ActewAGL Distribution Determination 2009-14

Regulatory Proposal to the Australian Energy Regulator
June 2008

ActewAGL
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ActewAGL Distribution

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Australian Energy Regulator

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ActewAGL Distribution partners are
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Overview

ActewAGL Distribution submits this regulatory proposal in accordance with the requirements set out in Appendix 1 of Chapter 11 of the *National Electricity Amendment Rules* (the transitional *Rules*). The proposal contains the required elements listed in clauses 6.8.2 and S6.1 of the transitional *Rules* as well as all the supporting information required in the Australian Energy Regulator's (AER's) Regulatory Information Notice (RIN). The regulatory proposal applies to the five-year regulatory period starting 1 July 2009.

The regulatory proposal relates to the standard control services and alternative control services provided by ActewAGL Distribution. As required by the transitional *Rules*, ActewAGL Distribution's standard control services are those previously classified as prescribed services in the Independent Competition and Regulatory Commission's (ICRC's) 2004 determination. These include all network use and connection services, other than alternative control services. Alternative control services are the provision and servicing of all meters for customers consuming fewer than 160 MWh per annum.

Context for the review

The regulatory proposal takes account of the characteristics of ActewAGL Distribution's network, customer base, demand and operating environment, as well as ActewAGL Distribution's performance over the current regulatory period. Elements of the proposal recognise that the ACT and New South Wales distribution determinations are the first such determinations to be made by the AER, and as a result a number of transitional matters must be addressed. The regulatory proposal also identifies areas where the regulatory framework is still evolving and the potential implications need to be addressed (chapter 2).

Complying with regulatory obligations and meeting or managing demand

ActewAGL Distribution's capital and operating expenditure forecasts have been developed to ensure that ActewAGL Distribution is able to achieve the *expenditure objectives* set out in the transitional *Rules*. This involves ensuring that ActewAGL Distribution is able to comply with all relevant regulatory obligations (set out in chapter 4), meet or manage expected demand for the period (chapter 5), maintain service quality, reliability and security (chapters 3 and 4) and maintain system security, safety and reliability (chapters 3 and 4). The expenditure forecasts are developed through a network planning and management process which ensures that all obligations, requirements and expectations are met in a prudent and efficient manner (chapter 6).

The building block proposal for standard control services

ActewAGL Distribution's building block proposal for standard control services has been developed in accordance with the requirements of Part C of the transitional *Rules* and the relevant AER guideline.[1]

ActewAGL Distribution's forecast capital and operating expenditures—key elements of the building block proposal for standard control services—are shown in Table 0.1.

Table 0.1 Forecast capital and operating expenditures

$ million (2008/09)	2009/10	2010/11	2011//12	2012/13	2013/14	Total
Net capital expenditure*	78.3	58.3	51.7	50.9	38.5	**277.7**
Operating expenditure†	58.7	59.8	61.0	62.9	63.1	**305.5**

* Net of capital contributions and disposals
† Including UNFT, debt raising costs and self-insurance costs

The forecast capital expenditure program is $277.7 million ($2008/09), which is 71 per cent higher than actual and estimated capital expenditure over the 2004–09 regulatory period. The main components of the forecast capital expenditure include:

- major supply augmentation projects—including two new zone substations (the first to be built in the ACT since 1994), plus augmentation of a third—involving total expenditure of $43.8 million ($2008/09) over the period;
- the Southern Supply Point Project—required by the ACT Government and involving expenditure of $22.5 million over the period; and
- the pole replacement program—involving expenditure of $51.1 million over the period.

Total operating expenditure is forecast to increase by an average of 1.8 per cent per annum during 2009–14—considerably less than the average growth rate of 4.5 per cent per annum during the current regulatory period. ActewAGL Distribution is proposing a commercially prudent increase in its operating expenditure that manages the cost pressures associated with:

- labour shortages in Canberra, particularly in the non-residential construction sector;
- an increasing number of assets to maintain; and
- the ageing of the network from an average age of 25.6 years to 27.5 years over the next regulatory period, assuming the proposed capital expenditure program is approved.

Key assumptions in relation to the underlying cost drivers for the expenditure forecasts include:

[1] Australian Energy Regulator 2008, *Final decision on control mechanisms for standard control services for the ACT and NSW 2009 distribution determinations, February*

- materials costs to increase only by growth in the Consumer Price Index (CPI) annually;
- CPI increases of between 2.4 per cent and 2.6 per cent per annum; and
- labour costs to increase by 6.5 per cent per annum on average over the regulatory period.

Other elements of the building block proposal for standard control services include:

- an assumed growth rate in energy throughput over the 2009–14 regulatory period of 1.6 per cent per annum;
- a nominal vanilla weighted average cost of capital of 10.70 per cent based on current market parameters;
- a Regulatory Asset Base (RAB) rolled forward in accordance with the AER Roll Forward Model and guideline—the opening RAB value is $593 million for standard control services; and
- a Tax Asset Base and proposed depreciation schedules developed in accordance with the AER's requirements set out in section 2.4.5 of the RIN and informed by the AER's June 2006 Issues Paper and correspondence on the topic (as described in chapter 11 of this regulatory proposal).

Revenue requirement and X factors for standard control services

ActewAGL Distribution's proposed revenue requirement and X factors for standard control services are shown in Table 0.2. The proposal involves an adjustment of CPI + 20.37 per cent in 2009/10 followed by CPI + 2 per cent in the remaining years of the regulatory period. Under ActewAGL Distribution's proposal, most of the required increase in the revenue requirement has been factored into year 1 of the price path to meet cash flow needs and comply with transitional *Rules* requirements.

Table 0.2 Proposed standard control service revenue and X factors

	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Proposed smoothed revenue requirement ($ million 2008/09)	*116.01*	145.33	154.42	164.04	174.21	185.05
X factor		+20.37%	+2.00%	+2.00%	+2.00%	+2.00%

In the current regulatory period, the Utilities Network Facilities Tax (UNFT) is treated as a cost pass through. ActewAGL Distribution has forecast UNFT liability in the next regulatory period as part of its operating expenditure. Removing the effect of the UNFT, the first year X factor price adjustment falls from 20.37 per cent to 17.07 per cent.

Impact of ActewAGL Distribution's regulatory proposal on an average customer bill

In 2009/10, ActewAGL Distribution's proposal would result in a real increase in the average ACT regulated domestic electricity bill of 3.0 per cent.[2]

This is the assessed impact of the proposal by ActewAGL Distribution for recovering its required network distribution use of system charges (DUOS) in 2009/10, if they are fully implemented based on the current input parameters in the proposal. The calculation presumes that the current Draft Decision by the ICRC for the supply of electricity to franchise customers by ActewAGL Retail is applied as the Final Decision for 2008/9 prices and that this, and all other non DUOS costs, remain constant in 2009/10. The retail pricing decision is due on 13 June 2008.

Building block proposal for alternative control services

ActewAGL Distribution's proposal for alternative control services (metering services) is a building block proposal in line with the previous determination of the ICRC and has been developed in accordance with the AER's *Final Decision* on alternative control services[3] and the relevant transitional *Rules* provisions.

The proposed revenue and price path for alternative control services is shown in Table 0.3.

Table 0.3 Proposed alternative control service revenue and X factors

	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Proposed revenue requirement ($ million 2008/09)	5.67	7.57	7.76	7.96	8.16	8.36
X factor (full Po adjustment)		+41.01%	0%	0%	0%	0%

Key assumptions underpinning the alternative control services proposal include:

- the provision of metering data by ActewAGL Distribution is a service that falls outside the AER regulation of alternative control services in the ACT. It is categorised as forming part of ActewAGL Distribution's standard control services; and
- the escalation of maximum allowable revenue by CPI each year will occur from 2010/11 to 2013/14. There will be a 'full P_0 adjustment' in the first year of the regulatory period to ensure the net present value of allowed revenue over the regulatory period is equal to the net present value of the revenue requirement over the regulatory period.

If ActewAGL Distribution's proposal for alternative control (metering) services was applied from 2009/10, the overall impact on the average domestic customer's electricity bill would be a further 1.2 per cent increase, in addition to the 3 per cent referred to above for standard control services.

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[2] ActewAGL Distribution has assessed this impact on a typical domestic customer in the ACT, using 8,000kWh, at the indicative network distribution prices that would apply as provided in the submission.
[3] AER 2008, *Final Decision on Control Mechanisms for Alternative Control Services for the ACT and NSW 2009 distribution determination, February*

Indicative prices and demand management

As required by the transitional *Rules*, ActewAGL Distribution has prepared indicative prices for standard control and alternative control services. The regulatory proposal also includes proposed approaches to assessing compliance with the control mechanisms and making annual adjustments to prices. Pricing measures are a key element of ActewAGL Distribution's approach to demand-side management. ActewAGL Distribution's tariff structure is explained and the success of demand management initiatives in providing greater customer choice and improving network utilisation is outlined in chapter 13.

Cost pass through

ActewAGL Distribution proposes that five additional cost pass-through events be added to those defined in the transitional *Rules*: a *major natural disaster event*, a *transitional period event*, a *smart meters event*, an *input price event* and a *supply curtailment event*. ActewAGL Distribution proposes that the cost pass through provisions apply to both standard control and alternative control services (chapter 16).

1. Introduction

1.1 Purpose and scope of the regulatory proposal

ActewAGL Distribution submits this regulatory proposal to the Australian Energy Regulator (AER) in accordance with the requirements set out in Appendix 1 of Chapter 11 of the *National Electricity Amendment Rules* (the transitional *Rules*).[4]

The regulatory proposal applies to the five-year regulatory control period starting 1 July 2009. The proposal contains all the elements required by clauses 6.8.2 and S6.1 of the transitional *Rules*, as well as all the supporting information required by the AER's Regulatory Information Notice (RIN), including the completed pro formas and the required certifications.

The regulatory proposal is submitted by ActewAGL Distribution, the regulated network service provider (RNSP) in the ACT.[5] As required by the RIN, the relevant business details are as follows:

Trading name:	ActewAGL Distribution
ABN:	76 670 568 688
Postal address:	GPO Box 366, Canberra ACT 2601
Business address:	221-223 London Circuit, Canberra ACT 2601
Contact person:	David Graham, Director Regulatory Affairs and Pricing
	Phone 02 6248 3605
	Email david.graham@actewagl.com.au

The following section provides an overview of the structure of ActewAGL Distribution and the services to be covered by the AER's distribution determination. Section 1.3 then describes the regulatory framework and how this regulatory proposal addresses the requirements set out in the transitional *Rules* and the RIN.

[4] As notified in the *South Australia Gazette* of 20 December 2007

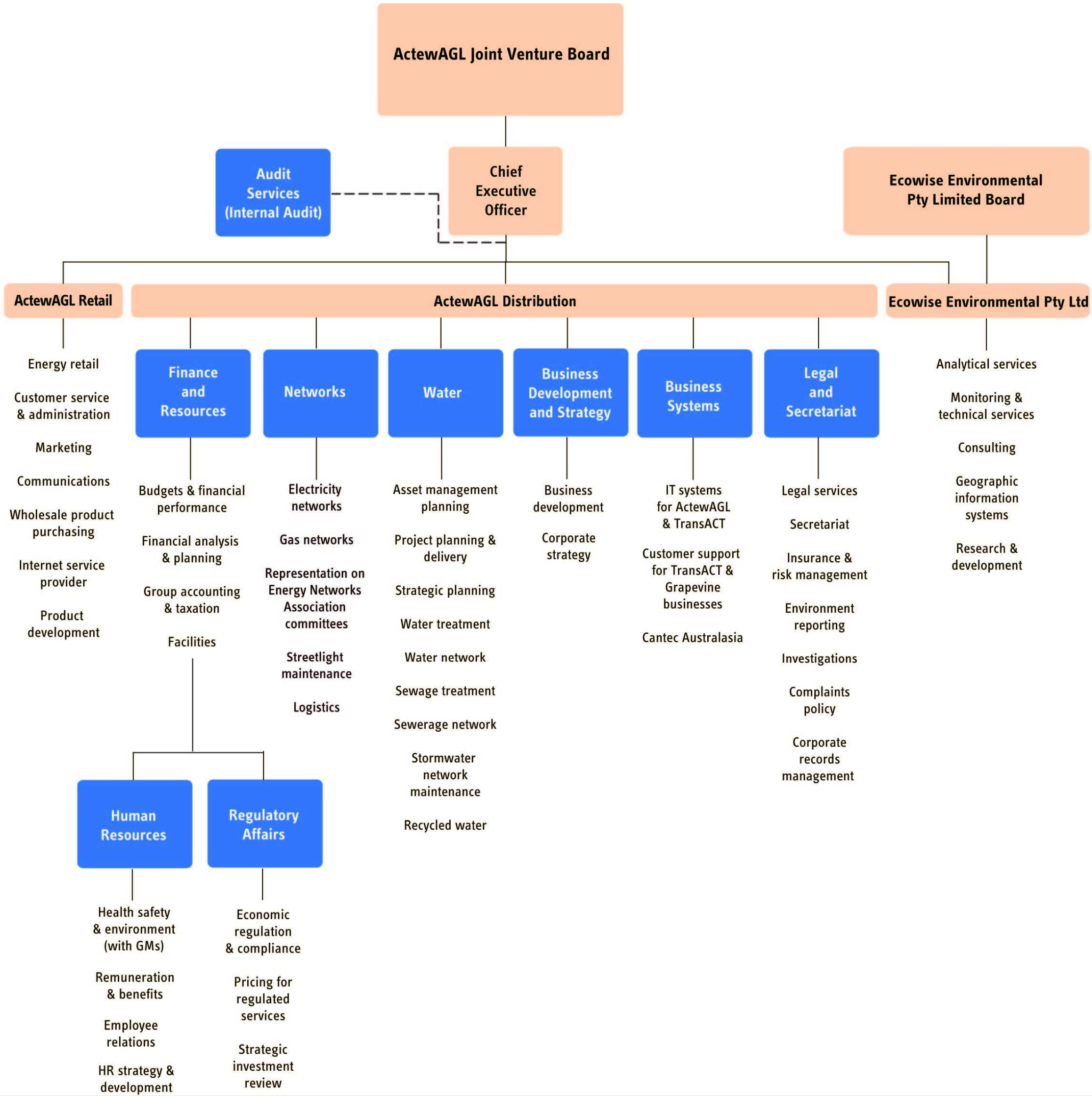
[5] Note that the transitional *Rules* refer to the regulated network service provider as *ActewAGL* which is defined (clause 6.1.7) as "the joint venture between ACTEW Distribution Ltd and Alinta GCA Ltd providing distribution services in the ACT, or any successor and successors of that joint venture". This definition refers to *ActewAGL Distribution*. ActewAGL involves two partnerships—ActewAGL Distribution and ActewAGL Retail—as described in section 1.2 of this regulatory proposal.

1.2 ActewAGL Distribution's structure and services

1.2.1 Structure and ownership of ActewAGL Distribution

ActewAGL Distribution owns and operates the electricity distribution network in the ACT. ActewAGL Distribution also owns the gas distribution network in the ACT, Greater Queanbeyan and Shoalhaven, and operates and maintains Canberra's water and sewerage networks under a Utilities Management Agreement (UMA) with ACTEW Corporation. ActewAGL Distribution also owns and operates Ecowise Environmental Pty Ltd and operates elements of the businesses of TransACT Capital Communications Pty Ltd and Neighbourhood Cable Ltd under management services agreements.

Figure 1.1 Structure of ActewAGL Joint Venture and ActewAGL Distribution



Electricity network services are provided by ActewAGL Networks, one of the business units in ActewAGL Distribution as at May 2008. Other units within ActewAGL Distribution contribute to the provision of electricity network services by providing the following services:

- Audit Services (internal audit);
- Human Resources;
- Facilities Management;
- Legal and Secretariat;
- Corporate Finance;
- Business Systems and Commercial Development; and
- Office of the Chief Executive.

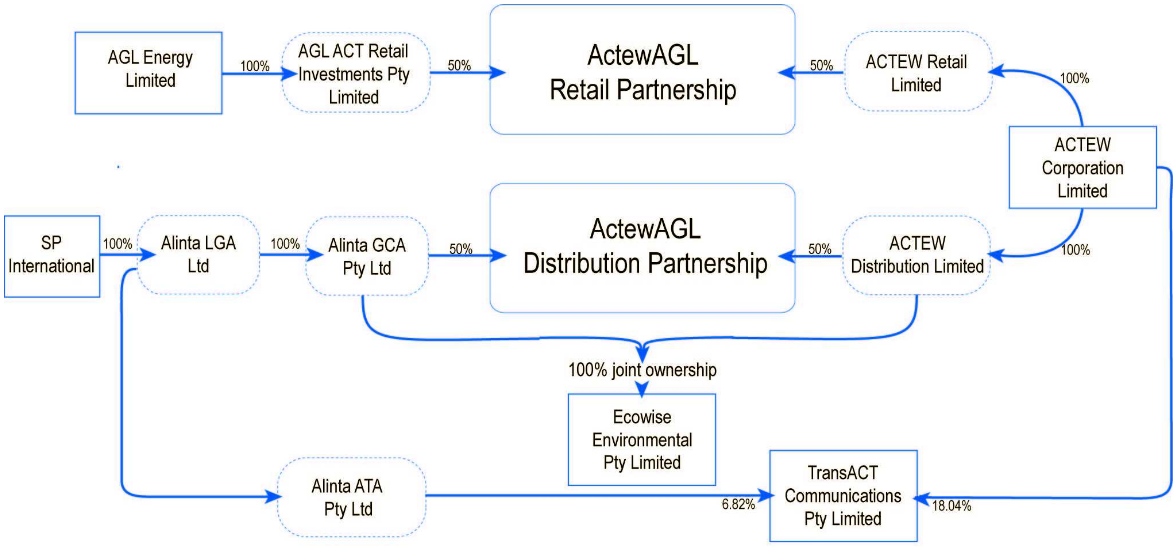
ActewAGL was formed in October 2000 when the then Australian Gas Light Company (AGL) and ACTEW Corporation Limited entered into Australia's first utility joint venture. ActewAGL is organised as two partnerships, ActewAGL Distribution and ActewAGL Retail.

Following October 2006 business dealings between AGL and Alinta, ownership of ActewAGL's retail arm was shared equally between AGL Energy Limited and ACTEW Corporation Limited and ownership of ActewAGL's distribution arm was shared equally between Alinta Limited and ACTEW Corporation Limited. Further changes to the distribution partnership occurred when a consortium including Singapore Power purchased Alinta in 2007. The distribution partnership is now owned equally by Singapore Power and ACTEW Corporation. The two partnerships are now made up as follows:

- The ActewAGL Distribution partners are ACTEW Distribution Limited (ABN 83 073 025 224) and Alinta GCA Pty Ltd (ABN 24 008 552 663) trading as ActewAGL Distribution (ABN 76 670 568 688); and
- The ActewAGL Retail partners are ACTEW Retail Limited (ABN 23 074 371 207) and AGL ACT Retail Investments Pty Ltd (ABN 53 093 631 586) trading as ActewAGL Retail (ABN 46 221 314 841).

The ActewAGL ownership structure is illustrated Figure 1.2.

Figure 1.2 Ownership of ActewAGL Distribution



ActewAGL Retail provides customer services, billing and marketing services to ActewAGL Distribution.

As a condition of their operating licences, the distribution and retail partnerships must comply with the Independent Competition and Regulatory Commission's (ICRC's) ring-fencing guidelines.[6] Under clause 6.17.1 of the transitional *Rules*, these guidelines are adopted by the AER for the 2009–14 regulatory period.

Further information about ActewAGL Distribution, as required by the AER in the RIN (2.3.1), is provided in attachment 2 of this regulatory proposal.

1.2.2 ActewAGL Distribution's electricity distribution services

The National Electricity Rules (NER) define a *distribution service* as "a service provided by means of, or in connection with, a *distribution system*".[7]

A *distribution system* is, in turn, defined as:

> A distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system.
>
> Connection assets on their own do not constitute a distribution system.[8]

[6] ICRC 2002, *Ring fencing guidelines for gas and electricity network service operators in the ACT*, November.
[7] *National Electricity Rules* (version 19), Chapter 10, Glossary, p 826
[8] *National Electricity Rules* (version 19), Chapter 10, Glossary, p 826. A *distribution network* is further defined in the NER (p 826) as "A *network* which is not a *transmission network*".

ActewAGL Distribution's *distribution services* comprise:

- standard control services, which include all network use and connection services except the alternative control services;
- alternative control services, which comprise the provision and servicing of all meters for customers consuming fewer than 160 MWh per annum. This covers meter testing, meter reading, meter checking, processing of meter data and provision of non-standard meters; and
- unregulated services, which include streetlighting, training and contestable metering services.

ActewAGL Distribution does not provide any services that are classified as negotiated services.

As required by clause 6.2.3C of the transitional *Rules*, ActewAGL Distribution's standard control services are those which were previously classified by the ICRC as *prescribed services*. ActewAGL Distribution's alternative control services are those which were classified by the ICRC as *excluded services*.

The proposed control mechanisms are consistent with those set out in the AER's transitional guidelines.[9] As required by the transitional *Rules* (clause 6.2.5), the control mechanism for standard control services will be varied by the AER for the imposition of the new requirement for side constraints and *overs and unders* adjustment for TUOS charges. The proposed control mechanism for alternative control services is substantially the same as that determined by the ICRC for the 2004–09 regulatory period. ActewAGL Distribution's interpretation of certain elements of the AER's proposed mechanism for alternative control services is set out in chapter 15.

1.3 *Rules* requirements and the structure of the proposal

The structure and content of this regulatory proposal are driven by the requirements of the transitional *Rules* and the AER's RIN. The relevant requirements are referenced throughout the proposal, and the tables in attachment 1 provide a checklist of the requirements and where they are satisfied or addressed in the regulatory proposal.

1.3.1 The transitional *Rules*

Clause 6.2.4 of the transitional *Rules* requires the AER to make a distribution determination following the processes set out in Part E. Clauses 6.8 to 6.11 in Part E contain the requirements for the proposal and the determination process. Clause 6.12 sets out the constituent decisions that the AER must make in its determination and the extent of its discretion in making determinations.

[9] AER 2008, *Final Decision on Control Mechanisms for Standard Control Services for the ACT and NSW 2009 distribution determinations, February* and AER 2008, *Final Decision on Control Mechanisms for Alternative Control Services for the ACT and NSW 2009 distribution determinations, February*

The AER must approve the provider's proposed total revenue requirement for the regulatory period and annual revenue requirement, as set out in its building block proposal, if it is satisfied that those amounts have been properly calculated and are based on the amounts determined or forecast in accordance with the requirements of Part C of the transitional *Rules*. ActewAGL Distribution's regulatory and building block proposals focus on ensuring that these requirements are met.

Part C of the transitional *Rules* deals with building block determinations for standard control services. It sets out the required components of a building block proposal and the objectives, factors and criteria that the AER must address in making its determination.

The operating and capital expenditure forecasts are key elements of the building block proposal. Clause 6.5.6 of the transitional *Rules* requires the AER to accept the operating cost forecast if it is satisfied that the forecast reasonably reflects:

- the efficient costs of achieving the *operating expenditure objectives;*
- the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider (DNSP) would require to achieve the *operating expenditure objectives;* and
- a realistic expectation of the demand forecast and cost inputs required to achieve the *operating expenditure objectives*.

The operating expenditure objectives are to:

- meet or manage the expected demand for the standard control services over the period;
- comply with all applicable regulatory obligations or requirements associated with the provision of 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 through the supply of standard control services.

Clause 6.5.7 of the transitional *Rules* mirrors these requirements and objectives for capital expenditure forecasts.

Recognising these requirements, ActewAGL Distribution's regulatory proposal is structured as follows:

- chapter 2 sets out the context for the determination, helps to establish the *circumstances of the relevant DNSP* and provides other relevant background information as required by the RIN;
- chapters 3, 4 and 5 explain ActewAGL Distribution's service standards and other regulatory obligations, and expected demand during the regulatory period, and indicate how these drive capital and operating expenditures;

- chapters 6, 7 and 8 then explain how planning and management policies are designed to ensure ActewAGL Distribution meets its regulatory obligations and expected demand, and the quantum of prudent and efficient expenditure that must be incurred to achieve this;
- chapters 9 to 13 provide the other elements of the building block proposal for ActewAGL Distribution's standard control services and the resulting X factors and indicative prices; and
- chapters 14 to 16 deal with the remaining matters on which the AER must make a determination—the negotiating framework for negotiable components of direct control services, the building block proposal for alternative control services, and cost pass through for direct control services.

1.3.2 The AER's Regulatory Information Notice

Clause 6.8.2 of the transitional *Rules* requires the regulatory proposal to comply with all the requirements set out in the AER's RIN.

In accordance with section 28F(1)(a) of the *National Electricity Law*, the AER served a RIN on ActewAGL Distribution on 24 April 2008.

The AER's purpose in serving the RIN is to obtain information to assist its assessment of the regulatory proposal. The RIN also sets out the form in which the AER seeks the information. The RIN requirements are in addition to those in the transitional *Rules*.

Attachment 1 of the RIN sets out the purpose of the requested information. Most of the information is required to assess operating and capital expenditure forecasts against operating and capital expenditure objectives and criteria. The main requirements of the RIN in addition to those explicitly covered in the transitional *Rules* are to provide:

- details of material projects and programs (both current period and proposed);
- an explanation of significant variations;
- an organisational overview, including an explanation of relationships with other entities;
- information on transactions with persons other than the provider (both current period and proposed);
- details of the cost estimation process; and
- an identification and explanation of transitional factors.

The RIN requirements are addressed throughout the regulatory proposal. A checklist of where the requirements are met is provided in attachment 1 of this regulatory proposal.

1.3.3 The AER's transitional guidelines

The AER has exercised the discretion conferred upon it by clause 6.2.8 of the transitional *Rules* and released guidelines on:

- the post-tax revenue model;
- the roll forward model;
- control mechanisms for alternative control services;
- control mechanisms for direct control services;
- an efficiency benefit sharing scheme;
- a service target performance incentive scheme; and
- a demand management incentive scheme.

ActewAGL Distribution has addressed the relevant guidelines throughout the regulatory proposal.

2. Context for the 2009–14 determination

This chapter provides an overview of the key features of ActewAGL Distribution's electricity network, demand, customer base and operating environment and highlights the factors driving capital and operating expenditure programs. The chapter also reviews outcomes from the 2004–09 regulatory period and identifies issues associated with the transition to a new national regulatory framework. A range of factors and issues that need to be considered in the determination are identified and then examined more closely in the chapters that follow.

The information presented in this chapter meets several of the AER's Regulatory Information Notice (RIN) requirements.[10] It also helps to establish the *circumstances of the relevant DNSP*—one of the factors in the transitional *Rules* that the AER must consider in making its determination.[11]

2.1 ActewAGL Distribution's network, demand and operating environment

2.1.1 ActewAGL Distribution's electricity distribution network

ActewAGL Distribution's electricity distribution network supplies electricity to around 156,000 customers in the ACT. A map of the network is provided in attachment 3.

The ACT is supplied with electricity from the New South Wales transmission grid through two bulk supply points—Canberra Bulk Supply Point (330 kV/132 kV) at Holt and Queanbeyan Bulk Supply Point (132 kV/66 kV) at Oaks Estate.

Both of the bulk supply substations and the incoming 330 kV and 132 kV transmission lines are owned and operated by TransGrid. The three 132 kV sub-transmission lines from the Canberra Bulk Supply Point are owned by ActewAGL Distribution, as are the two 66 kV lines from the Queanbeyan Bulk Supply Point.

In 2006 the ACT Government introduced a new statutory network performance requirement (Network Service Criterion) requiring the establishment of a second 132 kV connection to ActewAGL Distribution's distribution network.[12] ActewAGL Distribution is required to construct two new 132 kV lines to connect the new southern supply point to the existing ACT distribution network. The purpose of the southern supply point requirement is to enhance the security of electricity supply for the ACT.

Accommodation of the southern supply point requires the largest upgrade of ActewAGL Distribution's network for several decades and is a major component of ActewAGL

[10] For example, RIN section 2.3.1 seeks information on the organisation and factors impacting on expenditure forecasts and section 2.4.1 seeks information on transitional issues.
[11] Transitional *Rules* clauses 6.5.6(e)(5) and 6.5.7(e)(5).
[12] Utilities Exemption 2006 (No.1) Disallowable Instrument DI2006-47 made under the *Utilities Act 2000*, section 22

Distribution's capital expenditure program for the 2009–14 regulatory period. The project is discussed in chapter 7, with further details provided in the project justification.

ActewAGL Distribution operates 11 zone substations and two switching stations. The zone substations reduce voltage to a level at which distribution feeders operate. The Fyshwick Zone Substation is supplied by the Queanbeyan Bulk Supply Point, while the others are supplied from the Canberra Bulk Supply Point. Ten of the 11 zone substations and the two switching stations were commissioned before 1990, while the remaining Gold Creek Zone Substation was commissioned in 1994. The need to repair and maintain ageing zone substations is an important driver of ActewAGL Distribution's operating expenditure forecasts.

Five of the 11 zone substations are expected to reach their full capacity during the next 10 years. Two new zone substations (East Lake and Molonglo) and one major zone substation capacity augmentation (at Civic) will be required before the end of the 2009–14 regulatory period. Zone substation expenditure represents a significant component of ActewAGL Distribution's capital expenditure proposal for the 2009–14 regulatory period.

ActewAGL Distribution's reticulation system includes underground and overhead conductors and more than 4,000 distribution substations that are required to further reduce the voltage to the level at which the electrical energy is distributed through overhead or underground low-voltage lines.

Until the late 1980s, all reticulation in the ACT was through overhead lines. However since then all greenfield developments (residential, commercial and/or industrial subdivisions in urban areas requiring new infrastructure) have been serviced with underground reticulation, in accordance with the ACT Government's requirements. Underground lines now account for almost half the total line length in ActewAGL Distribution's network (see Table 2.1). This proportion is considerably higher than the national average of around 12 per cent underground.[13]

Underground reticulation typically reduces routine maintenance. However, the impact of the higher proportion of underground lines on maintenance costs is outweighed by the relatively high costs of maintaining overhead lines in the ACT. The characteristics of ActewAGL Distribution's overhead network make it especially costly to maintain and replace, relative to those of other distributors. The two major characteristics are backyard overhead reticulation and the large proportion of natural hardwood poles.

ActewAGL Distribution has a much larger proportion of natural (untreated) hardwood poles in service than is typical in the electricity supply industry—natural poles represent over 50 per cent of ActewAGL Distribution's pole population, whereas the typical level throughout the industry is around 10 per cent.

The need for increased maintenance of pole tops, cross-arms and fittings due to the deteriorating condition of ageing wooden poles and associated concerns about safety are

[13] Energy Supply Association of Australia 2008, *Electricity distribution report 2006–07*, confidential report to ActewAGL Distribution

significant drivers of ActewAGL Distribution's increased operating expenditures during the current regulatory period and the operating expenditure forecasts for the 2009–14 regulatory period.

The costs of inspecting, maintaining and replacing poles are increased by the requirement in the ACT for backyard electricity reticulation and the associated planning and regulatory requirements (discussed further below). Expenditure on pole inspection and tree clearing during the 2004–09 regulatory period has been higher than forecast (see section 2.2.3 below).

The pole replacement program, as discussed in detail in chapter 7, is the largest single component of ActewAGL Distribution's forecast capital expenditure. It was also a significant driver of capital expenditure outcomes in the 2004–09 regulatory period. The regulatory treatment of pole replacement expenditure is also an important transitional issue. This is discussed in section 2.3 below.

