX for the *2010-15 regulatory control period*

Consideration	AER's position
Maximum annual revenue at risk	▪ ±2% of the average smoothed revenue requirement over 2010-15.
Service performance parameters **included**	▪ Reliability – unplanned SAIDI and unplanned SAIFI by network type: CBD; Urban; Short Rural; and ▪ Customer service – timeliness of telephone call answering.
Service performance parameters **not included**	▪ Reliability – MAIFI; ▪ Customer service – street light repair, new connections and response to written enquiries; ▪ Quality of supply; and ▪ GSL component.

57 In its 2005-10 regulatory arrangements, the QCA decided not to introduce a service incentive scheme with revenue at risk.

17.5.3 ENERGEX's proposed STPIS

This section identifies the main components of ENERGEX's STPIS proposition.

17.5.3.1 Service parameters

ENERGEX proposes to:

- accept the unplanned SAIDI and SAIFI reliability parameters (segmented by CBD, urban and short rural feeder type). This segmentation is consistent with segments proposed in the STPIS (Section 3.2.2), with ENERGEX's current reporting to the QCA and QME and with the AER's Stage 2: Framework and approach paper;
- accept the customer service telephone answering parameter as proposed by the AER with a modification. ENERGEX proposes to apply the Average Speed of Answer (ASA) measure to the fault line rather than the Grade of Service (GOS) in the STPIS Guideline. The ENERGEX fault line is its Loss of Supply (LOS) line, which is measured by the ASA measure. This is a more appropriate measure for ENERGEX's LOS line due to the nature of the technological strategy supporting the LOS line and the fact that this methodology deliberately encourages customers to abandon their calls by providing the most recent outage information to them while they queue (a GOS measure would penalise this). **Appendix 17.2** provides more detail on ENERGEX's reasoning for the use of an ASA measure for telephone answering;
- exclude Momentary Average Interruption Frequency Index (MAIFI) as ENERGEX does not measure this parameter across the network;
- exclude quality of supply parameters as there are no parameters specified in the scheme;
- exclude the GSL component of the scheme because ENERGEX is already subject to such a scheme under the EIC (Clause 6.1(a) of the STPIS Guideline); and
- exclude the remaining three customer service parameters as street light repair is an *alternative control service* and there is insufficient information (including incentive rates) on the other two to justify proposing their inclusion for the *2010-15 regulatory control period*.

17.5.3.2 Revenue at risk – overall

Under the STPIS Version 1.1, the AER set the maximum revenue at risk to be ±5 per cent of ARR. Clause 2.5(b) of the scheme allows ENERGEX to propose different revenue at risk, provided it satisfies the objectives of the scheme. In addition, in the Stage 2: Framework and approach paper the AER proposed a revenue at risk of ±2 per cent of ARR.

ENERGEX proposes to adopt the overall revenue at risk outlined in the Stage 2: Framework and approach with the lower and upper limits of ±2 per cent, subject to a staged introduction. The proposed incremental approach to introduction of overall revenue at risk is in order to enable ENERGEX to understand and prepare for the financial and operational implications of the scheme prior to application of significant financial penalties/rewards. Based on

ENERGEX's average aggregate ARR of $1,423.5 million[58] in $2010-11, the limit of ±2 per cent would result in approximately $28 million of revenue at risk on an annual basis.

ENERGEX considers that this approach satisfies the objectives of the scheme Clause 1.5(b) as outlined below:

- STPIS Clause 1.5(b)(1) requires that the benefits to consumers resulting from the scheme should be sufficient to warrant the reward or penalty. A low powered and incremental approach during the initial introduction of the STPIS would allow ENERGEX to prudently manage its risks and protect the interests of its customers. ENERGEX has not been subject to a service incentive scheme under any previous revenue determinations and the national STPIS is untested having only very recently been formulated.
- STPIS Clause 1.5(b)(2) requires consideration of any relevant regulatory obligation or requirement. Under Section 2.4 of the EIC, ENERGEX has MSS obligations and these must be considered in introducing the STPIS. ENERGEX has a significant operational consideration in regard to the interplay between MSS and STPIS as discussed in Section 17.5.1.
- STPIS Clause 1.5(b)(3) requires consideration of past performance of the distribution network. Over the *current regulatory control period*, ENERGEX's overall reliability performance has improved significantly, particularly in the CBD, and ENERGEX considers that the risk is not symmetrical given there is limited opportunity for further improvement.
- STPIS Clause 1.5(b)(5) requires the incentives to be sufficient to offset any financial incentives to reduce costs at the expense of service levels. Under MSS, ENERGEX is accountable to the Queensland government for improving reliability performance.
- STPIS Clause 1.5(b)(6) requires consideration of the willingness of customers to pay for improved performance. In 2007, ENERGEX engaged KPMG to undertake a study[59] to better understand consumer preferences for electricity distribution service standards (**Appendix 17.3)**. Of the 1,809 customers surveyed, KPMG found that although 39 per cent desired a more reliable electricity supply, only 25 per cent indicated a willingness to pay 'a little more' for a more reliable electricity supply.

This proposed phased introduction is consistent with the transitional arrangements in Clause 11.16.5(3) of the *Rules*, which require the AER to consider the application of the STPIS by way of a paper trial or a lower powered incentive scheme. It is noted that the AER rejected ENERGEX's previous proposal of a paper trial for the full duration of the *regulatory control period* in its Stage 2: Framework and approach paper. In ENERGEX's view, a one year paper trial strikes a reasonable balance between enabling ENERGEX to transition into the STPIS and ensuring that ENERGEX is exposed to the incentive impacts of the STPIS.

58 Rounded for simplicity, the revenue at risk is calculated using the detailed average aggregate ARR.

59 Source: KPMG, *Consumer Preference for Service Standards in Electricity Distribution – Final Report*, January 2008.

In summary, ENERGEX's proposal for overall revenue at risk is to:

- apply a paper trial with no revenue at risk for year 1 (2010-11);
- apply ±1 per cent revenue at risk for year 2 (2011-12); and
- apply ±2 per cent revenue at risk for years 3-5 (2012-13 to 2014-15).

17.5.3.3 Revenue at risk – customer service parameters

Clause 5.2 of the STPIS provides that the upper and lower limits for revenue at risk for the customer service parameters in aggregate must be ±1 per cent, with an individual customer service parameter subject to a limit on maximum permissible revenue at risk of ±0.5 per cent. However, a DNSP may propose different revenue at risk limits where this would satisfy the objectives of the STPIS (Clause 1.5).

ENERGEX proposes to adopt lower and upper limits for the revenue at risk for its telephone answering customer service parameter of ±0.05 per cent, subject to a staged introduction to allow the time for ENERGEX to form a data base from which to forecast targets. Based on ENERGEX's average aggregate ARR of $1,423.5 million in 2010-11, these limits would result in approximately $712,000 of revenue at risk on an annual basis.

ENERGEX considers that this approach satisfies the objectives of the scheme as outlined below:

- Clause 1.5(b)(1) of the STPIS requires that likely benefits to consumers are consistent with the reward or penalty faced by a DNSP in relation to its service performance. A level of revenue of ±0.05 per cent is comparable with approximately 10 per cent of the forecast annual budget for ENERGEX's Network Contact Centre over the *regulatory control period*. The Network Contact Centre delivers a broader range of services than the LOS line and ENERGEX does not believe that the delivery of this broader range of services should be potentially compromised by the operation of the STPIS, focused on only one contact centre service (the LOS line).
- STPIS Clause 1.5(b)(3) requires consideration of past performance of the distribution network. As outlined earlier, ENERGEX has less than one financial year of telephone answering data for its network only contact centre. The historical trends associated with the previous Retail/Network Contact Centre are not representative of performance for the smaller Network Contact Centre. Hence, in the absence of long-term trends there is an insufficient basis on which to forecast STPIS targets for telephone answering for the Network Contact Centre. ENERGEX is particularly concerned that any STPIS targets based on historical performance data prior to 2008-09 would pose an unreasonable financial risk. ENERGEX disagrees with the AER's position in its Stage 2: Framework and approach paper that there would be sufficient data available from the time of the introduction of FRC (from July 2007). In addition, the contact centre transition associated with the trade sale and introduction of FRC was not completed until April 2008. ENERGEX does not consider that there is a satisfactory alternative methodology or benchmark that could be applied to formulate targets.

- STPIS Clause 1.5(b)(6) requires consideration of the willingness of customers to pay for improved performance in service delivery. Customer surveys undertaken by ENERGEX over the past 12 months have revealed high satisfaction levels regarding its Network Contact Centre performance. ENERGEX considers it unlikely that customers would be willing to pay significantly more for improved performance.

In summary, ENERGEX's proposal for the customer service parameter is:

- to apply a paper trial for years 1-2 (2010-11 and 2011-12). A notional target would be established and data would be collected over this period to establish a basis for targets for 2012-13 to 2104-15 (these targets to be confirmed following consultation with the AER in the second half of 2011-12); and
- to apply a revenue at risk of ±0.05 per cent for years 3-5 (2012-13 to 2014-15).

17.5.3.4 Incentive rate – value of customer reliability

Under the STPIS, a DNSP is able to propose and justify an alternative value of customer reliability (VCR) to that specified in the scheme for the CBD segment and all other network segments. A proposal for an alternative VCR must be made in accordance with Section 2.2 of the STPIS, which (among other things) requires ENERGEX to provide reasons and an explanation for the alternative VCR, to demonstrate the consistency of the alternative VCR with the objectives of the STPIS and to set out the calculation of the alternative VCR (Clause 1.5).

ENERGEX has applied the VCRs from STPIS Version 1 (based on the 2002 CRA study) and these are lower than those in the updated Version 1.1 (using the CRA 2007 study). ENERGEX is concerned that small sample sizes were used in both the 2002 and the 2007 studies. Further, the VCR for the CBD segment appears to be a derived value.

ENERGEX has not conducted quantitative studies to determine an alternative VCR. Qualitative studies undertaken by ENERGEX indicate that its customers are not generally prepared to pay for increased reliability. Hence, it is proposed to apply the more conservative VCRs included in the STPIS Version 1.0, to reflect concerns that the small sample sizes and Victorian customer profile may not fully represent the Queensland position.

The basis of concerns regarding the willingness of ENERGEX's customers to pay more for improved reliability (STPIS Clause 1.5(b)(6)) include:

- In 2007, ENERGEX engaged KPMG to undertake a study[60] to quantify and understand consumer preferences for electricity distribution service standards. This study is included in **Appendix 17.3**. KPMG found that only 25 per cent of respondents indicated a willingness to pay 'a little more' for a more reliable electricity supply, while approximately 47 per cent of respondents were not willing to pay more and 28 per cent were open to persuasion; and

60 Source: KPMG, *Consumer Preference for Service Standards in Electricity Distribution – Final Report*, January 2008.

- Issues associated with the upward price effects of ENERGEX's significant investment in its distribution network over the course of the *current regulatory control period* and foreshadowed to continue in the *2010-15 regulatory control period*. Consumer concerns about increasing electricity prices in Queensland due to the cost of this network investment, as well as higher electricity generation costs, have been evident during the QCA's consultation processes associated with its setting of the Retail Cost Benchmark Index for Queensland in 2007-08.

With annual SAIDI levels below five minutes, ENERGEX's CBD reliability performance consistently outperforms other jurisdictions[61]. This very strong absolute and comparative performance is such that it is very difficult to argue that CBD customers would be willing to pay more for improved reliability. Consequently ENERGEX proposes that the CBD value be set at the same level as for urban and short rural segments.

Given these factors, ENERGEX considers that a uniform VCR of $29,600/MW.h adjusted for CPI will provide sufficient incentive to offset any financial incentives it may have to reduce service levels (Clause 1.5(b)(5)).

17.5.3.5 Incentive rate – telephone answering parameter

ENERGEX proposes to apply the incentive rate of 0.040 per cent as set out in the scheme (STPIS, Clause 5.3.2(a)), although it is adjusted in the formula to remove the negative sign (i.e. ENERGEX would apply +0.040 per cent rather than -0.040 per cent). This is discussed in **Appendix 17.2**.

17.5.3.6 Incentive rate – SAIDI and SAIFI weightings

ENERGEX proposes to apply the weightings for unplanned SAIDI and SAIFI as set out in the scheme (STPIS, Clause 3.2.2, Table 1).

17.5.3.7 Application of formulas – calculated incentive rates for reliability

Clause 3.3.2 and Appendix B of the STPIS Guideline outline how incentive rates should be calculated for the reliability parameters. Table 17.3 summarises ENERGEX's proposed incentive rates for the *2010-15 regulatory control period* based on these requirements.

61 Source: AER, *State of the Energy Market 2008,* Figure 5.10a.

Table 17.3 Proposed incentive rates

Parameter	Segment	Incentive rate	Unit of measure
CBD	SAIFI	0.2946	Per 0.01
Urban	SAIFI	3.1216	Per 0.01
Rural	SAIFI	0.8075	Per 0.01
CBD	SAIDI	0.0032	Per minute
Urban	SAIDI	0.0467	Per minute
Rural	SAIDI	0.0099	Per minute
Telephone answering	N/A	0.0400	Seconds

The input values applicable in the calculation were:

- VCR for the network type, escalated to the start of the *regulatory control period*. The VCR for CBD, Urban and Short Rural is $37,885, as outlined in STPIS Guideline Version 1.0 and adjusted for CPI[62].
- Average Energy Consumption by network type. The percentage split was based on calculated energy consumption per feeder, which was then 'rolled up' to feeder category level by network type. This data is based on 2007-08 feeder loading data. The forecast average annual energy over the *regulatory control period* is 24,047,200 MW.h. Of this, five per cent has been attributed to the CBD segment, 78 per cent to the urban segment and 17 per cent to the Short Rural segment.
- Average of the smoothed ARR for 2010-15 is forecast at $1,423.5 million expressed in $2010.
- The average of the unplanned SAIDI targets in 2010-15 by network type are:
  - CBD segment: 3.3 minutes;
  - Urban segment: 66.09 minutes; and
  - Short Rural segment: 159.11 minutes.
- The average of the unplanned SAIFI targets in 2010-15 by network type are:
  - CBD segment: 0.032;
  - Urban segment: 1.020; and
  - Short Rural segment: 2.123.

---

62 The CPI escalation to June 2010 is as follows:

- escalate 2002 VCRs to June 2008 values using ABS CPI June Quarter 2008 (for Brisbane); and
- escalate the June 2008 VCR values to June 2010 using a CPI assumption of 2.45 per cent.

17.5.3.8 Summary of STPIS targets

Under the STPIS, targets are to be based on average performance over the previous five financial years and adjusted to reflect the impact of capital and operating programs included in previous regulatory determinations and prospectively in this *Regulatory Proposal*. In the absence of five years of financial data, an alternative methodology or benchmark is to be proposed.

ENERGEX's proposed targets have been established having regard to the relevant provisions of the STPIS and the guiding principles identified above. These targets are summarised in Table 17.4 and Table 17.5 and represent STPIS targets for reliability (unplanned SAIDI and unplanned SAIFI) and a notional STPIS target for telephone answering (to be applied during the first two years).

Table 17.4 Proposed STPIS SAIDI and SAIFI targets for 2010-11 to 2014-15

	SAIDI (unplanned)			SAIFI (unplanned)		
	CBD	Urban	Short rural	CBD	Urban	Short rural
2010-11	3.3	69.37	173.19	0.032	1.044	2.285
2011-12	3.3	67.73	164.44	0.032	1.032	2.201
2012-13	3.3	66.01	157.95	0.032	1.020	2.120
2013-14	3.3	64.29	152.37	0.032	1.008	2.041
2014-15	3.3	63.03	147.60	0.032	0.996	1.967

Table 17.5 Proposed notional telephone answering targets for 2010-11 to 2014-15

	2010-11	2011-12	2012-13	2012-14	2014-15
ASA	35*	35*	**	**	**

* *Notional targets.*

*** ENERGEX proposes to seek the AER's approval for confirmed targets for 2012-15 following assessment of the ASA performance data from 2008-09 to 2011-12.*

17.5.3.9 Methodology to develop targets

The methodology to derive these reliability targets is outlined in **Appendix 17.4**. ENERGEX engaged consultants (Evans & Peck) to develop the methodology and their report is in **Appendix 17.5**. The reliability targets are based on normalised historical performance data, adjusted to account for the impact of ENERGEX's forward reliability programs.

The forecast STPIS targets are based on the assumption that ENERGEX implements the works program and achieves stated gains as discussed in **Appendix 17.5**. The telephone answering targets are notional targets as discussed earlier. There is insufficient historical data to establish STPIS targets for the Network Contact Centre and ENERGEX does not consider there is a satisfactory alternative methodology or benchmark. Notional targets based on historical performance of the Retail/Network Contact Centre combined with the Network Contact Centre will be used for a paper trial until indicative performance data is available. The methodology to establish these is outlined in more detail in **Appendix 17.6**.

If the AER does not accept the capital and operating programs as forecast in this *Regulatory Proposal*, the STPIS targets will require revision.

18 Annual revenue requirements

The *Rules* require ENERGEX to prepare its *building block proposal* in accordance with the AER's PTRM. The AER's PTRM is based on the building block approach that provides allowances for return on capital, return of capital, operating expenditure and taxation.

The purpose of this chapter is to outline ENERGEX's revenue requirements for the *2010-15 regulatory control period* for *standard control services* including:

- key requirements of the *Rules* and transitional arrangements;
- an overview of the completed PTRM and ENERGEX's total revenue requirements;
- ENERGEX's proposed control mechanism for *standard control services*;
- the methodology used by ENERGEX to calculate its proposed revenue requirements;
- proposed X factors (including the first year X factor termed the P_0);
- ENERGEX's proposed CC Bank mechanism;
- indicative prices; and
- TUOS arrangements.

Revenue requirements in relation to *alternative control services* are set out in Part 2 of this *Regulatory Proposal*.

18.1 Summary

A summary of ENERGEX's proposed smoothed revenue requirements and X factors for the *2010-15 regulatory control period* for *standard control services* is shown in Table 18.1. The table provides a summary of ENERGEX's final revenue requirements as calculated from the AER's PTRM in **Attachment 3** and relevant adjustments and proposed smoothing as shown in **Attachment 5**.

Table 18.1 Smoothed revenue requirements over *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Notional building block revenue (PTRM)	1,282.5	1,430.7	1,592.9	1,760.4	1,900.0
Revenue adjustments*	(142.4)	(73.2)	(75.9)	(79.1)	(80.7)
Adjusted Notional Revenue	1,140.1	1,357.5	1,517.1	1,681.3	1,819.3
Smoothing	62.6	(21.3)	(32.6)	(32.1)	12.2
Smoothed building block revenue	1,202.7	1,336.2	1,484.5	1,649.2	1,831.5
X factors	-25.3%	-8.4%	-8.4%	-8.4%	-8.4%

Total may not add due to rounding.

**Revenue adjustments are discussed in detail in Table 18.3.*

The PTRM is modelled based on a revenue cap control mechanism as determined by the AER in the Stage 1: Framework and approach paper.

18.2 Regulatory information requirements

A distribution determination is predicated on the AER's decisions on the following:

- Clause 6.12.1(2) – a decision on ENERGEX's *building block proposal* which sets out the ARR for each regulatory year.
- Clause 6.12.1(17) – a decision on the procedures for assigning and reassigning customers to tariff classes.
- Clause 6.12.1(19) – a decision on how ENERGEX 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 under or over recovery of those charges.

Clause 6.8.2(c)(2) requires a *building block proposal* for *standard control services*.

Clause 6.3.1(c)(1) and Clause S6.1.3(10) require that the *building block proposal* must be prepared in accordance with the PTRM.