The key characteristics of ActewAGL Distribution's electricity distribution network are summarised in Table 2.1.

Table 2.1 ActewAGL Distribution's electricity distribution network

Line asset type	Kilometres	
Total	4,696	
Sub-transmission	205	
High-voltage	2,282	
Low-voltage	2,209	
Underground	2,283	
Overhead	2,413	
Transformers	**Number**	**Capacity (MVA)**
Sub-transmission	28	1,341
Distribution	4,670	1,752
Line structures	**Number**	
Sub-transmission line structures	1,325	
Distribution and sub-transmission poles	53,037	

In terms of line length, ActewAGL Distribution's network is the smallest in the National Electricity Market. ActewAGL Distribution also has the smallest customer base and the lowest regulatory asset base (RAB) valuation (Table 2.2). Nevertheless, it serves an important role in reliably supplying several of the nation's major political and strategic institutions and its largest inland city.

Table 2.2 Relative size of distribution network service providers

Utility	Length of line (km)	Customers (number)	RAB ($ million)
ActewAGL	4,696	156,360	528
Citipower	6,488	286,107	1,022
United Energy	12,308	609,585	1,229
Alinta	5,579	286,085	589
Energy Australia	47,144	1,539,030	4,116
Integral Energy	33,863	822,446	2,283
Energex	48,115	1,217,193	5,023
SP AusNet	29,397	573,766	1,363
Powercor	80,577	644,113	1,671
Ergon Energy	142,793	736,710	4,690
Country Energy	182,023	734,074	2,375

Source: AER 2007, *State of the Energy Market 2007*, p 147

An important implication of ActewAGL Distribution's relatively small size is that major network augmentations have a significant step impact on total capital expenditure. This is apparent in the capital expenditure forecasts presented in chapter 7. While no new zone substations were built during the 2004–09 regulatory period, two new zone substations and a major substation augmentation will be required during the 2009–14 regulatory period. These zone substation projects, along with the required southern supply point augmentation, are major drivers of the forecast increase in augmentation capital expenditure from $13.9 million in the current regulatory period to $76.5 million for the 2009–14 period.

The relatively small size of ActewAGL Distribution is also a key consideration in any comparison of costs between distribution businesses. A distribution business with a relatively small customer base will tend to have higher costs per customer as largely fixed costs such as system control, billing systems and national electricity market operations must be spread across a smaller base. It is therefore crucial that any comparisons be based on a range of measures, rather than a single measure such as costs per customer or costs per kilometre of line. This is discussed in chapter 8.

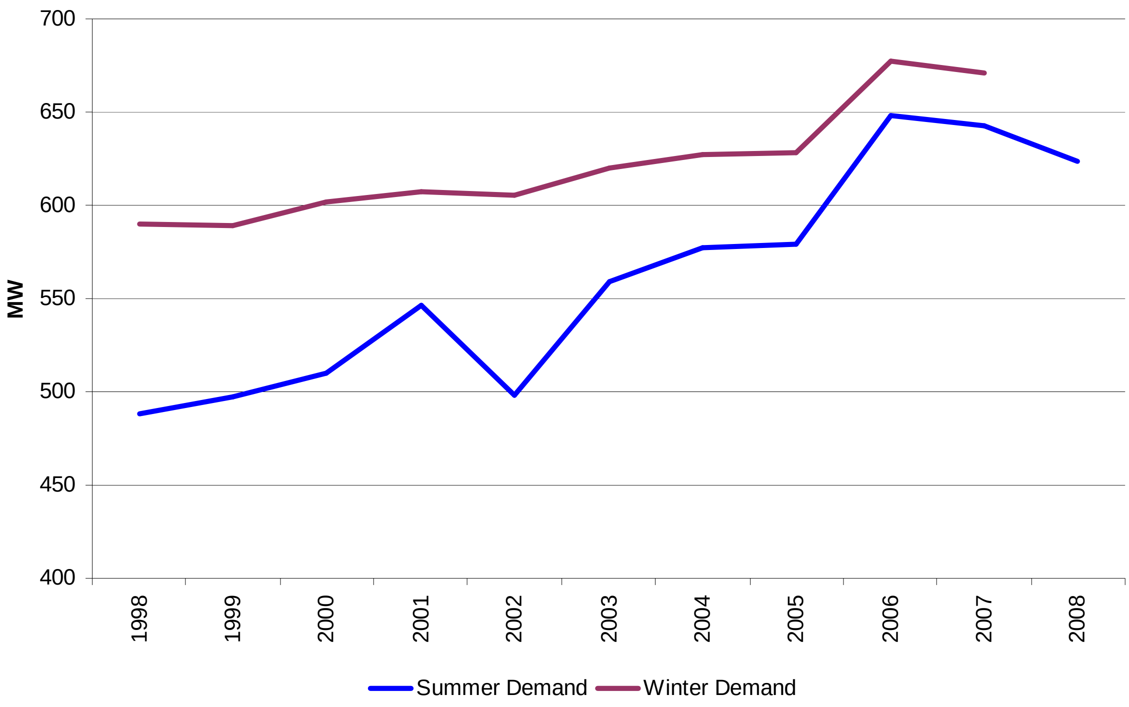
2.1.2 ActewAGL Distribution's demand and electricity sales

ActewAGL Distribution's electricity distribution network was originally designed to meet peak winter demand, which is driven largely by Canberra's cold winters. The network was designed to also provide a high level of supply security and reliability, recognising the role and status of Canberra as the national capital and home to many institutions of national significance.

Until the early 1980s, winter peak demand grew steadily, driven by expansion in Canberra's residential and commercial base. The rate of growth in electricity winter peak demand has slowed since then, largely as a result of substitution by gas for home and water heating. Natural gas first became available in the ACT in 1982 and the gas network has gradually expanded throughout the ACT. Since the mid 1980s the winter electricity peak has remained fairly stable, although subject to some variation across years reflecting the significant influence of the weather.

In recent years, the summer peak has been growing strongly as more households install reverse cycle air conditioning. Furthermore, the recent growth of the commercial load, which has a significant cooling load, has contributed to a rise in summer demand. The convergence between the summer and winter peaks is shown in Figure 2.1.

Figure 2.1 Maximum demand—summer and winter (MVA), 1994 to 2008



The growth in summer maximum demand has contributed to the gradual improvement in ActewAGL Distribution's asset utilisation in recent years (Table 2.3 and Table 2.4). ActewAGL Distribution's network management policies and demand management initiatives (discussed in chapters 6 and 13) have been contributing factors in these improvements.

Table 2.3 Zone substation utilisation

Year	Total Name Plate Rating	Aggregated zone substation winter MD	Winter utilisation	Aggregated zone substation summer MD	Summer utilisation
2002/03	1,341	606	45.2%	512	38.2%
2003/04	1,341	613	45.7%	541	40.4%
2004/05	1,341	621	46.3%	540	40.3%
2005/06	1,341	613	45.7%	594	44.3%
2006/07	1,344	654	48.6%	600	44.6%

Note: Utilisation is calculated as aggregated zone substation maximum demand (MD) divided by total nameplate rating.

Table 2.4 Distribution substation utilisation

Year	Total Name Plate Rating	Aggregated Summer MD	Summer Utilisation	Aggregated Winter MD	Winter Utilisation
2002/03	1,576	551	35.0%	669	42.4%
2003/04	1,605	575	35.8%	667	41.5%
2004/05	1,635	567	34.7%	660	40.4%
2005/06	1,682	635	37.8%	675	40.1%
2006/07	1,752	656	37.4%	759	43.3%

Note: Calculated from estimated distribution substation maximum demand (MD) divided by total nameplate rating.

However, while load factors have improved, this remains constrained by the following factors:

- the predominantly residential customer base, with strong winter peaks;
- the physical separation of commercial and residential loads, which have different demand patterns;
- the historical development of the network to ensure high levels of supply security, particularly for installations of national significance; and
- the introduction of gas to the ACT in the 1980s (discussed above), which reduced the rate of growth in electricity consumption and left some zone substations with utilisation that is lower than anticipated at the time of construction.

The first three factors are discussed further below.

ActewAGL Distribution's electricity network customers are predominantly residential. In 2006/07, 91 per cent of customers were residential, nine per cent were low-voltage non-residential customers and the remainder (22 customers) were high-voltage commercial customers. The number of high-voltage commercial customers has remained fairly stable in recent years, with two new customers and one customer disconnected over the past 15 years. There are no customers classified as industrial in the ACT.

Residential customers accounted for 41 per cent of ActewAGL Distribution's total electricity throughput in 2006/07. As a result of Canberra's planning policies, commercial customers tend to be clustered, separate from the major residential areas. This has implications for load management. As residential load peaks in winter and commercial load in summer (Table 2.5), and residential and commercial load daily peaks occur at different times of the day, better overall asset utilisation would be achieved if residential and commercial load could be supplied from the same lines and transformers. Such opportunities are relatively limited in the ACT due to national capital planning requirements.

Table 2.5 ActewAGL Distribution load factors 2007/08

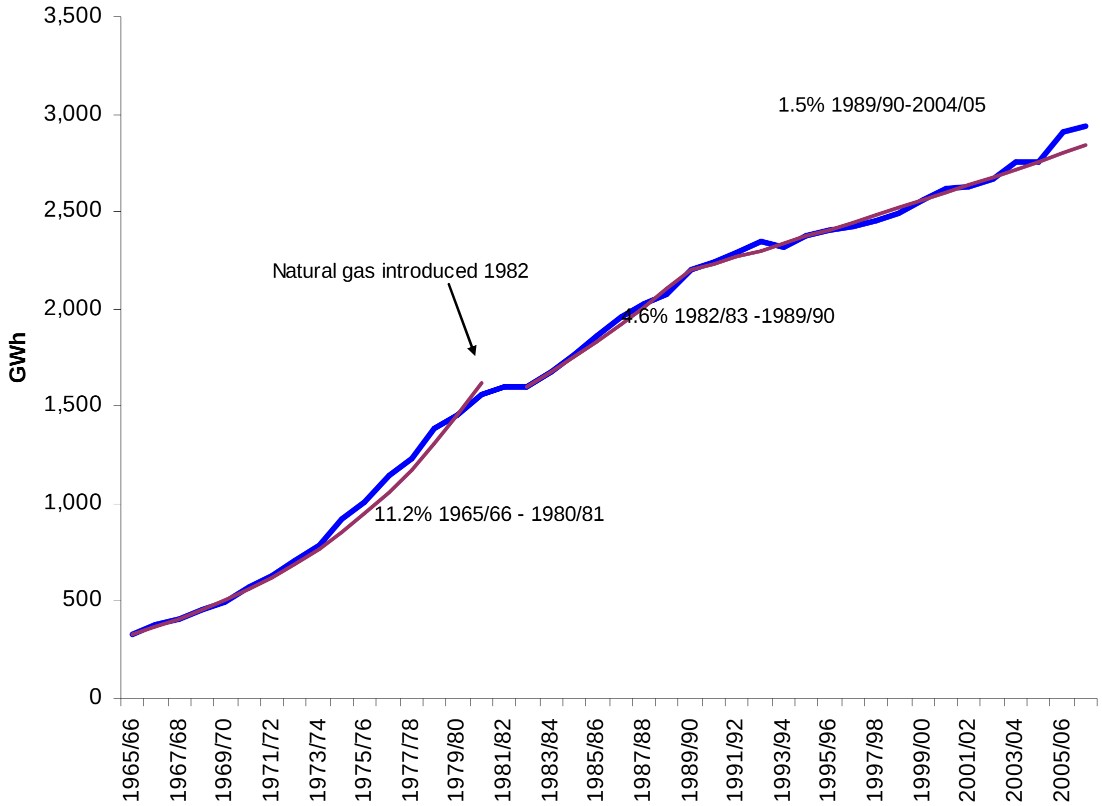
System load					
Peak MVA		Average MVA		Load Factor	
Winter	Summer	Winter	Summer	Winter	Summer
664.6	611.5	387.7	325.7	58%	53%
Typical zone substation with predominantly commercial load					
Peak MVA		Average MVA		Load Factor	
Winter	Summer	Winter	Summer	Winter	Summer
92.7	94.8	58.9	52.2	64%	55%
Typical zone substation with predominantly residential load					
Peak MVA		Average MVA		Load Factor	
Winter	Summer	Winter	Summer	Winter	Summer
70.2	45.3	35.1	25.4	50%	56%

Note: *Load factor* is defined as average demand divided by maximum demand.

Average electricity consumption per customer is relatively low in the ACT (lower than all other jurisdictions, except Tasmania), reflecting the absence of an industrial base. However, average consumption per *residential* customer tends to be relatively high, due to Canberra's cold winters and the relatively high disposable incomes of Canberra households.

Electricity sales in the ACT grew rapidly during the 1960s and 1970s. The average growth rate was just over 11 per cent per annum. In the early 1980s, the growth rate slowed, due to the introduction of natural gas and a slowdown in economic growth. Over the past 15 years the growth rate of demand has further slowed to an average of 1.5 per cent per annum. The recent jump in the growth rate is above the trend line, and can be largely explained by weather factors, as well as strong growth in the commercial sector (discussed further in the section below on outcomes in the current regulatory period).

Figure 2.2 ACT electricity purchases 1965/66 to 2006/07 (GWh)



A notable trend in recent years has been the shift to time-of-use tariffs by commercial customers, encouraged by ActewAGL Distribution's demand management policies. Approximately 80 per cent of commercial customer load is now billed using time-of-use tariffs. ActewAGL Distribution has developed a range of innovative tariff options and these have helped to improve network utilisation, while at the same time better meeting the diverse needs of customers. ActewAGL Distribution's tariff initiatives and their impact on different customer types and network utilisation are discussed in chapters 6 and 13 of this regulatory proposal.

2.1.3 ActewAGL Distribution's operating environment

ActewAGL Distribution's operating environment is shaped by a wide range of regulatory and legislative obligations as well as customer requirements and expectations. Service standard obligations and regulatory obligations and requirements are examined in detail in chapters 3 and 4. In this section, three key elements of the operating environment that significantly impact on ActewAGL Distribution's capital and operating expenditure and network planning and management are examined. They are:

- backyard reticulation;
- ACT urban planning and development; and
- customer requirements and expectations.

While these are not necessarily direct obligations on ActewAGL Distribution, they are critical and unique elements of the operating environment in the ACT and together they impact significantly on ActewAGL Distribution’s management of the network and capital and operating expenditures.

Backyard reticulation

Historically, ACT planning approaches have meant that low-voltage electricity reticulation, unless underground, must run along rear boundaries of properties, rather than on street verges as is normal practice elsewhere. The consequences of this long-standing and unique requirement are significantly higher construction, operational and maintenance costs compared with the costs of a street reticulated network.

Backyard reticulation increases costs in three main areas—the impacts of vegetation, difficulties of access, and requirements for pole inspection, maintenance and replacement.

Vegetation impacts

Screen vegetation planted by lessees[14] around the boundaries of properties significantly increases susceptibility to outages. While it is the lessees’ responsibility to maintain trees away from powerlines, many ignore their responsibilities, even following formal notice from ActewAGL Distribution. The *Utilities Act 2000* (ACT) requires ActewAGL Distribution to cover the costs of emergency tree-cutting and associated removal of debris, even if the lessee had previously been requested to remedy the situation.

While other electricity utilities mostly deal with individual local government authorities on the issue of tree management, ActewAGL Distribution must, due to backyard reticulation, deal with individual property owners. The high proportion of trees on private leases potentially interfering with power lines requires comprehensive ongoing community awareness programs.

It should be also noted that defined *pre-existing* trees, that is, trees that existed before a block of land was released for residential or commercial use, are not the responsibility of the leaseholder. ActewAGL Distribution has the responsibility for managing these trees. The *Tree Protection Act 2005* (ACT) significantly impacts on the actions of ActewAGL Distribution employees when working in the vicinity of trees to minimise the impact of construction and maintenance activities on trees and tree root systems. The costs associated with *Tree Protection Act* compliance are discussed in chapter 4.

Access issues

Access to backyards is required to inspect for vegetation clearances and to monitor and maintain the condition of infrastructure. ActewAGL Distribution incurs a high administrative cost through the requirement of the *Utilities Act* to provide to residents at least seven days notice of an intention to enter their property (discussed in chapter 4). Protracted processes are often necessary to contact the lessee and negotiate a suitable arrangement for access.

[14] The ACT has no freehold title. Properties are typically held on 99-year leases.

Significant public relations effort is also needed to satisfy lessees of the need for ActewAGL Distribution to enter their land.

Should a planned outage have to be rescheduled for any reason (such as the necessary redeployment of resources to attend to an emergency elsewhere on the system or staff resources being depleted through illness) the whole process of notification and negotiation has to be repeated.

Particular obstacles to access include:

- locked gates;
- obstruction by retaining walls, garden sheds, swimming pools and other structures which do not allow access for plant;
- pets including dangerous dogs and the need to guard against pets escaping while working in the backyards; and
- trees, vegetable gardens, flower beds and shrubs in close proximity to the reticulation assets.

Not only do these restrict planned activities, they also adversely affect reactive and operational activities. Low-voltage fuses and switching devises are located with lines in backyards, and need to be available for access at any time and in all conditions. Difficult access can be detrimental to supply restoration in fault and emergency conditions, requiring negotiations or an assessment of more costly alternative actions.

Pole replacement and inspection impacts

Poles are usually located at the rear corners of blocks, adjacent to boundary fences. Lessees frequently build around poles and occasionally even use them as part of an unapproved structure. Limited access to poles and lines because of vegetation, structures, fences and gates is a constant challenge to ActewAGL Distribution employees and often prevents the use of machinery such as elevated work platform vehicles and borer lifters. This affects planning, time and cost of jobs. In some cases, smaller, less efficient, machinery—Dingo or Bobcat mini-excavators—can be used. In some exceptional circumstances, entire jobs, including digging holes, have had to be performed manually without machinery.

The location of backyard poles often prevents stays from being installed to counter deviational loads. Even where oversized poles have been installed, they will tend with the passage of time to lean in the direction of loads. Leaning poles, at the very least, alarm householders, and may lead to property damage if they eventually break or dislodge. Where stays cannot be installed, an otherwise sound pole may need to be replaced prematurely.

ActewAGL Distribution is very limited in how it can undertake live low-voltage maintenance works on its backyard network. Generally, the lack of access for suitable machinery, and the lack of clear space around poles will prevent live-line maintenance techniques from being used. To undertake maintenance activities in these situations, ActewAGL Distribution must notify those affected, negotiate and schedule planned outages to undertake the work, adding to both customer inconvenience and maintenance costs.

ActewAGL Distribution faces higher than industry-typical costs when a condemned pole in a backyard has to be replaced. The lack of machinery access to hold and extract the condemned pole has significant safety implications for the staff trying to remove it. To complete the task may require significantly more resources than otherwise. Sometimes the condemned pole may need to be cut down in small sections using a chainsaw aloft. Often the only safe way to do this is to erect a scaffold alongside the condemned pole.

Access difficulties and obstructions can prevent installation of long one-piece poles as replacements with standard machinery. Wood and concrete poles are too heavy to be manhandled into position and so ActewAGL Distribution has had to develop and use sectionalised steel poles, though significantly more expensive than standard poles.

Jobs undertaken in backyards inevitably have higher site restoration costs. Structures such as sheds sometimes need to be removed to allow the required access to a pole. Removal and reinstatement are additional costs to ActewAGL Distribution. Steps and retaining walls may require the construction of temporary ramps to allow access for machinery. In gaining access, paths, lawns and garden beds may be damaged, necessitating costly restoration.

While low-voltage reticulation is confined to backyards, the high-voltage network, whether overhead or underground, remains in the street verge. Economies of scale available to most distributors, through use of common high and low-voltage poles, are not available to ActewAGL Distribution. Assets over a wider geographical area increase construction costs, as well as exposure to potential damage and ongoing maintenance costs.

ACT urban planning and development

ACT planning and development is the responsibility of two agencies—the National Capital Authority (NCA) and the ACT Planning and Land Authority (ACTPLA). The NCA’s role is to manage the Australian Government's continuing interest in the planning, promotion, enhancement and maintenance of Canberra as the nation's capital. The NCA is responsible for the National Capital Plan, which sets out planning principles and policies to ensure the maintenance and enhancement of the character of the national capital. It also sets out general policies for land use and general standards and aesthetic principles to be adhered to in the development of the national capital.[15]

ACTPLA is the ACT Government’s planning agency. It administers the *Territory Plan* and the supporting codes and planning instruments, and manages the detailed planning and development of the ACT.

The planning policies and principles implemented by the NCA (and its predecessor the National Capital Planning Authority) and ACTPLA have significant implications for ActewAGL Distribution’s network planning and management and capital and operating costs. They

[15] National Capital Authority 2002, *Consolidated National Capital Plan*, updated February, p 2.

contribute to ActewAGL Distribution's relatively high cost operating environment in several ways.

The National Capital Plan explicitly refers to Canberra as the "Bush Capital". This concept has been enhanced by planting trees on road reserves and encouraging property owners to landscape their nature strips. As a result, Canberra has one of the highest concentrations of suburban trees in Australia. This results in significantly increased costs for capital and maintenance projects associated with working in the vicinity of trees and reinstating landscaped nature strips. For example, a high incidence of costly underground directional boring is required to route cables around the protection perimeters afforded to root systems under the *Tree Protection Act*.

Planning authorities in the ACT aim to minimise the amount of street furniture. This forces substations off the street wherever possible, leading to additional cable costs. This also affects the placement and, consequently, the installation cost of minipillars associated with residential underground supply. Inspection and maintenance of assets such as minipillars are also hampered by vegetation planted around them. A 2007 audit by the ACT Technical Regulator identified safety and reliability concerns associated with access to "landscaped" minipillars.[16] As a result, ActewAGL Distribution has moved towards more planned rather than reactive inspection and maintenance of these assets. This is reflected in the operating expenditure forecasts.

Canberra's planners require that the sub-transmission network remain out of sight and on the fringe of urban development. Consequently, zone substations are located further from major load centres and sub-transmission lines follow longer, more circuitous, routes (through nature parks) than they might otherwise. ActewAGL Distribution has a considerably smaller number of larger capacity zone substations compared to other distributors and these are further distant from load centres. This increases both capital expenditure and maintenance expenditure.

The city planners required geographic separation of commercial and residential electrical load. The objectives have been achieved through separating dormitory suburbs from commercial and industrial centres. This concept resulted in the dedicated light industrial/commercial areas of Fyshwick, Hume and Mitchell as well as satellite town centres with predominantly commercial load. On the other hand, dormitory suburbs include only few commercial loads restricted to the local shopping facilities. As discussed in section 2.1.2 above, this separation of commercial and residential development means that ActewAGL Distribution is not able to exploit natural diversity between domestic and commercial loads.

Customer requirements and expectations

The role of Canberra as the national capital has implications for the requirements and expectations of ActewAGL Distribution's customers. ActewAGL Distribution has a relatively high number of customers with special requirements. Strategically important facilities and

[16] Email from Derek Bulpitt (ACT Technical Regulator) to Michael Charlton (ActewAGL Distribution), 11 July 2007.

institutions such as Parliament House, Defence Signals Directorate, Defence Department, ASIO, Centrelink and the National Data Centre require a high level of supply security.

Historically, the requirements for a relatively high level of supply security have resulted in additional capacity being built into the network. Since 2001, the need to accommodate the demands of customers with special requirements has been explicitly addressed in the *Electricity Network Capital Contributions Code* and internal ActewAGL Distribution procedures. The code sets out the charging principles to be applied to cases where a customer requires “infrastructure of a higher standard” to be installed (clause 3.3).

The additional capacity built into the system over many years to meet customers’ supply security requirements has an adverse impact on utilisation of capacity in some parts of the network (discussed in section 2.1.2 above).

The historical development of the network to meet expectations of secure supply is reflected in ActewAGL Distribution’s strong service reliability record. As a result, the broader ACT community has also come to expect a reliable supply. While costs associated with the specific needs of some customers can be partly recovered in accordance with the *Capital Contributions Code*, ongoing expenditure on maintenance and investment by ActewAGL Distribution is required to ensure that customer requirements and expectations are met. The requirements and expectations of the broad customer base continue to be key drivers of ActewAGL Distribution’s approach to network planning and management and service delivery.

Reflecting its commitment to respond to the needs and preferences of its customers, and responding to a desire from the ICRC to better understand customer preferences for reliability, ActewAGL Distribution commissioned a major study of customers’ willingness to pay in 2003. The results indicate a high level of customer satisfaction with existing service standards, with 95 per cent of electricity customers rating ActewAGL Distribution’s service as good or better. The survey results also indicate that both residential and commercial customers prefer existing levels of reliability over lower reliability at a reduced price. Furthermore, customers may be willing to pay more for higher levels of reliability. The willingness to pay study is discussed further in chapter 3 of this regulatory proposal.

Electricity supply to the ACT

The ACT has minimal generation capacity and ActewAGL Distribution principally transports electricity that is imported via NSW power transmission lines owned by TransGrid.

A debate is under way into the possible sale of existing NSW generators and the need for greater private sector involvement in augmenting the State’s power infrastructure to meet forecast demands.[17]

Given its reliance on external power supply, the ACT incurs costs with the delivery of this power to the Territory and can be substantially impacted by any impediments to this supply

[17] See, for example, Robins, Brian 2008, “NSW flicks the switch to gas power”, *Sydney Moring Herald*, 28 May, p 5 which reports that “The [NSW] Government has indicated that NSW faces power shortfalls from as early as 2013 without additional baseload electricity power stations, which can operate 24 hours a day.”

chain. This risk to ActewAGL Distribution arises principally in relation to its ability to supply power in emergencies and to its revenue stream given the form of regulation. This is covered in more detail in chapter 16 on cost pass through provisions.

Climate change

There is potentially a number of emerging Commonwealth and ACT based policy initiatives that may impact the operations and costs of ActewAGL Distribution. These will likely include:

- the costs imposed on the business from meeting expectations and requirements for minimising its carbon footprint and being a role model for ecologically sustainable development. An example is the intention to relocate to a new building that will be constructed to an accredited five-star Greenhouse rated design;
- the impact on ACT electricity usage from any new carbon pricing and emissions trading schemes; and
- new mechanisms and incentives for renewable energy which may involve ActewAGL Distribution in the cost of managing and administering schemes.

The impacts of climate change initiatives and requirements need to be addressed in the determination. ActewAGL Distribution proposes that the costs arising from climate change related policies and requirements be dealt with through the cost pass through mechanism, as discussed in chapter 16.

2.2 Outcomes in the 2004–09 regulatory period

The 2004–09 regulatory period has been characterised by:

- continuation of ActewAGL Distribution's strong service standard performance;
- average annual growth in electricity sales slightly above the forecast average, largely due to the impact of more extreme weather and higher than expected growth in the commercial load;
- capital expenditure higher than forecast, due mainly to higher than forecast expenditure on pole replacement and reinforcement; and
- operating expenditure slightly higher than forecast, due mainly to increased apprentice training costs and higher than forecast pole inspection and tree clearing expenditure.

These outcomes are discussed further in the following sections.

2.2.1 Service standards

In determining the revenue settings for the 2004–09 regulatory period, the ICRC recognised the importance of ensuring that ActewAGL Distribution was able to meet its service level obligations. In the *Final Decision*, the ICRC said that it:

> …considers that the revenues provided in this final decision are adequate to ensure that ActewAGL is able to continue to meet all of its current service level obligations as imposed by the Utilities Act 2000, the [National Electricity Code] and its licence. Furthermore, the commission expects that the revenue settings are sufficient for ActewAGL to continue to exceed these minimum service standards over the regulatory period. The commission has based the findings and price settings contained in its final decision on the continuation of the current service levels throughout the five-year regulatory period noting that effectively the building block approach and regulatory modelling used by the commission compensates ActewAGL for any costs of maintaining service standards. [18]

Chapter 3 of this regulatory proposal describes ActewAGL Distribution's service standard obligations, as set out in the *Electricity Distribution (Supply Standards) Code* and the *Customer Protection Code* and supplemented by ActewAGL Distribution's own corporate targets. ActewAGL Distribution's performance in relation to these targets is examined and intended targets for the 2009–14 regulatory period are set out in chapter 3. The key outcomes from the current regulatory period are as follows:

- The system average duration of interruptions (SAIDI) has remained better than (that is, average duration of interruptions was shorter than) the targets;
- The system average frequency of interruptions (SAIFI) has also remained better than (that is, average interruptions were less frequent than) the targets;
- The customer average duration of interruptions (CAIDI) has been above (that is, average duration of interruptions per affected customer was longer than) the target, largely as a result of planned interruptions for pole replacement; and
- Rebates paid to customers for failure to comply with customer service obligations under the Consumer Protection Code, have remained low (less than $8,000 per annum).

In relation to the CAIDI performance, it should be noted that CAIDI is a measure derived directly from SAIDI and SAIFI. ActewAGL Distribution's good SAIFI performance—significantly better than the target—has an adverse impact on CAIDI. ActewAGL Distribution's CAIDI performance has also been significantly affected by the high level of pole replacements and reinforcements that require planned outages of longer duration. The pole replacement program is discussed in chapter 7 of this regulatory proposal.

2.2.2 Demand growth—actual, estimates and forecasts 2004–09

The energy carried by ActewAGL Distribution's electricity network is estimated to grow at an average rate of 1.5 per cent per annum from 2003/04 and 2008/09. This growth rate is slightly above ActewAGL Distribution's 2003 forecast. The main drivers for the higher than expected growth are weather (relatively hot summers and cold winters) and a higher than expected increase in commercial load. Commercial consumption increased by 10.4 per cent between 2004 and 2006.

[18] ICRC 2004, *Final Decision: Investigation into prices for electricity distribution services in the ACT*, March, p xv.

Table 2.6 Growth in ACT electricity sales—actual and forecast 2004–09

	2004/05	2005/06	2006/07	2007/08	2008/09
ActewAGL forecast 2003	-0.55%	1.5%	1.48%	1.46%	1.43%
ICRC decision 2004	-0.55%	1.5%	1.48%	1.46%	1.43%
Actual (and estimate)	-0.41%	5.78%	0.94%	0.08%	1.19%

2.2.3 Capital and operating expenditure—actual and forecasts 2004–09

In its 2004 Final Decision, the ICRC reduced ActewAGL Distribution's proposed capital expenditure program for 2004–09 by $5.9 million (2002/03 dollars).[19]

ActewAGL Distribution's capital expenditure for 2004–09 has exceeded the ICRC's decision in the 2004 Final Decision by $41.6 million ($2008/09). This overspend is largely due to the higher than anticipated condemning rate of poles inspected since 2003. This has severely impacted the business and created an urgent priority both to replace poles and to minimise risk by pole reinforcement (nailing) at a rate not envisaged in 2003. In 2003/04 ActewAGL Distribution forecast expenditure of $16.7 million ($2008/09) on pole replacements over the period, but will actually spend $52.8 million ($2008/09). Neither ActewAGL Distribution nor the ICRC anticipated the necessary pole replacement and reinforcement costs in the current period.