Clause S6.1.3(6) requires that the *building block proposal* contain ENERGEX's calculation of revenues or prices for the purposes of the control mechanism proposed by ENERGEX.

Clause 6.3.2 lists the matters ENERGEX must address in relation to its *building block proposal* including the ARR for each regulatory year of the *regulatory control period*, the appropriate indexation methods, application of the relevant schemes and any other amounts, values or inputs relevant to the calculation.

Clause 6.5.9 requires that a building block determination must include the X factor for each control mechanism for each regulatory year of the *regulatory control period*. The X factor must be designed to provide ENERGEX with a NPV neutral revenue over the *regulatory control period* and to minimise any variance of the expected revenue in the last regulatory year.

In relation to prices, Clause 6.8.2(c)(4) requires that ENERGEX's *Regulatory Proposal* include indicative prices for direct control services for each year of the *regulatory control period*.

In addition to these Rule requirements, Clause 2.4.2 of the RIN requires the inclusion of information regarding X factors that ENERGEX considers relevant.

Clause 2.2.5 of the RIN requires the following information in relation to *standard control services* be provided:

- the name and a description of each individual *standard control service* provided by ENERGEX that is the subject of the *Regulatory Proposal*.
- actual customer numbers, revenue and prices for equivalent services provided in each regulatory year of the *current regulatory control period*.
- indicative prices for each individual *standard control service* in each regulatory year of the next *regulatory control period*.

18.3 Queensland transitional arrangements

Under the transitional arrangement outlined in Clause 11.16.10, ENERGEX may continue with the approach adopted by the QCA in relation to the inclusion of capital contributions from customers in the RAB. To offset the inclusion of these contributed assets, the equivalent amount is deducted from the revenue determined for the year that the assets are received and included in the RAB. This approach is consistent with Clause 6.21.2 (3) which states that 'where assets have been the subject of contribution or prepayment, the DNSP must amend the revenue related to the provision of direct control services'. ENERGEX has proposed to continue with this approach for the *2010-15 regulatory control period*.

In addition, as provided for in the transitional arrangements under Clause 11.16.3, ENERGEX has retained all of its non-system assets in its RAB. An adjustment to the revenue as calculated by the PTRM for *standard control services* is required to account for the portion of non-system assets used in the provision of *alternative control services*.

18.4 Approach to determining revenue requirement

In this *Regulatory Proposal*, ENERGEX has utilised the AER's PTRM and PTRM Handbook to derive the revenue building blocks. The completed PTRM for *standard control services* is provided in **Attachment 3**. Components of the building block revenue and other relevant inputs to the PTRM have been discussed in detail as follows:

- Chapter 12: Forecast operating expenditure;
- Chapter 13: Forecast capital expenditure;
- Chapter 14: Regulatory Asset Base;
- Chapter 15: Depreciation;
- Chapter 16: Return on capital, inflation and taxation; and
- Chapter 17: Application of schemes.

The building block formula to be applied in each year of the *regulatory control period* is:

ARR = Return on capital + Return of capital + Opex + Tax
= (WACC x RAB) + D + Opex + Tax

Where:

- ARR = Annual Revenue Requirement
- WACC = Post tax nominal *weighted average cost of capital*
- RAB = Regulatory Asset Base
- D = Regulatory depreciation (nominal depreciation – indexation of the RAB)
- Opex = Operating and maintenance expenditure
- Tax = Benchmark tax allowance

The notional (unsmoothed) building block revenue requirement for ENERGEX over the *2010-15 regulatory control period* is then adjusted for increments and decrements as provided for in the *Rules*, in particular Clauses 6.21.2(3) (Capital Contributions), 6.4.3.(a)(5) (Schemes), 6.4.3(a)(6) (adjustments carrying over from the *current regulatory control period*) and 11.16.3 (RAB).

The adjusted allowable revenue is then smoothed to determine X factors in accordance with the requirements of the *Rules*. The smoothing mechanism adopted by ENERGEX is the method outlined for the revenue cap methodology in the AER's PTRM.

To determine the P_0 adjustment (the X factor applying to the initial year), ENERGEX has used the 2009-10 allowable revenue as advised by the QCA which incorporates the following:

- *QCA's 2005 final determination*;
- *ENERGEX's application for capital expenditure cost pass through*;
- *FRC pass through*;

- adjustment for prior years' under and over DUOS and capital contribution recoveries; and
- excluded services revenue allocation.

Revenue in subsequent years is then adjusted by appropriate X factors selected to minimise annual price volatility to customers and to comply with Clause 6.5.9. The adjustments and proposed smoothing is detailed in **Attachment 5**.

18.5 Completed post tax revenue model

The notional building block revenue requirement for each year of the *2010-15 regulatory control period*, as shown in Table 18.2, is calculated as the sum of the return on capital, return of capital, operating and maintenance expenditure and the benchmark tax liability.

Table 18.2 Building block revenue requirements for *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-11	2013-14	2014-15	Total NPV
Return on capital	748.5	863.5	983.8	1,109.4	1,234.7	**3,710.1**
Return of capital (regulatory depreciation)	87.1	96.4	108.0	119.5	120.6	**402.1**
Operating expenses	363.8	378.8	399.2	419.0	423.9	**1,513.4**
Benchmark tax liability	83.0	92.1	102.0	112.4	120.8	**385.3**
Notional building block revenue	1,282.5	1,430.7	1,592.9	1,760.4	1,900.0	**6,010.9**

Total may not add due to rounding.

As shown in Table 18.2, the notional building block revenue requirements will increase from $1,283 million in 2010-11 to $1,900 million in 2014-5.

18.6 Revenue cap adjustments

ENERGEX's notional building block revenue requirement, derived from the PTRM, must then be adjusted for:

- revenue expected to be received via the DMIA;
- under and over DUOS and capital contribution recoveries carrying over from the *current regulatory control period*;
- any capital contributions forecast to be received over the *2010-15 regulatory control period*; and
- revenue associated with non-system assets used to provide *alternative control services*.

ENERGEX's revenue requirements adjusted for these factors are shown in Table 18.3 and in **Attachment 5**.

Table 18.3 ENERGEX adjusted revenue requirement over *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Notional building block revenue	1,282.5	1,430.7	1,592.9	1,760.4	1,900.0
DMIA	1.0	1.0	1.0	1.0	1.0
Under and over DUOS and capital contribution recoveries (current period)	(74.2)	-	-	-	-
Capital contributions	(64.6)	(68.9)	(70.9)	(73.6)	(75.7)
Non-system asset revenue adjustment	(4.5)	(5.3)	(5.9)	(6.5)	(6.0)
Adjusted notional revenue	1,140.1	1,357.5	1,517.1	1,681.3	1,819.3

Total may not add due to rounding.

18.6.1 DMIA adjustments

On page 45 of the Stage 2: Framework and approach paper, the AER has decided that the DMIS that applies to ENERGEX will be in the form of a DMIA of $5 million over the *regulatory control period*. ENERGEX has included an amount of $1 million per annum over the *2010-15 regulatory control period* for the DMIA. This allowance is an increment to ENERGEX's notional building block revenue requirement.

18.6.2 Current regulatory control period over recovery adjustments

In line with regulatory arrangements for the *current regulatory control period*, ENERGEX must return any over recoveries of DUOS and Capital Contributions. The forecast revenue requirement has been adjusted to reflect forecast over recoveries for 2008-09 and 2009-10. The adjustments for the over recovery are decrements to the notional building block revenue requirement.

18.6.3 Capital contributions adjustment

In Queensland, assets arising from capital contributions from customers are included in the RAB. An amount equivalent to the value of the asset is deducted from the revenue determined for the year that the assets are received and included in the RAB. This is consistent with Clause 6.21.2(3) which states that 'where assets have been the subject of contribution or pre-payment, the DNSP must amend the revenue related to the provision of direct control services'.

Under the transitional arrangement as outlined in Clause 11.16.10, ENERGEX may continue with the approach adopted by the QCA. ENERGEX has proposed a capital contributions approach for the *2010-15 regulatory control period* that is consistent with the approach in the *QCA's 2005 final determination*.

Forecast capital contributions are comprised of both in-kind and cash contributions. For the *2010-15 regulatory control period*, the methodology for forecasting each type of contribution is as follows:

- In-kind contributions: based on anticipated growth in subdivision lots (based on historical trends) and increased contribution rates following an update to the capital contributions policy.
- Cash contributions: based on historical trends and adjusted for any known material changes.

Capital contributions will be decrements to the notional revenue requirements.

18.6.4 Non-system asset revenue adjustment

An adjustment to ENERGEX's revenue requirement is necessary for revenue associated with non-system assets, used in the provision of *standard control services* and *alternative control services*. The adjustment reflects the amount of the revenue requirement that is associated with the non-system assets used for the provision of *alternative control services*. This adjustment is consistent with Clause 11.16.3 as discussed in Section 18.3.

The methodology for calculating the revenue attributable to *alternative control services* for non-system assets is based on the forecast expenditure for *alternative control services* as a proportion of forecast total expenditure (for all services), where total spend includes capital and operating expenditure.

Non-system asset revenue adjustments will be decrements to the notional revenue requirements.

18.7 X factors

ENERGEX has proposed X factors that comply with the requirements of Clause 6.5.9, as shown in Table 18.4. The proposed X factors are based on a scenario with an initial year revenue increase (P_0) followed by moderate increases over the remaining years of the *2010-15 regulatory control period* with a final X factor that allows for a smooth transition into the following regulatory period. A negative X factor indicates an increase in the ARR. Indicative network prices for *Standard Control Services* are discussed below in Section 18.9.

Table 18.4 Proposed X factors over the *2010-15 regulatory control period*

	2010-11	2011-12	2012-13	2013-14	2014-15
X factor	-25.3%	- 8.4%	-8.4%	-8.4%	-8.4%

** Under the Rules the control mechanism must be the CPI minus X form, indicating a revenue increase.*

The X factor smoothing proposed by ENERGEX satisfies the requirements of Clause 6.5.9(b)(2) and (3) of the *Rules* in that it meets the following criteria:

- the ARRs are equal to the NPV of the annual building block revenue requirements; and
- the expected revenue for the last regulatory year (2014-15) is as close as reasonably possible to the ARR for that year.

As shown in Table 18.5, ENERGEX's proposed X factors result in the following smoothed revenue requirement for the *2010-15 regulatory control period.*

Table 18.5 ENERGEX smoothed revenue requirement for the *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15	Total NPV
Adjusted notional Revenue	1,140.1	1,357.5	1,517.1	1,681.3	1,819.3	**5,655.7**
Smoothing	62.6	(21.3)	(32.6)	(32.1)	12.2	**0.0**
Smoothed building block revenue	1,202.7	1,336.2	1,484.5	1,649.2	1,831.5	**5,655.7**

Note: numbers may not add due to rounding.

18.8 Capital contributions bank

ENERGEX considers that the current treatment of capital contributions via the under and over recovery mechanism is not consistent with the methodology used in the building block to determine revenue for the regulatory period. Expenditure on works for which capital contributions are received is included in the forecast capital expenditure program and the building block approach to determining revenue requirements is based on this forecast amount. To the extent that the actual capital contribution is above forecast, no extra revenue is earned within the regulatory period. This is because the revenue has been pre-determined on a RAB based on the forecast capital expenditure. The extra capital expenditure will however be rolled into the RAB for the subsequent regulatory period and ENERGEX will start to earn a ROA and return of asset from that time.

In accordance with Clause 6.21.2(3) of the *Rules*, contributed assets that form part of ENERGEX's RAB must have a revenue adjustment to ensure that a return on and of asset is not earned twice on these contributed assets. The key issue is the timing of the revenue adjustments.

Under the current regulatory arrangements, under and over recovery of capital contributions are adjusted in accordance with the normal annual revenue adjustments (i.e. with a two year lag) of a revenue cap control mechanism.

ENERGEX is proposing an adjustment mechanism in the form of a CC Bank to align the recovery of revenue with the timing of inclusion of the contributed assets in the RAB. Under the proposed arrangement, capital contribution forecast amounts would continue to be included in the building block revenue determination. Any variation to this forecast amount will be adjusted on an ex-post basis at each regulatory reset. This will require variations for capital contributions to be quarantined until the end of the *regulatory control period*. A revenue adjustment would be applied at the start of the next regulatory period when the contributed assets are included in the RAB.

The operation of this CC Bank mechanism is outlined in the following section.

18.8.1 Operation of the CC bank

ENERGEX proposes the application of a CC Bank mechanism in lieu of the current process of effecting annual revenue adjustments to reflect the variance between actual and forecast capital contributions for *standard control services*.

The CC Bank provides an efficient approach to dealing with cash and in-kind capital contributions received for *standard control services*. It would not impose additional costs on ENERGEX's customers in NPV terms.

Under a CC Bank:

- the indexed value of cash and in-kind contributions revenues would be banked throughout the regulatory period;
- indexation would reflect ENERGEX's approved post-tax nominal WACC to preserve the time value of money and in so doing protect the interests of both ENERGEX and its customers;
- balances would be cleared as part of any P_O revenue adjustment made at the commencement of the subsequent *regulatory control period*; and
- ENERGEX would provide annual reports to the AER on the value of the actual capital contributions for the year and the value of the CC Bank balance.

The CC Bank arrangement would commence for capital contributions received from 1 July 2010 onwards. The forecast adjustment for Capital Contributions received in 2008-09 has been incorporated into the P_O for the *2010-15 regulatory control period* and any variations to this forecast will be treated under the normal annual unders and overs process. Any under or over recovery for the 2009-10 year will also be treated in accordance with current regulatory arrangements.

Appendix 18.1 provides more detail on the CC Bank and its operation.

18.9 Indicative prices

This section outlines the indicative prices for ENERGEX's *standard control services*. Indicative prices for *alternative control services* are provided in Chapters 21 and 22.

As per the AER's Stage 1: Framework and approach paper, *standard control services* for ENERGEX are the DUOS services, namely network, connection (excluding the design and construction of large connection assets) and metering services.

Indicative prices for DUOS services are provided in Table 18.6 and in pro forma 2.2.5 in **Attachment 1.** These prices have been produced using the energy forecasts in Chapter 10, and the ARR and X factors calculated by the PTRM outlined above. Overall, in calculating the ARR, ENERGEX has utilised smoothing options to minimise price volatility for customers and allow a smooth transition into the following regulatory period. Average indicative network prices for each customer class have been calculated by using the average network price for 2009-10 and escalating this by the average total network price arising from the application of the P_0 and X factors across the *2010-15 regulatory control period*. This differs to the actual pricing process which uses a distributed cost model to determine cost reflective prices for individual customers.

Table 18.6 Indicative DUOS prices (c/kW.h nominal)

Customer class	2010-11	2011-12	2012-13	2013-14	2014-15
Individually calculated customers	1.65	1.77	1.90	2.04	2.18
Connection asset customers (CAC)	2.23	2.40	2.56	2.76	2.94
Standard asset customers*	6.53	7.03	7.52	8.10	8.63

All indicative prices are exclusive of GST.

Indicative prices have been shown in nominal cents per kW.h for energy consumed but it should be noted that actual prices depend on the specific tariffs which are made up of a number of components of fixed, energy, demand and capacity charges. For this reason these prices are indicative only, are not binding and are only to provide a high level overview of the expected price impact for the next regulatory period.

The actual prices will be determined based on the ARR, X factors, any pass through events during the *2010-15 regulatory control period*, and the annual pricing proposals submitted by ENERGEX to the AER for approval each year of the *regulatory control period* in accordance with Clause 6.18.7 of the *Rules*.

ENERGEX notes that a significant proportion of the average price increase from 2009-10 to 2010-11 is a result of:

- recognition of the increased costs associated with the operation and maintenance of the ENERGEX network to deliver the required capacity, reliability and security;

- operational expenditure claw backs applied by the QCA during the *current regulatory control period*, relating to the prior *regulatory control period*, that resulted in a non NPV neutral adjustment for the *current regulatory control period;* and
- inclusion of additional prudent and efficient capital expenditure in the *current regulatory control period* rolling into the RAB at the commencement of the *2010-15 regulatory control period*.

18.9.1 Assigning customers to tariff classes

As part of the determination process, Clause 6.12.1(17) requires the AER to make a decision on the procedures for assigning and reassigning customers to tariff classes. This section outlines ENERGEX's proposed approach to the assignment and reassignment of customers to tariff classes, consistent with the principles outlined in Clause 6.18.4 of the *Rules*.

In line with the requirements of Clause 6.18.4(a)(1), ENERGEX's customer assignment to tariff class is determined based on the sequential assessment of the following criteria:

- energy consumption;
- voltage level;
- meter type;
- demand; and
- for unmetered supply, whether the supply is for street lighting or other unmetered supplies.

A pictorial representation of this process is outlined in **Appendix 18.2.**

In addition to the above, the following guidelines apply:

- Allocation of an embedded generator customer to a network tariff will be made on the same basis as other connections.
- Allocation of a customer with micro-generation facilities to a network tariff will be made on the same basis as other connections.
- Where a new network tariff is applied to a customer, the backdating of the new network tariff beyond the current billing period is not standard practice and is only permitted where approved by ENERGEX.
- Customers are allowed one tariff change per 12-month period unless approved by ENERGEX. This is to limit unnecessary transaction costs and ensure pricing signals are not distorted by constant change in customer tariff assignment.
- For new connections with no previous load history, the default tariff is based on the customer type and their expected energy usage, supply voltage and meter type.

In accordance with Clause 6.18.4(a)(4) and 6.18.4(b), assignment of customers to network tariffs is reviewed periodically to assess if the tariff assignment is still applicable given potential changes in annual usage and meter type. Any changes in voltage are treated as if it was a new connection.

To mitigate variability in tariff assignment/reassignment and subsequently limit customer impact, ENERGEX applies a tolerance limit of 20 per cent around tariff thresholds.

This procedure for assigning and reassigning customers to tariff classes reflects the procedure published in the 2009-10 price schedule and is consistent with the requirements of Clause 6.18.4. This procedure relates specifically to the application of mandated tariffs. Where voluntary tariffs are offered by ENERGEX, customers will only be assigned to those tariffs if it is specifically requested by the customer.

ENERGEX believes this approach satisfies the requirements of Clauses 6.18.3(d) and 6.18.4, namely:

- balancing the grouping of customers on an economically efficient basis with the need to avoid unnecessary transaction costs; and
- ensuring customers with a similar connection and usage profile are treated on an equal basis and customers with micro-generation facilitates are not treated less favourably.

18.9.2 TUOS pass through

As part of the determination process, Clause 6.12.1(19) requires the AER to make a decision on the method for reporting recovery of TUOS charges and adjustments for under or over recovery of those charges. This section outlines ENERGEX's proposed approach to the treatment of TUOS recovery, consistent with the requirements of the *Rules*.

In accordance with Clauses 6.18.2(b)(6) and 6.18.7 of the *Rules*, tariffs outlined in ENERGEX's initial and annual pricing proposals will allow for the pass through of charges for TUOS services, including any adjustments for under or over recovery. To comply with Clauses 6.18.2(b)(6) and 6.18.7, information reported as part of the annual pricing proposal will include:

Payments:

- regulated transmission charges paid to Transmission Network Service Providers (TNSP);
- avoided TUOS payments to embedded generators; and
- payments made to other DNSPs for use of their network.

Receipts:

- payments received from network users; and
- payments received from other DNSPs.

Adjustments for under/over recovery:

Difference between receipts and payments.

ENERGEX's transmission cost recovery tariffs will be based on a forecast of TUOS charges for each year, adjusted for under or over recoveries to be applied that year. Where administratively efficient and locational signals are material, the forecast TUOS charges will be passed on to customers in the same form of price structure as received from the TNSP. The under or over adjustments are based on a two year implementation lag to reflect timing of annual reporting and the price approval process. To demonstrate compliance with Clauses 6.18.2(b)(7) and 6.18.17 the under or over recovery will be maintained in a Transmission Unders and Overs account and be calculated as per the formula below:

Unders and overs adjustments to be applied in year t	=	TUOS paid by DNSP in t-2 minus the TUOS recovered from customers in year t-2

To maintain NPV neutrality to the cash value of the under and over balance, ENERGEX will apply an indexation rate of the approved WACC for the *regulatory control period*.

19 Outcomes of regulatory proposal

In the *current regulatory control period* to June 2010 ENERGEX has accelerated operations to efficiently deliver record capital and operating programs and submits that it has the capability, capacity and resources to deliver the proposed capital and operating programs for the *2010-15 regulatory control period*.

This chapter provides a summary of this *Regulatory Proposal* and discusses the outcomes in terms of reliability, network security, impacts on prices and financial sustainability for ENERGEX's business and its customers and stakeholders.

19.1 Balanced outcomes

In preparation of this *Regulatory Proposal*, ENERGEX has remained cognisant of the need to achieve a balanced result when faced with often competing objectives in relation to customer outcomes, business sustainability and risk management.

The key objectives of the programs that result in the operating and capital expenditure programs contained in this *Regulatory Proposal* are:

- meeting the capacity requirements arising from sustained growth;
- meeting customer reliability and service requirements;
- progression toward security compliance;
- prudent management in relation to the renewal and replacement of assets;
- working efficiently within the characteristics of SEQ's operating environment; and
- establishing a sound platform for an effective response to the management of electricity distribution in a contemporary age.

ENERGEX believes the proposed capital and operating expenditure contained in this *Regulatory Proposal* is necessary to comply with the operating and capital expenditure objectives of the Rules. The implementation of the recommendations of the EDSD, which were subsequently endorsed by the Queensland parliament, are viewed as essential to ensure a reliable electricity supply to Queenslanders.

While ENERGEX has made substantial progress towards EDSD compliance in the *current regulatory control period*, achievement will require record investment in compliance based projects for more than 10 years. Although some projects satisfy the dual objectives of meeting demand growth and compliance (security and reliability), during the sustained growth period experienced in the SEQ region, projects that meet demand for electricity have retained priority.

This *Regulatory Proposal* for ENERGEX's electricity network has been prepared to progress toward EDSD compliance at the same time as striking a balance between the impact on customers, business sustainability and management of risk.

The revenue outcome from this *Regulatory Proposal* is required to support the nominated programs and recognises that investment in electricity infrastructure requires long-term financial sustainability, based on sound management of electricity assets with an operational life expectancy of between 40-60 years.

19.2 Preparation of this regulatory proposal

Key drivers for network expenditure include continued growth, albeit at a more moderate rate than experienced in the past, progression toward security compliance, renewal and replacement of assets as well as meeting reliability standards.

This *Regulatory Proposal* ensures investment in network augmentation continues, while at the same time includes expenditure on accepted technologies to modernise existing infrastructure to more closely align with changing customer expectations of electricity networks. Development of a platform for DM initiatives in the *2010-15 regulatory control period* is critical to the realisation of cost effective alternatives to network augmentation in the future.

Preparation of this *Regulatory Proposal* was further challenged by the uncertainty surrounding recent events in financial and energy markets. The baseline capital program for this *Regulatory Proposal* was developed using forecasts prepared at the end of 2008.

ENERGEX has sought to accommodate an anticipated reduction in peak demand relative to the 2008 forecast by making a reduction in forecast demand which equates to approximately 550 MW at the end of the *2010-15 regulatory control period*.

ENERGEX has also committed to reviewing the capital expenditure forecasts and program following the finalisation of the 2009 forecasts.

19.3 Components of regulatory proposal

ENERGEX submits that a forecast capital expenditure of $6,466 million is required for the *2010-15 regulatory control period*. The main drivers of growth, security compliance, replacement and refurbishment of assets and provision of reliability, account for 90 per cent of this expenditure.

ENERGEX submits a forecast operating expenditure of $1,843.1 million is required for the *2010-15 regulatory control period*. This investment represents the cost of operating and maintaining a significantly expanded electricity network, the integration of a Condition Based Risk Management of assets and establishes a platform for the development of efficient demand-side management solutions.

ENERGEX's forecast expenditure for the *2010-15 regulatory control period* has been developed as an integrated package, containing capital and operating programs to deliver ENERGEX's obligations and responsibilities.

Provisions such as cost pass through nominations and escalation forecasts have been incorporated to manage the risks that ENERGEX can foresee for both customers and itself over the *2010-15 regulatory control period*.

Targets for STPIS have been established based on the progressive delivery of the capital and operating programs incorporated in this *Regulatory Proposal*. Movements in these expenditure programs will require a consequential adjustment to STPIS targets.

ENERGEX submits that the interrelated nature of the components of this *Regulatory Proposal* require its consideration as an integrated package. Modifications to any one element will have a consequential effect on the other elements of this total package.

19.4 Outcomes

ENERGEX's *Regulatory Proposal* represents a balanced outcome that provides value for our customers, manages risk, and builds a sustainable future. In summary, this *Regulatory Proposal* provides for:

Customer outcomes – ENERGEX has balanced customer needs and expectations against the investment program necessary to meet and manage forecast demand, improve reliability and provide security of electricity supply. Overall this *Regulatory Proposal* provides value for customers that reflect the long-term interests of the community.

Reliability outcomes – ENERGEX's forecast expenditure contains the programs required to deliver the reliability performance as outlined by the EIC and as required by other statutory and industry based obligations. Increased focus on preventative maintenance is key to an enhanced reliability outcome over the *2010-15 regulatory control period.*

Security outcomes – A significant component of ENERGEX's capital program is allocated to meet compliance with security standards. This expenditure is required to reduce the level of load at risk under an N-1 scenario. The programs and projects contained in ENERGEX's forecast expenditure will result in an improved security outcome for customers.

Financial outcomes – ENERGEX has assessed the impacts of this *Regulatory Proposal* in terms of the financial sustainability of its network business. The analysis identified that a lower revenue requirement will impact on ENERGEX's ability to meet regulatory obligations, including those within its distribution licence.

This *Regulatory Proposal* will deliver the following benefits:

- A 40 per cent increase or 6,514 MV.A of additional capacity;
- Infrastructure with capacity to accommodate a 24 per cent increase or an additional 1,247 MW in demand;

- 56 new zone substations and four bulk supply substations;
- A 12 per cent improvement in reliability as measured by the SAIDI;
- Reduction in compliance load at risk from 135 MV.A to 7 MV.A for bulk supply substations and from 444 MV.A to 213 MV.A for zone substations programs;
- Ongoing safety, service delivery and operation of the electricity network to levels required by SEQ customers; and,
- Development of alternative solutions to manage the network in a financial and environmentally sustainable way.

19.5 Customer pricing outcomes

The ongoing average price increases across the *regulatory control period* are necessary for ENERGEX to deliver the capital and operating expenditure programs which support development and growth in SEQ as well as improving reliability and security of supply. Overall the network charges that will be applied through electricity prices will rise as a result of this investment program from 4.20 c/kW.h[63] to 5.37 c/kW.h in 2010-11. Using the Benchmark Retail Cost Index published by the QCA, ENERGEX has calculated the impact of the changes in network prices on the notified prices that customers pay. If all other components of the notified prices increase at the rate of predicted inflation, the increase in 2010-11 will be approximately 10 per cent. This will be followed by annual increases of approximately 4 per cent for the following four years.

63 All indicative prices are exclusive of GST.

20 Pass through events

The regulatory framework recognises that a distribution business cannot be reasonably expected to forecast costs for all foreseen and unforeseen events over the *regulatory control period*.

The *Rules* define a number of events which cannot be reasonably foreseen at the time of the determination, for which a pass through of costs (positive or negative) would apply. Pass through events for distribution determinations are defined in Chapter 10 of the *Rules* as follows:

- a regulatory change event;
- a service standard event;
- a tax change event; and
- a terrorism event.

These defined pass through events are summarised in **Appendix 20.1.**

A distribution determination may also nominate events, in addition to those listed above, as pass through events.

This chapter sets out ENERGEX's nominated pass through events for direct control services (inclusive of *standard control services* and *alternative control services*).

20.1 Summary

The *Rules* provide for and define a number of events which cannot be reasonably foreseen at the time of submitting this *Regulatory Proposal*, for which a pass through of costs is appropriate.

Consistent with the *Rules*, ENERGEX submits that the following events, of which the cost and timing impacts cannot be forecast at this time, will have a material effect on ENERGEX's costs if they were to occur and therefore should be included as additional pass through events:

- Specific pass through events for the following:
  - a feed-in tariff event;
  - a smart meter event;
  - a CPRS event;
  - an OH&S event;
  - a Henry Review event;

- a RIO reporting event;
- an NECF event;
- a national broadband network (NBN) event;
- a GSL event; and
- a storm disaster event.

- A general nominated pass through event.

ENERGEX proposes that a threshold that is commensurate with the administrative costs of assessing the pass through application be applied for specific nominated events. ENERGEX strongly disagrees that annual revenue is the only basis on which materiality for general nominated pass through events should be assessed, as this is a very arbitrary approach and does not provide for appropriate incentives for a DNSP to provide a prudent response to an 'event' and could lead to some perverse behaviour. ENERGEX instead submits that a fairer and more reasonable approach to measuring the materiality threshold for a general nominated pass through events is to include an absolute dollar materiality threshold in addition to a per cent of (average) annual revenue materiality threshold, and that costs should be assessed as material when the total of those costs (and not just the costs incurred in any one year) exceed the relevant materiality threshold. For general nominated pass through events, ENERGEX proposes that the lower of $5 million or one per cent of average annual revenue per event be applied.

ENERGEX also proposes that the additional nominated (specific and general) and defined pass through events will apply to all direct control services (both *standard control services* and *alternative control services*).

20.2 Regulatory information requirements

Clause 6.12.1 of the *Rules* provides that a distribution determination is predicated on the AER making constituent decisions on several matters. Additional pass through events is one of the matters and is provided for under Clause 6.12.1(14).

Clause S6.1.3(2) requires ENERGEX to include in its *Regulatory Proposal* a proposed pass through clause with a proposal as to the events that should be defined as pass through events.

Clause 6.2.8(a)(4) provides that the AER may publish a guideline in relation to its likely approach to determining materiality in the context of possible pass through events. ENERGEX notes that the AER has yet to publish a national guideline on materiality thresholds in the context of pass through events.

Clause 6.6.1 provides for the pass through of costs and savings associated with positive pass through and negative pass through events respectively.

Clause 6.2.6(c) allows the control mechanism for *alternative control services* to utilise elements of Part C of Chapter 6 of the *Rules*.

20.3 Final decision – NSW distribution determination 2009-10 to 2013-14

In its *Final Decision – NSW distribution determination 2009-10 to 2013-14*, the AER considered that nominated pass through events should be divided into two categories:

- specific nominated pass through events to cover certain foreseeable events that can easily be defined; and
- general nominated pass through events to cover unforeseeable changes in circumstances falling outside of the normal operations of the relevant DNSP's business.

In deciding what events should be specific nominated pass through events, the AER considered the following criteria:

- whether the event is already captured by the defined event definitions;
- whether the event is clearly defined;
- whether the event is uncontrollable, that is, whether a prudent service provider through its actions could have reasonably prevented or substantially mitigated the event;
- despite the event being foreseeable, whether the timing and/or cost impact of the event could not be reasonably forecast by the relevant DNSP at the time of submitting this *Regulatory Proposal*;
- whether the event is already insured for (either externally or self-insured);
- whether the event cannot be self-insured because a self insurance premium cannot be calculated or the potential loss to the relevant DNSP is catastrophic;
- whether the party who is in the best position to manage the risk is bearing the risk; and
- whether the passing through of the costs associated with the event would undermine the incentive regime arrangements within the regulatory regime.

In this *Regulatory Proposal*, ENERGEX has used the AER's final decision on the NSW distribution determination as providing guidance to ENERGEX's nominated pass through events.

20.4 ENERGEX's specific nominated pass through events

In addition to the events defined as pass through events under the *Rules*, ENERGEX nominates the events listed in **Appendix 20.2** as specific pass through events for the *2010-15 regulatory control period*.

ENERGEX confirms that the costs associated with these events are not included in the forecast capital and operating expenditure for the *2010-15 regulatory control period.*

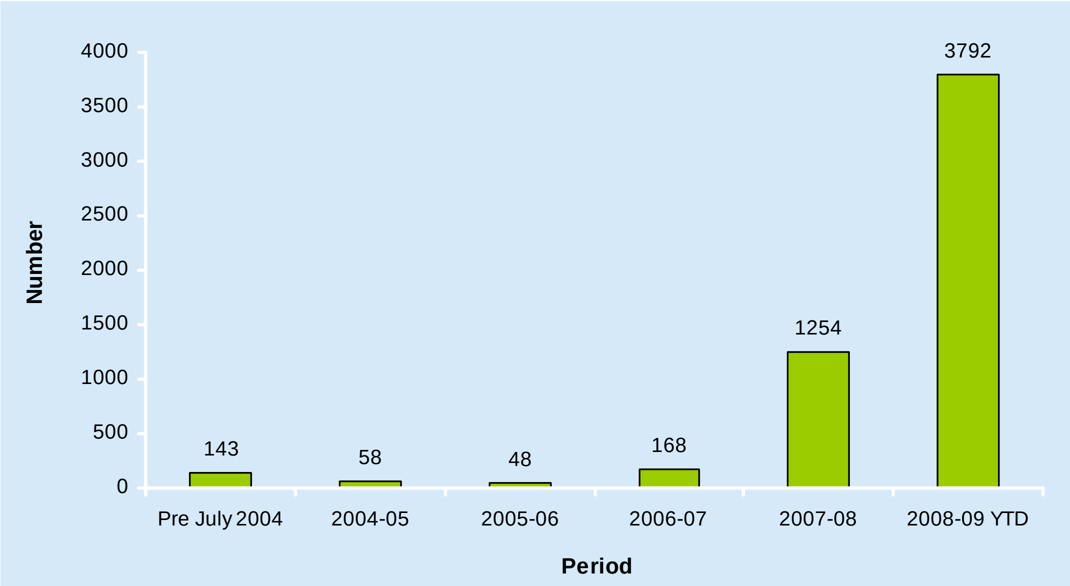
The specific nominated pass through events are discussed in the following sections.

20.4.1 Feed-in tariff event

In March 2008, the Queensland government announced the Solar Bonus Scheme to encourage greater use of solar energy systems and boost the renewable energy market. Under this scheme, a feed-in tariff was introduced where households and businesses will be paid 44 cents by the DNSP for every kilowatt-hour generated from solar power systems and fed into the grid[64]. The feed-in tariff commenced on 1 July 2008 and is guaranteed for 20 years.

ENERGEX is seeing an upward trend in the adoption of PV systems within SEQ as demonstrated by the number of PV Agreement applications shown in Figure 20.1. The uptake in PV installations is expected to increase rapidly in the *2010-15 regulatory control period.*

Figure 20.1 Grid connected PV systems in SEQ (as at 31 March 2009)



ENERGEX is unable to reasonably forecast the cost impact of this event. Any forecast will have to be based on the reasonable forecast installation of the PV systems and estimated energy that will be fed into the grid by each unit. ENERGEX currently has insufficient historical information to reasonably forecast either of these input parameters to determine the cost impact.

64 Source: *Electricity Act 1994* – s44A 'Additional condition to allow credit for electricity produced by photovoltaic generators'.

ENERGEX submits that the feed-in tariff payment made by ENERGEX qualifies as a specific nominated pass through event because:

- the event is not already captured by the defined event definitions;
- the event is uncontrollable as it is a new legislative obligation and installation of PV systems is the customer's choice and is beyond ENERGEX's control;
- the event is certain, however the cost impact of the event could not be reasonably forecast by ENERGEX at the time of submitting this *Regulatory Proposal*;
- the event is not an insurable event; and
- the passing through of the costs associated with the event would not undermine any of the incentive regime arrangements within the regulatory regime, given that the obligation is externally imposed.

Further, ENERGEX proposes that no materiality threshold be applied for the pass through of the feed-in tariff. ENERGEX is required under s44A(c)(ii) of the *Electricity Act* to report to the regulator on a six monthly basis the amount of electricity supplied to the network in the previous six month period for which credit was given. The full cost of the feed-in tariff credit to customers (via their retailer bill) should qualify as a pass through as this amount is an incremental cost to ENERGEX operating as a prudent DNSP.

ENERGEX proposes that a process similar to the revenue cap unders and overs mechanism be adopted for the pass through of feed-in tariff costs. Payments made by ENERGEX for the feed-in tariff will be recouped annually in arrears after a two year lag and appropriately adjusted by WACC through an increment of the target revenue during the annual network pricing process.

20.4.2 Smart meter event

The MCE SCO has initiated consultation relating to proposed NEL changes to facilitate and support the accelerated roll-out and pilot/trials of smart meters. In the June 2008 meeting, the MCE determined that Queensland and some other states and territories will undertake extensive pilots and business cases prior to a further national review of deployment timelines in 2012.

Whilst the MCE has formed a National Stakeholder Steering Committee to co-ordinate industry trials, ENERGEX still believes that there is considerable uncertainty regarding the form, scope, associated cost and timeframe of smart meter roll-out and associated pilots and trials. Therefore ENERGEX proposes that any pilots/ trials or roll-out of smart meters be treated as pass through events.

ENERGEX submits that the smart meter event qualifies as a specific nominated pass through event because:

- the event is not already captured by the defined event definitions;
- the event is uncontrollable because if the event occurs, ENERGEX will be legally obliged to undertake trials and/or roll-outs;

- the event is foreseeable, however the timing and cost impact of the event cannot be reasonably forecast because the form, scope, associated cost and timeframe of the smart meter roll-out and associated pilots and trials is not known at this time;
- the event is not an insurable event; and
- the passing through of the costs associated with the event would not undermine regulatory incentives, given that the obligation will be imposed externally.

Further ENERGEX proposes that a materiality threshold of $200,000 be applied for pass through of smart meter event costs. This threshold amount is set on the basis that the administrative costs of assessing the application for pass through is estimated to be in the order of $100,000.

ENERGEX submits that the incremental cost of the smart meter event should qualify as a pass through for the *2010-15 regulatory control period*.

20.4.3 Carbon pollution reduction scheme event

The CPRS is the Australian Emissions Trading Scheme (ETS) developed by the Commonwealth government. The CPRS is the policy through which Australia will reduce greenhouse gas emissions and meet its obligations under the Kyoto Protocol, and is likely to come into effect on 1 July 2011. In addition the Queensland government's Toward Q2[65] has called for a one third reduction in Queensland's carbon footprint by 2020.

Emissions that contribute to a carbon footprint are described as Scope 1 (direct emissions e.g. fuel burn in company fleet), Scope 2 (e.g. electricity used by ENERGEX) and Scope 3 (indirect emissions e.g. employee travel). The initial ETS proposed to commence on 1 July 2011 will likely only deal with Scope 1 emissions.

Based on current Scope 1 levels of activity, ENERGEX will not be required to participate in the ETS. However if in the future the threshold for Scope 1 emissions is reduced or Scope 2 and 3 emissions are included, ENERGEX could be liable for significant costs based on its 2006-07 carbon footprint. During 2006-07 ENERGEX's combined Scope 1, 2 and 3 emissions were 1,672,945 tonnes equivalent of carbon dioxide.

ENERGEX has a draft Carbon Management Plan which describes objectives and tactics to achieve progressive reduction of ENERGEX's carbon footprint.