Table 2.7 Capital expenditure—actual and forecast 2004–09

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	**Total**
Net capital expenditure*	24.3	25.6	31.3	38.9	42.7	**162.7**
ICRC decision	24.1	23.8	26.4	22.9	23.9	**121.1**
Overspend (underspend)	**0.1**	**1.8**	**4.9**	**16.0**	**18.8**	**41.6**
Overspend (underspend) excluding pole related overspend	**(5.4)**	**(3.9)**	**(4.4)**	**6.7**	**12.4**	**5.5**

*Net of capital contributions

In the 2004 Final Decision, the ICRC accepted ActewAGL Distribution's proposed operating expenditure for the regulatory period but excluded an allowance for obsolete stock of $0.9 million (2002/03 dollars). The ICRC also deducted a one per cent compounding efficiency factor from total operating expenditure proposed by ActewAGL Distribution totalling $6.0 million (2002/03 dollars).[20]

ActewAGL Distribution's operating expenditure for 2004–09 is only slightly above the ICRC's decision. Adjusting for approved cost pass throughs ($2.3 million), actual and estimated

[19] ActewAGL total proposed capital program for 2004/05 to 2008/09 was $156.6 million including $42.9 million in capital contributions (both $2002/03). See ICRC 2004 *Final Decision*, table 8.2, p 51.
[20] ICRC 2004, *Final Decision: Investigation into Prices for Electricity Distribution Services in the ACT*, March, table ES.7, p xxii

expenditure is, excluding UNFT, only $1.4 million ($2008/09) above the ICRC's decision for the period. ActewAGL Distribution has been able to keep operating expenditure close to the ICRC decision despite significant cost pressures that were not anticipated at the time of the 2004 Final Decision. These include:

- The expansion of the apprentice training program which has resulted in an increase in the number of apprenticeship, trainee, cadet and graduate staff from 33 in 2003/04 to 85 in 2008/09. At the time of the 2004 Final Decision, ActewAGL Distribution's forecast for 2004–09 was $6.7 million. The actual and estimated expenditure is $18.1 million.
- The significant increase in pole inspection and tree clearing expenditure. The forecast for the current regulatory period was $11.8 million but actual and expected expenditures have risen to $23.3 million over the regulatory period mainly due to reassessment of and sensitivity to requirements in the wake of the Canberra bushfires of 2001 and 2003.
- The Enterprise Bargaining Agreement that came into force in 2005 included a retention allowance for all electrical workers due to the difficulties of recruiting and retaining staff. This has in total increased operating expenditure by $2.4 million in the current regulatory period.

Table 2.8 Operating expenditure—actual and forecast 2004–09

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	**Total**
Operating expenditure	42.5	43.6	44.3	47.6	50.7	**228.7**
ICRC decision	44.4	44.6	44.2	45.3	46.6	**225.0**
Approved cost pass throughs	**1.2**	**1.1**	**0.0**	**0.0**	**0.0**	**2.3**
Overspend (underspend)	**(3.1)**	**(2.1)**	**0.1**	**2.3**	**4.1**	**1.4**

2.3 The transition to a new regulatory framework

The AER's 2009–14 distribution determination for the ACT and NSW distribution businesses will be the first under the new national framework for economic regulation of electricity distribution networks in the national electricity market. The transition from the jurisdictional regulatory framework to the national framework raises a range of transitional issues that need to be recognised and addressed in the determination.

The transitional *Rules* explicitly address the need to recognise elements of the previous regulatory regime in an effort to provide a balanced approach to the conversion to a national framework. In relation to the roll forward of the RAB, the transitional *Rules* (6.5.1(g)) require the AER to adopt the approach taken by the ICRC and to take account of any written representations by the ICRC to ActewAGL Distribution in relation to the roll-forward. This requirement recognises that investment decisions during the 2004–09 regulatory period were based on the regulatory framework at that time, and ActewAGL Distribution should not be penalised because a new framework has been substituted.

The AER has also undertaken to address transitional issues and is seeking information on these issues via the RIN. The AER defines a transitional issue as:

> …an issue having a material impact on the RNSP which arises from the transition from the current regulatory control period to the next regulatory control period and the RNSP believes needs to be addressed in the AER's 2009 distribution determination.[21]

ActewAGL Distribution has identified several transitional issues arising from the ICRC's 2004 determination and subsequent ICRC decisions and statements during the 2004–09 regulatory period. These matters have implications for the 2009–14 regulatory period, and need to be addressed or recognised in the AER's 2009–14 determination. These transitional issues are discussed in section 2.3.1 below.

A further set of transitional issues arises because the determination is made at a time of significant and ongoing development within the national regulatory framework. Several significant changes are scheduled but will not be finalised until after the submission date for this regulatory proposal. To ensure that ActewAGL Distribution is not disadvantaged, the AER's determination must provide appropriate mechanisms for passing through any costs arising from new requirements introduced after 2 June 2008. These transitional issues and ActewAGL Distribution's proposals for addressing them are discussed in section 2.3.2 below.

2.3.1 Transitional issues arising from the 2004–09 regulatory period

ActewAGL Distribution has identified the following matters as transitional issues arising from the ICRC's 2004 decision or subsequent ICRC statements during the 2004–09 regulatory period and having implications that need to be addressed or recognised in the 2009–14 determination.

Pole replacement costs

Clause 6.5.1(g) of the transitional *Rules* requires the AER to take account of any written representations from the ICRC to ActewAGL Distribution in relation to the roll-forward of the RAB.

In May 2007 the Senior Commissioner of the ICRC wrote to the Chief Executive Officer of ActewAGL advising of an expectation that prudent expenditure including poles would be included in the RAB at the next price path reset by the AER.[22]

Consistent with this representation, ActewAGL Distribution has included the additional prudent expenditure on poles in its RAB. These additional costs are further discussed in chapter 7.

[21] AER RIN pro forma 2.4.1
[22] Letter of 10 May 2007 from ICRC to ActewAGL Distribution

Southern supply to the ACT 132 kV lines Stage 1

As outlined in section 2.1 above, and discussed further in chapter 7, the need for the southern supply point project has arisen because of a new service standard requirement introduced by the ACT Government in 2006. Any additional costs incurred during the current regulatory period as a result of the new requirement should therefore be covered by the *service standard event* in the ICRC's 2004 determination.

Land access and development approval issues have delayed the commencement of the project, and no claims for pass through of southern supply point project costs have been made to the ICRC. In its annual pricing report to the ICRC in March 2008, ActewAGL Distribution proposed to the ICRC that project costs be passed through on a calendar year basis once actual costs are known and that the costs incurred to date would be rolled into the RAB as at 1 July 2009.

In March 2008, the ICRC wrote to the ActewAGL advising that the ICRC expects that the AER will review the roll forward of costs for the second supply point up to 30 June 2009 and will make an adjustment, where necessary, as part of its review. The ICRC advised that it would write to the AER regarding this matter.[23]

ActewAGL Distribution has included the prudent costs associated with the southern supply point obligation in its RAB.

The Regulatory Asset Base

The ICRC's previous treatment of ActewAGL Distribution's RAB has influenced the approach taken in the Post Tax Revenue Model for this determination. Consistent with the approach taken in the 2004–09 determination, ActewAGL Distribution has maintained one asset class in the RAB. ActewAGL believes that maintaining consistency with the ICRC's previous treatment of the RAB is important to ensure that all assets are depreciated using a consistent approach over their entire economic lives. This matter is discussed further in chapter 12.

Costs of complying with the ICRC's decision on interval meters

In December 2005, the ICRC introduced a requirement that ActewAGL Distribution install interval (type 5) meters in new dwellings, as a replacement for existing accumulation (type 6) meters which have reached the end of their operating life and when requested by a customer.[24] The ICRC concluded that ActewAGL Distribution should not be financially disadvantaged as a result of its decision and allowed it to pass on the additional cost of implementing the interval meter program.

For the 2009–14 regulatory period, the higher costs of installing interval meters are apparent in the higher expenditure proposals and opening RAB for alternative control services. This is discussed in chapter 15 of this regulatory proposal.

[23] Letter of 8 March 2008 from ICRC to ActewAGL Distribution
[24] ICRC 2005, *Final Decision: Review of Metrology Procedures*, Report 15 of 2005, December

The Utilities Network Facilities Tax

In 2006 the ACT Government introduced a new Utilities Network Facilities Tax (UNFT). Given that the tax was introduced during the 2004–09 regulatory period and has qualified as a tax change event the ICRC approved pass through of the tax.[25]

For the 2009–14 regulatory period ActewAGL Distribution has included in its operating expenditure forecasts an estimate of the UNFT payable to the ACT Government. The inclusion of this tax, which was treated as a pass through in the current regulatory period, results in a significant step increase ($4 million in 2009/10) in ActewAGL Distribution's operating expenditure.

ActewAGL Distribution notes that it is difficult to estimate future UNFT liabilities. The ACT Government provides the rate to apply for the coming year, but does not set the rate to apply to future years. The 2008/09 ACT Budget includes estimates for total UNFT revenue for each year to 2011/12. ActewAGL Distribution uses the forecast growth in UNFT revenue as a basis for estimating the UNFT applying to its electricity network.

ActewAGL Distribution proposes an annual adjustment, as part of the annual pricing approval process, for the difference between the forecast amount and actual tax payable. This is discussed in chapter 13 of this regulatory proposal.

Treatment of Transmission Use of System charges

ActewAGL Distribution is not formally subject to an *overs and unders* adjustment for Transmission Use of System (TUOS) charges under the current ICRC price determination.

Clause 6.18.7 of the transitional *Rules* requires the AER to apply an annual adjustment for over or under recovery of TUOS in the previous regulatory year. The AER must make a determination on how the DNSP will report its TUOS recovery each year and the adjustments to be made to account for under or over recovery. ActewAGL Distribution's proposed approach to the annual adjustment is set out in chapter 13.

As noted by the AER in its guideline for direct control services, the first formal *overs* and *unders* adjustment will occur in setting prices for year three of the current 2009–14 regulatory period.[26] Existing TUOS arrangements in the ACT will be maintained until the start of the 2009–14 period.

Under the current TUOS arrangements, ActewAGL Distribution advised the ICRC in its March 2008 *Annual Pricing Report*[27] that it will include a variation for actual TUOS charges for 2008/09 in its prices in 2009/10, when actual TUOS charges are known. ActewAGL Distribution will make this adjustment, which is consistent with the transitional *Rules*

[25] ICRC 2007*, Final Decision Electricity Distribution Services: Proposed Amendment to the 2004 Pricing Direction.*

[26] AER 2008, *Guideline on control mechanisms for direct control services for the ACT and NSW 2009 determinations*, February, p 12

[27] ActewAGL 2008*, Annual Pricing Report to ICRC*, March 2008

requirement to introduce an annual overs and unders adjustment, in its 2009/10 prices. This is discussed in chapter 13 of this regulatory proposal.

2.3.2 Ongoing development of the regulatory framework

ActewAGL Distribution submits this regulatory proposal at a time when the regulatory framework for distribution businesses is undergoing fundamental change. Several developments with potentially significant implications for electricity distribution businesses are scheduled or anticipated between the submission date and the end of the 2009–14 regulatory period. These include the following developments.

- The AER is still developing new schemes, guidelines and reporting requirements, and compliance with these is likely to impose additional administrative costs on ActewAGL Distribution during the 2009–14 regulatory period. For example, the AER has indicated that work on a new national approach to annual reporting requirements will be progressed in 2008.[28] The AER recognises that this may require Distribution Network Service Providers to modify their reporting systems to be able to report under the new approach. However, until the new requirements are finalised it is not possible to estimate the likely costs.

- A Ministerial Council on Energy decision on the staged approach for the national mandated roll out of electricity smart meters is expected in June 2008. A decision by the ACT Government to require the roll out of smart meters, or for ActewAGL Distribution (or another party) to conduct smart meter pilots and trials, is likely to involve significant costs for ActewAGL Distribution. These costs would include not only the costs of the installed meters but also the costs of the associated infrastructure, including communications and IT systems. However, until a decision is made on the details of any roll out or pilots or trials it is not possible to accurately forecast the costs involved.

- The legislative package for the transfer of the non-economic regulatory functions from jurisdictional regulators to the AER is scheduled to be introduced into the South Australian Parliament by 30 September 2009. The transfer of regulatory functions will require resolution of a complex set of issues and will have far-reaching implications for the obligations and requirements, and associated costs, for distribution network businesses.

ActewAGL Distribution recognises that the cost pass-through provisions in the transitional *Rules,* and in particular the regulatory change event provisions, are designed to deal with the costs associated with regulatory changes during the regulatory period.

However, the possible timing of the changes listed above (potentially in the period between submission of this proposal and the start of the 2009–14 period) and the nature of some of the changes (changes are foreseen, but policy details are uncertain so costs cannot be estimated) mean that explicit transitional arrangements should be considered.

ActewAGL Distribution proposes that a *transitional period event* be added to the cost pass through events defined in the transitional *Rules*, to ensure that the costs associated with

[28] AER 2007, *Guidelines, models and schemes for electricity distribution network service providers, Issues Paper*, November, p 6

events occurring between the submission date (2 June 2008) and the end of the current regulatory period (30 June 2009) are adequately covered by the pass through provisions.

ActewAGL Distribution also proposes that no materiality threshold should apply to pass through applications in the cases listed above where the regulatory change is anticipated or scheduled, but the details are uncertain so costs cannot be estimated at this stage. It is unreasonable for ActewAGL Distribution to be penalised, being unable to pass through legitimate costs that do not meet some threshold, because the policy details have not been finalised before the submission date.

These matters are discussed in detail in chapter 16 of this regulatory proposal.

Feed-in tariffs

A further potential policy development that has transitional implications is the introduction of feed-in tariffs in the ACT. A Private Members Bill on a feed-in tariff scheme has been introduced into the ACT Legislative Assembly. ActewAGL Distribution understands that the Bill is to be debated after the lodgement of this regulatory proposal.

Details on the proposed scheme and ActewAGL Distribution's proposed treatment are provided in chapter 4 of this regulatory proposal.

While the details of the scheme are still to be finalised, it is likely to have significant expenditure implications for ActewAGL Distribution. The introduction of the scheme would fall under the scope of a *regulatory change event* as defined in the cost pass through provisions in the *NER*. However, given the potential introduction of the new scheme between the submission date and the start of the new regulatory period on 1 July 2009, transitional arrangements need to be considered. ActewAGL Distribution's proposal is set out in chapter 16 of this regulatory proposal.

3. Service standards

To determine the efficient cost of service provision, the AER must make certain assumptions regarding the level of service that will be provided by ActewAGL Distribution in the 2009–14 regulatory period. This chapter discusses ActewAGL Distribution's service standard obligations and ACT consumers' preferences for service quality, which drive investment in, and maintenance of, the ACT electricity distribution network.

The phrase "service standards" is understood to refer mainly to the set of minimum acceptable performance levels of system reliability and customer service set by legislation and associated regulations and codes. ActewAGL Distribution's service standard obligations are discussed in section 3.1 below. Section 3.2 discusses ActewAGL Distribution's service performance targets, which include both external and internal reliability and customer service targets, as provided for in pro forma 2.3.5. Section 3.3 discusses ActewAGL Distribution's service performance against relevant targets and service reliability procedures and programs are set out in section 3.4.

The AER published a guideline in February 2008 on Service Target Performance Incentive Scheme (STPIS) arrangements to apply in the 2009–14 regulatory period. These STPIS arrangements will include information gathering and reporting requirements, to be determined after the due date for this regulatory proposal. The AER has also published a proposed National STPIS that will apply to ActewAGL Distribution from 2014/15. The potential effect of the new STPIS arrangements is discussed in section 3.5.

The service standards described in this chapter are an important subset of ActewAGL Distribution's regulatory obligations and requirements discussed in chapter 4 of this regulatory proposal. Almost all of the service standard obligations described in this chapter are also regulatory obligations, with the exception of some internal business targets. There is therefore some overlap between this chapter and the description of relevant obligations in chapter 4 of this regulatory proposal. Chapter 4, however, covers a broader set of obligations, where compliance requires an action or set of actions to be undertaken (or avoided), often with civil, criminal or licence penalties for non-compliance.

3.1 Service standard regulatory obligations

ActewAGL Distribution's service standard obligations mainly arise from the application of the *Utilities Act 2000* (ACT). The *Utilities Act* requires ActewAGL Distribution to comply with all relevant industry and technical codes, and any directions by the Independent Competition and Regulatory Commission (ICRC) or the Chief Executive of the ACT Planning and Land Authority (ACTPLA) made under the Act. Relevant Codes include the *Consumer Protection Code*, and the *Electricity Distribution (Supply Standards) Code*.

3.1.1 Consumer Protection Code

The *Consumer Protection Code* specifies a number of performance standards applying to electricity network service operators. Failure to meet a performance standard may, in some instances, attract a requirement to pay a rebate. Relevant rebateable performance standards cover:

- customer connection times;
- keeping agreed appointments;
- responding to written queries and complaints;
- acceptable response times to customer notification of a problem or concern;
- required notice periods for planned interruptions of supply; and
- provision of a reporting service and reasonableness of time for rectification of unplanned interruptions to supply.

Specific obligations and rebates are included in Schedule 1 to the *Consumer Protection Code* and are detailed in pro forma 2.3.5.

In considering the case for introducing an STPIS in the ACT, the AER observed that these Guaranteed Service Level (GSL) obligations compared favourably with other jurisdictions.[29]

3.1.2 Electricity Distribution (Supply Standards) Code

The *Electricity Distribution (Supply Standards) Code* sets out parameters for electricity supply for the ActewAGL Distribution network. These include a number of technical and system parameters, which are described in chapter 4 and detailed in pro forma 2.3.4.

In addition to complying with these technical obligations, the *Supply Standards Code* includes some obligations that could be interpreted as service standards, as they include measures identified in the proposed AER National STPIS.

Under the *Supply Standards Code*, each year ActewAGL Distribution must publish its targets for supply reliability for the following year. Separate targets are required where groups of customers are expected to receive substantially different levels of service and, at a minimum, reliability targets should be as advantageous to customers as the reliability targets set out in Schedule 2 to the *Supply Standards Code* (clause 7.1). The *Code* also specifies that these targets must include the following measures:

- the total time customers may experience loss of supply each year, expressed as the Customer Average Interruption Duration Index (CAIDI);

[29] AER 2008, *Service Target Performance Incentive Arrangements for the ACT and NSW 2009 Distribution Determinations: Final Decision*, February, p 11

- the frequency with which supply to customers may be interrupted, expressed as the Supply Average Interruption Frequency Index (SAIFI); and
- the duration of interruptions to supply that customers may experience, expressed as the System Average Interruption Duration Index (SAIDI).

ActewAGL Distribution publishes these targets, and they are outlined in section 3.2.1 below.

3.1.3 Application of service standards to alternative control services

All of the obligations outlined above relate to standard control services. There are no obligations that could be interpreted as service standards specifically applying to alternative control services in specific codes and guidelines.

A possible exception is the application of some rebates relating to planned outages and customer connections and appointments that could also include some metering-related activities. These are included with the GSL obligations outlined in this chapter. Further discussion of the regulatory obligations relating to alternative control services can be found in chapter 15 of this regulatory proposal.

3.2 Performance targets

ActewAGL Distribution is committed to developing its understanding of socially-optimal service performance in the ACT. To this end, ActewAGL Distribution has started to incorporate estimates of consumer willingness to pay (from the 2003 study conducted in the ACT by NERA Economic Consulting) in assessing potential investments.

Over the coming regulatory period, ActewAGL Distribution plans to incorporate willingness to pay results as a decision support tool that will assist ActewAGL Distribution in developing asset management plans that maximise social net benefits, as part of the AER's s-factor incentive scheme to apply from 2014/15. The required integrated systems to model expected reliability benefits and costs of investment are discussed in section 3.5.2.

3.2.1 Reliability targets

Under the *Supply Standards Code,* ActewAGL Distribution must establish targets for CAIDI, SAIFI and SAIDI, with separate targets where customer groups can expect significantly different levels of service. As reflected in pro forma 2.3.5, and Table 3.1, these targets remain unchanged for the 2009–14 regulatory period.

Table 3.1 Supply reliability targets for 2009–14 regulatory period

Parameter	Target	Units
Outage time (CAIDI)*	74.6	minutes
Outage frequency (SAIFI)	1.2	number
Outage duration (SAIDI)	91.0	minutes

* The value of CAIDI (which is an average outage duration) is normally calculated from SAIDI and SAIFI (CAIDI=SAIDI/SAIFI). This measure is most meaningful when planned and unplanned outages are considered separately, rather than for combined outages.

ActewAGL Distribution internal performance targets comply with the above requirement. ActewAGL Distribution has carried out two studies to ascertain both customers' marginal willingness to pay for different reliability and other service levels, and the likely cost to improve system wide reliability. The two studies are:

- the 2003 customer willingness to pay study; and
- an analysis of the marginal cost of improvements in unplanned SAIDI for the 2009–14 regulatory period.

Willingness to pay study

Prior to 2004, the ICRC and ActewAGL Distribution had limited information on whether customers considered current service levels appropriate, or on the marginal value consumers place on increases or decreases in the levels of various aspects of service quality.

To better understand these issues, NERA Economic Consulting was commissioned in 2003 to establish customers' marginal willingness to pay (WTP) for a range of service quality dimensions. NERA used a stated preference choice modelling survey to reveal customer preferences, simulating a market environment by providing customers with choices between various service quality and price options. This technique has been accepted as the most appropriate and robust approach for electricity consumer preferences for utility service performance. It was recommended for future studies in the *Centre for International Economics* 2001 review of methodologies for Independent Pricing and Regulatory Tribunal, and in Charles River Associates Value of Customer Reliability Study for VENCorp in 2002.[30]

A clear outcome from the WTP study was customers' aversion to the frequency and duration of both planned and unplanned outages. The study found that customers were less concerned with *planned* outages (of a given duration), as long as they were given sufficient notice of that outage (two to seven days prior notice).

This discovered difference between customer acceptance of planned and unplanned outages is not reflected in the minimum SAIDI targets in the *Electricity Distribution (Supply Standards)*

[30] Centre for International Economics 2001, *Review of willingness-to*-pay methodologies, Report prepared for the Independent Pricing and Regulatory Tribunal of NSW, August; Charles River Associates Asia Pacific Pty Ltd 2002, *Assessment of the value of customer reliability (VCR)*, Report submitted to VENCorp, December, p 45

Code. The targets in the *Supply Standards Code* have been supplemented by ActewAGL Distribution's internal business targets which better reflect customer preferences, and target reliability improvements in areas that customers value. ActewAGL Distribution has set a target for unplanned SAIDI of 40 minutes, to apply as a category within the overall externally-set SAIDI target of 91 minutes in the *Supply Standards Code*. This target for unplanned SAIDI also allows ActewAGL Distribution to monitor its unplanned SAIDI performance more closely, to assist in ensuring that it meets the overall SAIDI target. Performance against both combined and unplanned SAIDI targets is reported in ActewAGL's annual report.

In addition to unplanned SAIDI limits, ActewAGL Distribution has set feeder-level SAIDI performance limits of 480 and 240 minutes for rural and urban feeder outage durations respectively. These establish limits for worst performing feeders in order to maintain consistent performance levels across the network and to ensure that individual customers do not experience service performance that substantially deviates from the system average. In practice, maintenance or augmentation of these feeders is usually initiated well before these limits are exceeded. These targets are documented in the ActewAGL *Distribution Network Reliability and Standard Supply Arrangements* procedure, and potential activities to meet these feeder targets are discussed further in section 3.4 below.

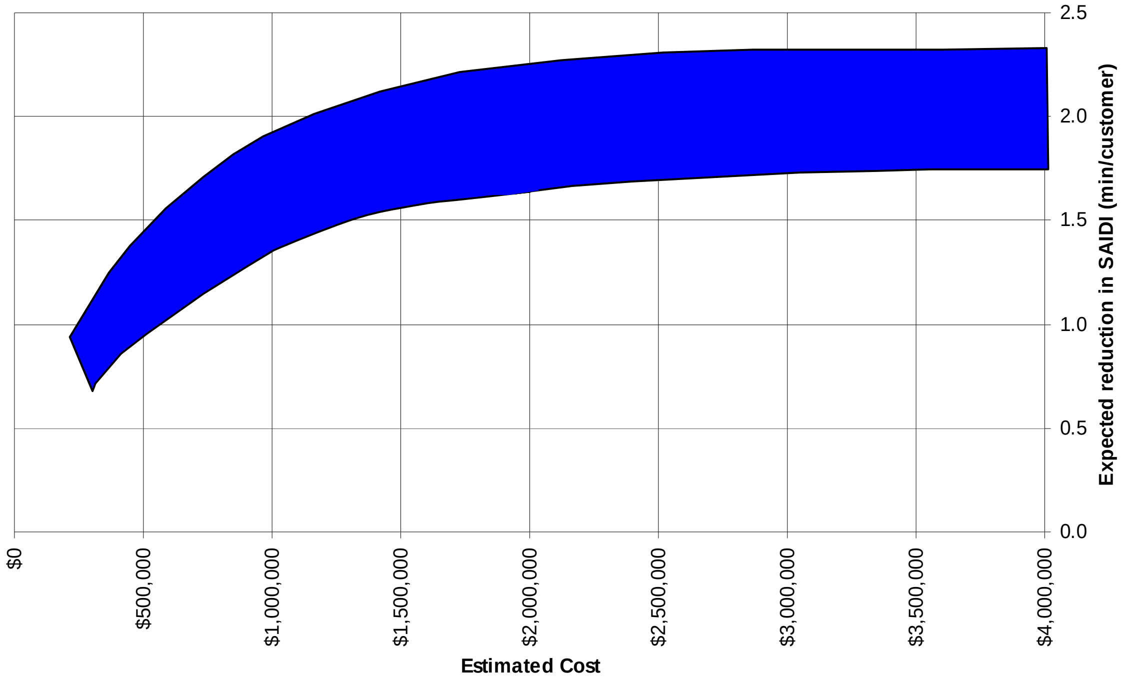
Marginal costs of improvements in SAIDI

ActewAGL Distribution has developed estimates of the indicative costs of improving unplanned SAIDI through a system-wide recloser-installation program, which is considered to be one of the most cost-effective for broad-based reliability improvement based on industry-wide experience.

The potentially most efficient way to improve overall unplanned SAIDI is to install reclosers on overhead 11 kV feeders. ActewAGL Distribution has undertaken an analysis of the estimated costs of installing reclosers, against expected improvements in unplanned SAIDI. This analysis is carried out on ActewAGL Distribution's worst performing overhead feeders and is based on typical feeder layout and current operational practice in the use of reclosers. It should be noted that any improvements in unplanned SAIDI would mainly benefit customers supplied from overhead high-voltage lines and have only limited application to commercial customers or customer supplied from an underground network.

Based on this analysis, ActewAGL Distribution calculated a range of expected values and forecast SAIDI improvements that would be achieved through a system-wide recloser installation program, against indicative costs of such a program. As shown in Figure 3.1, investments in improvements in SAIDI are subject to rapidly diminishing returns. This is because, while the cost increase is linear to the number of installations, performance improvement diminishes for reclosers installed on feeders with better reliability performance. Furthermore, due to significant variation in outages on each feeder from year to year, if only a small number of reclosers are installed, the long-term average improvement will not be measurable over a short period.

Figure 3.1 Reductions in unplanned SAIDI expected from installation of reclosers on 11 kV lines (on worst performing feeders)



Note: The upper bound values are based on a recloser cost of $45,000 and an expected reduction in unplanned SAIDI of 20 per cent. The lower bound values are based on a recloser cost of $55,000 and an expected reduction in SAIDI of 15 per cent.

Comparison of costs and benefits

Outcomes of this analysis suggest that the indicative cost of delivering a marginal improvement in supply reliability via a system-wide recloser installation program would outweigh the estimated benefit (customers' willingness to pay).

By comparing these costs with the WTP study outcomes, ActewAGL Distribution has concluded that these broad-based investments are not warranted at this stage. While the study found that customers were prepared to accept some price increases for improved services, the costs reflected here are greater than those discovered thresholds for customers' willingness to pay. ActewAGL Distribution is, however, proceeding with targeted measures to improve reliability on *selected* worst performing feeders. This is discussed further in section 3.4 below on reliability procedures and projects.

Evidence from the WTP study also suggests that customers would not support a reduction in service for a reduction in price.

ActewAGL Distribution has therefore decided to maintain current targets for service reliability in the 2009–14 regulatory period. This reflects ActewAGL Distribution's high level of service reliability, and customers' high degree of satisfaction with these levels of service reliability, as expressed in the WTP study. Ongoing analysis of data from the WTP study will focus on heterogeneity in willingness to pay across customer segments and the value of alternative solutions to maximising net community benefits.

3.2.2 Other internal business targets

Call centre performance

ActewAGL Distribution has established a further internal service standard target related to call centre performance. The target is to answer greater than 80 per cent of fault and emergency calls within 30 seconds. A call is answered when a caller speaks to a human operator or to an interactive service that provides the information requested, but not when a call is placed in an automated queue or continues to ring without a response.

The 80 per cent target has been selected to represent a reasonable level of service delivery, taking account of the “peakiness” of calls, particularly during an emergency event. The 30-second target is consistent with ICRC-imposed public reporting requirements for call centre performance.

3.3 Service performance

3.3.1 Performance against GSL obligations

The *Consumer Protection Code* requires ActewAGL Distribution to pay rebates (or GSLs) to customers in certain circumstances. The service level requirements to which rebates apply are set out in Schedule 1 to the *Consumer Protection Code*, and the rebates must be paid to the customer on application where service levels do not meet the standards in the Code.

Historically, these costs have been small, amounting to less than $8,000 per annum ($2007/08). ActewAGL Distribution forecasts that these rebate costs will remain stable over the 2009–14 regulatory period, assuming that there are no changes in the *Consumer Protection Code* obligations.[31] These costs are reflected in the proposed operating expenditure described in chapter 8 of this regulatory proposal.

3.3.2 Reliability performance outcomes

ActewAGL Distribution’s reliability performance against external and internal targets is shown in Table 3.2. This performance shows an increase in overall SAIDI levels over the past five years, mainly driven by increases in planned SAIDI levels brought about by the pole replacement/reinforcement program.

[31] The main cause of GSL payments is insufficient notice periods for planned outages. These mainly derive from the pole replacement/reinforcement program, the activity for which is expected to remain consistent across the 2009–14 regulatory period.