ENERGEX submits that the change to the CPRS as described above qualifies as a specific nominated pass through event because:

- the event is not already captured by the defined event definitions;
- the event is uncontrollable because if the event occurs, ENERGEX will be legally obliged to comply with the scheme;

65 Source: Toward Q2, *Tomorrow's Queensland*, page 22 (www.towardq2.qld.gov.au).

- although the event is foreseeable, the timing and cost impact of the event cannot be reasonably forecast as the scope of the obligation is not known at this time;
- the event is not an insurable event; and
- the passing through of the costs associated with the event would not undermine the incentive regime arrangement.

Further ENERGEX proposes that no materiality threshold be applied for pass through of CPRS event costs as the amount will be clearly identified and reported.

ENERGEX proposes that a process similar to the revenue cap unders and overs mechanism be adopted for the pass through of CPRS event costs. Payments made by ENERGEX for CPRS will be recouped annually in arrears after a two year lag and appropriately adjusted by WACC through an increment of the target revenue during the annual network pricing process.

20.4.4 Occupational, health and safety event

In 2008 the Federal government commissioned a National Review into Model Occupational Health and Safety (OH&S) Laws. A panel was established to review OH&S legislation in each State, Territory and Commonwealth jurisdiction with a view to developing a model *OH&S Act*[66]. The purpose of this review is to produce a model that can be adopted by all jurisdictions and thereby increase harmonisation of OH&S legislation across Australia.

In February 2009, the panel released two papers which address a wide range of issues including duties of care, the concept of 'reasonable practicality', a review of offence provisions and compliance/enforcement options, consultative arrangements, and licensing arrangements relating to high risk work and work with certain plant and hazardous substances. While recommendations have arisen from the reports, it is unknown how these may be adopted by the Queensland government and the possible impact on ENERGEX.

ENERGEX believes that the panel's report qualifies as a specific nominated pass through event because:

- the event is not already captured by the defined event definitions;
- the event is uncontrollable because if the event occurs, ENERGEX will be legally obliged to comply with legislation;
- although the event is foreseeable, the timing and/or cost impact of the event cannot be reasonably determined as the recommendations from the panel will need to be implemented but the shape and form (i.e. legislative changes, codes, etc) of the actions is unknown at this time;

66 Source: Australian Government, *National review into model occupational health and safety laws*, January 2009.

- the event is not an insurable event; and
- the passing through of the costs associated with the event would not undermine regulatory incentives, given that the obligation will be imposed externally.

Further ENERGEX proposes that a materiality threshold of $200,000 be applied for pass through of OH&S event costs. This threshold amount is set on the basis that the administrative costs of assessing the application for pass through is estimated to be in the order of $100,000.

ENERGEX submits that the incremental cost of the OH&S event should qualify as a pass through for the *2010-15 regulatory control period*.

20.4.5 Henry review tax event

On 13 May 2008, the Federal government announced that it would undertake a comprehensive review of Australia's tax system. The review will encompass Federal and State taxes (excluding GST). A panel chaired by the Secretary to the Treasury, Dr Ken Henry, was established to undertake the review. A discussion paper was subsequently released on August 2008 entitled *Architecture of Australia's Tax and Transfer System*. This report (also referred to as the 'Henry Review') is the start of the consultation process which is still in progress.

Submissions from interested parties include proposed changes to the way Fringe Benefits Tax (FBT) on motor vehicles is calculated. At present, the government has not given any indication of what the other changes (other than the FBT changes) are likely to be. Some of these changes may impact on ENERGEX's costs.

The Review Panel is to make recommendations by the end of 2009 and changes are likely to be implemented in May 2010.

ENERGEX believes that potential changes arising from the Henry Review, including the issue of FBT, qualify as a specific nominated pass through event because:

- the event is not already captured by the defined event definitions;
- the event is uncontrollable because if the event occurs, ENERGEX will be legally obliged to comply;
- although the event is foreseeable, the timing and cost impact of the event could not be reasonably forecast, as the scope of the obligation is not known at this time;
- the event is not an insurable event; and
- the passing through of the costs associated with the event would not undermine regulatory incentives, given that the obligation will be imposed externally.

Further ENERGEX proposes that a materiality threshold of $200,000 be applied for pass through of the Henry Review event costs. This threshold amount is set on the basis that the administrative costs of assessing the application for pass through is estimated to be in the order of $100,000.

ENERGEX submits that the incremental cost of the Henry Review event should qualify as a pass through for the *2010-15 regulatory control period*.

20.4.6 Regulatory information notice reporting event

In August 2008, the AER released an issues paper on the proposed annual information reporting requirements for DNSPs. The paper discusses the proposed annual reporting requirements (including information templates) for DNSPs. In the paper, the AER stated that it intends to publish a RIO under the NEL setting out a nationally consistent framework for annual information reporting by DNSPs. The RIO for annual information reporting will set out general guidance and protocols underlying the annual collection of information.

In response to the issues paper, ENERGEX has raised concerns in relation to the format and the level of detail of the annual information reporting requirements. ENERGEX anticipates that it would be required to invest in a considerable amount of resources, time and effort to enable the development of the newly proposed reporting processes. ENERGEX believes that the costs of implementing changes to meet reporting requirements may be significant and would expect the AER to allow these costs to be passed through.

The AER has not yet commenced formal consultation on the RIO for DNSPs but has indicated that the reporting framework as proposed under the RIO will commence from 1 July 2010.

ENERGEX believes that costs associated with implementation of the regulatory reporting requirement under the AER's RIO qualify as a specific nominated pass through event because:

- the event is not already captured by the defined event definitions;
- the event is uncontrollable because if the event occurs, ENERGEX will be legally obliged to comply;
- although the event is foreseeable, the timing and cost impact of the event could not be reasonably forecast, as the scope of the obligation is not known at this time;
- the event is not an insurable event; and
- the passing through of the costs associated with the event would not undermine regulatory incentives, given that the obligation will be imposed externally.

Further ENERGEX proposes that a materiality threshold of $200,000 be applied for pass through of the RIO reporting event costs. This threshold amount is set on the basis that the administrative costs of assessing the application for pass through is estimated to be in the order of $100,000.

ENERGEX submits that the incremental cost of the RIO reporting event should qualify as a pass through for the *2010-15 regulatory control period*.

20.4.7 National energy customer framework event

The Ministerial Council on Energy (MCE) is tasked with creating a national framework for regulating the sale and supply of energy (both electricity and gas) to retail customers – a National Energy Customer Framework (NECF). The NECF forms part of the ongoing national energy market reforms set out in the Australian Energy Market Agreement (AEMA), which was amended in June 2006 to include the transfer of retail and distribution regulation (other than retail pricing) to a national framework.

The introduction of the NECF is a major regulatory transition which will impact on ENERGEX's operations. The current jurisdictional arrangements, while containing many similarities, have developed in different contexts and therefore reflect a range of different starting positions for the transition to the NECF. Whilst some jurisdictional obligations and requirements will be retained, the transition to the NECF will require significant parts of the Queensland legislation to be removed or amended before the NECF can become operational in Queensland.

On 30 April 2009, the first exposure draft of the NECF was released for consultation and the legislative package includes:

- a new stand-alone National Energy Retail Law (NERL) that sets up the framework for the NECF to be applied as the law of each jurisdiction in the same way as the NEL is currently applied;
- new National Energy Retail Rules (NERR), which focus on consumer protection matters, including three model contracts governing the relationship between customers, distributors and retailers, and which would be made under the NERL in the same way that the *Rules* are made under the NEL; and
- a new set of Regulations, National Energy Retail Regulations, which would be made under the NERL.

Matters considered in the NECF legislative package, which are currently being consulted on, include obligations to supply and connect, legal architecture, service definitions, liability and indemnity regimes, entry criteria for retail licences, retail credit support arrangements and the AER enforcement regime.

ENERGEX is unable to reasonably forecast the cost impact of the NECF legislative package at the moment. However, based on the current proposed contracts, service definitions and associated liability, it is likely that there will be required system changes, similar (but not to the same extent) to those that were implemented for FRC in Queensland.

ENERGEX submits that the NECF legislative changes qualify as a specific nominated pass through event because:

- the event will require a shift from the current legislative model and contracts currently in place at the time of this *Regulatory Proposal*;
- the event is uncontrollable as it will be a new legislative obligation;

- although the event is foreseeable, the timing and cost impact of the event cannot be reasonably forecast because the legislative package is still open for consultation and the transition to the national regime is yet to be determined by the Queensland government; and
- the passing through of the costs associated with the event would not undermine regulatory incentives, given that the obligation will be imposed externally.

Further ENERGEX proposes that a materiality threshold of $200,000 be applied for pass through of NECF event costs. This threshold amount is set on the basis that the administrative costs of assessing the application for pass through is estimated to be in the order of $100,000. As the Queensland government may determine that the introduction of the NECF package in Queensland will be a staged approach, ENERGEX proposes that the materiality threshold be applied to the event and not in any given year or in the year of introduction of the legislation.

ENERGEX submits that the incremental cost of the NECF event should qualify as a pass through for the *2010-15 regulatory control period*.

20.4.8 National broadband network event

On 7 April 2009 the Australian government announced it will establish a new company that will invest up to $43 billion over eight years to build and operate an NBN delivering super fast broadband to Australian homes and workplaces. One of the immediate steps the Australian government announced was that fibre-to-the-premises (FTTP) infrastructure would be required in Greenfield estates that receive planning approval after 1 July 2010.

Broadly, there are two potential models to ensure that FTTP infrastructure is installed in new Greenfield estates that receive planning approval from 1 July 2010:

1. the Australian government could legislate to directly require developers to ensure pit, pipe and FTTP infrastructure and services are available to consumers; or
2. the Australian government could work with state, territory and local governments to require the installation of FTTP and could support this with legislation to prohibit the installation of non-fibre networks in Greenfield estates.

The Australian government is currently seeking feedback on this issue on the preferred model. It is possible that local government/developers may attempt to transfer responsibility and costs for installing FTTP networks onto energy networks.

ENERGEX submits that the NBN event qualify as a specific nominated pass through event because:

- the event is not already captured by the defined event definitions;
- the event is uncontrollable because if the event occurs, ENERGEX will be legally obliged to comply;
- although the event is foreseeable, the timing and cost impact of the event could not be reasonably forecast, as the scope of the obligation is not known at this time;

- the event is not an insurable event; and
- the passing through of the costs associated with the event would not undermine regulatory incentives, given that the obligation will be imposed externally.

Further ENERGEX proposes that a materiality threshold of $200,000 be applied for pass through of the NBN event costs. This threshold amount is set on the basis that the administrative costs of assessing the application for pass through is estimated to be in the order of $100,000.

ENERGEX submits that the incremental cost of the NBN event should qualify as a pass through for the *2010-15 regulatory control period*.

20.4.9 GSL event

Following its final decision on the review of electricity distribution network MSSs and GSLs to apply in Queensland from 1 July 2010, the QCA released a discussion paper on further changes to the GSLs in relation to process and timeliness of payments.

The proposals outlined in the discussion paper will require changes to systems and processes and may have significant cost impact. The QCA anticipates releasing its final decision on this matter on 24 July 2009.

ENERGEX believes that costs associated with implementation of systems and processes to support the proposal qualify as a specific nominated pass through event because:

- the event is not already captured by the defined event definitions;
- the event is uncontrollable because if the event occurs, ENERGEX will be legally obliged to comply;
- although the event is foreseeable, the timing and cost impact of the event could not be reasonably forecast, as the scope of the obligation is not known at this time;
- the event is not an insurable event; and
- the passing through of the costs associated with the event would not undermine regulatory incentives, given that the obligation will be imposed externally.

Further ENERGEX proposes that a materiality threshold of $200,000 be applied for pass through of the GSL event costs. This threshold amount is set on the basis that the administrative costs of assessing the application for pass through is estimated to be in the order of $100,000.

ENERGEX submits that the incremental cost of the GSL event should qualify as a pass through for the *2010-15 regulatory control period*.

20.4.10 Storm disaster event

In its final decision on the NSW distribution determination, the AER considered that a force majeure event which includes major fire, earthquake, storm and other weather related or natural disaster, act of God, riot, civil disorder, rebellion or other similar events beyond the control of the DNSP should be a general nominated pass through event on the basis that the event is not foreseeable.

Historical data identifies that ENERGEX faces a "foreseeable" catastrophic storm risk, as outlined in the self insurance report prepared by the actuarial firm, Finity Consulting Pty Ltd. For this reason, ENERGEX has proposed forecast losses for this risk be included in the self insurance allowance. In quantifying the catastrophic storm risk for the purpose of calculating self insured losses, ENERGEX has adopted a prudent approach and capped the estimates of catastrophic storm losses to events with costs below $10 million.

ENERGEX's self insurance estimates for catastrophic storm events only provide cover to the level at which ENERGEX could reasonably estimate the potential cost based on historical data, and does not encompass all potential damage that may result from a major severe storm event. ENERGEX believes that including catastrophic storm events under self insurance would avoid the administrative costs of preparing and assessing pass through applications.

The risk of a storm event imposing losses above $10 million remains and needs to be mitigated. It is inappropriate to include storm disaster events as a general pass through due to its unique circumstance of the higher probability of occurrence and the materiality threshold of an absolute amount of $10 million. ENERGEX submits that the nomination of storm events with damage in excess of $10 million as specific nominated pass through events represents an optimum outcome and provides the incentive to ENERGEX to manage the network risk in the least cost manner.

ENERGEX believes that a storm disaster event (incurring costs over $10 million) qualifies as a specific nominated pass through event because:

- the event is not captured by the defined event definitions;
- the event is uncontrollable;
- the event is not foreseeable but highly is likely to occur given ENERGEX’s operating environment;
- the event is not already insured for (either externally or self-insured); and
- the passing through of the costs associated with the event would not undermine the incentive regime arrangements within the regulatory regime.

In these circumstances ENERGEX proposes that it should be entitled to recover, by way of cost pass through, such costs that exceed $10 million.

20.5 General nominated pass through events

In its final decision on the NSW distribution determination[67], the AER considered that an event should be classified as a general pass through event in the following circumstances:

- an uncontrollable and unforeseeable event that falls outside of the normal operations of the business, such that prudent operational risk management could not have prevented or mitigated the effect of the event, occurs during the *regulatory control period*;
- the change in costs of providing distribution services as a result of the event is material, and is likely to significantly affect the DNSP's ability to achieve its operating expenditure objectives and/or capital expenditure objectives during the *regulatory control period*; and
- the event does not fall within a defined pass through event or a specified pass through event.

Events that the AER considered may constitute a general nominated pass through event, and which ENERGEX wishes to have treated as such for the purposes of this *Regulatory Proposal*, are:

- force majeure event;
- earthquakes above the magnitude of five;
- compliance event/functional change event/changes in reporting requirements;
- distribution loss event;
- electric magnetic fields event;
- customer connection event;
- insurance event;
- retailer of last resort;
- joint planning event; and
- events for which self insurance allowances were rejected.

In addition to the events identified by the AER that may constitute a general pass through event, ENERGEX submits that interim change events and retailer credit risk events should also be considered. ENERGEX believes that these are uncontrollable and unforeseeable events that fall outside the normal operations of the business. The change in costs as a result of these events may be material, and is likely to significantly affect ENERGEX's ability to achieve its operating expenditure objectives and/or capital expenditure objectives during the next *regulatory control period*.

67 Source: AER, *Final Decision NSW Distribution Determination 2009-10 to 2013-14*, page xlv.

20.5.1 Interim change events

ENERGEX is concerned that there may be events that occur during the *current regulatory control period* but the cost impacts would take place in the next *regulatory control period*. These events are both uncontrollable and unforeseeable and also fall outside of the normal operations of the business. Due to the timing of this *Regulatory Proposal* and timing of the event, legitimate costs arising from these events cannot be included or envisaged in the operating and capital expenditure forecasts. The change in costs of providing distribution services as a result of such an event could be material and may significantly affect ENERGEX's ability to achieve its operating expenditure objectives and/or capital expenditure objectives during the next *regulatory control period*.

ENERGEX submits that the AER should consider that interim change events may constitute general nominated pass through events.

20.5.2 Retailer credit risk event

The contractual arrangements in Queensland provide for retailers to bill customers for the DUOS charges on behalf of the distribution businesses. ENERGEX is now a distribution only business and its exposure to retailer credit risk is increased. The current regulatory framework provides limited risk mitigation options for ENERGEX to cover such events. ENERGEX is also facing reduced credit diversification due to the aggregated billing arrangement of approximately 16 active retailers as opposed to the 1.2 million customers prior to FRC and the trade sale of its retail business in 2007.

ENERGEX is seeking to include retailer credit risk in its self insurance. To ensure that the self insurance premium is within a reasonable range, the self insurance for retailer credit risk will be limited to amounts up to $5 million. ENERGEX wishes to apply for pass through for amounts in excess of $5 million under the general nominated pass through event.

ENERGEX submits that the AER should consider that retailer credit risk events may constitute general nominated pass through events.

20.6 Materiality threshold

Cost pass through should apply to those costs that are beyond the distributor's control and influence. There is likely to be a range of costs that will impact on ENERGEX over the course of the *2010-15 regulatory control period* that cannot be included in the forecast operating or capital expenditure forecasts due to the uncertainty of the timing, scope and costs of the event.

In its final decision on the NSW distribution determination for 2009-10 to 2013-14, the AER stated that a lower materiality threshold is appropriate for specific nominated events. ENERGEX agrees that a threshold that is commensurate with the administrative costs of assessing the pass through application be applied for specific nominated events. ENERGEX has nominated a threshold to apply to each specific nominated event.

In addition, the AER considered that a general pass through event will have a material impact if the costs associated with the event exceed one per cent of the smoothed forecast revenue in the year that the costs are incurred. ENERGEX disagrees with this position on two fronts:

1. the relative threshold of one per cent of revenue; and
2. the application of the threshold to the revenue in the year.

While ENERGEX agrees that a materiality threshold should apply to a general nominated pass through event, it is unreasonable that the threshold be based solely on the annual revenue. ENERGEX believes that a one per cent of revenue materiality threshold is unfair to DNSPs that have high revenues due to the relative size of the business. The thirteen electricity distribution businesses that are the subject of economic regulation by the AER cover a broad spectrum with annual revenue ranging from $100 million to well over $1,000 million per annum. A one per cent materiality threshold on a DNSP with $1,000 million revenue is $10 million, which would have a significant impact on the financial returns of the DNSP.

As the pass through cost should cover only the incremental cost of the event, any amount that is not passed through will be reflected in reduced earnings for ENERGEX and would affect its ability to achieve its operating expenditure objectives and/or capital expenditure objectives.

As discussed in Section 20.5.2, ENERGEX's self insurance for retailer's credit risk is capped at $5 million. ENERGEX believes this amount is a fair and balanced approach for all stakeholders and avoids an unreasonable premium on the self insurance costs that is included in the forecast operating expenditure.

ENERGEX submits that a materiality threshold of one per cent of average annual revenue or a fixed amount of $5 million, whichever is lower, be applied to the general nominated pass through events.

ENERGEX also disagrees with the application of the threshold to the smoothed forecast revenue in the year that the costs are incurred. Pass through events generally do not occur in one year, but spread over a period of time. ENERGEX submits that the application on the basis of the smoothed forecast revenue in the year that the costs are incurred is arbitrary and does not support a prudent approach to the management of events. Potentially this could drive perverse behaviour by the DNSP.

An example of the arbitrary approach to materiality is the recent application for FRC cost pass through made by ENERGEX. The QCA's Final Decision on the FRC Application in November 2008 disallowed $4 million of costs incurred in 2005-06 and 2006-07 due to not meeting the annual materiality threshold for costs incurred in those years. This single reduction represented in excess of six per cent of ENERGEX's total FRC pass through application. This decision by the QCA was despite the fact that its consultant's assessment was that these costs were prudent and efficient and should be eligible for pass through.