Table 3.2 ActewAGL Distribution reliability performance against external and internal targets

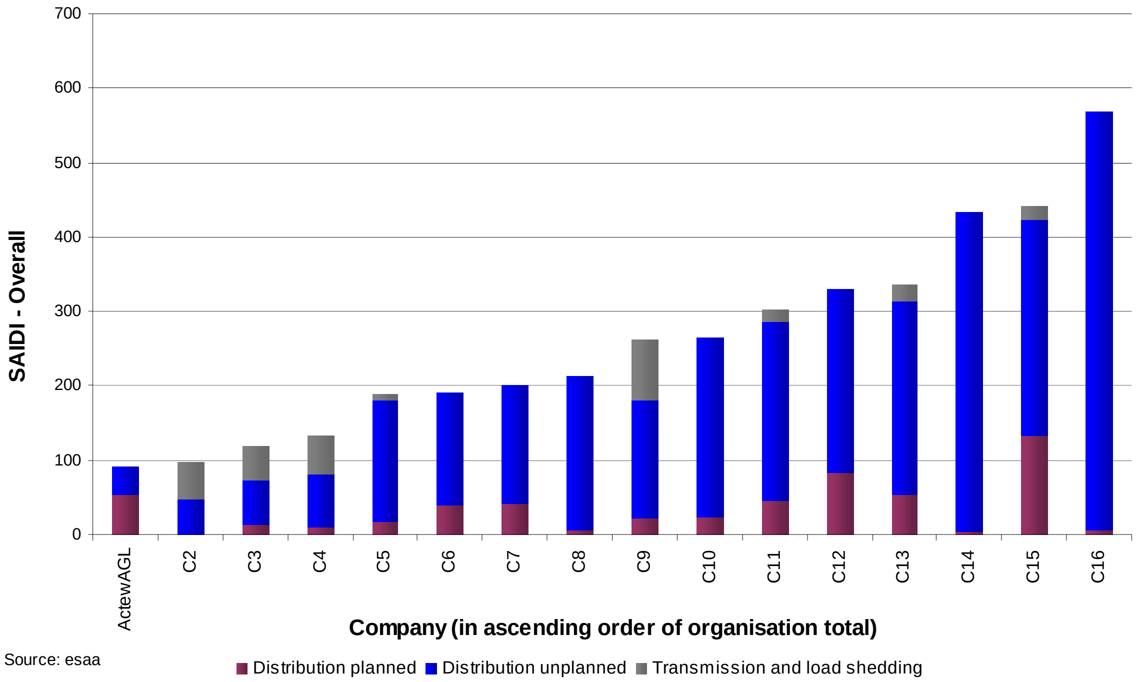
Parameter		2002/03	2003/04	2004/05	2005/06	2006/07	**Target**
SAIDI	Overall	67.4	77.2	87.6	93.6	83.6	**91***
	Planned	37.3	40.6	46.6	49.5	51.4	
	Unplanned	30.1‡	36.6	31.0	44.1	32.2	**40**†
SAIFI	Overall	0.8	0.9	0.8	1.0	0.8	**1.2***
	Planned	0.2	0.2	0.2	0.2	0.2	
	Unplanned	0.6‡	0.7	0.6	0.8	0.6	
CAIDI	Overall	83.2	83	99.5	90.9	104.5	**74.6***
	Planned	168.7	190.5	215.5	215.2	243	
	Unplanned	49.3	50.9	51.5	55.1	54.7	

* Regulatory target
† Internal target
‡ Excludes unplanned outages directly attributable to the fires of 18 January 2003

As noted in chapter 2, ActewAGL Distribution's operating environment includes a number of factors that are unique to the ACT.

Access difficulties in addressing unplanned outages in relation to the overhead low-voltage network, mainly driven by backyard reticulation, means that ActewAGL Distribution undertakes a higher proportion of planned (than reactive) maintenance on the network. This means that outages are generally planned and works conducted on the basis of a risk analysis of the likelihood of failure. As a result, ActewAGL Distribution SAIDI performance for planned outages is a higher proportion of overall SAIDI than the industry average. This relatively high proportion of planned maintenance has a positive effect on unplanned SAIDI, meaning network assets are identified and replaced proactively on an identified risk basis. This has meant that ActewAGL Distribution's unplanned SAIDI performance is consistently one of the best in Australia, and overall SAIDI compares well with other utilities, as shown in Figure 3.2.

Figure 3.2 ActewAGL Distribution overall SAIDI performance compared to other Australian utilities 2006/07



Source: esaa Electricity Distribution Report 2006/07: ActewAGL

This approach delivers a substantial benefit to ACT consumers, who have indicated through the WTP study that planned outages are considered much less disruptive than unplanned outages. The *Consumer Protection Code* requires ActewAGL Distribution to notify customers of planned outages and these notifications generally give customers opportunity to plan activities to avoid inconvenience.

The pole replacement/reinforcement program, is having a strong influence on ActewAGL Distribution’s current planned SAIDI outcomes. The accelerated pole replacement/reinforcement program was initiated due to high condemnation rates of wooden poles. Condemnation rates are a concern as these poles can impact reliability levels, people and property.

The level of pole replacement/reinforcement activity has significantly increased in recent years, and is reflected in an increase in planned CAIDI and SAIDI. The level of pole replacement/reinforcement activity is expected to decline over time, principally after the end of the 2009–14 regulatory period. Overall, however, ActewAGL Distribution’s reliability performance has met external and internal reliability targets for unplanned and total SAIDI, as well as SAIFI. CAIDI levels are higher than the targets, though this is mainly driven by planned CAIDI, as a result of the pole replacement/reinforcement program.

3.3.3 Call Centre Performance Outcomes

ActewAGL Distribution's call centre performance over the past five years has been influenced by a number of factors but primarily by exceptional events. Table 3.3 sets out ActewAGL Distribution's call centre performance over the past five years.

The lower levels of performance in 2002/03 (particularly in time taken to answer calls) were heavily influenced by the Canberra bushfires and emergency response, which saw a very high number of calls come into the call centre. The scale and severity of the Canberra bushfires arguably resulted in more callers accepting longer call answering times in order to provide and gain information from a call taker.

Short isolated events such as storms can also significantly impact the overall performance results. As a small utility operating over a limited area, storm activity is likely to impact a larger proportion of the network than is experienced by other distribution businesses. This has a disproportional impact on call centre performance. For example, a December 2005 storm contributed almost 22 per cent of the total calls abandoned in 2005/06. A storm on 2 November 2006 accounted for almost 25 per cent of the total abandoned calls in 2006/07. The frequency, number and impact of these natural events cannot be predicted, but can considerably skew long term performance. Currently there is no normalisation approach to recording call centre performance.

In addition, the reported *Calls Abandoned* category does not distinguish between calls where an automated voice message satisfied the customer inquiry/complaint and the customer subsequently hung up, and those where customer calls may not have been answered to the customer's satisfaction. ActewAGL Distribution is in the midst of converting its telephony system to a new system. The new system will have the ability to record the number of abandoned calls before and after receiving regional fault and emergency information via an automated announcement system. This will allow ActewAGL Distribution to distinguish between those callers reluctant to wait and those receiving the information they sought.

Table 3.3 ActewAGL Distribution call centre performance

Year	Number of calls	No of calls answered within 30 seconds (per cent)	Average waiting time before a call is answered (seconds)	Number of calls abandoned
2002/03	72,438	29.8	31	8,982
2003/04	62,762	76.1	33	7,978
2004/05	52,037	65.6	29	8,778
2005/06	59,412	60.3	33.9	13,386
2006/07	58,849	61.1	35.3	13,015

3.4 Service reliability procedures and projects

3.4.1 Procedures and plans

ActewAGL Distribution management procedures and investment plans have been directed at maintaining and building the network to meet all regulatory obligations, including meeting expected demand and reliability performance. As noted above, ActewAGL Distribution faces a number of regulatory obligations that relate to service reliability, though these are mainly expressed as direct regulatory obligations rather than as service standards of relevance to this chapter.

The key ActewAGL Distribution document relating to service reliability is *Management Procedure EN 4.4 P07: Distribution network reliability and standard supply arrangements*. This procedure sets out design requirements for feeders and substations, as well as some special arrangements, including emergency and backup supply, to ensure reliability is maintained and that ActewAGL Distribution can continue to satisfy its reliability requirements.

Over the 2009-14 regulatory period, ActewAGL Distribution will continue to integrate the WTP study results more fully into its procedures and investment plans. This will also facilitate any changes in service standard performance as part of the AER's s-factor incentive scheme to apply from 2014/15.

3.4.2 Works and programs

Despite the observed steady increase in planned outages, which can be attributed principally to the pole replacement/reinforcement project, ActewAGL Distribution's network offers one of the highest levels of system reliability compared to other Australian utilities. There are some areas of additional expenditure, however, that are required in order to ensure that ActewAGL Distribution can maintain its current reliability performance and meet customer expectations of service, as well as the ACT Government efforts to enhance the level of supply security to the ACT.

ActewAGL Distribution's reliability performance has been achieved in an operating environment characterised by ageing assets, the direct implications of which for network planning and maintenance are discussed further in chapter 6 of this regulatory proposal. The increasing network maintenance and replacement forecasts for the 2009–14 regulatory period are intended to manage the risk of ActewAGL Distribution's ageing asset profile and maintain system reliability, for instance through the pole nailing and pole replacement programs and the Civic Zone Substation switchboard replacement project. Vegetation management is also critical for service reliability, and is a key part of ActewAGL Distribution's strategy in maintaining reliability levels within required reliability targets.

ActewAGL Distribution is also aware that "average" measures of reliability may conceal an underlying level of worsening performance for some customers. ActewAGL Distribution is regularly reviewing the performance of its worst performing feeders against internal feeder targets, and considering approaches to address any problems that may be identified. This may involve targeted installation of a variety of augmentation measures, including reclosers on selected worst performing feeders. The targeted installation approach is of a different scale to the broad based recloser program discussed above, and delivers important distributional benefits by improving service to customers experiencing worst performance. The Ten Year Augmentation Plan consists of projects that address the identified performance and capacity augmentation requirements, and includes an allowance for anticipated performance and capacity augmentation requirements.

The internally imposed performance standards have been developed to assist ActewAGL Distribution in identifying cost effective measures to ensure SAIDI meets externally imposed targets. The effect of augmentation work is reviewed through the annual network performance review and on-going network performance monitoring, to assess the impact of approaches in satisfying performance standards.

While forecast levels of capital and operating expenditure are predicated on meeting current *reliability* targets, the Southern Supply Project will significantly improve *security of supply* in the ACT. This project is the result of new ACT Government Network Service Criteria introduced in 2006, which require an additional point of supply to the ACT network.

In addition, ActewAGL Distribution is considering a program to underground the existing overhead network ACT over a long-term investment horizon. The WTP study has informed the preliminary cost benefit analysis of this project. The early results from this review indicate a potential net economic benefit from an underground conversion program in the ACT, but these results need to be tested further, particularly to determine a staged program that would maximise the net benefits to the community.

3.5 AER Service target performance incentive arrangements

The AER *Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations: Final Decision* was released in February 2008. The AER Final Decision was released in accordance with clause 6.6.2 of the transitional *Rules*, which allow the AER to develop and publish an incentive scheme or schemes to provide incentives for DNSPs to maintain and improve performance.

The *Final Decision* sets out the AER's approach to regulation of service standards for ActewAGL Distribution in the 2009–14 regulatory period. In its decision, the AER determined not to impose a financial incentive in the 2009–14 regulatory period, in line with the restrictions in the transitional *Rules*. The AER recognised that the current minimum service levels in technical codes applying in the ACT, as well as GSL payments (the rebates under the *Consumer Protection Code* outlined above), were adequate protections against any incentives ActewAGL Distribution may face to reduce service reliability in the 2009–14 regulatory period.[32]

The AER further decided to implement a data collection and analysis exercise as provided for under clause 6.6.2(h) of the transitional *Rules*, with no associated revenue impacts from

[32] AER 2008, *Service Target Performance Incentive Arrangements for the ACT and NSW 2009 Distribution Determinations: Final Decision*, February, p 10

incentives or penalties in the 2009–14 regulatory period. The data collection and analysis requirements will be determined through the National STPIS, developed by the AER under the general chapter 6 *Rules.*

The AER has released its proposed National STPIS, which was still in draft form at the time of submission of this regulatory proposal. Some details of the scheme, including the application of the scheme to individual distributors, will be determined in subsequent consultation processes. These include information gathering requirements and parameter definitions. Therefore, ActewAGL Distribution has had to make some assumptions over the future shape of the National STPIS information requirements to apply to ActewAGL Distribution in the 2009–14 regulatory period, and include costs associated with the implementation of this scheme in this regulatory proposal. The proposed approach includes a mix of cost estimates included in the forecast, and pass throughs. To the extent that the final requirements of the National STPIS change materially from what is in the draft scheme, ActewAGL Distribution expects that the associated costs would be recoverable via the cost pass through arrangements. ActewAGL Distribution's proposed cost pass through arrangements are discussed further in chapter 16.

3.5.1 Implications of AER service target incentive scheme decision for ActewAGL Distribution

Structure and design of the National STPIS

The AER Proposed National STPIS includes considerable detail of the proposed default regime to apply to distribution businesses. The Explanatory Statement that accompanied the proposed national STPIS states:

> …the AER will undertake data collection and analysis of service performance in the Australian Capital Territory (ACT) … over the 2009–14 period, and the approach will be based on the national STPIS. The AER will commence data collection from DNSPs in NSW and ACT as soon as is practical.[33]

The AER also states in the Explanatory Statement that:

> The proposed scheme has also been designed to provide a degree of flexibility that may be exercised in application to take account of transitional issues and the circumstances of DNSPs operating in different regulatory environments.[34]

ActewAGL Distribution notes, however, that the proposed scope for flexibility is limited to customer segmentation, incentive rates and revenue at risk, rather than the overall design of the scheme.

While ActewAGL Distribution recognises that some changes to the National STPIS may arise as a result of the consultation process, it is not possible to predict the nature of these changes. Therefore, ActewAGL Distribution is assuming for the purposes of this regulatory proposal that the final structure of the National STPIS, and therefore the information requirements that will

[33] AER 2008, *Proposed Electricity distribution network service providers service target performance incentive scheme: Explanatory Statement and Discussion Paper*, April, p 1
[34] AER 2008, *Proposed National STPIS Explanatory Statement*, April, p 3

be imposed on ActewAGL Distribution in the 2009–14 regulatory period, will be similar to that set out in the proposed National STPIS.

ActewAGL Distribution would expect that any significant changes to the National STPIS occurring after the submission date which have cost impacts for the 2009–14 regulatory period could be addressed in response to the AER's draft decision on ActewAGL Distribution's regulatory proposal, or alternatively, through the pass through mechanisms outlined in chapter 16.[35]

Expected application of the proposed National STPIS to ActewAGL Distribution

The AER proposed National STPIS is intended to accommodate existing state and territory service standard regimes. As noted in the AER Final Decision on transitional STPIS arrangements for the ACT and NSW for the 2009–14 regulatory period, ActewAGL Distribution is currently subject to a GSL regime with targets and rebates that "compare favourably to other jurisdictions in terms of scope and nature".[36] ActewAGL Distribution expects that this jurisdictional GSL scheme will continue beyond the 2009–14 regulatory period, in line with AER's comments in the proposed National STPIS that:

> It is noted that the GSL component of the AER's proposed STPIS would not apply to a DNSP where jurisdictional electricity legislation imposes an obligation on a DNSP to operate a GSL scheme. That is, where a jurisdictional GSL scheme is already in place, the GSL component of the AER's scheme will not apply to a DNSP.[37]

ActewAGL Distribution understands, however, that different arrangements are intended for the proposed s-factor incentive scheme. Except where proposed variations are agreed by the AER through the development of the framework and approach and distribution determination process, the national s-factor scheme will apply.

The AER proposed National STPIS states that a public reporting regime using a common set of agreed measures would apply to all distributors.[38] The details of this regime, including common definitions for measures and data reporting, will be set through a consultation process expected to commence later in 2008.[39]

There is currently significant diversity across Australian distribution businesses on the use and application of service standard measures. This diversity arises from:

- *Differences in definitions of measures*—for example, whether businesses use actual or estimated customer numbers, as well as how measures are segmented between customer classes/asset types;

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[35] ActewAGL Distribution notes that in order for this issue to be addressed in its response to the Draft Decision, the AER would need to invite relevant submissions from ActewAGL Distribution on this matter.
[36] AER 2008, *Service Target Performance Incentive Arrangements for the ACT and NSW*, February 2008, p 11
[37] AER 2008, *Proposed National STPIS Explanatory Statement*, April, p 8
[38] AER 2008, *Proposed National STPIS Explanatory Statement*, April, p 14
[39] AER 2008, *Proposed National STPIS Explanatory Statement*, April, p 30

- *Differences in the ability to collect data against some measures*—for example, some distribution businesses have the capacity to capture data on the frequency and duration of momentary outages, while others do not; and
- *Differences in the treatment of data sets*—for example, differences in methodology for identifying trend performance, such as the use of a five-year rolling average, as opposed to regression analysis.

ActewAGL Distribution expects that the national public reporting regime, as well as the s-factor incentive scheme, will move to nationally consistent definitions and analyses of data sets. This is likely to lead to significant costs for ActewAGL Distribution, particularly if the approach adopted moves data collection from average system performance to the customer level.

3.5.2 Expected expenditure impacts of National STPIS on ActewAGL Distribution

ActewAGL Distribution is concerned to ensure that the potential costs of complying with future AER obligations under the National STPIS that are incurred in the 2009–14 regulatory period can be recovered. Those costs, however, are very difficult to predict as the final AER approach has not yet been determined.

ActewAGL Distribution has identified two key areas where the new National STPIS and regulatory reporting requirements may drive costs in the 2009–14 regulatory period. These are:

- the establishment of new systems and processes for the application of the National STPIS from 2014; and
- a requirement to improve the accuracy of individual customer details for upstream outages and disturbances, and a requirement to include in the network model individual customer connectivity, as part of the information gathering regime to apply in the 2009–14 regulatory period.

Systems and processes for the application of the National STPIS from 2014/15

ActewAGL Distribution expects to incur costs in the 2009–14 regulatory period related to establishing systems and processes in the lead up to the implementation of an s-factor incentive scheme for ActewAGL Distribution in 2014/15.

These costs include compliance with information gathering and reporting obligations expected to apply in the 2009–14 regulatory period, as well as development of integrated systems to model expected reliability benefits and costs, to assist in understanding the incentive impacts of the proposed national s-factor scheme in future periods. It will also assist in the manipulation of data sets in line with requirements under the proposed National STPIS, including the application of the 2.5 beta statistical methodology, which ActewAGL Distribution currently calculates manually for its limited reliability data sets.

ActewAGL Distribution estimates the costs of establishing this system to be in the order of $0.3 million to $0.6 million in capital expenditure ($2008/09), with ongoing operating costs of about $30,000 to $60,000 per annum ($2008/09). The average costs from these ranges have been included in the capital and operating expenditure forecasts. ActewAGL Distribution considers this is appropriate due to the certainty of incurring costs in establishing the STPIS in the 2009–14 regulatory period, and the timing of release of the proposed National STPIS, which has limited the ability of ActewAGL Distribution to accurately forecast its costs in complying with the scheme.

Accuracy of customer details for upstream outages and disturbances

The AER proposed National STPIS recognises that some distribution businesses may only collect data at the average network level, and may not have data available at less aggregated levels. However, AER states that it would:

> …expect a DNSP to have less aggregated data available for a subsequent regulatory control period where a 'soft-start' (e.g. through average network level targets) has been applied initially.[40]

The AER notes that the proposed scheme is intended to provide sufficient clarity and certainty so that distribution businesses can be reasonably expected to start taking the necessary action to comply with the scheme.[41]

As it is currently drafted, the proposed National STPIS appears only to require reliability reporting on a feeder-type basis, rather than on an individual customer basis. Any extension of the National STPIS to require collection of data at an individual customer level would lead to significant additional costs for ActewAGL Distribution. Reflecting the proposed AER position above, if the final National STPIS were to include this requirement, then these costs would be incurred in the 2009–14 regulatory period.

ActewAGL Distribution's current network connectivity model links the upstream assets to distribution substations and individual customers are allocated to the distribution substations. In many cases, especially in commercial and multi-tenancy situations, information on customers' supply relationship between the premises and the distribution substation low-voltage circuits is not available. The next level of discrimination to supply-phase is not captured at all. All this information will be required to accurately identify part and no supply issues experienced by individual customers.

Therefore currently, ActewAGL Distribution systems are not fully integrated, meaning that outages cannot be accurately mapped to particular customers. This limits the ability of ActewAGL Distribution to accurately report on reliability measures and GSLs on a per customer basis, as opposed to on a system-wide or feeder-type basis as is currently the case. To extend the network connectivity model to individual customers would require modelling of around 2,500 kilometres of lines and associated service cables following exhaustive field inspections.

[40] AER 2008, *Proposed National STPIS Explanatory Statement*, April, p 28
[41] AER 2008, *Proposed National STPIS Explanatory Statement*, April, p 28

As part of the *ActewAGL Technology and Information Management Strategy*, ActewAGL Distribution has identified as a high-level priority a project to establish a single source of customer information, which includes network outages experienced by particular customers.

This project has a number of components. The first component is to establish an integrated system for managing customer data. This project is included in the Network Ten Year Augmentation Plan. ActewAGL Distribution forecasts the costs of this Information Technology project to be $0.3 million ($2007/08), and is included in forecast expenditure of the 2009-14 regulatory period. This project is focused on improving the utilisation of *existing* data and maintaining customer histories.

A further component is the extension of the connectivity model to individual customers. This involves manually mapping feeder, low voltage circuit, service and phase connections for each customer, and integrating this information into a centralised database that is also linked to the outage management system.

The extension of the connectivity model to individual customers, including capturing and managing full phase connection details, would cost several million dollars, and take a number of years to complete. At this stage, the proposed National STPIS appears to require customer segmentation down to a feeder level. If customer-level details were required to comply with requirements under the National STPIS, or the final National STPIS were to change materially from the current draft, ActewAGL Distribution expects that it would receive an appropriate pass through of the costs of complying with these requirements. Given the expected timing for the finalisation of the National STPIS, ActewAGL Distribution expects that such a change would constitute a transitional period pass through event, as discussed in chapter 16.

4. Regulatory obligations and requirements

Compliance with legislative requirements and standards is a substantial driver of the costs facing ActewAGL Distribution in the construction, operation and maintenance of its electricity network.

Compliance with applicable regulatory obligations and requirements is one of the four objectives for capital and operating expenditure set out in the transitional *Rules*.[42] The building block proposal prepared by ActewAGL Distribution under the transitional *Rules* must include the total forecast capital and operating expenditure for the relevant regulatory control period, which ActewAGL Distribution considers to be required to meet the capital and operating expenditure objectives.

Section 4.2 of this chapter describes the broad range of regulatory obligations facing ActewAGL Distribution in its day-to-day business. These obligations are reflected in ActewAGL Distribution's plans and procedures, and demonstrated through activities and projects in the 2009–14 regulatory period, described in chapters 6, 7 and 8. The chapter also includes new or changing obligations in section 4.3.

This chapter and associated pro forma do not set out all legislative and regulatory obligations to which ActewAGL Distribution is subject. The principal laws, regulations, rules, codes and guidelines that regulate ActewAGL Distribution's operation as an electricity utility are included, as well as other instruments with a particular impact on ActewAGL Distribution's operations as an electricity utility. ActewAGL Distribution has not sought to include in detail laws of general application to corporations and individuals, such as the *Trade Practices Act, Corporations Act, Privacy Act*, intellectual property legislation or motor traffic legislation.

The discussion below focuses on territory-specific laws, rules, codes and guidelines. While they arise mainly from ACT laws, codes and guidelines, in many cases similar requirements apply in other jurisdictions. This is particularly the case for technical and safety requirements, which have their source in the *National Electricity Rules,* Australian Standards and national codes of practice.

The application of these obligations in the ACT can differ, however, particularly in relation to some of the specific characteristics of the ACT network described in chapter 2. These relate mainly to emergency, environmental and planning obligations. Pro forma 2.3.4 covers a broader range of instruments in greater detail, and complements this chapter.

4.1 Categories of obligations

ActewAGL Distribution is subject to a broad range of Commonwealth and territory-specific laws, as well as a number of Codes and procedures established by the ICRC and other relevant regulators. These obligations fall under the following broad categories.

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[42] Transitional *Rules* clauses 6.5.6(a)(2) and 6.5.7(a)(2)

- *Industry obligations*—these are mainly associated with the characteristics of ActewAGL Distribution as a natural monopoly provider of electricity distribution services in the ACT. These include many of the obligations under the *Utilities Act 2000* (ACT), *Utilities (Network Facilities) Tax Act 2006* (ACT), *Territory-owned Corporations Act 1990* (ACT), Utility Services Licence, *Consumer Protection Code*, and *Ring-fencing guidelines*. These obligations mainly drive operating costs.

- *Technical obligations*—these are associated with the technical requirements involved in owning, managing and operating electricity network assets. These obligations include aspects of the *Utilities Act 2000* (ACT) and codes established under that Act such as the *Management of Electricity Network Assets Code*, and a variety of relevant Australian Standards. Compliance with ActewAGL Distribution and Industry Procedures developed in accordance with these Acts also create regulatory obligations. These obligations are a key driver of capital costs.

- *Safety obligations*—these are associated with the safety risks involved in owning an electricity network, and the procedures and processes required to operate, maintain and build network assets and ensure employee and community safety. Relevant instruments include the *Occupational Health and Safety Act 1989* (ACT), the *Electrical Safety Act 1971* (ACT), the *Building Act 2004* (ACT), the *Construction (Occupation) Licensing Act 2004* (ACT), the *Scaffolding and Lifts Act 1912* (ACT), the *Dangerous Substances Act 2004* (ACT), the *Crimes Act 2000* (ACT), the *Utilities Act 2000* (ACT), and regulations, codes and procedures under these Acts. These obligations drive both capital and operating costs.

- *Environment, emergency and heritage obligations*—these relate to the operation of ActewAGL Distribution in the ACT environment, its responsibilities to prepare for, and in the event of, an emergency, as well as heritage issues. Obligations arise from the *Environment Protection Act 1997* (ACT), the *Litter Act 2004* (ACT), the *Planning and Development Act 2007* (ACT), the *Tree Protection Act 2005* (ACT), the *Nature Conservation Act 1980* (ACT) the *Emergencies Act 2004* (ACT), *Heritage Act 2004* (ACT) and the *Native Title Act 1993* (Cwth). Obligations under these acts, and associated regulations and codes, drive both capital and operating costs.

- *Market obligations*—these relate to the role of ActewAGL Distribution as a distribution network service provider in the National Electricity Market (NEM). These obligations include compliance with the *National Electricity Law* and *National Electricity Rules*, and policies and procedures developed by the National Electricity Market Management Company (NEMMCO), *Electricity Metering Code*, including business-to-business (B2B) obligations and procedures, metrology procedures, and other rules and directions. These obligations drive capital and operating costs.

- *Corporate obligations*—these are associated with running a large and complex business in Australia, which has significant economic, environmental, employment, and safety impacts in the community. These obligations relate to finance and taxation, intellectual property, human resources, terrorism and criminal matters, and ensuring appropriate compliance systems, internal auditing and due diligence procedures are in place. Relevant acts include *the Annual Reports (Government Agencies) Act 2004* (ACT), *Taxation (Government Business Enterprises) Act 2003* (ACT), *Corporations Act 2001* (Cwth) and the *Privacy Act 1988* (Cwth). These obligations give rise to capital and operating costs.

4.2 Key obligations

4.2.1 Industry obligations

The Ministerial Council on Energy is currently developing new arrangements for the transfer of non-economic distribution and retail functions to a national framework. These arrangements are expected to support a new national consumer protection code, national customer/retailer/distributor contracting arrangements, and new licensing and ring-fencing arrangements. Legislation to support these new arrangements is not expected to be introduced into the South Australian Parliament until 30 September 2009, with their application, including the development of relevant codes, guidelines and contracts, to be concluded after this date.

It is expected that there will be significant transitional issues associated with the move to national arrangements, as they will impact on current customer contracts, and business and compliance structures. This will mean that effective transitional arrangements will be required for all businesses affected by the new arrangements. Furthermore, as most relevant instruments, such as the *Utilities Act 2000*, perform both industry and technical regulatory functions, they are likely to remain in place for the foreseeable future.

Given the expected timeline for the national process, the expectation that transitional arrangements will be developed, and the dual roles performed by many relevant instruments, ActewAGL Distribution has proceeded on the basis that current industry regulation and obligations will continue throughout the 2009–14 regulatory period.

While ActewAGL Distribution recognises that some obligations are likely to change in the future, it is very difficult to predict future changes and their possible effect for the forthcoming regulatory review period. ActewAGL Distribution proposes that costs associated with the new arrangements be treated as regulatory change pass through events, as discussed in section 4.3.9 below.

The following regulatory instruments make up the key industry obligations applying to ActewAGL Distribution. Further instruments and obligations are outlined in the attached pro forma 2.3.4.

Utilities Act 2000 (ACT)

The *Utilities Act 2000* (ACT) is the key Act in the ACT that gives a utility service provider the power to own, operate and maintain an electricity distribution network in the ACT. It imposes a range of obligations on the providers of electricity distribution services, including significant information and reporting requirements. The *Utilities Act* also restricts the actions of utility service providers in some instances.

The *Utilities Act* requires a utility service provider to hold a *Utility Services Licence*. The Act includes substantial penalties for non-compliance with certain provisions (in addition to the potential for loss of licence).

The *Utilities Act* also requires a utility to pay an annual licence fee, determined by the ICRC. The licence fee currently covers the costs of the ICRC, as well as the Technical Regulator, ACT Planning and Land Authority (ACTPLA). As both of these regulators will have an ongoing role in regulating ActewAGL Distribution, ActewAGL Distribution expects that these licence costs will continue in the 2009–14 regulatory period.

In addition to the licence fee, the *Utilities Act* requires utilities to pay an annual levy to cover national and local regulatory costs, including a contribution to support the Australian Energy Market Commission (AEMC). The ACT government has also recently introduced a network facilities tax which applies to utility services and represents an additional cost on the business. Further details of this tax are outlined in section 4.3.6 below.

All three of these costs (fee, levy and tax) are determined annually, and can change from year to year, as determined either by the ICRC or the ACT government.

Part 6 of the *Utilities Act* also imposes an obligation on electricity distributors to:

- connect a person's premises to the network following an application by the person;
- on application, vary the capacity of the connection between the premises and the network; and
- if the person elects, allow the connection or variation to be undertaken by an accredited third party.

This obligation leads to significant customer initiated capital expenditure. In 2006/07, ActewAGL Distribution completed over 6,000 customer connections (*energisations*) and over 3,000 new physical connections.

Part 7 of the *Utilities Act* sets out electricity distributors' rights and obligations in relation to the performance of network operations, and the provision of notices to landowners regarding any such work. These obligations are largely unique to the operating environment in the ACT, which includes long standing planning practices where low-voltage electricity reticulation, unless underground, is located in backyards and not on street verges. This gives rise to a set of legislative obligations regarding access to assets on private property, the location of machinery and plant on private property during works, and restoration of private property damaged through works. Specifically, a utility is required:

- to take all reasonable steps to ensure that as little inconvenience, detriment and damage as is practicable is caused (section 108);
- to provide minimum notice to landholders before performing network operations (section 109) or tree lopping (section 110) on their land;

- to provide minimum notice to other public trustees whose operation may be affected by the network operations (section 111);
- to remove machinery, property and waste from the land on which network operations have been undertaken (section 112);
- as soon as practicable, to restore the land to a condition that is similar to its condition before the network operations began (section 113); and
- to issue photographic identity cards to authorised persons (section 115).

These carry implications particularly for the ActewAGL Distribution *Asset Management Plan*, and drive significant capital and operating costs. For example, costs associated with issuing notices to enter private property alone amount to over $300,000 per annum. Additional costs are incurred where there are delays in issuing notices so that they delay projects, and where there are problems in gaining access, such as locked gates, that mean that works cannot proceed as planned.

Regulations under the *Utilities Act*, the *Utilities (Electricity Restrictions) Regulations 2004*, allow the responsible Minister to approve an electricity restriction scheme if satisfied that the scheme is necessary to: facilitate, as far as practicable, the provision of efficient, reliable and sustainable electricity services by utilities to consumers; protect the interests of consumers; manage the safety and security of the electricity network; or protect public safety.

The implementation of such a scheme would have significant implications for ActewAGL Distribution's revenue, which is discussed in chapter 16 with reference to proposed pass through mechanisms.

Territory-owned Corporations Act 1990 (ACT)

The *Territory-owned Corporations Act 1990* (ACT) does not directly apply to ActewAGL (the unincorporated partnership). However, it does directly apply to ACTEW Corporation Limited and its subsidiary ACTEW Distribution Limited which is one of the two partners in ActewAGL. As a result, ActewAGL is bound by, at least, a residual application of the *Territory-owned Corporations Act 1990* (ACT) through its application to ACTEW Distribution Limited.