The QCA based this decision on the criteria for assessing materiality as established in its 2005 final determination and supported this position by stating in the Final Decision on the FRC Application 'Where costs associated with a pass through event are spread over several years, the financial consequence for the annual returns of the business will be similarly reduced'[68].

ENERGEX considers that this regulatory position implies that in these circumstances legitimate costs borne by a business need not be recovered and that regulators consider that it is acceptable for regulated businesses to experience losses if they are reduced by spreading over a period of time. ENERGEX believes that this approach to the materiality threshold should be reviewed as the framework for regulation should not be designed to produce such uncommercial outcomes for regulated businesses. In addition, this approach clearly contradicts the revenue and pricing principles, as outlined in Section 7A of the NEL, which provides a regulated NSP to recover at least efficient costs. As a result ENERGEX proposes that the appropriate approach is to apply the materiality test to the total of the costs that result from the event rather than just to the costs that are incurred in a specific year.

20.7 Application to alternative control services

The cost pass through provisions in the *Rules* are incorporated under Part C of Chapter 6: Building Block Determinations for *standard control services*. However, Clause 6.2.6(c) of the *Rules* allows the control mechanism for *alternative control services* to utilise elements of Part C of Chapter 6.

ENERGEX considers that the pass through events identified under Part C of Chapter 6 are equally applicable to *alternative control services*. The costs of *alternative control services* are equally subject to uncertainty as a result of the pass through events set out in the *Rules*, namely changes in applicable regulation, service standard requirements and relevant taxes, and terrorism events. The costs of *alternative control services* may also be open to uncertainty as a result of the additional pass through events nominated by ENERGEX in this *Regulatory Proposal*.

ENERGEX notes that the key definitions[69] in the *Rules* in relation to the cost pass through regime are all defined in relation to events that have an impact on the costs of direct control services, which includes both *standard control services* and *alternative control services*.

On that basis and consistent with the AER's final decision on the NSW distribution determination, ENERGEX pass through provisions for the defined events and nominated events should be applied to both standard control and *alternative control services*.

68 Source: ENERGEX, *FRC Pass-through Application Final Decision*, November 2008, page 41.

69 Source: Chapter 10 of the *Rules* – definitions of 'negative change event', 'positive change event', 'regulatory change event', 'tax change event', 'service standard event', and 'terrorism event'.

20.8 Pass through clause

In accordance with Clause S6.1.3(2), ENERGEX's *building block proposal* must contain a proposed pass through clause with a proposal as to the events that should be defined as pass through events. ENERGEX proposed pass through clause is set out in **Appendix 20.3**.

Part Two – Alternative control services

positive energy

21 Street lighting

ENERGEX's street lighting services are one of three service groups proposed to be classified as an *alternative control service* under a price cap form of control for the *2010-15 regulatory control period*. The *Rules* require that a *Regulatory Proposal* for *alternative control services* include:

- a demonstration of the application of the control mechanism; and
- the necessary supporting information.

This chapter describes ENERGEX's approach to the provision of the *alternative control service* of street lighting for the *2010-15 regulatory control period*.

21.1 Summary

In the *current regulatory control period*, ENERGEX's street lighting services included both the conveyance of electricity to street lights and services relating to the provision, construction and maintenance of street lighting. These services are regulated as a prescribed distribution service under a revenue cap control mechanism.

In the Stage 1: Framework and approach paper, the AER classified ENERGEX's street lighting services relating to the provision, construction and maintenance of street lighting assets as an *alternative control service* under the stand-alone street lighting services group. The conveyance of electricity to street lights was classified as a *standard control service* under a revenue cap control mechanism. *Standard control services* are discussed in Part 1 of this *Regulatory Proposal*. ENERGEX accepts the AER's proposed classification of street lighting services as an *alternative control service* and highlights that this is a significant change from the current regulatory approach.

As highlighted in Chapter 7, this has resulted in the need for transitional arrangements for street lighting services to move from a prescribed distribution service under a revenue cap control mechanism to an *alternative control service* under a price cap control mechanism. ENERGEX has outlined its proposed transition approach in Section 21.4.

The principal source of service standard obligations for street lighting in Queensland is the Australian Standard AS/NZS 1158 (series) – Lighting for Roads and Public Spaces and the street lighting program included in this *Regulatory Proposal* has been prepared to comply with this standard. In addition ENERGEX has internal standards for street lighting repair times. ENERGEX proposes to maintain the current levels of service performance for the *2010-15 regulatory control period*.

The AER has decided a price cap form of control for street lighting services will apply over the *2010-15 regulatory control period*. This consists of:

- a schedule of fixed prices for street lighting services for the first year of the *2010-15 regulatory control period*; and
- a price path for the remaining years of the *2010-15 regulatory control period*.

The AER will apply a limited building block approach to determine the efficient costs of providing street lighting services under a price cap control mechanism in the first year of the *regulatory control period*. The simplified building block assumptions provided in the Stage 1: Framework and approach paper have been adopted by ENERGEX in determining the revenue required to provide street lighting services.

21.2 Regulatory information requirements

A distribution determination is predicated on decisions by the AER on the following:

- Clause 6.12.1(12) – a decision on the control mechanism for *alternative control services* (to be in accordance with the relevant Stage 1: Framework and approach paper).
- Clause 6.12.1(13) – a decision on how compliance with the control mechanism is to be demonstrated.

Clauses 6.2.6(b) and 6.2.6(c) of the *Rules* set out the basis of control mechanisms for *alternative control services*.

For *alternative control services*, Clause 6.8.2(c)(3) of the *Rules* provides that a *Regulatory Proposal* must include the proposed control mechanism, a demonstration of the application of the control mechanism, and the necessary supporting information.

Clause 6.8.2(c)(4) of the *Rules* provides that a *Regulatory Proposal* must include indicative prices for each year of the *regulatory control period*.

In addition under Clause 2.2.5 of the RIN , the AER requires the following information:

- name and description of services provided in the *current regulatory control period*;
- job numbers, revenue and prices for services provided in the *current regulatory control period*; and
- indicative prices for each service for the next *regulatory control period*.

Further, for street lighting services the AER requires the following specific information under Clause 2.4.6 of its RIN:

- information to support the application of the proposed control mechanism;
- expenditure information;
- asset value information;
- demand information; and
- service level information.

21.3 Overview of street lighting services

ENERGEX currently serves 12 street lighting customers (Councils and government departments), with approximately 300,000 installed lights. The objective of street lighting is to provide a lighted environment to ensure the safety and security of vehicle and pedestrian traffic in public streets and thoroughfares.

In the Stage 1: Framework and approach paper, the AER classified street lighting services (i.e. the provision, construction and maintenance of street lights) as an *alternative control service* under a price cap control mechanism and the network services (including the conveyance of electricity to street lights) as a *standard control service* under a revenue cap control mechanism. This is a departure from the current regulatory approach and impacts on the regulatory framework for street lighting services as discussed in Section 21.4.

ENERGEX's street lighting services for the *2010-15 regulatory control period* are outlined in Table 21.1. ENERGEX provides major and minor street lighting services. The classification of major and minor refers to the road categorisation where the street light is located, which is a significant driver of costs, e.g. lamp size and associated installation costs. For major or minor street lighting services, the network charge applicable (i.e. non-contributed or contributed) depends on whether the street light construction is funded by ENERGEX or the customer or their agent.

Table 21.1 Outline of *alternative control services* – street lighting for the *2010-15 regulatory control period*

Street lighting service	Located on a main or arterial road	Non-contributed service *	Contributed service **
Major	Y	Y	Y
Minor	N	Y	Y

** Non-contributed service – Network charge includes cost of supply (capital), installation and maintenance. Street light is owned by ENERGEX.*

*** Contributed service – Network charge includes cost of maintenance. Supply (capital) and installation of the street light is funded by the customer or their agent. Ownership is vested in ENERGEX on completion of the installation and upon commissioning.*

21.4 Regulatory framework

In accordance with Clause 6.12.1(12) ENERGEX has adopted the AER's control mechanism as outlined in the Stage 1: Framework and approach paper. The Stage 1: Framework and approach paper necessitates a change in the regulatory framework to comply with the *Rules* and the control mechanism for the *2010-15 regulatory control period*.

21.4.1 Street lighting services where ENERGEX constructs the asset

In the *current regulatory control period* where ENERGEX constructs the asset and the customer request differs from the standard street light provided under the non-contributed service, ENERGEX requests a cash contribution. These cash contributions are treated under the revenue cap in accordance with the QCA approved methodology, which requires that contributions received are netted from the revenue pool used to calculate prices and the full asset value is recognised in the RAB.

In the *2010-15 regulatory control period* where a non-standard street light is requested by the customer, a separate charge for the incremental cost difference will be levied as a quoted service. Revenue received will be an upfront payment for a superior service under the price cap control mechanism and therefore will no longer be netted from the revenue pool. The customer will still receive an ongoing charge for the non-contributed service. Alternatively, non-standard street lights can be provided under the contributed service.

21.4.2 Street lighting services where customer or agent constructs the asset

In the *current regulatory control period* where the customer or their agent constructs the asset and the capital cost of the street light is paid upfront, the asset is gifted to ENERGEX following construction and upon commissioning. Gifted assets are treated under the revenue cap in accordance with the QCA approved capital contribution methodology outlined previously.

In the *2010-15 regulatory control period* ENERGEX proposes to recognise gifted assets as contributed assets and not seek to recover any asset-related costs from the customer. Any asset-related costs will have been paid upfront by the customer. The customer will receive an ongoing charge for the maintenance of the street light asset under the contributed service.

21.4.3 Impact on the asset base

A transitional asset base issue arises as a result of the change in regulatory framework for street light services and the way that ENERGEX has historically dealt with street light assets, particularly those that are contributed by customers or their agents.

In the *current regulatory control period* under the QCA approved methodology all assets, whether contributed or non-contributed, have been recognised in the RAB. ENERGEX has adjusted the annual allowable revenue for the value of contributions received, and is eligible to recover an annual ROA and depreciation charge over the life of the assets. This means that at 1 July 2010, a residual asset cost for contributed street lights gifted in the *current regulatory control period* and previous *regulatory control periods* remains to be recovered.

In assessing options to recover the residual asset cost for contributed street lights, ENERGEX has identified the following issues:

- pricing signals;
- size of recovery pool;
- potential for distortion of prices;
- customer impact; and
- simplicity.

To address these issues in the *2010-15 regulatory control period*, ENERGEX's options are to:

1. introduce pre and post 1 July 2010 prices for contributed street lighting services; or
2. maintain consistency in prices for contributed street lighting services and manage the residual asset costs for contributed street lights through an alternate mechanism.

ENERGEX considers that option 1 would significantly impact on customers and confuse pricing signals. The current capital contributions mechanism has distorted prices in the *current regulatory control period*, and consequently pre and post 1 July 2010 prices would have significantly different values, even though the service is unchanged. Given that the same customer would be charged both pre and post 1 July 2010 prices, pricing signals would be confused.

Based on the objective of limiting pricing distortions, ENERGEX proposes to adopt option 2. To achieve this, ENERGEX proposes to establish an opening street light asset base that encompasses non-contributed street lights only. In light of the change to the regulatory framework for street lighting services, ENERGEX proposes to account for the residual contributed, but recognised, street light assets within *standard control services*. This aligns with the historical capital contributions treatment where benefits from the street light asset contributions were accrued by all Standard Asset Customers (SACs), and reflects that SACs are the end-beneficiary of the contributed street lighting service and would otherwise pay through council charges. It is proposed to allocate the residual asset cost across this group on a c/kW.h basis. The establishment of the respective asset values for non-contributed and contributed assets at 1 July 2010 is explained further in Section 21.9.

ENERGEX submits that the proposed approach for treatment of street lighting assets, contributed and non-contributed, will satisfy Rule requirements and deliver network charges which directly correlate with the level of service provided and account for the change in regulatory framework.

21.5 Service obligations

In accordance with Clause 2.4.6 (5) of the RIN, where applicable, ENERGEX's prices for street lighting services are developed based on the following service obligations and standards.

The principal source of service standard obligations for street lighting in Queensland is the Australian Standard AS/NZS 1158 (series) – Lighting for Roads and Public Spaces. ENERGEX's provision of street lighting services complies with the Australian Standard as a minimum and the specified design requirements of the customer. In addition, ENERGEX provides street lighting services in accordance with the *Electricity Safety Act's* Codes of Practice 'Working Near Exposed Live Parts'.

Street lights are maintained in accordance with ENERGEX's Maintenance Asset Management Policy (MAMP) and the Australian Standard. The obligations of ENERGEX and the customer are outlined in ENERGEX's 'Standard Conditions for the Provision of Public Lighting Services'. The provision of street lighting services is in accordance with these documents.

Other obligations include reporting, environmental, health and safety, etc. These obligations also apply to *standard control services* and are discussed in detail in Chapters 3 and 9 and in pro forma 2.3.5 in **Attachment 1**. ENERGEX's internal service performance obligations in relation to street lighting services are explained further below. ENERGEX's capital and operating programs have been developed to deliver against these service obligations.

21.5.1 Service performance obligations

ENERGEX's internal standard, 'Standard Conditions for the Provision of Public Lighting Services', details the conditions for the design, installation and maintenance of street lighting to comply with the Australian Standard. This document outlines the responsibilities of the customer and ENERGEX, and the standard equipment to be used.

Since 2002, ENERGEX has complied with regulatory reporting obligations and reported performance against the parameters for street lights in Table 21.2 (refer QCA Service Quality Reports). There are no performance targets for these parameters, although internally the target is to maintain current service levels.

Table 21.2 Street light – service performance parameters

Parameter	Description	Reporting frequency
Street lights	The number of street lights in the distribution area.	Quarterly
Street lights out during period	The number of street lights reported by customers as not working.	Quarterly
Street lights not repaired by agreed date	The total number of street lights reported as not working which were not fixed by the date agreed with the customer.	Quarterly
Average time taken to repair faulty street lights	To be calculated from receipt of the notification of the fault.	Quarterly

In addition, to ensure public safety and manage risks associated with the continuity of street lighting services, ENERGEX's internal requirements are to repair:

- 95 per cent of all failed street lights under its control within three business days subsequent to the date of being notified by a customer; and
- 100 per cent of all failed street lights under its control within five business days after the date of notification, or as agreed with the customer.

21.5.2 Historical service performance

In the *current regulatory control period*, street lights have been maintained by ENERGEX in accordance with the MAMP and 'Standard Conditions for the Provision of Public Lighting Services', to meet the requirements of the applicable service conditions and the Australian Standard. ENERGEX has primarily utilised a spot maintenance program. In accordance with the Australian Standard ENERGEX has undertaken regular patrols of street lights to identify defects. All street lights are inspected and assessed on a six monthly cycle and identified defects are rectified within the agreed timeframes.

Historical service performance for street lights, as reported in the QCA quarterly service quality reports, is summarised in Figure 21.1 and Table 21.3.

Figure 21.1 Street light service performance

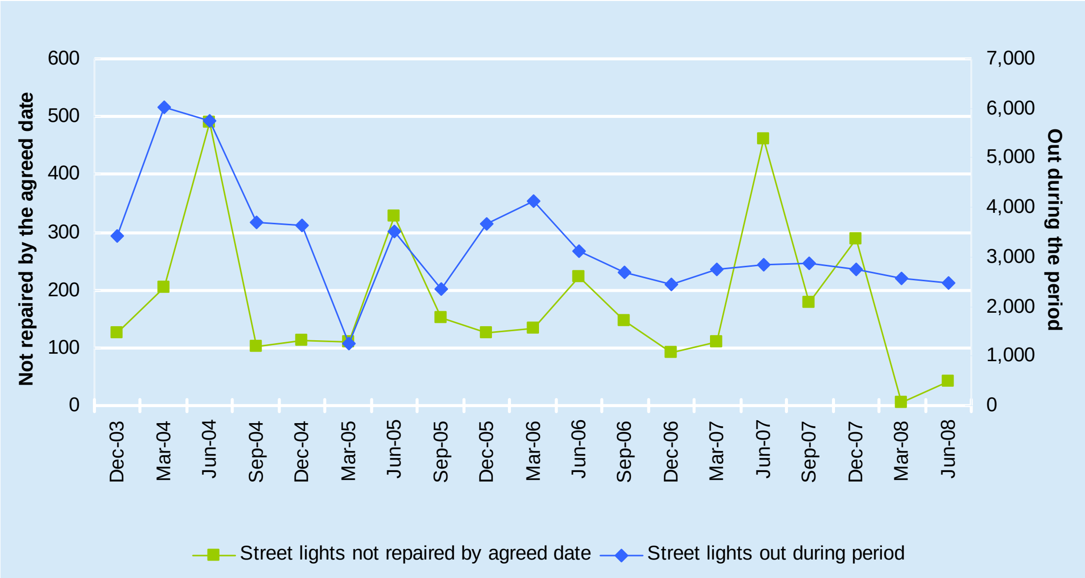


Table 21.3 Street light service performance

Days	Sep 2007	Dec 2007	Mar 2008	Jun 2008	Sep 2008
Average number of days taken to repair street lights	4.0	4.0	4.0	4.0	4.0

The average time indicated includes the day of notification.

21.5.3 Service performance over the 2010-15 regulatory control period

The forecast expenditure for the *2010-15 regulatory control period*, outlined in this chapter, is based on maintaining current expenditure and service levels with adjustments for identified cost input changes.

21.6 Application of control mechanism

This section provides information on the application of the control mechanism which has been proposed by the AER for street lighting services in the Stage 1: Framework and approach paper, and proposes how compliance with the control mechanism can be demonstrated (as per Clauses 6.12.1 (12) and (13) of the *Rules*). It also demonstrates the application of the control mechanism in accordance with Clause 6.8.2(c)(3).

In accordance with the Stage 1: Framework and approach paper, ENERGEX has utilised a limited building block approach to determine the efficient costs of providing street lighting services under the price cap control mechanism in the first year of the *regulatory control period* and has established a price path for the remaining years of that period.

Utilising a limited PTRM, as in **Attachment 4**, ENERGEX has determined the revenue for street lighting services using the building block components, adopting a similar approach to that used for *standard control services* as outlined in Chapter 18. Information on the individual building block components is provided in this chapter.

Based on the revenue requirement produced from the PTRM, ENERGEX has developed prices for the first year of the *regulatory control period* using a methodology that applies a revenue allocation based on the relative installation costs for major and minor street lights and the applicable asset funding arrangement (non-contributed and contributed). Street lights are allocated to major and minor according to luminare type and size, and non-contributed and contributed based on the funding arrangement. This methodology is outlined below.

<u>Connection charge for non-contributed street lighting services</u>

The revenue requirement for the recovery of forecast connection costs equates to the ROA and depreciation for non-contributed assets. The connection charge revenue is apportioned to major and minor street lighting services based on the relative installation costs for a typical street light configuration for the relevant locality (i.e. major or minor road). The relevant proportion is derived from replacement costs[70] for a sample of commonly used street light configurations of luminare, pole type and outreach bracket, weighted by the forecast number of street lights. The rates applied for 2010-11 are set at 47 per cent for the major services and 53 per cent for the minor services.

<u>Operating charge for all street lighting services</u>

The revenue requirement for the recovery of forecast operating expenditure is apportioned to:

- major and minor street lighting services – based on the same proportions as used for the connection charge; and
- non-contributed and contributed services – this is based on the proportion of forecast street lights under the respective funding arrangements.

In determining the operating charge in 2010-11, the following proportions in Table 21.4 have been applied.

70 Replacement costs were updated as at 28 April 2009 and the pricing methodology has been updated accordingly. Pricing methodology inputs are reviewed annually and monitored for appropriateness.

Table 21.4 Revenue proportions for first year prices

Street lighting service	Revenue proportion	Tariff	Revenue proportion
Major	47%	Non-contributed	48%
		Contributed	52%
Minor	53%	Non-contributed	50%
		Contributed	50%

This methodology for calculating the target revenue for the respective charges is considered to provide a balance between cost reflective pricing, simplicity and administrative costs.

The formula to calculate the individual tariffs is outlined below:

$$\left(\frac{\textit{Annual Target Revenue for Street light Tariff}}{\textit{Number of lamps for Street light Tariff}} \right) \Big/ \textit{Days in the year}$$

Prices for the *2010-15 regulatory control period* based on this methodology are provided in pro forma 2.2.5 in **Attachment 1**. Prices for the subsequent years of the *2010-15 regulatory control period* have been developed based on the first year's prices and the proposed price path outlined in Section 21.12 of this chapter.

21.7 Capital expenditure

21.7.1 Historic capital expenditure

The actual and forecast capital expenditures for the *current regulatory control period* are shown in Table 21.5. The estimated capital expenditure is based on the latest available information to reflect the current financial and market conditions.

Table 21.5 Street lighting capital expenditure for the *current regulatory control period*

	Actual			Estimated	
Nominal $M	**2005-06**	**2006-07**	**2007-08**	**2008-09**	**2009-10**
Capital expenditure	16.7	20.5	20.4	20.0	17.5

Numbers above reflect street light capital expenditure included in the RFM.

Fluctuations in street light capital expenditure are due to defect rates in inspected areas. Defect rates depend on the street light installation date and the type of street light asset. Actual work done is prioritised based on other network requirements.

There is a significant decrease in capital expenditure requirements between the *current regulatory control period* and the *2010-15 regulatory control period* due to the change in treatment for contributed street light assets.

21.7.2 Forecast capital expenditure

The forecast capital expenditure for the *2010-15 regulatory control period* is provided in Table 21.6. Forecast capital expenditure is net of contributed assets and only reflects street light assets to be constructed and provided by ENERGEX under the non-contributed service.

Table 21.6 Forecast street lighting capital expenditure for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15
Capital expenditure	6.8	6.8	7.0	7.1	6.9

Numbers above are net of contributed assets and reflect street light capital expenditure included in the PTRM.

This capital expenditure is required to deliver new non-contributed street lighting assets, as requested by customers, and replace existing assets that have reached the end of their economic lives or are deemed suspect or unserviceable. Forecasts are based on historical observation of usage and minimum street light design requirements to comply with the Australian Standard.

21.8 Operating expenditure

21.8.1 Historic operating expenditure

The actual and forecast operating expenditures for the *current regulatory control period* are shown in Table 21.7. The estimated operating expenditure is based on the latest available information to reflect the current financial and market conditions.

Table 21.7 Street lighting operating expenditure for the *current regulatory control period*

	Actual			Estimated	
Nominal $M	**2005-06**	**2006-07**	**2007-08**	**2008-09**	**2009-10**
Operating expenditure	10.2	10.4	12.2	13.0	13.8

Increases in street light operating expenditure are the result of:

- underlying growth in street lighting numbers of three per cent per annum;
- higher numbers of damaged street lights requiring repair; and
- an expected increase in the street light replacement quantities identified as part of the inspection program.

21.8.2 Forecast operating expenditure

The forecast operating expenditure for the *2010-15 regulatory control period* is provided in Table 21.8.

Table 21.8 Forecast street lighting operating expenditure for the *2010-15 regulatory control period*

2009-10 $M	2010-11	2011-12	2012-13	2013-14	2014-15
Operating expenditure	12.2	12.7	13.0	13.4	13.7

The forecast operating expenditure reflects all planned maintenance and corrective repair to street lights including street light patrols and follow up street light work associated with patrols. Street light assets are maintained to meet the requirements of the applicable tariff conditions and the Australian Standard.

Forecast costs have been determined, based on existing contract arrangements, to conduct patrols in accordance with MAMP specifications. In addition, a provision has been made for repairs arising from these patrols based on historical observed failure rates.

The forecast operating expenditure is based on unrestricted access to all street lights to conduct maintenance.

21.9 Street lighting regulatory asset base

21.9.1 Opening regulatory base as at 1 July 2010

For the *current regulatory control period*, ENERGEX's street lighting services are a prescribed distribution service and street light assets are part of the RAB. The following values have been taken from the RFM prepared for *standard control services*. ENERGEX has determined that the *standard control services* RAB value for street lights at 1 July 2005 is $236 million as shown in Table 21.9.

Table 21.9 Established street lighting RAB at 1 July 2010

Nominal $M	2005-06	2006-07	2007-08	2008-09	2009-10
Opening RAB 1 July	236.0	241.7	248.6	258.7	262.0
Actual capital expenditure/additions	17.4	21.3	21.4	20.8	25.6*
Depreciation	(18.8)	(20.3)	(21.9)	(23.9)	(25.6)
Indexation	7.0	5.9	10.5	6.4	6.4
Closing balance 30 June	241.7	248.6	258.7	262.0	268.4

Capital expenditure numbers above include a half WACC adjustment in accordance with the RFM.

** Includes adjustment in RFM made for difference between actual and forecast capital expenditure in 2004-05.*

In light of the Stage 1: Framework and approach paper, from 1 July 2010 ENERGEX proposes to recognise gifted assets as contributed assets. To implement this change, ENERGEX proposes to establish an opening asset base for 1 July 2010 for non-contributed assets only. ENERGEX's historical street light asset base included both contributed and non-contributed assets and ENERGEX has developed a methodology to determine the asset value attributable to non-contributed assets. This methodology is based on an apportionment of assets weighted by replacement costs and the number of lights. Further detail on the methodology is provided in **Appendix 21.1** and the revised opening asset base for 1 July 2010 is shown in Table 21.10.

Table 21.10 Revised street lighting asset base at 1 July 2010

Nominal $M	2010
Closing RAB balance 30 June	268.4
Less asset value for contributed assets	(172.3)*
Opening street light asset base 1 July	96.1

** Existing contributed assets have been retained in the standard control services RAB and are included in RAB values outlined in Chapter 14.*

21.9.2 Street lighting asset base for 2010-15 regulatory control period

ENERGEX proposes to recognise gifted assets as contributed assets for the *2010-15 regulatory control period*. This will mean that capital expenditure for the *2010-15 regulatory control period* will be for non-contributed assets only. ENERGEX will separately identify contributed assets and not seek to recover any asset-related costs for contributed assets from the customer until the asset is replaced.

The resulting closing asset base value for ENERGEX non-contributed street lights over the *2010-15 regulatory control period* is shown in Table 21.11.

Table 21.11 Roll forward street lighting asset base forecast for the *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Opening street lighting asset base 1 July	96.1	96.7	96.8	96.7	96.2
Forecast capital expenditure/additions	7.3	7.4	7.9	8.1	8.1
Regulatory depreciation	(6.7)	(7.3)	(7.9)	(8.6)	(9.3)
Closing balance 30 June	96.7	96.8	96.7	96.2	95.1

Capital expenditure numbers above include a half WACC adjustment in accordance with the PTRM.

21.9.3 Depreciation

ENERGEX has adopted straight line depreciation to calculate the depreciation allowance, consistent with the approach for *standard control services*.

Consistent with the QCA determination, a standard life of 20 years has been used for street lighting assets. A remaining life of 10.8 years has been used based on the asset register.

ENERGEX has forecast its depreciation schedules for the *2010-15 regulatory control period* based on the roll forward of the opening asset base and the forecast capital expenditure for non-contributed street light assets. The PTRM has been used to calculate the straight line depreciation and the total depreciation allowance forecast for the *2010-15 regulatory control period* is shown in Table 21.12.

Table 21.12 Street lighting depreciation forecast for the *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Depreciation	6.7	7.3	7.9	8.6	9.3

21.9.4 Return on capital and taxation

Consistent with the Stage 1: Framework and approach paper, ENERGEX has applied the same rate of return of 9.49 per cent for *alternative control services*, as set out for *standard control services* in Chapter 16.

ENERGEX has calculated its tax depreciation allowance on a straight line basis in accordance with the requirements of the PTRM.

21.10 Demand

At 30 June 2010 ENERGEX expects to operate and maintain 291,045 street lights – 149,711 non-contributed and 141,334 contributed. Based on the total number of new street lights forecast each year, as outlined in Table 21.13, the demand growth for street lighting services is 0.24 per cent for non-contributed street lights and 2.92 per cent for contributed street lights.

Table 21.13 Street light additions forecast for the *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Non-contributed	713	735	759	783	807
Contributed	8,489	8,758	9,035	9,320	9,615

Based on the above forecast, ENERGEX expects to operate and maintain 340,060 street lights by 30 June 2015 – 153,508 non-contributed and 186,552 contributed.

These forecasts have been developed based on a historical observation of usage. The demand growth for contributed street lighting services is linked to subdivision development in SEQ. Forecast subdivision lots are expected to grow at two per cent per annum over the *2010-15 regulatory control period*.

As street lights will be regulated under a price cap control mechanism in the *2010-15 regulatory control period*, ENERGEX does not see the need to make an assessment of the impact of the GFC at this stage.

21.11 Revenue requirements

ENERGEX's revenue requirements for street lighting services have been determined based on the revenue building block components consistent with the approach used for its *standard control services* set out in Chapter 18.

ENERGEX's forecast ARR for street lighting over the *2010-15 regulatory control period* is shown in Table 21.14 as calculated by the PTRM in **Attachment 4**.

Table 21.14 Building block revenue requirements for street lighting forecast for the *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Return on capital	9.1	9.2	9.2	9.2	9.1
Return of capital	6.7	7.3	7.9	8.6	9.3
Operating expenses	12.6	13.4	14.1	14.9	15.5
Tax allowance	6.0	6.1	6.2	6.2	6.2
Adjustment for non-system revenue allocation	1.9	2.4	2.6	2.9	2.6
Unsmoothed revenue requirement	36.4	38.4	40.0	41.7	42.7

Numbers may not add due to rounding.

An adjustment to the street lighting revenue is required to recognise revenue associated with non-system assets used in the provision of street lighting services. The adjustment reflects the amount of the revenue requirement associated with the non-system assets used for the provision of street lighting services and has been calculated according to the methodology outlined in Chapter 18.

ENERGEX's proposed street lighting ARR and resulting X factors over the *2010-15 regulatory control period* are shown in Table 21.15.

Table 21.15 Summary of street lighting revenue requirements forecast for the *2010-15 regulatory control period*

Nominal $M	2010-11	2011-12	2012-13	2013-14	2014-15
Notional revenue requirement	36.4	38.4	40.0	41.7	42.7
Smooth revenue requirement	35.3	37.5	39.9	42.3	44.9
X factors	20.2%	-3.6%	-3.6%	-3.6%	-3.6%

The above X factors result in real (i.e. greater then CPI) average street lighting price increases over the period and meet the NPV neutral revenue requirement. ENERGEX has chosen X factors that will minimise the impact on customers through smoothing, whilst achieving cost reflectivity.

Based on the proposed street light revenue requirement in Table 21.15, ENERGEX has applied the control mechanism outlined in 21.6, to determine the respective revenues and prices for the non-contributed and contributed street light services.

21.12 Proposed price path

Acknowledging the change in regulatory framework for street lighting services, ENERGEX is proposing a price path which consists of an initial price adjustment reflecting the removal of contributed assets from the street light asset base, followed by a smoothed price path with consistent annual increases in street lighting prices for the remainder of the *regulatory control period*.

This will be achieved by establishing efficient prices for street lighting services in 2010-11 using the price methodology outlined above and then adopting a straight-line price path for the remainder of the *regulatory control period*. This approach will result in a fixed indexation rate for 2011-15, which provides a balance between NPV neutrality, cost reflectivity and customer pricing impact.

ENERGEX is committed to efficient pricing signals for street lighting services. ENERGEX submits that the proposed approach for treatment of street lighting assets, contributed and non-contributed, in the *2010-15 regulatory control period* will deliver consistent and transparent pricing signals through street light charges, which directly correlate with the level of service being provided by ENERGEX.

21.13 Indicative prices

In accordance with Clause 6.8.2(c)(4) and transitional arrangements in the *Rules*, ENERGEX has provided indicative prices for the provision, construction and maintenance of street lights for the *2010-15 regulatory control period* in pro forma 2.2.5 in **Attachment 1** and summarised in Table 21.16. Street lighting charges are tailored to enable the customer to be charged according to the level of service requested.

Table 21.16 Prices for street lighting services for *2010-15 regulatory control period*

$/day	2010-11	2011-12	2012-13	2013-14	2014-15
Major street lights					
Non-contributed	0.86	0.90	0.94	0.98	1.02
Contributed	0.25	0.26	0.28	0.29	0.30
Minor street lights					
Non-contributed	0.37	0.38	0.40	0.42	0.43
Contributed	0.11	0.11	0.12	0.12	0.13

Prices for 2012-15 are based on the proposed price path outlined in Section 21.12.
All indicative prices are exclusive of GST

These prices reflect standardised lights and no restriction on access for operation, maintenance and repair. An additional charge may apply in the case of restricted access.

The applicable terms and conditions for each street light service are outlined in ENERGEX's published price schedule and are based on the following principles:

- The contributed street light tariff only applies where the capital cost of the street light has been paid upfront by the customer or their agent;
- At the conclusion of the street light's standard asset life, the non-contributed tariff will apply;
- Where ENERGEX has supplied the street light and the capital cost has been paid upfront by the customer, the contributed street light tariff will apply for the minimum period specified in the tariff's terms and conditions; and
- Where the capital cost of the street light has been funded by ENERGEX and no upfront payment made, whether the initial asset construction or replacement of an asset, the non contributed street light tariff applies.

21.13.1 Customer impact

In light of the new regulatory arrangements for street lighting services, the bundled prices that customers are charged will consist of a *standard control service* and an *alternative control service* from 1 July 2010. This reflects the separation of existing street lighting services into a *standard control service* for the conveyance of electricity to street lights and an *alternative control service* for the provision, construction and maintenance of street lights.

The Stage 1: Framework and approach paper necessitates a change in the regulatory framework for street lighting services to comply with the *Rules* and the control mechanism for the *2010-15 regulatory control period*. Changes that will impact on street lighting customers are:

- the treatment of gifted assets as contributed assets from 1 July 2010;
- the resulting changes to the structure of contributed and non-contributed tariffs; and
- the application of non-contributed street lighting services to standard street lights.

In the *2010-15 regulatory control period*, ENERGEX will continue to provide non-contributed and contributed street lighting services. With the change in treatment of gifted assets, customers will receive an ongoing charge for the maintenance of the street light asset under the contributed service from 1 July 2010. Continuing the current regulatory arrangements, engagement of a supplier for construction of the street light, which is then contributed to ENERGEX, will remain the responsibility of the customer.

From 1 July 2010, the non-contributed service will only apply where ENERGEX has constructed standard street lights. Customers will still receive an ongoing charge for the standard level of service provided under the non-contributed service. Non-standard street lights will be available under a quoted service (incremental cost) or contributed service. Charges associated with these services will need to be paid upfront by the customer.

In instances where work is required outside of business hours due to maintenance access restrictions or customer requirements, these services will be provided as a quoted service. Quoted services are outlined further in Chapter 22.

In determining prices for 2010-11 ENERGEX has updated its pricing methodology to reflect current replacement costs for major and minor street lights and the forecast number of different street light configurations. This update has resulted in a change to the revenue proportions for major and minor street lights. The major and minor proportions used for 2010-11 are 47 per cent and 53 per cent respectively. During the *current regulatory control period*, the major and minor proportions used were fixed at 58 per cent and 42 per cent respectively.

At an aggregated level this change results in a decrease of approximately 20 per cent to the major price and an increase of approximately 26 per cent to the minor price. The impact at a disaggregated level is an overall decrease in street light prices due to the mix of major and minor street lights for each individual customer. The average customer impact is a decrease of 9 per cent.

ENERGEX will communicate with the relevant stakeholders including the Local Government Association of Queensland, individual local authorities and the Queensland Department of Main Roads regarding these changes.

21.14 Pass through

ENERGEX considers that the pass through events identified under Part C of the *Rules* are equally applicable to *alternative control services*. Accordingly the pass through provisions for defined events and nominated events outlined in Chapter 20 will be applied to street lighting services.

22 Other alternative control services

22.1 Summary

ENERGEX's other *alternative control services* relate to the fee-based services and quoted services, including large customer connections, provided by ENERGEX which are ancillary to the main distribution services and are provided at the explicit request of third parties.

In its Stage 1: Framework and approach paper, the AER proposed that ENERGEX's fee-based services and quoted services be classified as *alternative control services*. ENERGEX accepts the AER's proposed classification of its fee-based services and quoted services.

These services are provided on an individual fee for service basis to retailers and end use customers. Depending on the service, ENERGEX will either provide the service for a fixed fee or quoted price. An outline of these services is provided below. The full list of fee-based services and quoted services currently offered by ENERGEX and the associated service description is provided in **Appendix 22.1**.

The AER has proposed a formula based price cap form of control mechanism for fee-based services and quoted services over the *2010-15 regulatory control period*. This consists of:

- a schedule of fixed prices for fee-based services and a schedule for rates for quoted services for the first year of the *2010-15 regulatory control period*; and
- a price path for the remaining years of the *2010-15 regulatory control period*.

In applying the control mechanism ENERGEX has utilised a formula of cost components for the different services to determine the proposed price.

22.2 Regulatory information requirements

A distribution determination is predicated on decisions by the AER including:

- Clause 6.12.1(12) – a decision on the control mechanism for *alternative control services* (to be in accordance with the relevant framework and approach paper); and
- Clause 6.12.1(13) – a decision on how compliance with the control mechanism is to be demonstrated.

Clauses 6.2.6(b) and 6.2.6(c) of the *Rules* set out the basis of control mechanisms for *alternative control services*.

For *alternative control services*, Clause 6.8.2(c) (3) of the *Rules* provides that a *Regulatory Proposal* must include the proposed control mechanism, a demonstration of the application of the control mechanism, and the necessary supporting information.

Clause 6.8.2(c)(4) of the *Rules* provides that a *Regulatory Proposal* must include indicative prices for each year of the *regulatory control period*.

In addition to these Rule requirements, the AER requires the following information under Clause 2.2.5 of its RIN:

- name and description of services provided in the *current regulatory control period*;
- job numbers, revenue and prices for services provided in the *current regulatory control period*; and
- indicative prices for each fee-based service and for a representative sample of typical quoted services for the next *regulatory control period*.

Further, for fee-based services and quoted services the AER requires the following specific information under Clause 2.4.7 of its RIN:

- information to support the application of the proposed control mechanism;
- cost information;
- asset value information;
- demand information; and
- service level information.

22.3 Overview of services

In its Stage 1: Framework and approach paper, the AER determined that there were two groups of services provided by ENERGEX, fee-based services and quoted services, that should be classified as *alternative control services* (in addition to street lighting services).

The definitions applied by the AER were:

- **fee-based services** – services relating to activities undertaken by ENERGEX at the request of customers or their agents (eg. Retailers or contractors). The costs for these activities can be directly attributed to customers and service-specific charges can therefore be levied; and
- **quoted services** – services for which the nature and scope cannot be known in advance irrespective of whether it is customer requested or there is an external event that triggers the need (e.g. price on application or compensable).