The *Territory-owned Corporations Act* includes objectives for a territory-owned corporation or a subsidiary. The objectives are:

- to operate at least as efficiently as any comparable business;
- to maximise the sustainable return to the Territory on its investment in the corporation or subsidiary in accordance with the performance targets in the latest statement of corporate intent of the corporation;
- to show a sense of social responsibility by having regard to the interests of the community in which it operates, and by trying to accommodate or encourage those interests; and

- if its activities affect the environment—to operate in accordance with the object of ecologically sustainable development.

The *Act* gives these objectives equal weighting.

Utilities Services Licence

Under the terms of the *Utility Services Licence*, a utility operating in the ACT must comply with all applicable laws, codes of practice, guidelines or directions, and inform the ICRC of any material breaches of the licence or any applicable laws, codes of practice, guidelines or directions. In addition, the *Licence* requires a utility to:

- publish an annual report on its obligations, and anything else required by the ICRC to be in that report;
- undertake audits of the services authorised by the licence to determine compliance; and
- keep comprehensive records in accordance with ICRC requirements, and provide those records to the ICRC on request.

A schedule to the *Licence* requires a utility to:

- maintain a 24-hour telephone service that is accessible to the public every day of the year to receive reports of network emergencies;
- develop and implement an ongoing program to cost effectively minimise losses of electricity power in the licensee's electricity network; and
- report annually to the ICRC on its implementation of measures to reduce network losses and greenhouse gas emissions attributable to its network operations.

ActewAGL maintains a 24-hour telephone service reporting of network emergencies, the costs of which are included in historic and forecast operating costs. In addition, approaches and measures to minimise network losses are highlighted in chapter 6 of this regulatory proposal, describing network planning and management.

Consumer Protection Code

Under the powers of the *Utilities Act*, the ICRC has developed a number of Codes of Practice that apply to ActewAGL Distribution.

The *Consumer Protection Code* applies to both retail and distribution businesses, and contains both common and specific obligations. The *Consumer Protection Code* governs many aspects of ActewAGL Distribution’s relationship with its customers, including the connection and disconnection of customers, information provision, and notices of planned interruptions. It also imposes minimum service levels to which rebates can apply, as discussed in chapter 3 of this regulatory proposal.

One of the more significant obligations relates to handling customer complaints. In line with the *Code*, ActewAGL has developed a complaints procedure consistent with the relevant

Australian Standard. While ActewAGL Distribution enjoys relatively high customer satisfaction levels, two staff members are directly engaged in managing complaints, in order to meet set *Consumer Protection Code* time frames for response to written complaints. In addition, complaints handling can involve extensive liaison with the legal and network managers where they involve complex procedural or technical issues. Effective management and resolution of all complaints is time consuming, and is a driver of operating costs.

Ring-fencing guidelines

Under clause 6.17.1 of the transitional *Rules*, any ring-fencing guidelines in effect immediately before the start of the regulatory control period are deemed to have been prepared by the AER under clause 6.17.2 and are to be complied with by ActewAGL Distribution.

Ring-fencing guidelines established under the obligations of section 6.20 of the then *National Electricity Code*, currently apply to ActewAGL Distribution. In accordance with the former *National Electricity Code*, these guidelines provide for:

- legal separation of the network business from other businesses;
- accounting and functional separation of prescribed distribution services from other services provided by electricity distribution businesses;
- allocation of costs of prescribed services and other services provided by the electricity distribution businesses;
- restrictions on the flow of information between the network service provider and any other person; and
- restrictions on the flow of information where there is the potential for a lessening of competition.

ActewAGL Distribution currently reports on compliance with the ring-fencing guidelines as part of its annual reporting obligations to the ICRC under the *Utilities Act*, and expects that these obligations will continue alongside any AER reporting requirements. Section 6.17 of the transitional *Rules* includes provisions for the AER to develop new guidelines for ring-fencing, which, if developed, could apply to ActewAGL Distribution from 2014.

4.2.2 Technical Obligations

Utilities Act 2000 (ACT)

The *Utilities Act 2000* (ACT) also includes obligations to comply with technical and safety regulations, administered through ACTPLA and the Chief Minister's Department. The general obligation under the *Utilities Act* to provide the ICRC with an annual report also includes an obligation to include in that report compliance against technical and safety codes, with the ICRC passing on relevant sections of the annual report to the appropriate bodies.

Electricity Distribution (Supply Standards) Code

The *Electricity Distribution (Supply Standards) Code* sets out the technical parameters for the network as well as procedures for dealing with customer concerns over interference and some reporting requirements, which are satisfied through the annual report outlined above.

The *Supply Standards Code* technical parameters include requirements with respect to voltage, earthing and management of electromagnetic fields. In general, the Code requires electricity work to be carried out in accordance with specified Australian Standards, as well as some published industry standards formerly developed by the Electricity Supply Association of Australia, and now administered by the Energy Networks Association through Standards Australia. At times, the *Code* also requires compliance with *Good Electricity Industry Practice*, for instance with respect to minimising the risk of damage due to lightning strikes. The meaning of *Good Electricity Industry Practice* is described in section 4.2.5 below.

One of the core obligations in the *Supply Standards Code* is that ActewAGL Distribution must include in its Standard Customer Contract provisions to the effect that it will take reasonable steps to ensure that its electricity network will have sufficient capacity to make an agreed level of supply available at the point of supply, providing that the Customer has complied with the requirements of the *Service and Installation Rules* and has paid any applicable fees.

The *Supply Standards Code* requires ActewAGL Distribution to publish, by the end of each year, supply reliability targets for SAIDI, SAIFI and CAIDI measures. Operating as service standard obligations, these regulatory obligations are described in chapter 3. Reliability targets must be equal to or better than the standards published in Schedule 2 of the *Supply Standards Code*.

Management of Electricity Network Assets Code

This *Code* is a key technical regulatory document, which also contains significant crossovers with safety regulatory requirements. Relevant technical elements include a requirement to develop a Network Operators Maintenance Plan, which must include various elements set out in the Code. This significant obligation is addressed through the ActewAGL Distribution *Asset Management Plan*, listed in the Plans, Policies, Procedures and Strategies pro forma 2.3.6 and described in chapter 6 of this regulatory proposal.

In addition, this *Management of Electricity Network Assets Code* requires that ActewAGL Distribution maintain a record of all underground and aerial lines under its control, such that those lines can be located and identified. ActewAGL Distribution must ensure that this information is available to the public during business hours. ActewAGL Distribution participates in the *Dial before you dig* program—the national referral service for information on underground pipes and cables to assist customers to locate underground infrastructure.

Electricity Service and Installation Rules Code

The *Electricity Service and Installation Rules Code* requires the development (or adoption) of *Service and Installation Rules* which:

- seek to preserve the security, reliability and the safety of the electricity network, while minimising interference to the customers of ActewAGL Distribution;
- seek to adopt standard industry practices; and
- specify requirements for ActewAGL Distribution's standard and alternative methods of connection to an electricity network.

ActewAGL Distribution has developed its own *Service and Installation Rules*, which are available on the ActewAGL website.

Machinery Act 1949 (ACT) and associated regulations

The *Machinery Act 1949* (ACT) gives rise to various regulations, some of which that specifically relate to ActewAGL Distribution. The *Machinery (Boilers and Pressure Vessels) Regulations 1954* apply to all premises that contain pressure vessels, with inspections every two years.

Australian Standards

A large number of Australian Standards govern technical and safety aspects of ActewAGL Distribution's activities. These Standards contain considerable detail on procedures, processes and product specifications. It is not possible to detail these standards here, however they are a key part of ActewAGL Distribution's technical and safety regulatory framework.

4.2.3 Safety Obligations

There is a significant number of national and territory specific safety acts, regulations, codes, guidelines and standards relevant to ActewAGL Distribution. It is not possible or productive to list all these obligations in this regulatory proposal, however, these health and safety obligations involve not only those related to the construction and maintenance of the electricity network, though these are significant, but also include safety obligations relating to the building and construction industry, the transport industry, office workplace safety, working outdoors, working at heights, working in confined spaces and the use of specific machinery and tools, to list just a few examples.

The Life Guard Health, Safety and Environment management system, listed in the Plans, Policies, Procedures and Strategies pro forma (2.3.6), has been designed to address these obligations, and puts in place training, procedures and processes to ensure compliance all health, safety and environment obligations.

Compliance with health and safety obligations makes up a significant component of capital and operating costs. Practices and approaches used to protect the health and safety of workers change continually as obligations increase, knowledge grows, and new, better practices emerge. Costs are also driven by increases in overall staffing levels, and a near quadrupling of the number of apprentices taken on from 2004–09 compared with the five years proceeding this period. The increase in apprentices is a response to the skills shortage and expected retirements from ActewAGL Distribution's ageing workforce, and makes up part of

ActewAGL Distribution's succession planning to ensure that it can deliver on its proposed capital and operating expenditure, and continue to maintain appropriate levels of service delivery.

Many safety-related acts, codes and guidelines require ActewAGL Distribution to keep a record of each accident or dangerous occurrence and record serious incidents to the safety regulator. In addition, the *Electrical Safety Act* and the *Management of Electricity Network Assets Code* require all incidences relating to electrical safety to be reported to the construction occupations registrar and Chief Executive of ACTPLA (the Technical Regulator), immediately that ActewAGL Distribution becomes aware of the incident. This includes incidents that may not be related to ActewAGL Distribution or its assets, but which are often reported to ActewAGL by tradespeople and other members of the public.

Some of the key health and safety legislative instruments and obligations are outlined below, as well as some examples of safety regulation outside of the sector, which directly affects ActewAGL Distribution operations and therefore costs. Further details of the extent of health and safety obligations, as well as ActewAGL's procedures to ensure compliance, are included in the Life Guard Health, Safety and Environment management system.

Occupational Health and Safety Act 1989 (ACT)

The *Occupational Health and Safety Act 1989* (ACT) requires ActewAGL Distribution to take all reasonable steps to protect the health, safety and welfare of its employees while at work. This includes providing a safe work environment, adequate facilities, safe access to work, safe handling and storage of plant or substances, provision of information, training, instruction and supervision to ensure safety at work, as well as maintaining adequate information and records relating to the employees' health and safety. Safety obligations also extend to the safety of the public at or near the workplace.

While these provisions carry heavy fines and the potential for imprisonment in the case of a negligent or intentional breach, the ACT also has in place industrial manslaughter legislation under the *Crimes Act 2000* (ACT), which significantly increases the scope for severe penalties and lengthy jail sentences in the event of the death of a worker or member of the public as a result of "criminally negligent or reckless" actions or omissions of individual directors or managers.

ActewAGL Distribution has developed the *Public Electrical Safety Plan 2008*, which includes an integrated public safety awareness campaign with seasonal messages, advice and answers to frequently asked questions. This document and communications plan was developed to educate the community on electrical safety, at least in part in response to the increased liability that ActewAGL Distribution potentially faces for electrical accidents involving the general public. A number of recent changes to legislation and regulations have increased ActewAGL Distribution's role in providing advice to the community, including builders and site managers, on electrical safety and risk management, which further underpin the need for greater ActewAGL Distribution involvement in public safety campaigns.

New regulations under the *Occupational Health and Safety Act* (*Occupational Health and Safety (General) Regulations 2007*) as well as the *Building (General) Regulation 2008,* introduce new obligations on ActewAGL Distribution to approve risk management strategies for building sites where workers come within clearances for overhead or underground wires. This obligation, discussed further in section 4.3 below, will require amendments to the *Public Electrical Safety Plan*, as well as education and communication activities to ensure that building site managers are aware of their obligations and the risks involved in order to develop a risk management strategy.

Further regulations under this Act (the *Occupational Health and Safety (Certification of Plant Users and Operators) Regulations*) require ActewAGL Distribution to ensure that all workers and trainees have the appropriate training and certifications to conduct the work required of them. Similarly, the *Building Act 2004* and the *Construction (Occupation) Licensing Act 2004* (ACT) include licensing requirements for all persons who work in the construction industry.

Ensuring compliance with these and other detailed obligations mean that ActewAGL Distribution must have in place considerable training and certification records and procedures to ensure that the qualifications of employees remain up to date, as well as ensuring that contractors are appropriately qualified. This is also part of the Life Guard Health, Safety and Environment management system and the Integrated Management System.

Electrical Safety Act 1971 (ACT)

The *Electrical Safety Act 1971* (ACT) requires ActewAGL Distribution to ensure that all new electricity installations are inspected, tested and passed by an inspector before they are connected to the electricity network. All electrical wiring must be carried out in accordance with AS 3000 and tested in accordance with AS/NZ 3017, and an inspector can direct ActewAGL Distribution to make electrical wiring work safe and compliant with the Act.

Dangerous Substances Act 2004 (ACT)

The *Dangerous Substances Act 2004* (ACT) applies to ActewAGL Distribution in respect of some current and historical substances used in the electricity network. Older transformers and capacitors contained polychlorinated biphenyls (PCBs) as coolants and insulating fluids. These PCBs are now recognised as a potent organic toxin, as well as a potential human carcinogen. In addition, asbestos has historically been used in a number of electricity-related applications, due to its resistance to heat, electricity and chemical damage, as well as its strength. Asbestos is commonly found in cabling conduits, as well as domestic meter boards installed prior to the 1980s.

While the identification, management and removal of PCBs is challenging and costly, these costs are generally predictable and are reflected in historic and forecast costs. ActewAGL Distribution is currently undertaking a transformer oil sampling program to identify PCBs on the network. The program will run over 10 years, sampling approximately 200 transformers per annum (in addition to those being working on or moved). The cost of this program is approximately $50,000 ($2007/08) per annum.

Discovery of asbestos, however, is highly unpredictable and regularly disrupts capital works. There are no accurate records on the use of asbestos in particular locations, and, since it tends to have been used in underground or concealed sites, is often not discovered until work is underway.

There are some areas where the costs of managing identified asbestos containing material have been included in the capital forecasts in this regulatory proposal. For example, the zone substation projects include some estimated costs associated with managing asbestos.

The management of dangerous substances in accordance with the *Act* and relevant regulations requires the development of a safety management system that identifies the hazards associated with the substance and what risks might result. The system must outline ways to control these risks by eliminating the hazards, or at least minimise them as much as possible by setting up security and safety procedures, identifying incidents of non-compliance and rectifying these, and educating and training employees. They must also record and document compliance with the system by persons with responsibilities under it.

Under the Life Guard Health Safety and Environment management system, ActewAGL Distribution has developed a set of general principles to be included in Safety Management Plans, however, each of these Plans must be tailored to the particular site and the hazards it presents. In certain circumstances an emergency plan is also required. While dangerous substances impact a relatively small number of sites, their effect is a significant increase in both capital and operating costs, relating to changes in the proposed project capital plan, delays in completing the project, costs of developing a safety management systems and training relevant staff, as well as ongoing monitoring and reporting of sites.

ActewAGL Distribution must also develop and maintain a database of non-residential asbestos sites as part of the asset register under section 327 of the *Dangerous Substances (General) Regulation*. The ACT government has directed that this database must be completed by 1 March 2010.

The development of this database is a component of the network IT systems budget for the 2009–14 regulatory period. In addition, ActewAGL Distribution is including residential sites in the database to meet its duty of care obligations for worker safety when working with asbestos meter boards and other asbestos containing material.

To comply with safety requirements in dealing with asbestos, all field staff, construction and asset performance staff must attend a one day training course on asbestos risks. ActewAGL Distribution is also required to have asbestos disposal arrangements in place, as well as an asbestos assessor and removalist on standing order.

In addition, ActewAGL Distribution faces prosecution under the *Environment Protection Act 1997* (ACT) if it knowingly, recklessly or negligently pollutes. The *Environmental Protection Regulation 2005* defines PCBs as causing environmental harm. These obligations place considerable responsibility on ActewAGL Distribution to ensure the security of any such dangerous or potentially polluting substances used on or in maintaining the network.

Scaffolding and Lifts Act 1912 (ACT)

The *Scaffolding and Lifts 1912* (ACT) *Act* requires ActewAGL Distribution to provide written notice to the chief inspector before erecting any scaffolding or carrying out any work where a crane, hoist or lift is used. The ACT's backyard reticulation means that in many cases cranes, lifts and hoists are required to inspect, maintain and replace network assets on leased property. This means that this notification requirement has particular relevance to ActewAGL Distribution, particularly as part of the proposed pole replacement/reinforcement project outlined in chapter 7.

Management of Electricity Network Assets Code

The *Management of Electricity Networks Assets Code* is a key piece of electrical safety regulation in the ACT. In particular, the *Code* requires ActewAGL Distribution to have in place a Safety Plan that includes a requirement to test, inspect and maintain its Electricity Network to ensure that the requirements of the *Code* are met. The Safety Plan must describe how ActewAGL Distribution will achieve compliance with the requirements of the *Management of Electricity Network Assets Code* and provide for modifications to the Safety Plan if experience or changes in the Act or relevant standards make them necessary. The *Code* also requires annual reporting to the ACTPLA Chief Executive on compliance with the Plan. In practice, ActewAGL Distribution Safety Plan requirements are incorporated into the Life Guard health, safety and environment management system.

Schedules to this Code set out specific safety obligations for ActewAGL Distribution with respect to the safe design and construction of the network. These obligations, which include the need to carry out a risk assessment of the environmental stresses within which the electrical apparatus will operate, consideration of electromagnetic fields, bushfire mitigation, the thermal capacity, strength and potential for unauthorised access of the electrical apparatus, are incorporated into the ActewAGL Integrated Management System which covers quality, environmental and safety management and procedures. This system includes over 1,000 procedures related to the construction and management of the network, as well as safety accreditation and practices.

4.2.4 Environment, emergency and heritage obligations

There have been significant changes in the application of environmental and emergency regulation in the ACT, as well as the focus on bushfire mitigation and vegetation management activities under current laws and regulation, since the last regulatory review. These changes arise from a number of influences.

Bushfire mitigation and vegetation management

There is an increasing awareness in the community, and reflected in ActewAGL Distribution, of the vulnerability of the ACT to bushfire since the 2003 fires devastated parts of Canberra. ActewAGL Distribution has general powers under the *Utilities Act* (subject to other environmental, heritage and tree protection legislation outlined below) to manage vegetation to ensure the safety and security of the electricity system. This requires considerable judgement as to appropriate levels of vegetation management, while maintaining Canberra's reputation as the *Bush Capital*.

The potential for ActewAGL Distribution electrical assets to cause fire, and the scope of the bushfire threat to the ACT, as well as the effect of the 2003 bushfire and ongoing drought on trees, has meant a significant step increase in the ActewAGL Distribution vegetation management program in the past few years. The *ACT Criminal Code* also imposes a potential 15-year sentence on an individual, or $750,000 fine on a corporation, for intentionally or recklessly causing a fire or recklessness about the spread of fire. In addition, the *Emergencies Act 2004* (ACT) requires owners of rural land to take all reasonable steps to prevent the outbreak and spread of fire on their land.

ActewAGL Distribution's approaches to vegetation management and bushfire mitigation are set out in the *Vegetation Management Strategy and Plan* and the *Bushfire Mitigation Strategy and Management Plan*. The *Vegetation Management Strategy and Plan* reflects obligations under various industry, environmental and emergency instruments for private land. By maintaining vegetation clearances from ActewAGL Distribution's powerlines, the objectives of the *Vegetation Management Strategy and Plan* are to:

- ensure safety to public and ActewAGL Distribution employees;
- reduce the risk of initiating a fire, damage to property and harm to environment;
- maintain a safe and reliable electricity supply; and
- minimise vegetation-related power outages.

The Plan complies with the *Utilities Act*, accepted vegetation management principles and is consistent with similar plans across the electricity supply industry.

As part of the *Vegetation Management Strategy and Plan* and other legislative requirements, ActewAGL Distribution may from time to time conduct audits of vegetation management works carried out near powerlines. The audit must include, but is not limited to, the following:

- minimum distances;
- risk management and HSE;
- arboricultural methods;
- plants, tools and equipment;
- accreditation certificates;
- disposal of debris and correct use of herbicide; and
- environmental considerations.

Cost associated with vegetation management have increased significantly since the start of the last regulatory control period. These increases are related to increased vegetation management activity, as well as new obligations associated with the protection of significant trees. The *Tree Protection Act* was introduced in 2005, with a process currently underway to establish a tree register. Interim measures, through the *Tree Protection (Interim Scheme) Act 2001* (ACT) have been in place for some time longer, however the full effect on the *Tree Protection Act 2005* on tree management practices (and therefore costs) has essentially emerged in the current review period and in forecast costs for the 2009–14 period. These cost impacts are discussed further in section 4.3.3 below.

In addition to practices and procedures for vegetation and bushfire mitigation on private land, ActewAGL Distribution is currently developing an agreement with the Department of Territory and Municipal Services (TAMS) regarding actions required for compliance with various Acts, codes and guidelines on public land under the control of TAMS.

Over time, the agreement will cover obligations relevant to fire safety, vegetation management, protection of the environment, heritage issues and the protection of significant trees. This includes obligations under the *Utilities Act*, *Utilities Network (Public Safety) Regulation 2001* (ACT), *Environment Protection Act 1997* (ACT), *Water Resources Act 2007* (ACT), *Tree Protection Act 2005* (ACT), *Nature Conservation Act 1980* (ACT), *Heritage Act 2004* (ACT), *Environment Protection and Biodiversity Conservation Act 1999* (Cwth). Many of these obligations are overlapping and potentially contradictory, leading to the desirability of developing an agreement to clarify rights and obligations under various instruments with respect to public land.

Obligations covered by the agreement include access to infrastructure on public land, as well as the management of access tracks and easements by ActewAGL Distribution. These obligations drive specific costs, and these are increasing as the implications of these obligations are better understood. For example, ActewAGL Distribution's estimated operating costs associated with track maintenance are increasing significantly in the next two years (from $75,000 to $250,000 per annum), in response to the need to ensure better access to ActewAGL Distribution powerlines, but also as a response to requirements not to drive on native grasses and cause wheel ruts in native parks. These costs are then expected to decrease in the later part of the 2009–14 regulatory period.

Security of supply and electrical infrastructure

There has also been a considerable increase in focus on network asset security and security of supply issues arising from the threat of terrorism, or other threats from natural disasters. In 2006, the ACT Government introduced a requirement, which included a new statutory network performance obligation (Network Service Criterion) requiring establishment of an additional 132kV connection to ActewAGL Distribution's network. This obligation applies to TransGrid directly, but also gives rise to significant obligations for ActewAGL Distribution. The purpose of the southern supply point requirement is to enhance the security of electricity supply for the ACT. ActewAGL Distribution is required to construct two new 132 kV lines to connect the new southern supply point to the existing ACT distribution network. This expenditure is included in

ActewAGL Distribution's capital expenditure forecasts for the 2009–14 regulatory period. Further details of this project are outlined below under *New or changing requirements* and in chapter 7.

In addition, ActewAGL Distribution is undertaking a capital project to upgrade fences around zone substations. These facilities have been recognised as *critical infrastructure* by the Australian and ACT governments. Critical infrastructure is defined as physical facilities that, if damaged and put out of action for an extended period of time, would adversely impact on the social or economic well-being of the nation or affect Australia's ability to ensure national security. The appropriate approach to protecting that infrastructure is in most cases left to the businesses that own and operate critical infrastructure. Some guidance is provided, however, through industry publications such as the Energy Networks Association (ENA) *National Electricity Network Safety Code* and the ENA *National Guidelines for Prevention of Unauthorised Access to Electricity Infrastructure*. The project complies with both of these industry codes.

Nature Conservation Act 1980 (ACT)

The *Nature Conservation Act* controls the management of trees on land leased for rural purposes. Trees on nature strips, unleased urban lands and public parks are protected through the ACT Trees Policy.

The ACT Trees Policy was developed by Environment ACT and incorporates all ACT Government tree related policies and strategies. It identifies various actions to deliver on the objective that Canberra's garden city heritage and bush capital character is maintained and enhanced by the protection and sustainable management of its trees - "The Vision for Tree Management in the ACT". All of these obligations are captured in the ActewAGL Distribution *Vegetation Management Strategy and Plan*, and the proposed agreement with TAMS, as appropriate.

Emergency Planning Code

Under the *Emergency Planning Code*, ActewAGL Distribution must adopt, implement and regularly update procedures to identify, detect and manage potential emergencies that threaten or affect the supply of utility services to a significant number of customers. Management of emergencies needs to include notifying customers and the public who are most likely to be affected by the occurrence of the emergency, the duration of the emergency, ActewAGL Distribution's response to the emergency, precautions people should take, the restrictions on the utility service which will take effect and how to apply for an exemption from these restrictions. These procedures must be audited annually.

ActewAGL Distribution must submit an annual emergency plan in accordance with the *Code* to ACTPLA for approval. In addition, ActewAGL Distribution must provide a list of the names and contact details of each employee or officer who has responsibility for the identification, prompt detection and management of emergencies under ActewAGL Distribution's emergency plan to ACTPLA and to each organisation, agency or person which has responsibility under ActewAGL Distribution's emergency plan.

ActewAGL Distribution also has ongoing obligations to ensure that workers are trained on their duties and authorisations during an emergency event, as well as ensuring compliance with the emergency plan. In addition, ActewAGL Distribution must immediately notify ACTPLA of an emergency event, and send a written report on any such event to the Chief Executive of ACTPLA within five business days of the event. Major storms have triggered this requirement in the past.

Heritage Act 2004 (ACT)

The *Heritage Act 2004* (ACT) covers listed and potential places and objects of heritage significance, including aboriginal sites of significance. It requires any person who discovers a site of potential significance not to damage that site and to report it to the Heritage Council within five days, as well as ensuring that owners or occupiers of recognised heritage sites ensure that those sites are not damaged.

While this *Act* mainly imposes obligations on other leaseholders, ActewAGL Distribution often must carry out electrical work or vegetation management activities on heritage sites, which requires particular sensitivity and can delay planned work. In the event that ActewAGL Distribution owns or occupies a heritage site, it must provide the ACT Heritage Council with a written report including details of each heritage place or object for which it is responsible, and may be directed to develop a Heritage Management Plan for a heritage place or object for which it is responsible.

Native Title Act 1993 (Cwth)

The *Native Title Act 1993* (Cwth) potentially applies to all land that is not under free-hold title, and therefore potentially covers much of the ACT.

Section 24 of the *Native Title Act* sets out types of future acts affected by the Act, and includes future acts by transmission and distribution businesses relating to a transmission or distribution facility. It requires that future acts on land where native title is established be subject to an agreed Indigenous Land Use Agreement (ILUA).

The Act defines ILUAs as voluntary agreements made with native title parties about the use and management of land and waters. An act can generally be done under an ILUA registered with the *National Native Title Tribunal*, whether or not it falls within any of the categories of acts allowed under the future act regime. This requires the native title parties to give their agreement or consent to the act being done.

As most of the ACT is managed through lease-hold title, the *Native Title Act* potentially applies to all ACT land. This has the potential to significantly impact on ActewAGL Distribution’s operations in the ACT, and creates operational risks, particularly in areas of new developments such as the Southern Supply Project. This Act does not directly drive any costs for ActewAGL Distribution in the 2009–14 regulatory period, however it represents an unpredictable and potentially uncontrollable future cost risk for ActewAGL Distribution.

4.2.5 Market obligations

As a registered participant in the NEM, ActewAGL Distribution must comply with a series of market obligations associated with its role as a network service provider. These obligations arise from the *National Electricity Law* (NEL) and *National Electricity Rules* (NER), and procedures developed under the NEL and NER.

This regulatory proposal is prepared under new obligations in the NEL and NER.

National Electricity Law

The *National Electricity Law* applies in the ACT through the *Electricity (National Scheme) Act*. The NEL sets the high level legislative framework within which the market operates and is developed, as well as establishing some high level rights and obligations for both market participants and market institutions. The NEL requires that a person owning, operating or controlling a distribution system that is part of the interconnected network, must be a registered participant. As a registered participant, ActewAGL Distribution must comply with the NEL and NER, as well as directions given under the NEL or NER, such as by NEMMCO, the market operator. The NEL also requires that a regulated distribution system operator comply with a distribution determination that applies to a particular network.

Another key set of obligations under the NEL involve the provision of information to the regulator. ActewAGL Distribution must comply with any *Regulatory Information Order* or *Regulatory Information Notice* that applies to it. The costs of complying with information requirements make up part of the legitimate costs of a network service provider in complying with obligations and can be recovered in its allowable revenue.

National Electricity Rules

The *National Electricity Rules* set out the detailed obligations of market participants. Describing all obligations arising from the NER would not be productive, however there are some classes of obligations that warrant some mention. These are obligations relating to system security, connection and planning, preparing a regulatory proposal and metering.

The system security obligations set out in Chapter 4 of the NER require ActewAGL Distribution to plan and operate its distribution system within power system stability guidelines, and assist NEMMCO in the event of a prolonged major supply shortage or extreme power system disruption.

The Chapter 5 connection and planning obligations introduce the concept of “good electricity industry practice” and requires ActewAGL Distribution to plan and operate all its equipment to this standard, as well in accordance with relevant Australian Standards. This means that ActewAGL Distribution has an obligation through the NER to comply with relevant Australian Standards, even where they have not been specifically called up in legislation or the NER.

The Chapter 5 connection obligations establish ActewAGL Distribution’s obligation to connect customers that have met minimum information and technical standards. It also sets out a detailed connection process, including a timeline for processing application connections and information requirements for both ActewAGL Distribution and the connection applicant.

Substantial negotiation over customer connection agreements can take time, and therefore can be quite costly. If the number of negotiated customer agreements were to increase, this is likely to lead to increased costs for ActewAGL Distribution.

The planning requirements of chapter 5 require ActewAGL Distribution to undertake an annual joint planning exercise with relevant transmission network service providers, for a five-year planning horizon. As part of this planning process, ActewAGL Distribution must provide NEMMCO with forecast load and planning information.

Where the planning process uncovers an expected limitation in the network, and the proposed network option to address that limitation would not be a small distribution network asset (that is, would be greater than $10 million), ActewAGL Distribution must apply the regulatory test published by the AER. This involves consulting with registered participants, NEMMCO and interested parties on possible options, including demand side options, generation options and market network service options, to address projected limitations in the network. Any network options recommended as a result of this regulatory test process must be available for service by the agreed time, and must include the costs of relevant assets in the calculation of distribution service prices determined in accordance with Chapter 6 of the NER.

Chapter 6 of the NER contains obligations that govern the preparation of this regulatory proposal. These have been highlighted in Chapter 1 of this regulatory proposal. Most notable and relevant of these obligations is the requirement to provide direct control services or negotiated distribution services on terms and conditions of access as determined through Chapters 4, 5, 6 and 7 of the NER.

Chapter 7 of the NER relates to metering. These obligations are discussed further in chapter 15.

Good Electricity Industry Practice

ActewAGL Distribution has an obligation to apply what is termed “good electricity industry practice” through the application of a number of technical industry codes. Most relevantly, the NER require that distribution businesses apply good electricity industry practice with respect to provision and maintenance of network facilities. ActewAGL Distribution must also apply the principle under the technical obligations of the *Electricity Service and Installation Rules Code*. The concept of good electricity industry practice is difficult to define with precision, however it is generally considered to have a number of components. These are:

- using up-to-date methods, practices and procedures;
- implementing improvements to processes as the benefits of doing so emerge;
- practicing due care in developing and maintaining the network, and in adopted new approaches and technologies; and
- participating in industry forums, information exchanges and studies to develop knowledge and understanding.