ENERGEX has adopted the AER service classification as outlined in the Stage 1: Framework and approach paper. Historically fee-based services and quoted services have represented approximately three per cent of ENERGEX's total annual regulated revenue. In accordance with Clause 2.4.7(a)(1)(i) of the RIN, further detail on fee-based services and quoted services is provided in **Appendix 22.1**.

22.4 Regulatory framework

In the *current regulatory control period* fee-based services and quoted services are classified as excluded distribution services and were initially regulated under the *QCA's 2005 final determination* as prescribed non-DUOS services under a revenue cap form of control.

In 2007, the QCA conducted a review of ENERGEX's services and in its December 2007 Final Decision 'Electricity Distribution: Review of Excluded Distribution Services' reclassified ENERGEX's prescribed non-DUOS services as excluded distribution services and determined that separate, more 'light-handed' regulatory arrangements would apply to these services. The driver for this decision was the introduction of FRC in Queensland. FRC was expected to trigger an increase in the demand for these services, which could lead to inappropriate cross-subsidisation between these services and prescribed DUOS services under a fixed revenue cap. The QCA changed the control mechanism for excluded distribution services from a revenue cap to a variant of a schedule of fixed charges.

In its Stage 1: Framework and approach paper the AER proposed the classification of fee-based services and quoted services as *alternative control services* under a price cap form of control mechanism for the *2010-15 regulatory control period*. The classification and control mechanism proposal for fee-based services and quoted services represents no departure from the current regulatory approach.

In the *current regulatory control period*, the service of design and construction of large connection assets (large customer connections) was classified as a prescribed service under a revenue cap form of control. In the Stage 1: Framework and approach paper, the AER proposed the classification of large customer connections as an *alternative control service* and its inclusion in the quoted services group. The commissioning, operation and maintenance of all connection assets, including large connections, was determined by the AER to be a *standard control service*, which represents no departure from the current regulatory approach. The definition of a large customer, in relation to large customer connections, is outlined below.

The AER's classification of large customer connections was based on an assessment that there was growing competition in the design and construction of large connection assets, and that connection asset costs can be directly attributed to an individual customer. The classification and control mechanism proposal for large customer connections departs from the current regulatory approach and is one of the key changes for ENERGEX and its customers in the *2010-15 regulatory control period*.

22.4.1 Definition of large customer connections

In the Stage 1: Framework and approach paper, the AER agreed that it was more appropriate to distinguish between small and large customers based on the nature of the connection assets than on energy consumption alone. The AER also identified that a clear demarcation can be made on the basis of whether connection costs are individually calculated or averaged. Other than for SACs, connection asset costs for all other customer groups and embedded generators are calculated on an individual basis.

For the purpose of classifying the design and construction of large connection assets, the AER considered it reasonable to adopt the DNSP's SAC as the small customer. A large customer would therefore be an embedded generator, ICC or CAC, or a customer other than a SAC, as defined by the DNSPs in their approved Pricing Principles Statement. SACs are defined in ENERGEX's 2009-10 Pricing Principles Statement as those customers with annual electricity consumption below 4 GW.h per annum, whose supply arrangements are consistent across the customer group.

ENERGEX accepts the AER proposed definition of a large customer and this *Regulatory Proposal* has been developed based on this definition.

22.5 Service obligations

In accordance with Clause 2.4.7(a)(4) of the RIN, where applicable ENERGEX's prices for fee-based services and quoted services are developed based on the following service obligations and standards.

ENERGEX's fee-based services and quoted services are provided under ENERGEX's standard commercial contracts and terms and conditions. This is in accordance with the EIC, incorporating the Standard Connection Contract (SCC) and Standard Co-ordination Agreement (SCA) and the Electricity Connection and Metering Manual (available from the ENERGEX website).

Any change to the standard terms and conditions will constitute a quoted service where the price reflects the specific requirements of the customer.

The conditions and timeframes for the provision of fee-based services by ENERGEX will be in accordance with the requirements of Chapter 5 of the EIC, which are outlined in pro forma 2.3.5 in **Attachment 1**. For quoted services, the conditions for service provision, including timeframes, will be dependent upon the type of work requested and subject to commercial negotiation between ENERGEX and the customer. Requests for the provision of fee-based services and quoted services may be received from the customer directly via the Network Contact Centre or from retailers.

Additionally, the provision of a number of fee-based services and quoted services is covered by the GSL framework outlined in the EIC (Section 2.5). GSL obligations require ENERGEX to pay rebates to customers where it does not achieve targeted performance levels. There are specific GSL requirements for wrongful disconnections, connections, reconnections and appointments which apply to the provision of fee-based services and quoted services.

In relation to large customer connections, customers may request a connection under the *Rules* or the *Electricity Act 1994 (Qld)*. Under Section 40A of the *Electricity Act*, ENERGEX has a connection obligation to all customers. This connection obligation is subject to Sections 40C and 40D, and the applicable limitations outlined in Section 40E. Where a customer requests a connection under the *Rules*, ENERGEX has obligations under Chapter 5 of the *Rules* for network connections and connection enquiries. This chapter provides the framework for connection to a distribution network and outlines the process to be followed by anyone electing to establish or modify a connection to ENERGEX's network.

ENERGEX ensures obligations are met and that a consistent level of service is provided to customers through adherence to policy documents and annual compliance reviews.

The Ministerial Council of Energy (MCE) Standing Committee of Officials (SCO) is currently consulting on the development of a national framework for Electricity Distribution Connection and Connection Charge Arrangements. The first exposure draft is anticipated in late 2009. In a submission to the MCE SCO, ENERGEX highlighted that the AER's service classification decision and the definition of capital contributions in Queensland was not considered. ENERGEX has concerns surrounding the practical implications of the proposed national framework. The final framework may have implications for this *Regulatory Proposal*. Any changes required as a result of the national framework would be covered under a regulatory change event unless the framework is introduced prior to 1 July 2010. In this case, changes should be covered under the Interim Change Event outlined in Chapter 20 of this *Regulatory Proposal*.

Forecast costs used to establish prices for the *2010-15 regulatory control period* are based on maintaining ENERGEX's current customer practice. The methodology for developing prices allows for a balancing of cost and reasonable service based on ENERGEX's historical experience and knowledge of customer expectations. The pricing formula is structured to facilitate the provision of a higher level of service if requested by the customer. Provision of a higher level of service is a quoted service as it requires balancing of internal versus external labour, timeframe requests and overhead costs, to ensure customers' requirements are met.

22.6 Application of control mechanism

This section provides information on the application of the control mechanism which has been proposed by the AER for fee-based services and quoted services in its Stage 1: Framework and approach paper and proposes how compliance with the control mechanism can be demonstrated (as per Clauses 6.12.1(12) and (13) of the *Rules*). It also demonstrates the application of the control mechanism in accordance with Clause 6.8.2(c)(3) of the *Rules* and Clause 2.4.7.(a)(1)(ii) of the RIN.

In its Stage 1: Framework and approach paper, the AER nominated a formula based approach (a non-building block approach) to determine the efficient costs of providing fee-based services and quoted services under a price cap form of control mechanism in the first year of the *regulatory control period*, and to establish a price path for remaining years of that period.

In accordance with Clause 6.12.1(12) ENERGEX will adopt the AER's proposed form of control mechanism and proposes to apply the control mechanism through using the formula outlined below to calculate the price for fee-based services and quoted services respectively.

Price = Labour + Contractor Services + Material + Capital Allowance + Profit Margin + GST

- **Labour (including overheads)** – consists of all labour costs directly incurred in the provision of the service, labour on-costs, fleet on-costs and overheads. The labour cost for each service is dependent on the skill level, travel time, number of hours and crew size required to perform the service;
- **Contractor services (including overheads)** – reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service e.g. traffic control, road closure permits;
- **Materials (including overheads)** – reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads;
- **Capital allowance** – represents a return on and return of capital for non-system assets used in the delivery of the service; and
- **Profit margin** – reflects a margin on direct costs (labour, contractor services and materials) to ensure competitive neutrality prevails in the service market and ensure an appropriate return is earned commensurate with the level of risk associated with the use of all assets in providing and delivering the service.

The inclusion of overhead costs relates to the indirect costs necessarily incurred in the provision of services and has been applied according to the AER approved CAM.

Depending on the service, some components of the formula may have a zero value. For example, prices for fee-based services generally include only labour, overhead, capital allowance, profit and GST components.

Prices for fee-based services for the first year of the *regulatory control period* have been calculated using the above formula and forecast costs for labour, fleet on-costs, overheads and capital allowance. Proposed prices for 2010-11 will be included in the initial pricing proposal submitted for AER approval in accordance with Clause 6.18.2(a)(1). Prices for each subsequent regulatory year of the *regulatory control period* will be based on the approved price path and will be included in the annual pricing proposal submitted for AER approval in accordance with Clause 6.18.2(a)(2). Indicative prices for the *2010-15 regulatory control period* are provided in pro forma 2.2.5 in **Attachment 1**.

ENERGEX has retained its current policy of not establishing a fixed price where variations in the precise nature of the services being sought mean that averaging would result in significant inequity for customers. The prices for quoted services will be calculated using the formula above to reflect the actual cost of service provision based on the specific requirements of the customer.

This formula for fee-based services and quoted services has been designed to ensure prices will be representative of the efficient costs of providing and delivering the service, and signal the economic costs of service provision by being subsidy free. This cost is between the incremental and stand-alone costs. Prices based on the above formula will be cost reflective, representing costs derived through the same allocative mechanism as that used to determine costs for *standard control services*, in accordance with the AER approved CAM.

This satisfies the requirements of the *Rules* and demonstrates the application of the control mechanism. Further detail on the formula components and its application are provided in **Appendix 22.2**.

The information provided in this section and in appendixes demonstrates the application of the control mechanism as set out in the Stage 1: Framework and approach paper and is submitted for the AER's consideration in making its constituent decision under Clause 6.12.1(13).

22.7 Cost information

In accordance with Clause 2.4.7(a)(2)(i) of the RIN, ENERGEX has provided historical and forecast cost information for other *alternative control services* and an explanation of material cost differences in **Appendix 22.3**. Additionally, to comply with the RIN, ENERGEX has provided a formula-based representation of the costs of providing each individual service in **Appendix 22.4** (fee-based services) and **Appendix 22.5** (quoted services).

22.8 Demand information

In accordance with Clause 2.4.7(a)(3) of the RIN, ENERGEX has provided the historic and forecast demand for individual fee-based services in **Appendix 22.6**. Demand information for quoted services is not available as ENERGEX does not capture or report this information at a disaggregated level.

22.9 Indicative prices

In accordance with Clause 6.8.2(c)(4), indicative prices for fee-based services for 2010-15 are provided in pro forma 2.2.5 in **Attachment 1** and summarised in Table 22.1. Prices for 2010-11 are based on the formula outlined above. Prices for the remaining years from 2011-15 have been calculated using the proposed price path outlined in section 22.10.

Table 22.1 Prices for fee-based services for the *2010-15 regulatory control period*

$/service (Nominal)	2010-11	2011-12	2012-13	2013-14	2014-15
Alterations and additions to current metering equipment	96.37	103.43	109.29	115.51	119.83
Attending loss of supply – LV customer installation at fault (BH)	108.05	115.96	122.54	129.51	134.36
Overhead service replacement – single phase	292.55	313.97	331.77	350.64	363.76
Overhead service replacement – multiple phase	344.97	370.23	391.22	413.48	428.94
De-energisation	47.75	51.24	54.15	57.23	59.37
Meter test	116.19	124.70	131.77	139.27	144.47
Meter inspection	86.57	92.91	98.18	103.77	107.65
Reconfigure meter	71.23	76.44	80.78	85.37	88.56
Off-cycle meter read	10.51	11.28	11.92	12.60	13.07
Site visit	75.92	81.47	86.09	90.99	94.39
Locating ENERGEX underground cables	137.02	147.05	155.39	164.23	170.37
Temporary connection	851.54	913.87	965.69	1,020.64	1,058.81
Re-energisation – business hours	41.61	44.66	47.19	49.88	51.74
Re-energisation – after hours	111.57	119.74	126.53	133.73	138.73
Re-energisation (visual) – business hours	70.46	75.62	79.91	84.45	87.61
Re-energisation (visual) – after hours	146.69	157.42	166.35	175.81	182.39
Re-energisation non-payment (visual) – business hours	70.46	75.62	79.91	84.45	87.61
Re-energisation non-payment (visual) – after hours	146.69	157.42	166.35	175.81	182.39
Supply abolishment	328.07	352.09	372.05	393.22	407.93
Unmetered supply	153.46	164.70	174.03	183.94	190.81
Street light glare screening	131.84	141.49	149.51	158.02	163.93
Replacement of standard luminaries with aero screen units (per street light)	299.98	321.94	340.20	359.56	373.00

All indicative prices are exclusive of GST

ENERGEX is not able to provide indicative prices for quoted services as prices are dependent on the customer's specific requirements. In accordance with the requirements of Clause 2.2.5 of the RIN, ENERGEX has provided a representative sample of typical quoted services for the *current regulatory period* and the *2010-15 regulatory control period* in **Appendix 22.5**.

Prices are developed based on forecast demand and cost information outlined in this *Regulatory Proposal*.

22.10 Proposed price path

ENERGEX proposes to escalate fee-based service prices according to Table 22.2, having applied the formula and established efficient prices for these services in 2010-11.

Table 22.2 Proposed price path (escalators) for fee-based services in the *2010-15 regulatory control period*

%	2010-11	2011-12	2012-13	2013-14	2014-15
Escalator	As per price	7.32%	5.67%	5.69%	3.74%

The proposed price path for fee-based services will provide a balanced outcome between cost reflectivity and simplicity, and deliver the expected revenue. Compared to alternative options considered, this approach will allow a smooth transition into the following regulatory period.

To maintain cost reflectivity and ensure prices for quoted services are economically efficient, ENERGEX proposes to escalate each formula component on an individual basis as summarised in Table 22.3.

Table 22.3 Proposed price path (escalators) for the *2010-15 regulatory control period*

Nominal	2010-11	2011-12	2012-13	2013-14	2014-15
Labour	As per price	5.5%	5.5%	5.5%	5.5%
Contractor costs	As per price	5.5%	5.5%	5.5%	5.5%
Materials	Direct pass through at cost				
Overheads	As per proposed rates outlined in **Appendix 22.3**				
Capital allowance	As per proposed costs outlined in **Appendix 22.3**				
Profit margin	Fixed 5% across the period				

ENERGEX proposes to escalate the labour and contractor component of each service at a rate of 5.5 per cent. This rate aligns with ENERGEX's Union Collective Agreement and the operating expenditure escalation factors proposed in Chapter 12.

The overhead component of prices will be adjusted in line with the proposed rates. These rates are reflective of forecast indirect costs for the *2010-15 regulatory control period* and are based on the AER approved CAM.

Part Three – Addendum

energex
positive energy

23 Governance, assurances and certifications

23.1 Summary

This chapter outlines ENERGEX's compliance with the regulatory obligations relating to certification of the information contained within this *Regulatory Proposal*.

23.2 Regulatory information requirements

Schedules 6.1.1(5) and 6.1.2(6) of the *Rules* require ENERGEX to submit a Directors' certification of the reasonableness of the key assumptions that underlie the capital and operating expenditure forecasts.

Clause 2.3.3 of the RIN identifies the key assumptions which have been used to develop the capital and operating expenditure forecasts.

Attachment 4 of the RIN contains the Directors' certification of the reasonableness of the key assumptions.

Section 28 M(d) of the NEL states that the RIN may specify that information described in it be verified by way of a statutory declaration by an officer of ENERGEX. The AER requires a statutory declaration by the CEO of ENERGEX to verify the information provided to the AER in accordance with the RIN.

23.3 Overview of ENERGEX corporate governance

ENERGEX Limited is a GOC established under the *GOC Act*. The *Corporations Act 2001* (Cth) applies to ENERGEX Limited except in so far as the *GOC Act* otherwise provides.

ENERGEX's robust corporate governance framework is advocated by the ENERGEX Board and senior management, who adopt a top down approach in promoting the achievement of best practice standards in corporate governance. The ENERGEX Board and management encourage staff to carry out their duties in an ethical and responsible manner, protecting the community interest and the integrity of ENERGEX.

ENERGEX reports against the 10 Corporate Governance Guidelines for GOCs issued by the Queensland government. These Guidelines reflect the eight *Corporate Governance Principles and Recommendations* issued by the Australian Stock Exchange Corporate Governance Council.

23.4 The ENERGEX board and supporting committees

The ENERGEX Board is responsible for providing effective governance, leadership and management oversight. It also carries out specific functions as set out in Section 88 of the *GOC Act 1993* in addition to its obligations and duties under the *Corporations Act 2001*.

The ENERGEX Board also monitors ENERGEX's environmental, safety and financial performance on a continuing basis and has systems in place to review internal controls and ensure compliance with laws and ethical behaviour.

23.4.1 ENERGEX board committees

The ENERGEX Board has established the following four Committees, which undertake various oversight responsibilities on its behalf:

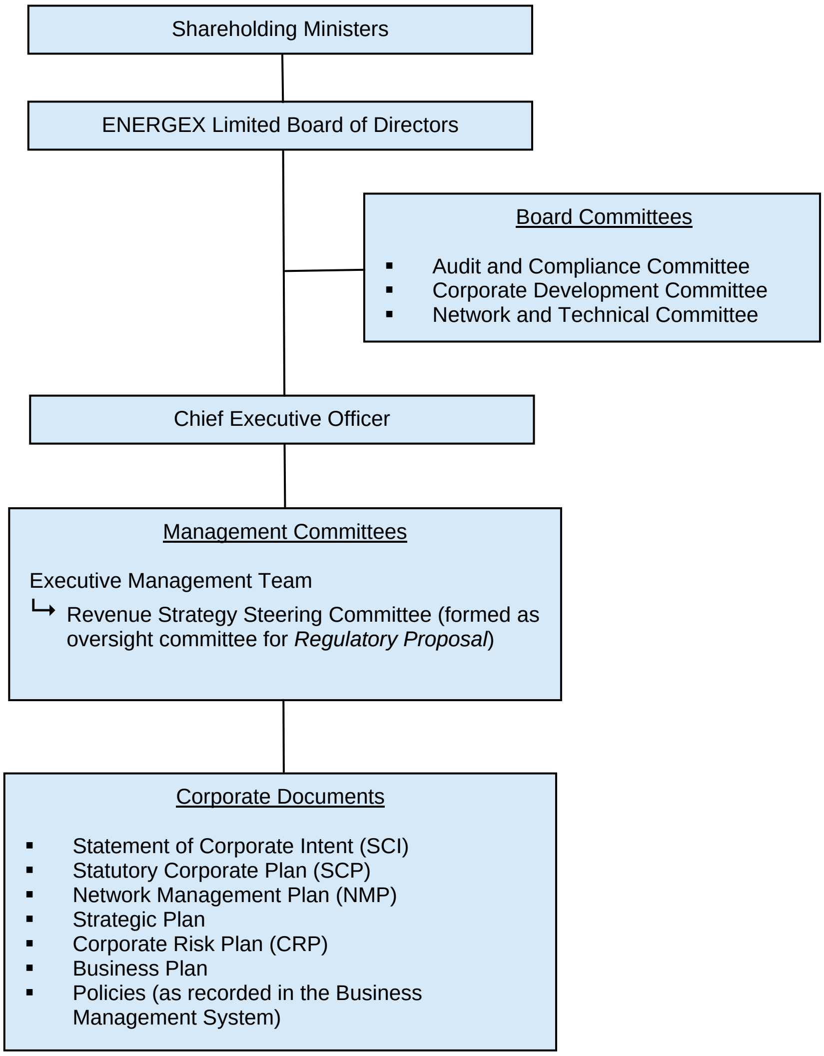
- **Audit and Compliance Committee**: The role of this Committee is to provide assurances to the ENERGEX Board that ENERGEX is properly meeting its obligations in relation to financial integrity, legal compliance, business risk management and ethics and integrity.
- **Network and Technical Committee**: The role of this Committee is to assist the ENERGEX Board in discharging its oversight responsibilities in relation to maintaining and improving technical and network standards for the delivery of electricity in a manner that meets the reasonable expectations of the community and complies with ENERGEX's legal and regulatory obligations.
- **Corporate Development Committee**: The role of this Committee is to consider the appropriateness of, and make recommendations in relation to, significant and complex corporate development proposals prior to their presentation to the ENERGEX Board. The Committee also supports the ENERGEX Board in the development of ENERGEX's corporate strategies.
- **Remuneration Committee**: The role of this Committee is to assist the ENERGEX Board in discharging its responsibilities in relation to remuneration and employment policies, consistent with the government objective of attracting and retaining valuable employees to the organisation.