In practice, it means implementing upgrades to the network and changes in practices and procedures not just in response to direct regulatory obligations, but also to deliver continuous improvements in the efficiency in network operations and the prudency of the Asset Management Plan.

Regulatory test

Under the section 5.6.5A of the NER, the AER must develop the *Regulatory Test*. The AER completed version 3 of the *Regulatory Test* in November 2007, which replaces earlier versions of the *Test*.

The current *Regulatory Test* is used by transmission and distribution businesses to test the efficiency of proposed network investment. The *Regulatory Test* only applies to network augmentations and does not apply to the replacement of assets. Transmission and distribution businesses are required to conduct a public consultation process on projects over $10 million. The *Test* includes reliability and market benefits limbs.

Augmentation proposals assessed under the reliability limb (being these required to meet service standards linked to technical requirements in Schedule 5.1 of the NER or applicable regulatory instruments) must minimise the costs of meeting those requirements, compared with alternative option/s in a majority of reasonable scenarios. Proposals assessed under the market benefits limb must maximise the expected net economic benefit to all those who produce, consume and transport electricity in the national electricity market compared to the likely alternative option/s in a majority of reasonable scenarios.

A small number of ActewAGL Distribution projects in the 2009–14 regulatory period are likely to require the application of the *Regulatory Test*.

The current *Regulatory Test* that applies to distribution network augmentations is being considered as part of the MCE's review of distribution and retail regulation. These changes and details of costs are discussed in section 4.3.8 below.

Electricity Metering Code and ICRC decision to require installation of interval meters on a new and replacement basis

The *Electricity Metering Code* (ACT) sets out minimum standards for meters installed in the ACT, and customer rights and responsibilities in respect of those meters, including information provision. This *Code* is complemented by a December 2005 decision by the ICRC to require the installation of interval metering on a new and replacement basis to all customers in the ACT, as well as on request. Costs associated with this decision have been recovered as a pass through in the current regulatory period. Future costs associated with this obligation are addressed in chapter 15 of this regulatory proposal.

NEM Metrology Procedure

The *NEM Metrology Procedure* governs obligations of relevant sectors with respect to the provision of metering services. Metering is discussed in chapter 15 of this regulatory proposal.

B2B Procedure

The B2B Procedure is developed by the Information Exchange Committee, a NEMMCO committee, and includes a number of components governing information exchange between retailers, distributors and NEMMCO to facilitate full retail contestability. These components are as follows:

- Customer and Site Details Notification Process;
- Meter Data Process;
- Service Order Process;
- Technical Delivery Specification; and
- Technical Guidelines for B2B Procedures.

Changes to obligations and processes under the B2B Procedure can lead to significant costs for both distribution and retail businesses in modifying data collection and management processes.

Electricity Customer Transfer Code

The *Electricity Customer Transfer Code* supports NEMMCO requirements for customer transfers and B2B information exchange under the *Rules*, to support full retail contestability in the ACT.

4.3 New or changing requirements

4.3.1 Overview of cost impacts from new or changing requirements

There are a number of new or changing regulatory requirements that have had an impact in the current regulatory period, or will emerge in the 2009–14 regulatory period. Table 4.1 provides an overview of the expected cost impacts of these changing obligations. Details of the changing regulatory obligations and associated costs are outlined in the sections that follow.

Table 4.1 Overview of new regulatory obligations and costs

New obligation	Forecast expenditure ($2008/09)	Comments
Occupational Health and Safety (General) Regulations 2007	$0.22 m pa - staff and vehicle costs (ongoing) Advice and communications costs	As the new regulations came into effect on 26 May 2008, ActewAGL Distribution will incur some costs the current regulatory period, and further, ongoing costs in the 2009–14 period. These costs have been included in forecast operating expenditure.
Tree Protection Act 2005	$14.0 m total 2009-14 forecast vegetation control maintenance	The 2009–14 vegetation control maintenance operating expenditure forecast is an increase of 33% on the 2004–09 period. There are a number of regulatory drivers for increased costs, which include the application of the *Tree Protection Act*.
Planning and Development Act 2007	$0.04 m upfront – establishment of on-line application process and database (current period) $0.12 m pa - staff and database management (ongoing)	Some of these costs will be incurred in the current review period, while many of the ongoing costs represent increases in operating costs for the current and 2009–14 regulatory period.
Utilities Exemption 2006 (Southern Supply Project)	$22.5 m	This is the forecast expenditure on this project for the 2009–14 regulatory period.
Proposed National STPIS	$0.45 m system establishment costs $0.045 m ongoing operating expenditure	Development of systems and processes to implement National STPIS discussed in detail in section 3.5 of this regulatory proposal.
Utilities (Network Facilities) Act 2006	$20.9 m	ActewAGL Distribution has included an estimate for this tax in its forecast operating expenditure, as well as an adjustment mechanism to address any changes in the tax amount.
Final Decision: Review of Metrology Procedures, Report 15 of 2005, December 2005	$0.5 m ongoing capital expenditure $0.4 m ongoing operating expenditure	This decision and other metering issues are discussed in chapter 15 of this regulatory proposal.
Electricity Feed-in (Renewable Energy Premium) Bill 2008	Unknown	This Bill is scheduled to be debated in the ACT Legislative Assembly in June 2008. ActewAGL Distribution proposes that additional expenditure related to the introduction of a feed-in tariff be treated as a transitional period pass through event or a regulatory change pass through event, depending on the timing of the event.

New obligation	Forecast expenditure ($2008/09)	Comments
Regulatory Test	Unknown	The current regulatory test that applies to distribution network augmentations is being considered as part of the MCE's review of distribution and retail regulation. ActewAGL Distribution proposes that additional expenditure to apply a new regulatory test be treated as a transitional period pass through event or a regulatory change pass through event, depending on the timing of the event.
MCE non-economic distribution and retail framework	Unknown	The MCE is currently consulting on several aspects of a proposed legislative package to transfer non-economic distribution and retail regulation to a national framework. ActewAGL Distribution proposes that additional expenditure to comply with the new laws, rules and codes be treated as a transitional period pass through event or a regulatory change pass through event, depending on the timing of the event.
MCE Smart meter decision	Unknown	The MCE is currently considering stakeholder comments on the draft Regulatory Impact Statement for smart meters. ActewAGL Distribution proposes that additional expenditure to comply with any new smart meters policy decisions be treated as a pass through event.
ARPANSA Standard on Electric and Magnetic Fields	Unknown	This standard is expected to be finalised by end 2008. ActewAGL Distribution proposes that additional expenditure to comply with the new Standard be treated as a transitional period pass through event or a regulatory change pass through event, depending on the timing of the event.
New national carbon emissions trading scheme or other carbon abatement measures	Unknown	The Australian Government is currently consulting on the establishment of an emissions trading scheme. ActewAGL Distribution proposes that additional expenditure to comply with any new laws or other instruments be treated as a transitional period pass through event or a regulatory change pass through event, depending on the timing of the event.
Workplace Safety Bill 2008 (exact title unknown as not yet introduced)	Unknown	This Bill is slated for introduction towards the end of the 2008, however the ACT Government has yet to release an exposure draft. ActewAGL Distribution proposes that additional expenditure to comply with the new Act be treated as a transitional period pass through event or a regulatory change pass through event, depending on the timing of the event.

4.3.2 Occupational Health and Safety (General) Regulations 2007

The ACT Government has recently enacted new regulations under the *Occupational Health and Safety Act 1989* (ACT). These regulations are called the Occupational Health and Safety (General) Regulations 2007 (the *General Regulations*), which came into force on 26 May 2008. The *General Regulations* repeal the *Occupational Health and Safety Regulation 1991*.

The *General Regulations* require that amenities such as personal hygiene facilities, change rooms, meal rooms, lockers, and other amenities be provided at workplaces, and provide for risk control, training for health and safety representatives and, reporting of and record keeping in relation to dangerous occurrences at the workplace.

Particular duties and safety measures relate to the management at workplaces of:

- entry and exit from the workplace;
- the use of personal protective and safety equipment;
- the prevention of falls;
- measures relating to atmosphere and ventilation;
- extremes of heat and cold;
- safe surfaces and floors;
- the safe use of electricity;
- work in confined spaces;
- lighting;
- noise, and the risk of hearing impairment;
- employees working in isolation;
- the risk of fire and explosion; and
- emergency procedures in the workplace.

While the *General Regulations* represent a significant increase in the detail and breadth of formal obligations compared to the *Occupational Health and Safety Regulation 1991* that it replaces, in most cases the new *General Regulations* do not impose a significant change in ActewAGL Distribution processes. In the future, the *General Regulations* are expected to be expanded to replace current regulations on the use of machinery, scaffolds and lifts, and hazardous materials.[43] The ACT Government has not published any indication of the proposed date for this to occur.

[43] ACT Parliamentary Counsel, *Occupational Health and Safety (General) Regulation 2007: Regulatory Impact Statement*, p 4

Many obligations contained in the new *General Regulations*, such as the provision of facilities at the workplace, are encompassed in current ActewAGL Distribution practices and provisions. There are some key areas, however, where the *General Regulations* may lead to increased operating costs for ActewAGL Distribution in the 2009–14 regulatory period. Specifically, these are the provision of water, responsibility for personal protective equipment, and measures for preventing electrical contact.

Provision of water (Reg 21)

General Regulation 21 creates an offence if an employer fails to provide water for employees at the workplace. In most cases where employees are working in ActewAGL Distribution offices and depots this obligation is easily met, however, this obligation is less straightforward where employees are working in the field, often on private land or on the roadside.

The *General Regulations* provide that reasonably practicable steps to provide the amenities are required, having regard to the nature of the work, the size, nature and location of the workplace, and the number of men and women at the workplace. It is not expected that the same level of amenities need be provided for field staff compared to office-based staff.

ActewAGL Distribution provides all field staff with a large water container, and encourages employees to fill this container at the depot before travelling to the field, and provides chilled water for this purpose. ActewAGL Distribution believes that this approach satisfies the requirements under the *General Regulations*. It is possible, however, that this obligation may be interpreted narrowly in practice, where an interpretation may be that ActewAGL Distribution is required to actually provide water to all work crews irrespective of the nature of the work and the location of the workplace, rather than rely on employees to personally fill water containers provided by ActewAGL Distribution. If so, this will lead to increased costs through purchase of large water containers for ActewAGL Distribution trucks, providing securing points in trucks to ensure containers do not pose a danger moving around or falling out of trucks, and ensuring that an employee is responsible for preparing water vessels for work crews each day. However, ActewAGL Distribution assesses that such a narrower interpretation is unlikely.

ActewAGL Distribution therefore considers that it is reasonable to assume that its current approach is adequate and has not included additional provision for this obligation in its operating expenditure forecast.

Personal protective and safety equipment (Reg 28)

General Regulation 28 states that if an employer takes measures to minimise a risk, which include providing personal protective and safety equipment to its employees, the employer must:

- ensure that the equipment is appropriate for the person and minimises the risk for the person;
- the person is told of any limitation of the equipment;

- the person is given the instruction and training necessary to ensure that the equipment minimises the risk for the person;
- the equipment is properly maintained and repaired or replaced as frequently as is necessary to minimise the risk for the person; and
- the equipment is kept in a clean and hygienic condition.

ActewAGL Distribution currently supplies its staff with appropriate personal protective and safety equipment and trains staff to use this equipment. ActewAGL Distribution directs its staff to keep personal protective equipment clean, and for staff to notify it if they face any difficulties in cleaning personal equipment. ActewAGL Distribution also periodically audits the state of personal protective equipment to ensure it is appropriate. In situations where ActewAGL Distribution staff may be handling hazardous substances such as asbestos, ActewAGL Distribution provides appropriate disposable protective equipment.

ActewAGL Distribution therefore considers that it is reasonable to assume that its current approach is adequate and has not included additional provision for this obligation in its operating expenditure forecast.

Electricity—measures for preventing contact (Reg 52)

General Regulation 52 requires a person in control of a workplace to ensure that a person working in, or undertaking maintenance at, the workplace is prevented from making inadvertent contact with a live, conductive part of an electrical installation by ensuring that workers are prevented from going within an unsafe distance of overhead or underground electrical power lines or exposed cables.

This obligation does not apply to a person undertaking electrical work if the person is licensed under the *Construction Occupations (Licensing) Act 2004* to undertake the work, or, in relation to clearances from overhead or underground electrical power lines or exposed cables, if a written risk assessment is given to the electricity network operator and the network operator is satisfied with the content of the risk assessment and that the work to be done in accordance with the risk assessment will be safe.

This obligation will apply to all builders, painters, landscapers and roofers, and any other workers conducting work near power lines that are not licensed electricity workers.

This regulation imposes a significant obligation on ActewAGL Distribution to establish a process to assess risk management plans. In essence the *General Regulations* impose on ActewAGL Distribution a new obligation to act as an *authority* for granting Permits to Work near or around electrical installations (for example, overhead power lines) subject to the submission of an approved safety management plan, which must be assessed as such by ActewAGL Distribution. The new regulatory requirements mean that ActewAGL Distribution will need to implement new processes such as:

- the development of guidelines for ActewAGL Distribution’s risk assessments of safety management plans;

- providing specialist advice and expertise to the broad community such as construction site managers, logistics companies, and others about safely working near electrical installations;

- allocating specialised resources to the risk assessment process; and perhaps oversee the process, for example, by inspections;

- de-energising part of the network may be assessed as the only way for the work to be carried out safely, leading to increased costs associated with outages; and

- promoting these services and the hazards of working near electrical installation to industry and the general public.

The obligation to be satisfied is that "work done in accordance with the risk assessment will be safe" (Regulation 58(4)(b)(ii)) also creates a considerable potential for liability. ActewAGL Distribution is likely to address this potential significant liability by ensuring that it inspects all sites before approving a risk assessment. This will have a considerable cost impact on ActewAGL Distribution, as discussed below.

Impacts on expenditure programs

ActewAGL Distribution has identified that the new measures for preventing contact under *Occupational Heath and Safety (General) Regulations* are likely to lead to a number of additional costs.

ActewAGL Distribution estimates that the new risk assessment process is likely to require additional staff and vehicle costs for onsite assessment of risks and proposed processes for managing those risks. These costs are estimated to be $222,000 per annum ($2008/09).

In addition to the direct costs of assessment, ActewAGL Distribution will need to develop guidelines for site managers to assist in developing risk assessments for working near ActewAGL Distribution assets, which will need to include issues to address, suggested processes and a description of the assessment and approval process. It is also likely that a web-based application processes will be developed over time. To assess applications, ActewAGL Distribution will need to develop internal guidelines and procedures for the consideration and approval of proposed risk assessments.

ActewAGL Distribution also expects to provide specialised advice to construction site managers, logistics companies, and others about safely working near electricity lines, as well as undertake a broader promotion of the need to develop a risk assessment. These processes and issues will also need to be incorporated into the ActewAGL *Public Electrical Safety Plan 2008.*

These costs have included in expenditure forecasts, as well as in Table 2 of pro forma 2.3.4.

4.3.3 Tree Protection Act 2005

The *Tree Protection Act 2005* (ACT) commenced in March 2006, and contains numerous provisions that are directly relevant to ActewAGL Distribution. It replaces interim measures through the *Tree Protection (Interim Scheme) Act 2001.*

The objectives of the *Tree Protection Act* are:

- to protect individual trees in the urban area that have exceptional qualities because of their natural and cultural heritage values or their contribution to the urban landscape;
- to protect urban forest values that may be at risk because of unnecessary loss or degradation;
- to protect urban forest values that contribute to the heritage significance of an area;
- to ensure that trees of value are protected during periods of construction activity;
- to promote the incorporation of the value of trees and their protection requirements into the design and planning of development; and
- to promote a broad appreciation of the role of trees in the urban environment and the benefits of good tree management and sound arboricultural practices.

The Act differentiates between regulated and registered trees, and includes an exemption for activities carried out in accordance with sections 105, 106, 125, 225F, 225G and 225X of the *Utilities Act*, with respect to regulated trees. Registered trees, which are those listed in the *ACT Tree Register*, have a higher level of protection and can be damaged only for the purpose of protecting life and property under sections 106 and 225G of the *Utilities Act*, where it is not practicable to get prior approval due to the urgency of the situation.

Except in accordance with these exemptions, ActewAGL Distribution is required to apply for approval for any activity that can be classed as damaging a registered tree, or which includes groundwork in the protection zone of a registered tree.

While the interim scheme has been in place since 2001, the Tree Register, which will list all trees to which ActewAGL Distribution must seek approval before damaging, has not yet been developed. After discussions with Environment ACT, ActewAGL Distribution understands that the development of the Tree Register will commence later this year, and is expected to take two to three years, with over 5,000 trees expected to eventually populate the register. Also, many trees in the ACT are on the verge of becoming a regulated tree, and are likely to meet minimum size limits in the 2009–14 regulatory period.

The impact of new procedures to manage protected trees are only now becoming evident in existing and forecast costs, as understanding and experience of the cost implications of this Act become more evident. This means that the full effect of this Act began in the current regulatory period, and will build throughout the 2009–14 regulatory period. This is reflected in the operating cost forecasts.

The ActewAGL Distribution *Vegetation Management Strategy and Plan* and the Agreement with TAMS described in section 4.2.4 above, reflects these changing requirements. Forecast vegetation management costs are described below, with more detail included in chapter 8 of this regulatory proposal.

Impacts on expenditure programs

ActewAGL Distribution's vegetation management activities have increased significantly over the current review period, and are forecast to remain at similar levels in the coming review period. As noted above, drivers for the increase include increased costs for managing trees in accordance the *Tree Protection Act*, and increased bushfire mitigation activities and maintenance of access tracks. These cost forecasts are reflected in Table 4.2.

Table 4.2 Actual and forecast vegetation control maintenance costs

2004–09 regulatory period ($'000 nominal)					
Year	2004/05	2005/06	2006/07	F2007/08	F2008/09
Vegetation control maintenance costs	1,812	1,636	1,885	2,466	2,957
2009–14 regulatory period ($'000 2008/09)					
Year	2009/10	2010/11	2011/12	2012/13	2013/14
Vegetation control maintenance costs	2,987	2,923	2,678	2,708	2,737

4.3.4 Planning and Development Act 2007 (ACT)

The *Planning and Development Act 2007* (ACT) is a new Act that replaces the *Land (Planning and Environment) Act 1991* and the *Planning and Land Act 2002*.

The *Planning and Development Act* affects almost all construction and large maintenance activities undertaken by ActewAGL Distribution. Before receiving planning approval under this Act, ActewAGL Distribution must prepare a preliminary assessment of the environmental impact of the proposal. All activities must be carried out in accordance with a relevant approval.

While these planning obligations involve the preparation and submission of development applications on a weekly basis, and contribute significantly to operating costs, these obligations are not new and are incorporated in historic and forecast operating costs.

The *Planning and Development Act* does, however, introduce a new obligation on ActewAGL Distribution to provide development applicants information on the location of electricity assets (sections 148 to 151). Under the new *Planning and Development Act*, ActewAGL Distribution, as an entity prescribed under the relevant regulation, must give the planning and land authority advice in relation to the development application not later than 15 working days after the day the authority gives the application to the entity.[44] If ActewAGL Distribution does not give advice within the required period, there is a deemed approval (section 150). The advice required from ActewAGL Distribution relates to the location of assets relevant to a development or building application (electricity assets being relevant to this regulatory proposal), and any access issues to ActewAGL Distribution assets that are relevant to the development or building application.

The new *Building (General) Regulation 2008* also includes an obligation on ActewAGL Distribution to provide similar advice in relation to building applications within 15 days. These obligations have been considered together with those under the *Planning and Development Act*.

Potential liability under these obligations arises if ActewAGL Distribution's advice to a proponent is incorrect, or the time limit for approval limits detailed consideration of the proposal, or where there is deemed approval because ActewAGL Distribution does not respond within the required time. In these cases, ActewAGL Distribution may incur costs for the relocation of assets or management of complex access issues, where a development builds over or obstructs access to ActewAGL Distribution's assets.

The process set out in the *Planning and Development Act* effectively replaces the more informal process previously undertaken, particularly with larger commercial developers, in identifying access issues and ensuring that development proposals did not interfere with ActewAGL Distribution's assets. By stipulating a legislative timeframe, there is a greater risk that proponents will not approach ActewAGL Distribution early in their planning processes, and complex site and access issues will require resolution over a very short timeframe.

ActewAGL Distribution also expects that the explicit requirement to gain approval from ActewAGL Distribution will also lead to an increase in the number of applications it must consider. It is probable that not all projects, particularly projects related to single and dual occupancy dwellings, currently seek approval for the proposed location and access to amenities.

Impacts on expenditure programs

ActewAGL Distribution currently considers development applications forwarded to it and provides advice on the location of electricity assets, as well as access to electricity assets for new developments. The additional costs associated with the new obligations under the *Planning and Development Act 2007* and *Building (General) Regulations 2008*, therefore relate to:

- the limited timeframe within which to consider applications;
- the expected increase in the number of application considered as a result of the positive obligation to consult with ActewAGL Distribution being included in the Act;

[44] This notification period could be shorter if prescribed by regulation.

- the development of an on-line application process and automated database of assets to assist the consideration of applications within the allotted timeframe; and
- the potential costs incurred if advice provided is inaccurate, incomplete or late and leads to the need to relocate assets or address difficult access issues.

ActewAGL Distribution forecasts that this enhanced approval role will require additional staff and database management resources at a yearly cost of $0.12 million. ActewAGL Distribution will also incur upfront costs for the establishment of an on-line application process and asset database in the order of $0.04 million. Note that the costs associated with the database are shared across the two main businesses, water and electricity, and hence are significantly less than stand-alone costs. ActewAGL Distribution will also carry the cost of the risk of providing inaccurate, incomplete or late advice.

These costs have been included in expenditure forecasts, as well as in Table 2 of pro forma 2.3.4.

4.3.5 Utilities Exemption 2006 (No1) made under the Utilities Act 2000 (Southern Supply Project)

This TransGrid licence exemption imposes a direct obligation on TransGrid to comply with Network Service Criteria set out in the exemption document. This includes an obligation to build a second 132 kV supply point into the ACT. While this obligation directly applies to TransGrid, utilisation of the supply point capacity requires ActewAGL Distribution to develop and connect 132 kV lines to the supply point.

TransGrid and ActewAGL Distribution considered two options for supply and applied the Regulatory Test to these options. The final project design (option 1), was found to best satisfy the regulatory test by having the lowest present worth of costs in all cases, and completes the project in two stages in line with the Network Service Criteria. This project is discussed in more detail in chapter 7 and forecast costs are included in Table 2 of pro forma 2.3.4, and in pro forma 2.2.3.

Impacts on expenditure programs

ActewAGL Distribution's cost for the Southern Supply Project are discussed in more detail in Chapter 7 on forecast capital expenditure. This forecast expenditure is reproduced below in Table 4.3.

Table 4.3 Forecast costs for Southern Supply 132 kV lines program

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	**Total**
Forecast costs for Southern Supply project	14.2	0.0	3.9	4.4	0.0	**22.5**

4.3.6 Utilities (Network Facilities) Tax Act 2006

From January 2007, ActewAGL Distribution must pay a yearly Utilities Network Facilities Tax to the ACT government, under the *Utilities (Network Facilities) Act 2006*. The tax rate is set by the responsible Minister under the *Tax Administration Act 1999* (ACT), and the final tax amount is calculated as the determined rate multiplied by route length.

As this tax was introduced during the 2004–09 regulatory period, tax amounts have been recovered as a pass through.

Impacts on expenditure programs

There is some potential volatility in these tax amounts, as the rate is set by the ACT Government each year and is therefore subject to change. ActewAGL Distribution has included the expected costs of this tax in its forecast operating expenditure, based on the growth in UNFT revenue assumed by the ACT Government in the 2008/09 budget forward estimates. ActewAGL Distribution's forecast costs are outlined in Table 4.4 below, as well as pro forma 2.2.2 and Table 2 of pro forma 2.3.4.

ActewAGL Distribution also proposes that an annual adjustment mechanism be introduced to allow adjustments in revenue associated with the actual value of this tax from year to year throughout the 2009–14 regulatory period.

Table 4.4 Forecast costs for Utilities (Network Facilities) Tax

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	**Total**
Forecast costs for UNFT	4.0	4.1	4.2	4.3	4.4	**20.9**

4.3.7 Renewable energy feed-in tariff

The ACT Legislative Assembly is considering a private member's Bill entitled *Electricity Feed-in (Renewable Energy Premium) Bill 2008*.

This Bill relates to the connection of renewable energy generators to the distribution network, and the payment of a feed-in tariff for energy supplied by the generator. The potential introduction of a feed-in tariff was subject to an ACT Government Discussion Paper in December 2007, to which ActewAGL provided a submission.

Section 6 of the Bill requires distribution businesses licensed in the ACT to connect renewable energy distributors to the network, and to buy the electricity supplied to the network. The premium tariff applies to the gross energy output of generators. Renewable energy generators are paid for the total amount of electricity supplied to the network:

- at 100 per cent the premium rate for generators with a total capacity of less than 10kWh;
- at 80 per cent of the premium rate for generators with a total capacity of more than 10kWh but less than 30kWh; and

- at 75 per cent of the premium rate for generators with a total capacity of more than 30kWh.

This is defined as a Utility Service under the *Utilities Act 2000* (ACT).

Section 8 requires the distribution business to determine the standards that apply in relation to renewable energy generators that may be connected to the network and to publish those standards in a daily newspaper circulated in the ACT, as well as making copies of the standard available for public inspection during office hours that the distributor's premises.

The premium rate is determined by the responsible minister each year under section 9 of the Bill. This determination is a disallowable instrument. In making the determination, the responsible minister must give priority to:

- the need to encourage generation of electricity from renewable sources;
- the need to reduce emissions from greenhouse gases; and
- the desirability of customers being able to recoup the investment on renewable energy generators within a reasonable period of time.

In addition, the responsible minister must have regard to the following in making a determination:

- the distributor's costs in making payments under the Act; and
- anything else the Minister considers relevant.

Until a determination is made, the premium rate is set at 3.88 times the highest retail price for electricity for a domestic customer on the day the Act commences.

Section 10 requires that the rate determined as applicable in the financial year in which the renewable energy generator is connected is to apply for 20 years in relation to the energy supplied to the network, if the generator remains connected (excluding temporary disconnections for repair, maintenance and the like).

Section 14 of the Bill inserts a new section into the *Independent Competition and Regulatory Commission Act 1997* to allow the ICRC to direct that any increase in the price of electricity attributable to the cost of renewable energy feed-in is applied to customers in proportion to the amount of electricity used by each customer.

The Explanatory Statement accompanying the Bill intends that the feed-in tariff enable a capital investment in renewable energy generation to be recouped within a 10-year period.

Impacts on expenditure programs

The *Electricity Feed-in (Renewable Energy Premium) Bill 2008* is expected to be debated after the lodgement of this regulatory proposal.

Given this uncertainty and the need for clarity as to the final arrangements that would apply, ActewAGL Distribution has not been able to forecast its expected costs under this scheme.

ActewAGL Distribution therefore considers that any future application of a renewable energy feed-in tariff in the ACT should be treated as a transitional period pass through event or a regulatory change pass through event, depending on the timing of the new obligation. Proposed pass through events are discussed further in chapter 16 of this regulatory proposal.

4.3.8 Changes to the Regulatory Test

The current regulatory test that applies to distribution network augmentations is being considered as part of the MCE's review of distribution and retail regulation. Given the changes that have been proposed by the AEMC in relation to the regulatory test applying to transmission investment, ActewAGL Distribution considers it probable that the form of the regulatory test and the circumstances in which ActewAGL Distribution is required to apply the test may change during the 2009–14 regulatory period.

ActewAGL Distribution considers that any additional expenditure that arises as a result of complying with a revised form or scope of the regulatory test should be treated as a transitional period pass through event or a regulatory change pass through event, depending on the timing of the revision.

4.3.9 MCE non-economic distribution and retail framework

The MCE phase two non-economic distribution and retail framework legislation is expected to be introduced into the South Australian Parliament by 30 September 2009. Associated rules, codes, guidelines and contracts are expected to be finalised after this date.

Since these changes are expected in the 2009–14 regulatory period and are very difficult to predict at this stage of the consultation process, ActewAGL Distribution proposes that they be treated as a transitional period pass through event or a regulatory change pass through event depending on the timing of the new legislation.

4.3.10 MCE smart meter decision

The MCE is currently considering a Regulatory Impact Statement (RIS) on a mandatory roll out of smart meters. This RIS is based on the outcomes of a cost benefit analysis undertaken in 2007/08, which concluded that a mandated distributor-led roll out of smart meters offered the lowest net costs of the metering options investigated.

There is currently significant uncertainty over costs that may be associated with any smart meter policy decision. ActewAGL Distribution therefore considers that any policy decision in relation to smart meters be considered as a pass through event. Details of this decision and ActewAGL Distribution’s proposed approach are outlined in more detail in chapter 15 on Alternative control services. Proposed pass through events are discussed further in chapter 16 of this regulatory proposal.

4.3.11 ARPANSA standard on exposure to electric and magnetic fields

The Australian Radiation Protection and Nuclear Safety Agency (ARPANSA) released a draft Standard and Regulatory Impact Statement in late 2006 entitled *Radiation Protection Standard: Maximum Exposure Levels to Electric and Magnetic Fields 0 Hz – 3 kHz*. The draft

Standard set very stringent controls on Electric and Magnetic Fields (EMF). The electricity transmission and distribution sectors estimated that the standard, if implemented as proposed in the draft, would cost the sector approximately $3 billion to implement.

In response to stakeholder comments on the draft standard, ARPANSA is considering reviewing proposed levels of exposure to EMF. A new draft of the standard is expected mid 2008, with the standard finalised by the end of 2008. The measures required to comply with the standard could range from fencing and warning signage for assets to extensive undergrounding of assets.

Given the potentially very high and uncertain cost impacts of this standard, as well as its timing, ActewAGL Distribution proposes that it be treated as a transitional period pass through or a regulatory change event pass through, depending on the timing for the implementation of the new Standard.

4.3.12 New national carbon emissions trading scheme or other carbon abatement measures

The Australian Government is currently consulting on the implementation of a national emissions trading scheme to commence no later than 2010. An emissions trading scheme could potentially lead to increased costs for ActewAGL Distribution through both carbon costs of operations, including line losses, and the potential for increased carbon accounting and reporting obligations.

ActewAGL Distribution considers that any expenditure arising from the introduction of an emissions trading scheme should be treated as a transitional period pass through event or a regulatory change pass through event depending on the timing of the scheme.

4.3.13 Anticipated Workplace Safety Bill 2008 (ACT)

ActewAGL Distribution expects the enactment of the *Workplace Safety Bill,* likely to be passed later in 2008, which will replace the current *Occupational Health and Safety Act 1989.* Unfortunately, an exposure draft of this Act (including an exact title) was not available prior to the due date for this regulatory proposal.

ActewAGL Distribution expects that the proposed Bill, if enacted, will impose additional obligations specific to construction sites across all industries, including the utilities industry, affecting ActewAGL Distribution’s capital works and maintenance programs leading to a significant cost impact on these programs. It is not possible at this stage to estimate these costs as the ACT Government has yet to release an exposure draft of the new Bill. ActewAGL Distribution considers that any expenditure required to comply with a new Act should be treated as a pass through, either as a transitional period pass through event or a regulatory change pass through event, depending on the timing of the new Act.

5. Energy and demand forecasts

The need to meet or manage expected demand for standard control services is one of the *expenditure objectives* that the AER must consider in assessing a DNSP's regulatory proposal.[45] The transitional *Rules* require the AER to accept the expenditure forecasts for the regulatory period if it is satisfied that they reasonably reflect the expenditure criteria, which include, among other things, 'a realistic expectation of the demand forecast'.