The ENERGEX Limited Board and each of the Board committees (except for the Remuneration Committee) were engaged in the development of this *Regulatory Proposal*.

23.5 Governance of this regulatory proposal

The governance of this *Regulatory Proposal* is summarised in Figure 23.1.

Figure 23.1 Corporate governance of ENERGEX's regulatory proposal



23.5.1 Revenue strategy steering committee

A Revenue Strategy Steering Committee, comprising ENERGEX's CEO, four General Managers and the Director Revenue Strategy was established to guide and oversee the regulatory review process. The approach to the certification process is aimed at supporting the Directors in discharging their duties in providing the certifications required under Schedule 6.1 of the *Rules* and the CEO in meeting the requirements of the RIN.

23.5.2 Certification process for the AER submission

This *Regulatory Proposal* was developed in alignment with the ENERGEX Strategic Plan, ENERGEX's policies and practices, the requirements of the *Rules* and other regulatory instruments. The preparation of the submission also involved the development and implementation of systems, processes and measures, including:

- legal advice on the Directors' Certification;
- development and implementation of a Data Verification Cover Sheet to be certified by managers developing elements of this submission;
- commissioning of two audits of ENERGEX's preparation process and final audit review by Deloitte during the finalisation of this *Regulatory Proposal*;
- development and implementation of governance arrangements for this *Regulatory Proposal*;
- engagement of experts in key areas to provide advice or review inputs, assumptions and processes as necessary; and
- final legal review of the completed *Regulatory Proposal*.

The ENERGEX Board was engaged early in the processes of development and validation of this *Regulatory Proposal*. In order to assist the Directors to make certifications of the reasonableness of the key assumptions which underlie the capital and operating expenditure forecasts, the ENERGEX Board delegated due diligence and oversight responsibilities to various ENERGEX Board Committees. ENERGEX's approach in this process was for various ENERGEX Board Committees to review the material and endorse it prior to the ENERGEX Board approving it.

23.5.3 Governance for approval of network expenditure

ENERGEX has aligned governance of forecast operating and capital expenditure with existing legislative requirements under the *GOC Act* and the EIC. ENERGEX has a three-tier governance process to oversee expenditure on the distribution network. The three tiers include:

1. high level targets and forecasts approved by the ENERGEX Board as part of the SCP and SCI;
2. endorsement of the five year rolling expenditure programs by the ENERGEX Board and the 12-month detailed programs of work as part of the NMP; and
3. annual budgets and delivery plans approved by the ENERGEX Board.

The governance in relation to the preparation of expenditure programs and the monitoring of program and expenditure outcomes is discussed in Chapter 4.

23.6 Certification statement

In accordance with Schedules 6.1.1(5) and 6.1.2(6) of the *Rules*, ENERGEX is required to lodge a *Regulatory Proposal* that contains a certification by the ENERGEX directors as to the reasonableness of the key assumptions that underlie the forecasts of capital expenditure and operating expenditure.

The certification statement is consistent with the form required in the RIN and is in **Appendix 23.1**.

23.7 CEO statutory declaration

ENERGEX's CEO is required to certify that the information and documentation provided to the AER in accordance with the RIN is complete and accurate in all material respects and can be relied upon by the AER to assess this *Regulatory Proposal* and make a distribution determination.

The CEO's statutory declaration in relation to the RIN is in **Appendix 23.2**.

Glossary

Term	Definition
ABS	Australian Bureau of Statistics
AER	Australian Energy Regulator
AGL	Australian Gas Light
AMI	Advanced Metering Infrastructure
APT	Australian Pipeline Trust
ARR	Annual Revenue Requirement
ASA	Average Speed of Answer
BMS	Business Management System
BOM	Bureau of Meteorology
C&I	Commercial and Industrial
CAC	Connection Asset Customers
CAIDI	Customer Average Interruption Duration Index
CAM	Cost Allocation Method
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CBRM	Condition Based Risk Management
CC Bank	Capital Contributions Bank
CEG	Competition Economists Group
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CRA	Charles River Associates

Term	Definition
CVU	Customer View Utility
DINIS	Distribution Network Information System
DM	Demand Management
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
ECC	Emergency Cyclic Capacity
EDSD Review	Electricity Distribution for Service Delivery in the 21st Century
EIC	Electricity Industry Code
EMF	Electro Magnetic Field
Ergon Energy	Ergon Energy Corporation Limited
ERP	Enterprise Resource Planning
ESO	Electrical Safety Office
ETS	Emissions Trading Scheme
FBT	Fringe Benefits Tax
FFA	Field Force Automation
FRC	Full Retail Competition
FTTP	Fibre-To-The-Premises
GFC	Global Financial Crisis
GOC	Government Owned Corporation
GOC Act	Government Owned Corporation Act
GOS	Grade of Service
GSL	Guaranteed Service Levels
GSP	Gross State Product

Term	Definition
GST	Goods and Services Tax
GW.h	Gigawatt hour
ICC	Individually Calculated Customers
ICT	Information and Communication Technology
IVR	Interactive Voice Response
kV	Kilovolt
kV.A	Kilovolt Ampere
LNSP	Local Network Service Provider
LOS	Loss of Supply
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MAMP	Mains Asset Maintenance Policy
MCE	Ministerial Council on Energy
MRP	Market risk premium
MSATS	Market Settlement and Transfer Solution
MSS	Minimum Service Standards
MV.A	Mega Volt Ampere
MW	Mega Watt
NBN	National Broadband Network
NCC	Normal Cyclic Capacity
NDP	Network Development Plan
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
Network Vision	Network Vision - Outlook to 2025

Term	Definition
NIEIR	National Institute of Economic and Industry Research
NMI	National Meter Identifier
NMP	Network Management Plan
NPV	Net Present Value
NSP	Network Service Provider
NSW	New South Wales
NTC	Network Technical Committee
OH&S	Occupational Health & Safety
PoE	Probability of Exceedence
PoW	Program of Work
PTRM	Post Tax Revenue Model
PV	Photovoltaic
QCA	Queensland Competition Authority
QME	Queensland Mines and Energy
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
Regulation	Electricity Regulation 2006
RFM	Roll Forward Model
RIN	Regulatory Information Notice
RIO	Regulatory Information Order
RMU	Ring Main Unit
ROA	Return on Asset
RRS	Regulatory Reporting Statement
Rules	National Electricity Rules
SAC	Standard Asset Customers
Saha	Saha International Limited

Term	Definition
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Substation Asset Maintenance Policy
SCA	Standard Coordination Agreement
SCADA	Supervisory Control and Data Acquisition
SCC	Standard Connection Contract
SCI	Statement of Corporate Intent
SCM	Service Call Management
SCO	Standing Committee of Officials
SCP	Statutory Corporate Plan
SEQ	South East Queensland
SEQ Plan	Draft South East Queensland Regional Plan 2009-2031
SFG	SFG Consulting
SME	Small to Medium Enterprises
SoRI	AER's Statement of Regulatory Intent on the WACC parameters (distribution)
SPARQ	SPARQ Solutions Pty Ltd
SPP	Summer Preparedness Plan
STPIS	Service Target Performance Incentive Scheme
Synergies	Synergies Economic Consulting
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital

Confidential information

Claim for confidentiality

Clause 6.8.2(c)(6) requires ENERGEX to provide an indication of the parts of this *Regulatory Proposal* ENERGEX claims to be confidential and wants suppressed from publication. **Attachment 3** of the RIN outlines the general provisions relating to the provision of information.

ENERGEX claims confidentiality over the following appendixes, attachments, RIN pro formas and RIN supporting documentation on the grounds that the information is either Commercial-in-confidence or contains intellectual property. ENERGEX requests that the AER does not disclose the information contained in these appendixes, attachments, RIN pro formas and RIN supporting documentation to any person outside of the AER:

Appendixes

No.	Title
3.3	High Level Map of ENERGEX Supply Area
4.1	ENERGEX Corporate Strategic Plan
4.2	ENERGEX Transmission Planning Guidelines
4.3	ENERGEX Distribution Planning Guidelines
4.4	Review of Proposed Supply Security Standards by Evans & Peck
4.5	Full Application of Condition Based Risk Management with ENERGEX by EA Technology Consulting
4.6	ENERGEX Substation Asset Maintenance Policy
4.7	ENERGEX Mains Asset Maintenance Policy
9.8	ENERGEX Safety Management System
10.1	ENERGEX Peak Demand and Energy Forecasts 2009-2015
10.2	Electricity Consumption and Maximum Projections for the ENERGEX Region to 2018 by NIEIR
10.3	System Maximum Demand and Forecasting Maximum Demand by ACIL Tasman
12.1	Maintenance Policy Review for ENERGEX by EA Technology Consulting
12.2	Review of Self Insurance Program by Finity Consulting
12.3	Self Insurance – Retailer Credit Risk by Finity Consulting
12.9	ENERGEX, Ergon Energy and SPARQ Solutions Joint ICT Plan – September 2008 Baseline

No.	Title
13.1	ENERGEX Statement of Corporate Intent 2009/10
13.2	ENERGEX Statutory Corporate Plan 2009/10 – 2013/14
13.3	ENERGEX Contract Strategy Update – Final Report by KPMG
16.1	Tax Asset Base for Regulatory Purposes as at 1 July 2008 – Final Report by KPMG
16.4	ENERGEX Letter to AER re Risk Free Rate
17.1	ENERGEX Fixed Asset Policy (Capitalisation Policy)
17.3	Consumer Preferences for Service Standards in Electricity Distribution Final Report by KPMG
17.5	Service Target Performance Incentive Scheme Assessment of Targets, Impacts and Risks by Evans & Peck
18.1	Capital Contributions Bank Proposal for Standard Control Services by Synergies Economic Consulting
21.1	Street Light Asset Base Methodology – Supplementary Information
22.3	Fee-Based Services and Quoted Services – Cost Information
22.4	Formula-Based Representation of Fee-Based Services
22.5	Representative Sample of Quoted Services
22.6	Fee-Based Services – Demand Information

Attachments

No.	Title
1	Regulatory Information Notice pro formas: 2.2.1 – Capital Expenditure 2.2.2 – Operating Expenditure 2.2.3 – Material Projects and Programs 2.2.4 – Variance Justifications 2.2.5 – Services and Indicative Prices 2.3.12 – Expenditure with Other Persons 2.4.5 – Corporate Income Tax
2	Roll Forward Model
3	Post Tax Revenue Model – Building Block
4	Post Tax Revenue Model – Street Lights
5	Post Tax Revenue Model – Revenue Adjustments

RIN Supporting Documentation

No.	Title
2.2.1(1)	ENERGEX Network Capital Expenditure Baseline Program for Standard Control Services 2010-2015
2.2.1(2)	ENERGEX Network Capital Expenditure Adjusted Program for Standard Control Services 2010-2015
2.2.2(1)	ENERGEX Network Operating Expenditure Baseline Program for Standard Control Services 2010-2015
2.2.2(2)	ENERGEX Network Operating Expenditure Adjusted Program for Standard Control Services 2010-2015
2.3.6(1) to (22)	ENERGEX's Plans, Policies, Procedures and Strategies
2.3.10(2)	Major Plant and Equipment

Attachments – NEL compliance documents

Attachment No.	Title
1.	*Regulatory information notice*
2.	Roll forward model
3.	Post tax revenue model – building block
4.	Post tax revenue model – street lights
5.	Post tax revenue model – revenue adjustments

Appendixes – ENERGEX supporting documents

No.	Title
2.1	Compliance with the *Regulatory Information Notice* (RIN) Requirements
3.1	ENERGEX Corporate Structure
3.2	Roles and Responsibilities
3.3	High Level Map of ENERGEX Supply Area
3.4	Draft SEQ Regional Plan 2009-2031
3.5	ENERGEX Network Vision – Outlook to 2025
3.6	Queenland's Regulatory Environment
3.7	An Action Plan for Queensland Electricity Distribution
3.8	Key Information Systems
4.1	ENERGEX Corporate Strategic Plan
4.2	ENERGEX Transmission Planning Guidelines
4.3	ENERGEX Distribution Planning Guidelines
4.4	Review of Proposed Supply Security Standards by Evans & Peck
4.5	Full Application of Condition Based Risk Management with ENERGEX by EA Technology Consulting
4.6	ENERGEX Substation Asset Maintenance Policy
4.7	ENERGEX Mains Asset Maintenance Policy
4.8	ENERGEX Environment Strategy
5.1	ENERGEX Network Demand Management Strategy 2010-2015
6.1	Grouping of Distribution Services
9.1	QCA's Final Decision: Review of Electricity Distribution Network Minimum Service Standards and Guaranteed Service Levels to apply in Queensland from 1 July 2010 (April 2009)
9.2	ENERGEX Network Management Plan 2008/09 to 2012/13
9.3	ENERGEX Application for Additional Capital Expenditure October 2006 - Part A
9.4	QCA's Discussion Paper on Proposed Amendments to the Electricity Industry Code regarding Customer Claims for Guaranteed Service Level (GSL) Payments (May 2009)
9.5	QCA's Electricity Distribution: Service Quality Reporting Guidelines
9.6	Department of Mines and Energy Annual Report to the Regulator under the *Electricity Act 1994*(pro forma)

No.	Title
9.7	Department of Mines and Energy Minimum Service Stadards, Guaranteed Service Levels, Service Quality and Operations Reporting Guidelines for Distribution Networks Connected to the Main Grid
9.8	ENERGEX Safety Management System
10.1	ENERGEX Peak Demand and Energy Forecasts 2009-2015
10.2	Electricity Consumption and Maximum Projections for the ENERGEX Region to 2018 by NIEIR
10.3	System Maximum Demand and Forecasting Maximum Demand by ACIL Tasman
12.1	Maintenance Policy Review for ENERGEX by EA Technology Consulting
12.2	Review of Self Insurance Program by Finity Consulting
12.3	Self Insurance – Retailer Credit Risk by Finity
12.4	ENERGEX Board Resolutions to Self Insure
12.5	Debt and Equity Raising Costs Report by Synergies Economic Consulting
12.6	Final Report on Escalation Rates for Labour, Materials & Contractors by KPMG
12.7	Final Report on Escalation Rates for Other Asset Categories & Materials by KPMG
12.8	ENERGEX Electricity Distribution Operational Expenditure Review by SAHA
12.9	ENERGEX, Ergon Energy and SPARQ Solutions Joint ICT Plan – September 2008 Baseline
12.10	Report on Efficiency of IT Services and Prudency of IT Forecasts by KPMG
13.1	ENERGEX Statement of Corporate Intent 2009/10
13.2	ENERGEX Statutory Corporate Plan 2009/10 – 2013/14
13.3	ENERGEX Contract Strategy Update – Final Report by KPMG
16.1	Tax Asset Base for Regulatory Purposes as at 1 July 2008 – Final Report by KPMG
16.2	The Reasonableness of Regulatory Estimates of the Cost of Equity Capital by SFG Consulting
16.3	Estimating the risk free rate in the context of the NER and the Global Financial Crisis by CEG
16.4	ENERGEX Letter to AER re Risk Free Rate
16.5	Estimating the Cost of the 10 Year BBB+ Debt by CEG
16.6	Gamma : New Analysis Using Tax Statistics by Synergies Economic Consulting
16.7	Advice on Inflation Rates – Final Report by KPMG
17.1	ENERGEX Fixed Asset Policy (Capitalisation Policy)
17.2	Proposed Telephone Answering Measure – Average Speed of Answer

No.	Title
17.3	Consumer Preferences for Service Standards in Electricity Distribution Final Report by KPMG
17.4	Establishment of Reliability Parameter Targets
17.5	Service Target Performance Incentive Scheme Assessment of Targets, Impacts and Risks by Evans & Peck
17.6	Establishment of Telephone Answering Notional Targets
18.1	Capital Contributions Bank Proposal for Standard Control Services by Synergies Economic Consulting
18.2	Assigning Customers to Tariff Classes Process Diagram
20.1	Defined Pass Through Events
20.2	Nominated Pass Through Events
20.3	ENERGEX's Proposed Pass Through Clause
21.1	Street Light Asset Base Methodology – Supplementary Information
22.1	Fee Based Services & Quoted Services
22.2	Application of Control Mechanism – Supporting Information
22.3	Fee-Based Services & Quoted Services – Cost Information
22.4	Formula-Based Representation of Fee-Based Services
22.5	Representative Sample of Quoted Services
22.6	Fee-Based Services – Demand Information
23.1	Directors' Certification of Key Assumptions
23.2	CEO's Statutory Declaration

RIN supporting documentation

No.	Title
2.2.1(1)	ENERGEX Network Capital Expenditure Baseline Program for Standard Control Services 2010-2015
2.2.1(2)	ENERGEX Network Capital Expenditure Adjusted Program for Standard Control Services 2010-2015
2.2.2(1)	ENERGEX Network Operating Expenditure Baseline Program for Standard Control Services 2010-2015
2.2.2(2)	ENERGEX Network Operating Expenditure Adjusted Program for Standard Control Services 2010-2015
2.3.4(1)	Regulatory Obligations Supplementary Information
2.3.5(1)	EDSD Report
2.3.5(2)	Electricity Industry Code
2.3.6(1)	Finance Policy Manual
2.3.6(2)	Treasury Risk Policy Manual
2.3.6(3)	Produce the Network Strategic Plan Procedure
2.3.6(4)	Produce the Total ENERGEX Demand Forecast Procedure
2.3.6(5)	Standard Network Building Blocks Manual
2.3.6(6)	Produce a Transmission Project Approval Report Procedure
2.3.6(7)	Produce a Distribution Project Approval Report Procedure
2.3.6(8)	Procurement Policy
2.3.6(9)	Purchasing Manual
2.3.6(10)	ICT Emergency Management Plan
2.3.6(11)	Acceptable use of ENERGEX Information and Communications Technologies Policy
2.3.6(12)	Standard for System and Network Access Management
2.3.6(13)	Information Security Policy
2.3.6(14)	Risk Management Using Insurance Policy
2.3.6(15)	Network Property Guidelines
2.3.6(16)	Infrastructure Acquisition and Approvals for 110kV and 132 kV Line Corridors Procedure
2.3.6(17)	Infrastructure Acquisition and Approvals for Substation Sites Procedure
2.3.6(18)	Network Risk Based Assessment Framework Policy

No.	Title
2.3.6(19)	Tier 1 Business Continuity Plan – Corporate Emergency Management Handbook
2.3.6(20)	Manage Counter Disaster Plans and Responsibilities Procedure
2.3.6(21)	Manage Level 2 Emergency – Severe Weather Procedure
2.3.6(22)	Manage Emergency Network Operations Procedure
2.3.8(1)	Demand Forecasts
2.3.10(1)	Expenditure Escalation Process
2.3.10(2)	Major Plant and Equipment
2.4.4(1)	Review of Procedures