Section 2.3.8 of the RIN sets out the information the AER has deemed necessary to assess ActewAGL Distribution's demand and energy forecasts and fulfil its obligations under the transitional *Rules*. ActewAGL Distribution provides the required forecasts, explanations and supporting documentation in this chapter, pro forma 2.3.8 and attachments 4 and 5 to this regulatory proposal. An explanation of how the demand forecast is used to derive capital expenditure forecasts is provided in chapter 6.

5.1 Forecasting methodology

ActewAGL Distribution engaged consultants Sinclair Knight Merz (SKM) to prepare an independent demand and energy forecast for the ACT electricity network. SKM's report, *ActewAGL Demand and Energy Forecast 2008*, and accompanying Excel Model, are provided as attachments 4 and 5 to this regulatory proposal. The SKM report provides a detailed description of the key assumptions, inputs and models used in determining the demand and energy forecasts.

SKM's demand forecasting methodology adhered to International Good Practice (IGP)[46] wherever the necessary data was available, and involved:

- a review of the variation between the 2003 forecasts and actual demand and energy consumption;
- an investigation of key drivers of energy consumption and demand in the ACT; and
- the production of system wide energy consumption, system wide demand and zone substation demand forecasts using dynamic econometric and trend modelling techniques.

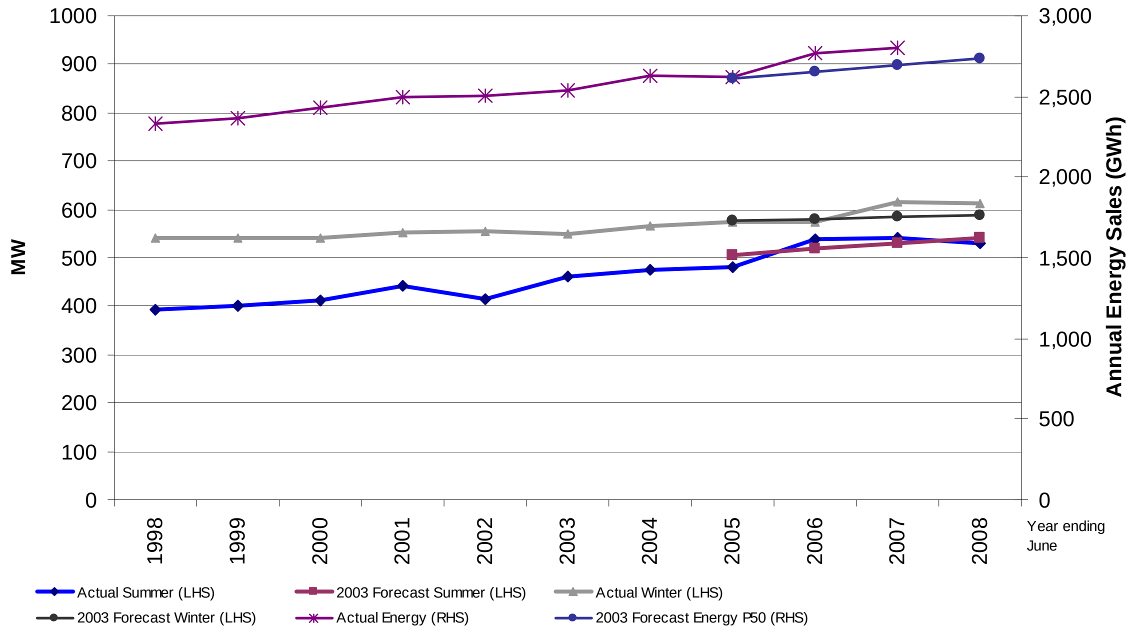
5.1.1 Review of previous forecast

ActewAGL Distribution's previous demand and energy forecasts were prepared for its 2004–09 regulatory proposal to the Independent Competition and Regulatory Commission (ICRC). The ICRC's consultants, McLennan Magasanik Associates (MMA), proposed lower demand forecasts than those proposed by ActewAGL Distribution. The ICRC subsequently approved ActewAGL Distribution's forecasts.

[45] Transitional *Rules* clauses 6.5.6 and 6.5.7.
[46] The elements of IGP are set out in SKM's report, at attachment 4.

The previous forecasts were prepared in 2003. For the first 3 years of the forecast period, including the first year of the current regulatory period, actual energy consumption and demand (both summer and winter) closely tracked the forecasts, as illustrated in Figure 5.1. However, since 2005/06 actual energy consumption and winter demand have exceeded the forecasts. Summer demand also exceeded the forecast in 2005/06 and 2006/07, although it has fallen below the forecast in 2007/08.

Figure 5.1 Comparison of previous forecast with actual



Note: From 2004/05, the actual load shown uses the figures generated from ActewAGL Distribution's accounting system. For modelling purposes, the data series used was one that reconciled the meter readings to the energy purchases on a monthly basis.

SKM analysed the differences between the forecasts and actuals and concluded that weather effects accounted for a significant proportion of the underestimate. SKM identified the other causes for differences between forecast and actual demand and consumption as:

- stronger than expected growth in the commercial sector; and
- increasing penetration of domestic reverse cycle air conditioners, which has an impact on summer peak demand.

SKM reviewed growth in the residential and commercial segments of the market and found that while residential growth was close to the forecast, actual commercial consumption significantly exceeded the forecast. Commercial sales increased by 2.0 per cent in 2004/05, and then increased sharply in the following two years – by 5.0 per cent in 2005/06 and 5.1 per cent in 2006/07.

From its analysis, SKM concluded that the accuracy of forecasts could be significantly improved by:

- using temperature correlation to correct historical data for weather variations;
- employing a number of econometric variables such as population, economic activity, price and substitute fuels to better predict future trend growth;
- separating one off major developments from underlying growth, particularly at the spatial (zone substation) level where a large development can have an impact equal to several years growth. Removing these "spot loads" from the underlying growth gives a better understanding of the underlying growth.[47]

SKM has implemented these findings in the 2009–14 forecasts it has produced for ActewAGL Distribution.

5.1.2 Drivers of energy and demand growth

In developing the method of forecasting, the key variables or *drivers* affecting energy consumption and demand growth in the ACT were identified by SKM and projected over the forecast period.

Economic activity

There is a positive relationship between economic activity and energy consumption. Growth in the output of electricity intensive industries influences commercial electricity sales. Growth in per capita incomes influences residential electricity sales.

The ACT is not heavily involved in the energy intensive mining, industrial, manufacturing or agricultural sectors. Therefore economic development and growth in the demand for energy within the ACT will be driven more broadly by factors generally affecting Gross State Product. State Final Demand (SFD) is an important measure of economic activity, providing an estimate of the level of spending in the local economy by the private and public sectors. As illustrated in Table 5.1, growth in SFD for the ACT was 1.7 per cent over 2007.

[47] The tendency is to overestimate spot loads in the short term, when there is knowledge of many potential developments, and underestimate in the longer term, when potential developments may not be known to planners.

Table 5.1 Quarterly and annual trend movement in state final demand

	Change since previous quarter(%)	Change over year ending Dec 2007(%)
New South Wales	1.0	4.6
Victoria	1.4	4.7
Queensland	1.1	6.6
South Australia	0.3	1.8
Western Australia	1.2	9.5
Tasmania	1.6	6.7
Northern Territory	0.9	2.5
Australian Capital Territory	0.2	1.7
Australia	**1.1**	**5.3**

Source: ABS Cat No 5206.0

The average weekly ordinary time earning (AWOTE)[48] within the ACT over the period 1983 to 2007 has increased by 4.8 per cent per annum. Household disposable income in the ACT has grown on average by approximately 5 per cent annually since 1990.

Demographics

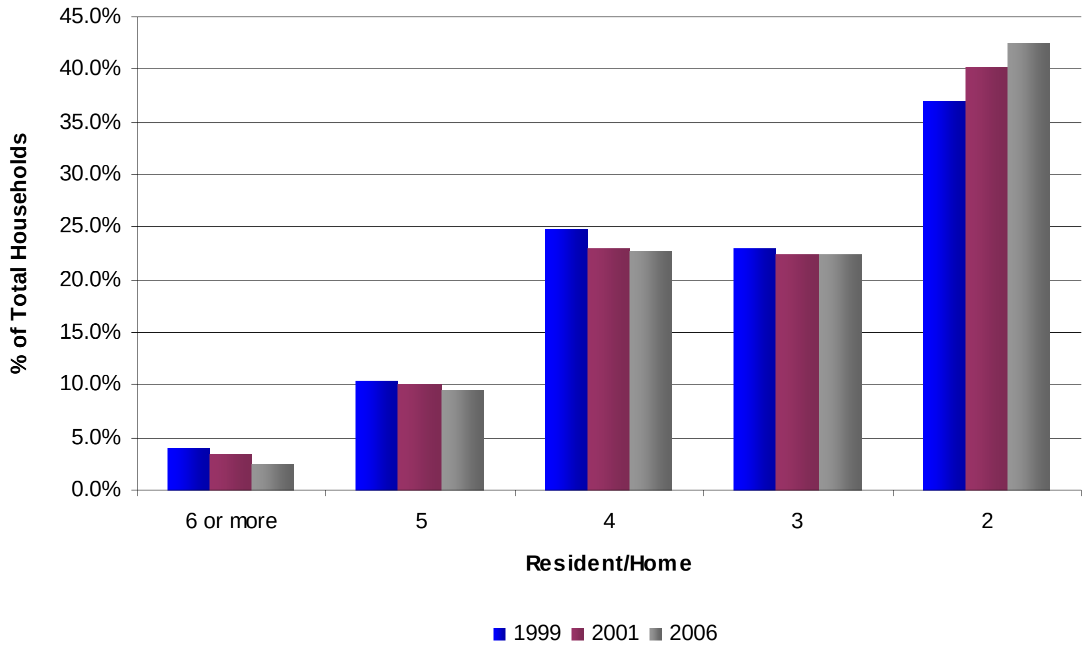
Population growth has a positive relationship with growth in electricity consumption. The ACT's population is growing, although the growth rate has slowed, with lower than average birth rates only partly offset by in-migration. There is a trend in the ACT towards smaller households as illustrated in Figure 5.2.

The trend toward fewer residents per home, together with the shift to gas heating and more efficient electricity appliances, means that average household consumption is declining. Total residential energy consumption has declined since 1994/95 despite a 21 per cent increase in the number of residential customers.[49]

On the other hand, the commercial load has been increasing and has grown from 44.1 per cent of the total ACT load in 1994/95 to 59.4 per cent in 2006/07.

[48] Using adult male, corresponding quarter, seasonally adjusted data in order to minimise influences due to changing social trends.
[49] Residential energy consumption was 0.2 per cent lower in 2006/07 than in 2004/05.

Figure 5.2 Trend toward smaller households in ACT[50]



Price

Consumers will respond to changes in prices by managing their energy usage. While precise demand elasticity estimates vary, ActewAGL Distribution's experience with tariff-based demand side management initiatives confirms a demand response (discussed further in chapter 13).

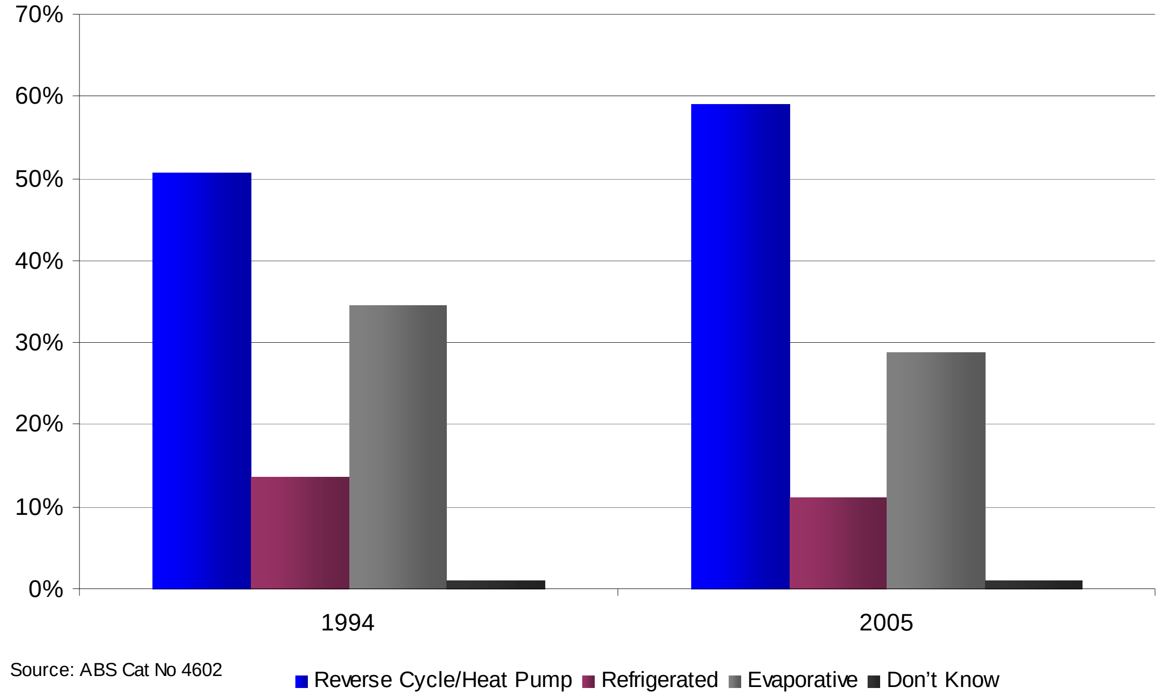
Domestic air conditioner penetration

There is a distinct trend in the ACT toward the installation of domestic reverse cycle air conditioning systems as shown in Figure 5.3. Between 1994 and 2005, the proportion of dwellings with reverse cycle air conditioners or heat pumps as their main cooler has increased from 51 per cent to 59 per cent.

This trend is consistent with the observed growth of summer demand. The combination of higher summer demand growth and slower winter demand growth has meant that the summer maximum demand may exceed the winter maximum demand in some years during the 2009–14 regulatory period.

[50] ABS Cat. No. 2068.0 - 2006 Census Tables

Figure 5.3 Coolers in dwellings, ACT

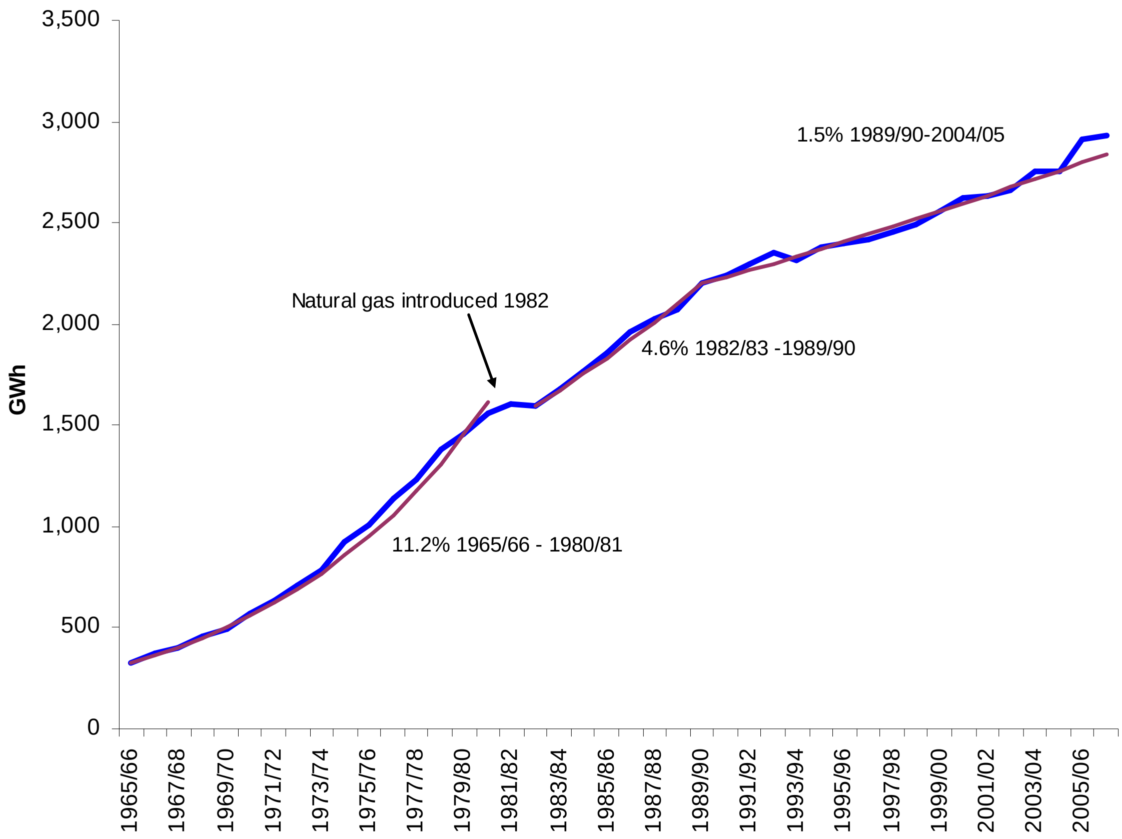


Impacts of other fuels[51]

The market share of natural gas a source of residential energy has increased significantly in Australia over the past twenty years. Market share has increased from 23.9 per cent in 1983/84 to 31.2 per cent in 2003/04. A similar trend is noticeable in the ACT. Not only has natural gas consumption increased by over 25 per cent in the past 10 years[52], the demand for electricity in the ACT has been influenced by the availability of natural gas. As shown in Figure 5.4, the annual growth in electricity sales in the ACT has been slowing significantly.

Figure 5.4 Electricity sales 1965/66 to 2005/06 in the ACT

[51] SKM has used the step change in marketing of gas as a fuel from 2000 when ACTEW became a dual-fuel supplier with AGL.
[52] ActewAGL internal sales statistics



5.2 Demand forecasts

ActewAGL Distribution's system demand forecasts are shown in Table 5.2. For both summer and winter demand three cases are presented: PoE90, PoE50 and PoE10.[53] Shaded cells show the peak (summer or winter) for each scenario.

Summer demand is expected to continue to grow more strongly than winter demand, and at PoE10, Canberra is expected to transition from a winter peaking load to a summer peaking load in 2009/10. The increasing summer demand is consistent with the forecast higher energy growth in the commercial sector (discussed in section 5.3). Continuing growth in the air conditioning load is also driving the summer demand trend.

Summer demand growth is expected to continue to progressively expose the network to capacity constraints in selected areas due to the fact that the rating of network equipment is often lower in summer than in winter.

[53] PoE refers to *probability of exceedance*. For example, PoE10 means 10 per cent probability of exceedance, or that the load would exceed the forecast once in every ten years. Similarly PoE50 means that the forecast will be exceeded every second year.

Table 5.2 Forecast system demand (MVA) 2007–14

MVA	Summer			Winter		
Year	POE90	POE50	POE10	POE90	POE50	POE10
2007/08	567	616	669	**648**	**667**	**679**
2008/09	576	626	681	**652**	**671**	**683**
2009/10	587	638	**694**	**659**	**678**	690
2010/11	598	651	**708**	**666**	**685**	698
2011/12	610	663	**721**	**673**	**692**	705
2012/13	621	675	**734**	**678**	**698**	711
2013/14	631	687	**748**	**685**	**705**	718

Table 5.3 and Table 5.4 contain ActewAGL Distribution's forecasts for the maximum demand of each zone substation for summer and winter respectively. Figures are PoE10, base case forecasts, with shaded cells indicating which season (summer or winter) is the peak for that zone. The zone substation demand forecast has taken into account the effect of inter-zone substation load transfers following major zone substation augmentations that are proposed for the 2009–14 regulatory period.

The zone substation demand forecasts are key drivers of the capital expenditure program (following the planning processes described in chapter 6). The geographical distribution of load growth, reflected in the zone substation forecasts, is more relevant to the capital expenditure program than are the system wide demand forecasts.

Table 5.3 Zone substation summer maximum demand forecast (MVA) 2007–14

MVA	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Belconnen	**59**	**60**	**60**	**60**	**60**	**61**	**61**
City East	**88**	**87**	**86**	**87**	**88**	**90**	**91**
Civic	**63**	**63**	**64**	**65**	**67**	**69**	**71**
Fyshwick	**37**	**39**	**42**	**45**	**45**	**45**	**44**
Gilmore	18	19	20	21	22	22	22
Gold Creek	29	33	36	40	43	48	53
Latham	52	54	57	58	59	61	62
Telopea Park	**100**	**100**	**100**	**100**	**100**	**98**	**97**
Theodore	24	24	24	25	25	25	26
Wanniassa	73	73	74	74	76	77	79
Woden	82	84	86	88	90	92	94

Table 5.4 Zone substation winter maximum demand forecast (MVA) 2007–14

MVA	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Belconnen	58	58	58	57	57	57	58
City East	75	73	72	71	72	73	73
Civic	57	58	58	59	60	62	64
Fyshwick	35	37	40	43	44	43	42
Gilmore	**27**	**28**	**28**	**29**	**29**	**30**	**30**
Gold Creek	**35**	**38**	**41**	**44**	**47**	**50**	**54**
Latham	**74**	**75**	**76**	**76**	**77**	**77**	**77**
Telopea Park	94	94	94	94	93	91	89
Theodore	**32**	**32**	**32**	**32**	**31**	**31**	**31**
Wanniassa	**94**	**94**	**93**	**93**	**94**	**95**	**96**
Woden	**87**	**87**	**89**	**91**	**92**	**93**	**95**

5.3 Energy forecast

ActewAGL Distribution’s energy consumption forecasts for weather adjusted base (or average), low and high economic growth scenarios are shown in Table 5.5.

ActewAGL Distribution has used the base growth projection to calculate its proposed average revenue requirement. Growth in energy consumption is forecast to average 1.6 per cent per annum over the 2009–14 regulatory period under the base growth projection.

Forecasts were prepared for the residential, residential off-peak and commercial loads as these sources of demand have different drivers. The main driver for the residential load (excluding off-peak) is the growth in the number of households (1.3 per cent per annum over the regulatory period). Annual growth of 0.9 per cent is forecast for the un-controlled residential load. The main drivers for the residential off-peak (controlled load) are the growth in the number of households as well as the number of years that ActewAGL Retail has been offering dual fuel (gas and electricity). Residential off-peak (controlled load) energy is forecast to decline 4.7 per cent per annum over the regulatory period. When these two residential loads are combined, the net growth rate for residential consumption is, on average, 0.4 per cent per annum over the regulatory period.

State final demand and population growth were found to be the most significant drivers of growth in the commercial load. The commercial load is forecast to grow at 2.4 per cent per annum on average over the regulatory period.

The sectoral energy forecasts were aggregated to determine the total energy forecast. A separate top down forecast was prepared to check the validity of the bottom up approach. The top down approach produced an outcome that was within 1 per cent of the bottom up approach. This confirms the validity of the bottom up approach. The bottom up approach was preferred to the top down approach as it allowed the residential and commercial loads to be forecast using the drivers that were directly relevant to each. Also, it provides a specification of residential and commercial consumption.

Table 5.5 System consumption forecast for base, high, and low economic projections

Year	Base (GWh)	High (GWh)	Low (GWh)
2007/08	2,802	2,807	2,796
2008/09	2,835	2,865	2,816
2009/10	2,878	2,940	2,839
2010/11	2,925	3,006	2,869
2011/12	2,972	3,076	2,897
2012/13	3,018	3,145	2,924
2013/14	3,066	3,220	2,948

Section 2.3.8 of the RIN requires an explanation of how the demand forecast has been used to develop the RNSP's capital expenditure and operating expenditure forecasts. Demand growth can have an impact on operating expenditure in a number of ways. However, determining the strength of the relationship is difficult to do with precision. The reasons for this are explained in chapter 8. There is, however, a relationship between demand forecasts and ActewAGL Distribution's planned capital augmentation programs. Supply capacity is maintained and improved through augmentation of electricity networks, equipment upgrades and replacement. At the zone substation level, the demand forecast is used to project zone substation load increases. This forecast then feeds into capital investment plans for zone substation and sub-transmission network augmentations. The relationship between augmentation capital expenditure forecasting and demand forecasting (particularly at the zone substation level) is discussed further in chapter 6 of this proposal.

6. Network planning and management

ActewAGL Distribution's network planning and asset management policies, plans and procedures provide the framework for ensuring that the regulatory obligations and customer requirements, as discussed in the previous chapters, are met in the most prudent and efficient way. ActewAGL Distribution's approach to network planning and asset management is based on sound and up-to-date network engineering and management practices and the application of good electricity industry practice as required under Chapter 5 of the *National Electricity Rules* (*NER*). It is also heavily influenced by practical experience in the operation of the ACT electricity network.

The key components of ActewAGL Distribution's network planning and asset management framework are the Network Ten Year Augmentation Plan, the Ten Year Customer Initiated Capital Investment Plan, the Asset Management Plan, the Technology and Information Management Strategy, and the Metering Asset Management Plan. These Plans contain long-term investment and asset management objectives and strategies, as well as criteria and procedures for identifying and assessing options and trade-offs.

The Plans provide the framework within which ActewAGL Distribution assesses the relative merit of capital and operating expenditure, asset replacement and management, and the appropriateness of network development, augmentation and demand management strategies to meet regulatory obligations and demand. ActewAGL Distribution's regulatory obligations and forecast demand are key inputs into each of the Plans. The Plans also reference subordinate plans, procedures and standards. The specific capital and operating expenditure programs presented in chapters 7 and 8 are the outcomes of these assessments.

To guide its assessment of forecast expenditure against the operating and capital expenditure objectives and criteria set out in clauses 6.5.6 and 6.5.7 of the transitional *Rules*, the AER requires the DNSP's regulatory proposal to contain details of its approach to network planning and management. The RIN (section 2.3.7) requires:

1. details about network performance and/or utilisation and comparison with targeted levels;
2. an explanation of the approach to network planning, investment evaluation and operating and maintenance expenditure decision making;
3. copies of the key documents used to plan the *RNSP*'s system and develop capital and operating expenditure forecasts;
4. an explanation of how the key documents support the capital and operating expenditure forecasts and relate to each other;
5. an explanation of the historic network capacity or performance levels and their impact on service levels at key points in the network;

6. an explanation of the target capacity or performance levels and how these meet external and internal performance standards;
7. an explanation of how network capacity in the *current regulatory control period* met actual demand relative to the demand forecasted for each period; and
8. an explanation of how forecast capacity will meet performance standards and forecast demand based on the capital and operating expenditure proposed for the *next regulatory control period*.

ActewAGL Distribution's planning process and the role of key documents (requirements 2 and 4) are explained in section 6.1 below. The remaining sections of this chapter then provide explanations of the key elements of ActewAGL Distribution's network planning and management approach, including the key plans and supporting models. The discussion of network augmentation planning includes an explanation of how historic and forecast network capacity has, and is expected to, meet demand and performance requirements and other regulatory requirements in the current and future regulatory periods (requirements 5 to 8). Details on expected demand are provided in chapter 5. Details on ActewAGL Distribution's network performance compared with targeted levels (requirement 1) are provided in chapter 3 of this regulatory proposal. Further supporting information is provided in the attached network planning and management pro forma (pro forma 2.3.7).

6.1 The planning process and key documents

Planning, developing and managing an electricity distribution network to meet regulatory obligations is a complex task. The decision to maintain, install, augment, replace or refurbish a particular asset is undertaken within a robust network planning framework which in turn must be flexible enough to encompass all existing and new regulatory obligations. Obligations are derived from such instruments as the *Electricity Distribution (Supply Standards) Code 2000*, which requires ActewAGL Distribution maintain sufficient network capacity to meet customer demand (clause 8.1). The *Supply Standards Code* also requires ActewAGL Distribution to maintain the network within specified technical limits for power quality (clause 5). There are also requirements under Chapter 5 of the *NER* with respect to network planning, reliability and power quality.

6.1.1 Network planning process

Electricity supply reliability, quality and system security is managed through effective network planning that includes network development and augmentation, equipment upgrades, asset replacement, repairs and maintenance. As the detailed discussion in the following sections demonstrates, many related components contribute to ActewAGL Distribution's planning processes and outcomes. ActewAGL Distribution's broad approach to network planning and management is summarised in Figure 6.1.

ActewAGL Distribution utilises an integrated network planning and performance management process. Networks Division is a primary part of ActewAGL Distribution with responsibility for the management and operations of the distribution system. The Networks Business Plan supports the Corporate Business Plan and is part of ActewAGL Distribution's annual planning cycle. The Networks Business Plan sets the overarching goals and targets that are necessary for the implementation of longer term plans and projects for the coming financial year, and includes human resources management, business processes and stakeholder management.

The Networks Business Plan is finalised at the conclusion of the planning and budgeting process and communicated to relevant ActewAGL Distribution personnel in time for identified priorities to be implemented in the coming financial year. Priorities under the Network Business Plan are set with reference to the risk management processes. The key targets of the Networks Business Plan are reflected in the Personal Performance Plans of the respective Branch Managers and other key personnel together with appropriate performance targets derived from relevant planning documents.

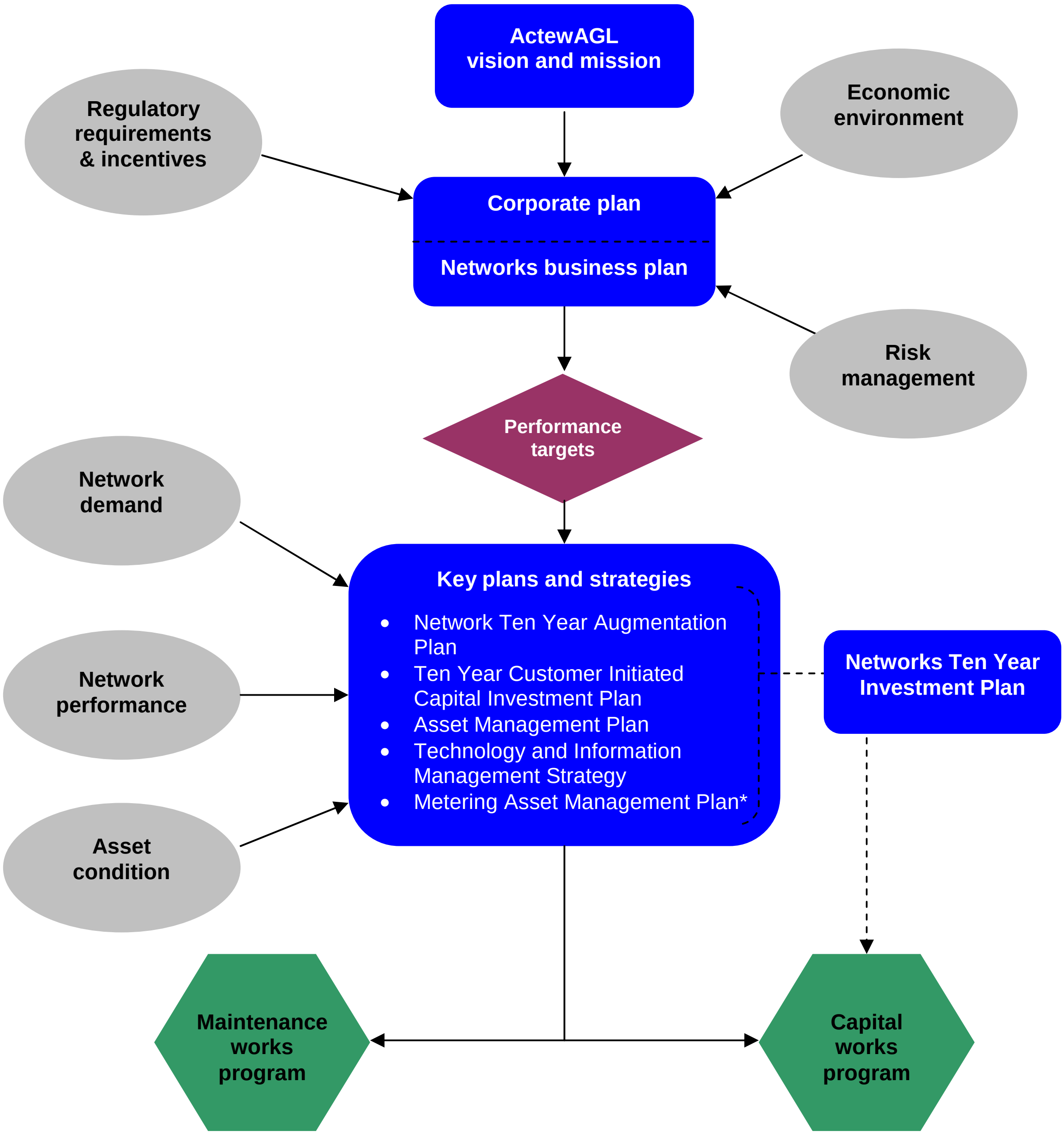
6.1.2 Key network planning documents

ActewAGL Distribution's key long-term planning documents are entitled:

- Network Ten Year Augmentation Plan (the Augmentation Plan);
- Ten Year Customer Initiated Capital Investment Plan (the Customer Initiated Plan);
- Asset Management Plan (the AMP);
- Technology and Information Management Strategy (the IT Strategy); and
- Metering Asset Management Plan (the MAMP).

These documents are also listed and described in the attached pro forma 2.3.6.

Figure 6.1 Overview of ActewAGL Distribution's network planning and management approach



*Note: *Alternative Control Services* is discussed separately in chapter 15.

The AMP, the IT Strategy and the MAMP include both capital and operating expenditure projects. The Augmentation Plan and the Customer Initiated Plan only consist of capital expenditure projects.

To assist in capital expenditure planning, capital expenditure components of all of these plans are incorporated into the Networks Ten Year Investment Plan (the Investment Plan). The Investment Plan is supported by other more specific and detailed planning and underlying analytical studies and project justifications. It also includes a comparison of actual expenditure and capital expenditure the ICRC had forecast to be prudent and efficient at the previous price review.

Forward projections are reviewed and amended each year, ensuring that the key planning documents remain current. Each of the key planning documents containing ten-year work plans and programs are also reviewed each year, allowing the projects identified through the longer term planning process to be prioritised with respect to current network conditions. This ensures that expenditure is prudent and efficient because it is consistent with the latest information on network performance, load demand and asset management developments.

Careful consideration is given to the timing of expenditures with respect to the overall business drivers, cash flow and availability of resources. This ensures that project timings are prudent, with less critical expenditures being deferred until the later years of the ten-year forecasts, allowing effective short term trade-offs between capital and operating expenditure (further discussed in section 6.7), within the longer term planning process.

All the key planning documents are developed with references to a number of policies and procedures. The plans for the 2009–14 regulatory period were developed with the aid of models including:

- Pole Asset Replacement / Refurbishment Model (the Pole Model);
- Network Assets Replacement / Refurbishment Model (the Network Model); and,
- Network Capex / Opex Trade-off Model (the Trade-off Model).

6.2 Network Ten Year Augmentation Plan

A key element of ActewAGL Distribution's network planning and management approach is the Augmentation Plan. This Plan is reviewed and updated annually. The primary objective of the Augmentation Plan is to provide network augmentation strategies and programs based on the current network capabilities and performance, projected load growth, performance improvement requirements and regulatory compliance requirements. Relevant aspects of this Plan are developed in consultation with TransGrid, as the designated Transmission Network Service Provider.

The Augmentation Plan is developed to ensure:

- adequate network capacity for anticipated load;

- supply reliability and quality;
- operational effectiveness and efficiency; and
- safety, environment and regulatory compliance.

6.2.1 Augmentation planning inputs

The starting point for the Augmentation Plan is a detailed review and analysis of network capacity and demand. Historical trends are reviewed and forecasts are prepared for system level demand (primarily to meet National Electricity Market (NEM) requirements) and zone substation demand, as discussed in chapter 5 of this regulatory proposal. Emerging network constraints are then identified through the application of the planning criteria, and options to address the constraints (while meeting all obligations) are assessed.

A review of the performance of the network in meeting external and internal targets and regulatory obligations (as discussed in chapters 3 and 4) is a further critical input into the network planning and management process. Network performance covers supply reliability (for example, outage duration), supply quality (for example, voltage level) and regulatory compliance matters (for example, power factor).

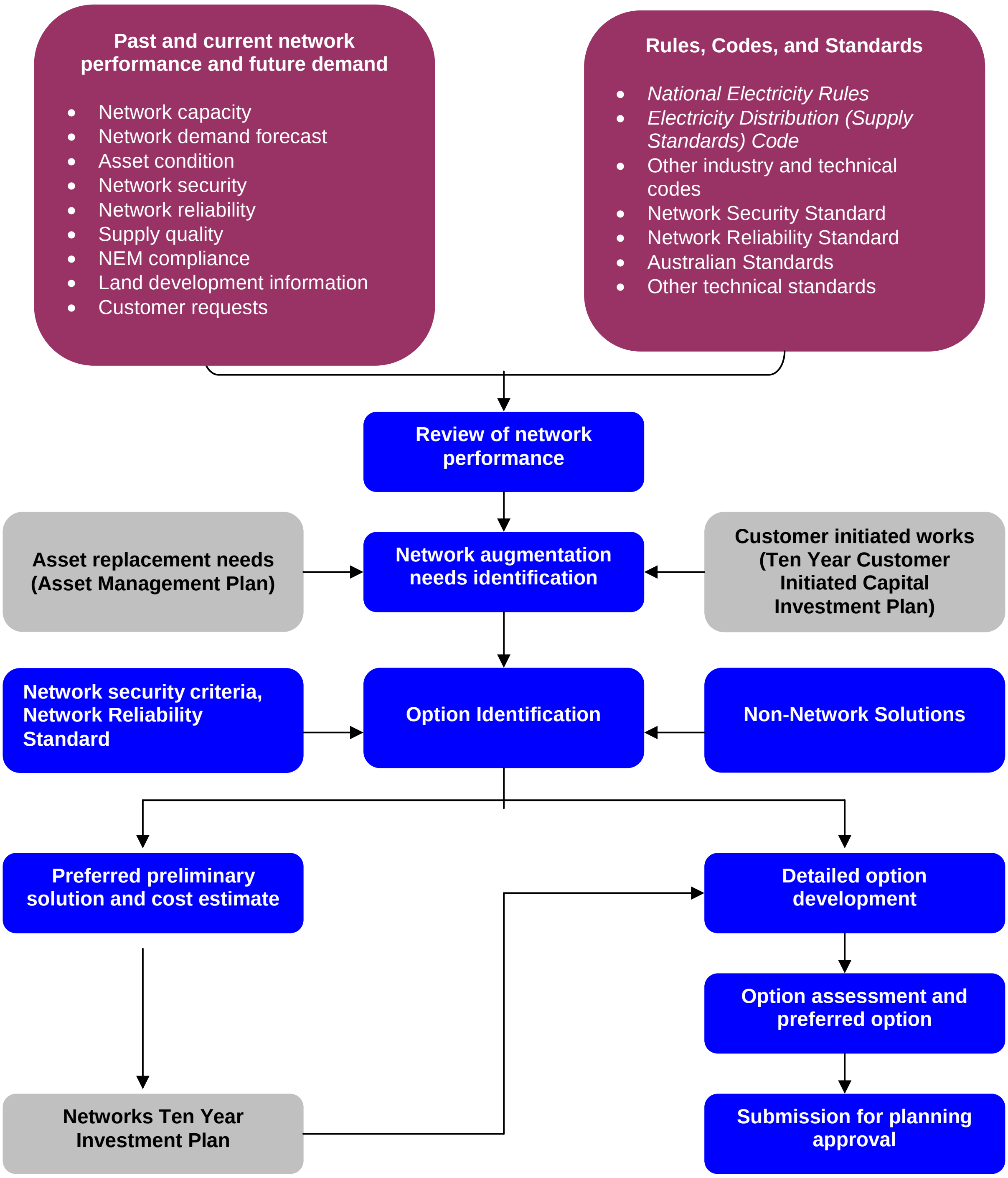
Figure 6.2 depicts the network augmentation process. The Augmentation Plan involves application of the network security criteria and network supply and reliability standards documented in the relevant internal ActewAGL Distribution procedures. The augmentation needs identified through the review of demand and network performance are considered in the context of the needs identified in the Customer Initiated Plan and the AMP. The overall investment plan is reviewed and prioritised in a coordinated manner with the prudency and efficiency objectives in mind.

The identification of potential augmentation needs is followed by a process of considering and evaluating options including non-network alternatives. A general review and consideration of options is conducted at the time of the ten-year plan preparation. Further assessment of options for specific projects is conducted closer to the proposed project implementation date, prior to obtaining planning and financial approvals. This is a two-stage process.

- Stage 1—the basic options are considered and the “most likely option” included in the Investment Plan.
- Stage 2—the project and the options are subject to further consideration on the basis of the updated data closer to the implementation date. Before the project is submitted for approval, detailed assessment of options is conducted. The consideration of options in Stage 2 includes consideration of non-network solutions further discussed below.

In addition, all large distribution projects are subject to the *Regulatory Test* process, which provides opportunities for parties external to ActewAGL Distribution to propose alternative solutions including non-network options. ActewAGL Distribution is obliged to consider any options on a non-discriminatory basis as part of the *Regulatory Test*.

Figure 6.2 Network augmentation process



6.2.2 Augmentation criteria

In order to ensure that network augmentation expenditure is prudent, augmentation needs are assessed using a combination of deterministic and probabilistic criteria. This means that while deterministic criteria are used to identify areas where system capacity may be exceeded, a risk assessment is applied in determining the priority and timing of augmentation as a result of exceeding these deterministic planning triggers.

These security criteria are typically an N-1 capacity rating threshold combined with time-based criteria which allow for the capacity to be exceeded for a limited time. ActewAGL Distribution's key security criteria for sub-transmission lines, zone substations and distribution feeders under an N-1 credible network contingency are summarised in Table 6.1.

Table 6.1 Network security criteria for key asset classes

Asset type	Network security criterion
Sub-transmission lines	The load should not exceed continuous rating of the line for more than 1% of the time; and/or The load should not exceed continuous rating of the line by 20% or more
Zone substations	The load should not exceed two-hour emergency rating of the substation
Distribution feeders	The load should not exceed feeder firm capacity* for more than 2% of time; and/or The load should not exceed feeder firm capacity* by 20% or more

* Feeder firm capacity is calculated with a reference to feeder thermal characteristics and network configuration.

The above distribution network security criteria allow ActewAGL Distribution to limit network augmentation expenditure to instances where the increase in demand is clear, and above the secure or firm capacity. The time-related components of the criteria (for example, exceeding secure capacity for one per cent of time) reflect additional risk, which is quantifiable and considered acceptable.

The planning approach outlined above also allows ActewAGL Distribution to identify system constraints and bottlenecks that limit the ability of a particular asset, such as a zone substation, to reach higher capacity ratings. This encourages more prudent and efficient investment to resolve these bottlenecks to allow higher utilisation of significant network infrastructure, where this is the most cost effective option to meet demand. This allows ActewAGL Distribution to increase utilisation of large assets such as zone substations.

Management of asset utilisation is also one of the network planning objectives. Some measures undertaken to improve asset utilisation include:

- setting distribution transformer loading limits up to 130 per cent of the continuous rating;
- setting zone substation transformers two-hour emergency loading limit to around 140 per cent of the continuous rating;

- ceasing the past practice of providing spare distribution transformers in the standard supply arrangement;
- restructuring demand tariffs to encourage reductions in peak load, which in turn improves network capacity utilisation;
- lifting the minimum load power factor from 0.85 to 0.90, which also reduces energy losses; and
- redeploying large under utilised transformers as opportunities arise.

The objectives of management of asset utilisation are balanced against other objectives such as supply security, supply quality, loss reduction and cost-benefit considerations. For example, conductors are sized to maintain supply voltage within the required range, to reduce losses and to meet capacity requirements. In certain circumstances, distribution substations may be sized bigger than that required for the initial load at a marginally increased cost to accommodate load growth and network development and avoid costly substation upgrades in the future.

As outlined in chapter 2, ActewAGL Distribution's zone substation and distribution substation utilisation has been gradually improving in recent years, partly as a result of the growing summer energy consumption, but also as a result of ActewAGL Distribution's network management and demand management strategies.

The details of ActewAGL Distribution's network security criteria are contained in the ActewAGL document *ActewAGL Management System Procedure No: SR 016 Network Supply Security Standard*.

6.2.3 Non-network options and demand management

Non-network options and demand-side management are potential alternatives to network augmentation solutions, and are provided for under the ActewAGL Distribution Management System Procedures *Network Augmentation Investment Criteria* (Procedure No: SR 018), and *Demand Management and Non-Network Solutions* (Procedure No: SR 017). ActewAGL Distribution's approach involves network-wide and project-specific initiatives and measures.

Network-wide initiatives include demand-side management measures and energy-efficiency measures such as electrical loss management.

As noted by the AER in its preliminary positions paper on demand side management,[54] the ICRC found in its 2004 Final Decision that price is the main tool for ActewAGL Distribution to manage demand and promote demand side response. These initiatives are discussed further below, and also in chapter 13.

Project-specific measures are identified and assessed through the augmentation planning process. ActewAGL Distribution's experience is that the opportunities for the project-specific

[54] AER 2007, *Matters relevant to the distribution determinations for ACT and NSW DNSPs for 2009–14, Preliminary Positions*, December.

demand-side management initiatives are usually not as cost effective as system-wide initiatives. For example, the strategies to provide suitable demand related pricing signals have proved to be successful (for discussion see chapter 13). However, the small industrial base in the ACT provides only limited scope for application of embedded generation as an alternative to network augmentation.

Demand management initiatives

As mentioned above, ActewAGL Distribution's approach to demand-side management has focused on developing and offering tariff incentive structures, such as time-of-use tariffs, to signal the higher cost of consumption during periods of high demand. These tariff measures have been successful in encouraging approximately 80 per cent of commercial customers on to time-of-use tariffs, and in some cases to install automated demand management systems.

In addition to time-of-use tariffs, ActewAGL Distribution has implemented a wide range of pricing and other demand management initiatives during the current regulatory period. Key tariff measures introduced by ActewAGL Distribution include:

- the use of kVA rather than kWh based maximum demand tariffs, which provides incentives for customers with poor power factors to improve their power factors and/or reduce demand;
- providing stronger demand related price signals by adjusting the balance between the energy and demand component of tariffs;
- introduction of the capacity tariff;
- continuing to offer several off-peak tariff options; and
- introduction of time-of-use residential Distribution Use of System charges to complement the mandatory introduction of interval meters in the ACT for all new and replacement installations.

In addition to these tariff measures, ActewAGL Distribution's demand management initiatives include the following.

- *Small-scale photovoltaic generation*—ActewAGL Distribution has established business processes and tariffs to facilitate the connection of solar energy generation systems to the network.
- *Embedded generation*—ActewAGL Distribution has developed technical guidelines and business processes, and ICRC approved standard charges to facilitate customer generator installation and connection.
- Power factor correction—ActewAGL Distribution has amended the requirements of the *Service and Installation Rules*. Power factor correction is a way of controlling or limiting the losses on the network.

- *Network loss management*—the process of planning and design of the network includes network losses as one of the considerations. Management of network losses is a requirement stated in ActewAGL Distribution's licence conditions. ActewAGL Distribution periodically or as part of the planning processes reviews open points on the network, to enable the network to be reconfigured to reduce losses. In addition, a special methodology for load balancing between transformers in zone substations, which results in transformer loss reduction, has been developed. ActewAGL Distribution's pricing, power factor and embedded generation measures, discussed above, have also helped to manage network losses. ActewAGL Distribution's network losses are currently at round 4.5 per cent, which is at the lower end of distribution utilities in Australia (esaa 2006/07 performance report). However, ActewAGL Distribution acknowledges that the losses are a function of the load characteristics and the topography of the network. The opportunities for further reductions in ActewAGL's network losses are limited.

ActewAGL Distribution's price-based demand management initiatives are discussed further in chapter 13 of this regulatory proposal.

In February 2008, the AER released a Final Decision *Demand management incentive schemes for the ACT and NSW 2009 distribution determinations*. In accordance with the requirements set out in the Final Decision, ActewAGL Distribution will provide its proposal in relation to the demand management innovation allowance in its annual pricing submission.

6.2.4 Key outcomes from the Network Ten Year Augmentation Plan

The RIN requires explanations of how the current network capacity has met demand in the current period and how forecast capacity will meet demand and performance standards.

The review of network capacity, performance and peak demand (historical and forecast) in the Augmentation Plan leads to the following conclusions about current capacity and future augmentation.

The sub-transmission lines have sufficient capacity to cope with load growth in the foreseeable future under the current operational regime.

Most zone substations have adequate capacity to cope with the current summer and winter peak load. However, demand at five zone substations will exceed their two-hour emergency ratings within ten years. Zone substation demand forecasts are provided in chapter 5. New zone substations and zone substation expansion are required to cope with the demand increase.

The 11kV distribution network has been able to meet the maximum demand in all parts of the network under normal operational conditions. However an increasing number of feeders have reached or exceeded feeder firm ratings in summer. Network capacity augmentations and network reconfigurations will continue to be required to address the distribution network capacity shortage.

Several major sub-transmission augmentation projects will be required over the 2009–14 regulatory period to cater for emerging capacity constraints, new developments, and other regulatory and operational requirements. These projects include:

- South Canberra Substation (capacity constraints);
- Molonglo Valley Substation (capacity constraints/new suburb development); and
- Civic Zone Substation—third transformer (capacity constraints).

In addition, there are several other planned major projects driven by factors other than capacity constraints. These projects are:

- Civic Zone Substation 11 kV switchboard replacement (safety, security, and operational needs); and
- 132 kV line from Southern Bulk Supply Point into the ACT (security of supply concerns and Network Security Criteria introduced by the ACT Government).

More information on the above sub-transmission projects is provided in chapter 7 of this regulatory proposal and in ActewAGL Distribution's Augmentation Plan.

6.3 Ten Year Customer Initiated Capital Investment Plan

The Customer Initiated Plan is a further component of the Investment Plan. The Customer Initiated Plan provides the framework for developing the expenditure forecasts for:

- new urban development;
- urban infill development;
- rural development;
- commercial and industrial development;
- special customer requests;
- community-based development;
- customer initiated asset replacement;
- relocations;
- services; and
- meter installations.[55]

[55] For further discussion of the relationship between Customer Initiated Plan and forecast metering installations see chapter 15 of this regulatory proposal.

The Plan contains separate ten-year plans for each of these categories.

Customer initiated work is driven primarily by residential land development, commercial property development, major commercial/industrial customers, major government initiatives and government planning agencies. Accordingly, the level of capital investment required by ActewAGL Distribution in responding to customer/developer requests is significantly influenced by broader economic factors in particular prevailing interest rates and the release of land by the ACT Government.

The Plan therefore involves a detailed review of forecasts of the key drivers of each category of customer initiated works. The relevant drivers are examined in chapter 7 of this proposal.

The Customer Initiated Plan is also linked to the other Plans within the Investment Plan. For example, flow-on requirements for network augmentation are identified and incorporated into the Augmentation Plan.

6.4 Asset Management Plan

The objective of ActewAGL Distribution's Asset Management Policy is to plan, operate and maintain all elements of the primary power and secondary networks, so as to:

- provide a safe and reliable supply of electricity to consumers
- maintain a safe and healthy working environment for all employees and contractors
- meet or better reliability performance targets
- comply with all relevant codes and regulations
- make sound investment and maintenance decisions which optimise life cycle costs of the assets
- maintain a socially, financially and environmentally sustainable asset performance/risk profile
- deliver outcomes that meet ActewAGL Distribution's objectives of commercial and environmental excellence
- support the achievement of aims and objectives outlined in ActewAGL Distribution's Corporate Business Plan and Networks Business Plan.

ActewAGL Distribution's AMP sets out the detailed plans, strategies and programs required to implement the asset management policy. The AMP also meets the regulatory obligation to ensure that the electricity networks are maintained in accordance with a maintenance plan.[56]

The AMP encompasses asset maintenance and asset replacement strategies and programs, and therefore underpins both the capital expenditure program and the operating expenditure

[56] See the *Utilities Act 2000* (ACT) and the *Management of Electricity Network Assets Code (Dec 2000)*.

program. As noted in section 6.1.2, the asset replacement component of the AMP makes up part of the Investment Plan.

ActewAGL Distribution's AMP is based on a set of targeted programs that take into account risk relating to asset conditions and reliability, safety, security and operational constraints.

6.4.1 Asset replacement

The asset replacement strategy is driven by business and regulatory requirements relating to safety, reliability, asset protection and the environment. The objective of the asset replacement program is to manage the risks and requirements relating to:

- electricity supply and reliability;
- maintaining operational functionality of the network;
- the work environment for ActewAGL Distribution's employees and contractors;
- public safety and property damage;
- the environment; and
- other legal obligations.

Generally, assets are replaced either as a result of equipment failure, deteriorating condition or where there is an indication of asset failure. Thus in most cases the justification for the asset renewal arises from a generic defect that causes serious problems relating to safety or operations, or from an on-going asset condition monitoring program. Ideally, condition monitoring identifies a problem well before failure will occur, but this is not always possible.

Other asset replacement considerations include the added value that new assets may provide, particularly if there are integrated features or other new technological developments (for example, new protection relay functionality that enhances primary equipment maintenance and fault diagnosis).

The asset replacement strategy encapsulated in the AMP focuses on critical assets where a reasonable failure probability exists and where failure would potentially result in high financial, reliability, safety or environmental risks.

ActewAGL Distribution has assessed its network asset replacement requirements against the outcomes of asset replacement and refurbishment modelling. ActewAGL Distribution has used models developed by consultants Sinclair Knight Merz (SKM) to inform its decision making. These models have assisted in identifying prudent and efficient options for asset management, but have been used in different ways in the preparation of work programs. The models are discussed further in section 6.7 below.

6.4.2 Asset maintenance

ActewAGL Distribution's asset maintenance planning involves:

- an analysis of maintenance needs against corporate objectives and service outcomes, identifying significant risks to the networks;
- the development of maintenance strategies and control measures; and
- the instigation of procedures to ensure adequate control of the implementation of the maintenance program.

Asset maintenance includes several main components:

- vegetation inspection and maintenance;
- pole and line inspections, surveys and auditing;
- servicing of distribution overhead line assets to extend life of assets;
- inspection and repair/maintenance of underground assets and zone substations; and
- reactive repairs of assets (for example after an outage or storm).

A maintenance strategy that seeks to prevent all failures from occurring would be costly and disruptive, and ultimately require an inefficient allocation of organisational resources. Conversely, a strategy that is based on maintenance only after failure (that is, reactive maintenance) would be equally costly, even more disruptive and will ultimately fail to meet regulatory and corporate requirements, and community expectations.

ActewAGL Distribution's maintenance plan involves an optimum balance between preventative and corrective maintenance. It also recognises that the most appropriate strategy depends on the type of asset, the risk of failure (using an assessment of likelihood, frequency and consequence) and the availability of appropriate maintenance resources, subject to regulatory requirements and business constraints. A number of subordinate plans make up the maintenance strategy, including the *Vegetation Management Strategy and Plan* and the *Bushfire Mitigation Strategy and Management Plan*.

6.4.3 Key outcomes from the Asset Management Plan

Pole replacements are expected to continue and to dominate ActewAGL Distribution's asset replacement program during the 2009–14 regulatory period. ActewAGL Distribution has introduced an enhanced pole inspection program due to significant increases in pole failures in the earlier part of the current regulatory period. As a direct consequence pole replacement and refurbishment has significantly increased. Future pole replacement requirements were modelled in detail (discussed further below) taking into account anticipated asset condition for different types of poles.

Pole reinforcement (nailing) is also a significant component of capital expenditure. Pole nailing is employed where prudent, to extend the life of the pole by up to 15 to 20 years by returning the pole to a serviceable condition. This approach will assist in reducing operating costs. There are a number of constraints which impact on opportunities to apply pole reinforcement as opposed to pole replacement. These factors are discussed in more detail in the AMP and the relevant project justifications.

Other significant planned projects are:

- the replacement of revenue meters to meet regulatory function and accuracy assurance requirements (discussed in detail in the MAMP);
- the replacement of the 11 kV switchboard at Civic Zone Substation;
- the replacement of protection relays;
- security enhancements to key infrastructure (for example, zone substation fencing); and
- distribution equipment lock replacement.

Relevant projects are discussed further in chapters 7, 8, and 15. Detailed modelling of capex/opex trade–offs and asset refurbishment/replacement are discussed further in section 6.7 below.

6.5 Technology and information management infrastructure planning

As stated in section 6.1.2, the *Technology and Information Management Strategy* (the "IT Strategy") is one of the five main documents on which ActewAGL Distribution's future investment program is based. The technology and information management projects included in the investment program were initially identified and prioritised through the development of the ActewAGL Distribution IT Strategy, finalised in March 2007, with assistance from consultants, Strada Associates.

An additional document, the *SCADA and Information Systems Strategy,* covers specific issues related to network control systems and further complements the IT Strategy. The future work program based on the strategy documents is described in the document *Ten Year Network Capital Investment Projects – Technology and Information Management*, which forms part of the overall ActewAGL investment program. The program is reviewed and updated annually.

The key goal of the IT Strategy is to ensure that ActewAGL Distribution's Technology and Information Management systems support current business requirements, as well as known future business directions and drivers. The guiding principles for the IT Strategy are therefore to:

- support current business processes;
- support end users and decision makers through readily available data with the aim of turning this data into information;
- prioritise the review and subsequent improvement to business processes;

- minimise data storage silos and related data entry to disparate systems;
- interface business specific systems with corporate systems to meet business drivers; and
- update IT hardware and adoption of new technology to enhance network performance.

The IT Strategy provides an overall vision and high-level project categorisation for communication and IT needs in ActewAGL electricity networks distribution business. Through the project implementation process and business review, it has become apparent that many objectives require further development to articulate/refine the business processes and clearly identify and scope the underpinning projects to deliver the overall strategy. Furthermore, external influences are constantly varying the forces on established priorities and needs. As such the IT Strategy is ever evolving. Notwithstanding this, as part of the IT Strategy, ActewAGL Distribution has identified as a priority the need to better integrate systems, databases and processes. The benefits of integration include improved access to better quality information, access to information across related and unrelated systems, and the ability to allow data mining for the production of decision-making information.

Currently, there are a large number of systems and related databases, many of which contain similar or duplicate data. A direct result of this can often be seen with conflicting information and reports being presented regarding the same asset from different systems or databases. This is counter-productive and impacts significantly on efforts to improve business efficiency and productivity.

ActewAGL Distribution's objective is to reduce the number of systems and related databases to a suitable and manageable level. This reduction can be achieved by defining requirements for corporate data and information products. These requirements will then be used to develop data models, databases and systems that will allow a program of amalgamation and consolidation of current databases and systems to be undertaken. A flow-on effect from this database and system rationalisation process will be the ability to more readily integrate key IT systems, allowing the controlled flow of data and information between databases and systems for analysis and reporting. The successful implementation of this overall strategy for ActewAGL Distribution will lead to the delivery of more effective business systems with improved data management processes and procedures. This will be due in part to the fact that data will only be entered and managed within one system and shared with others.

ActewAGL Distribution also faces the ongoing issue of dealing with a number of ageing or legacy systems. These systems currently hamper data management, reporting and information product delivery. The systems have been identified and a program to upgrade or replace these systems with suitable solutions must be undertaken to ensure that the overall objective of reducing the number of systems and databases can be achieved.

6.6 Delivery of proposed capital and operating programs

ActewAGL Distribution is aware that it will be competing with other Australian distribution businesses, as well as in the broader international market, for resources and expertise to deliver its proposed capital and operating expenditure program. As outlined in chapters 7 and 8, ActewAGL Distribution anticipates an increase in its capital and operating expenditures in the 2009–14 regulatory period, largely associated with the replacement of two zone substations, installation of a third transformer at Civic Zone Substation, and the new Southern Bulk Supply Point project.

In anticipation of this increase in activity, ActewAGL Distribution has undertaken a number of measures to ensure that it is able to successfully deliver this increased infrastructure program. These measures can be divided into staffing and resourcing measures and the establishment of supply arrangements and alliances.

6.6.1 Staffing and resources

ActewAGL Distribution has undertaken a strategic restructuring of its Electricity Networks Division and established a new Major Projects Branch in March 2008. This Branch has responsibility for delivering ActewAGL Distribution's current major projects, as well as those outlined in chapter 7. The restructure focuses organisational attention on to the delivery of major projects, and ensures that appropriate staff and other resources are available to meet necessary project deadlines. This restructure also increased ActewAGL Distribution's project management and planning staff, to assist in the successful and timely delivery of major projects.

ActewAGL Distribution has undertaken a resource matching exercise for the early years of the 2009–14 regulatory period, to ensure that it has sufficient resources and expertise to deliver on expected projects. Increases in resources will be necessary to deliver the expanded operating and capital expenditure programs. The process of assessing resource needs and availability will continue throughout the 2009–14 regulatory period to ensure that resources are available and sufficient to deliver anticipated projects. In anticipation of staff attrition due to retirement and ongoing escalation in the capital expenditure program and operating and maintenance programs, ActewAGL Distribution has also increased its apprenticeship program to ensure that the next generation of qualified technicians are available to develop and maintain ActewAGL Distribution's network long into the future.

6.6.2 Supply arrangements and alliances

ActewAGL Distribution will be using a combination of in-house and contract-based project delivery measures in the 2009–14 regulatory period. This approach will ensure that ActewAGL Distribution can access necessary technical expertise, particularly in relation to the construction of two new zone substations in the 2009–14 regulatory period. In addition, ActewAGL Distribution will continue to utilise its existing close relationships with its suppliers, and has engaged on the delivery of anticipated major projects with a number of potential suppliers.

ActewAGL Distribution can also draw on its recent experience in increasing its capital and operating expenditure programs, having already addressed many of the issues associated with any "ramp-up" in activity through organisational restructures and increasing staffing resources in key bottleneck areas. ActewAGL Distribution already has some large asset maintenance programs and contracts in place. These supply and resource alliances will also assist in the delivery of future programs.

ActewAGL Distribution considers that these measures will enable it to deliver the forecast capital and operating expenditure programs. As described earlier in this chapter, ActewAGL Distribution will continually review and assess project delivery timelines to ensure investment is undertaken in a structured, well-managed, and prudent fashion.

6.7 Asset age and replacement/refurbishment modelling

As mentioned above, ActewAGL Distribution commissioned SKM to assist in modelling asset replacement and refurbishment. Extensive age modelling was necessary for the asset replacement and refurbishment models, through the development of Network Capex/Opex Trade-off Model (the *Trade-off Model*). Asset replacement and refurbishment was undertaken in two distinct parts.

- Pole Asset Replacement/Refurbishment Model (the *Pole Model*); and
- Network Assets Replacement/Refurbishment Model (the *Network Model*).

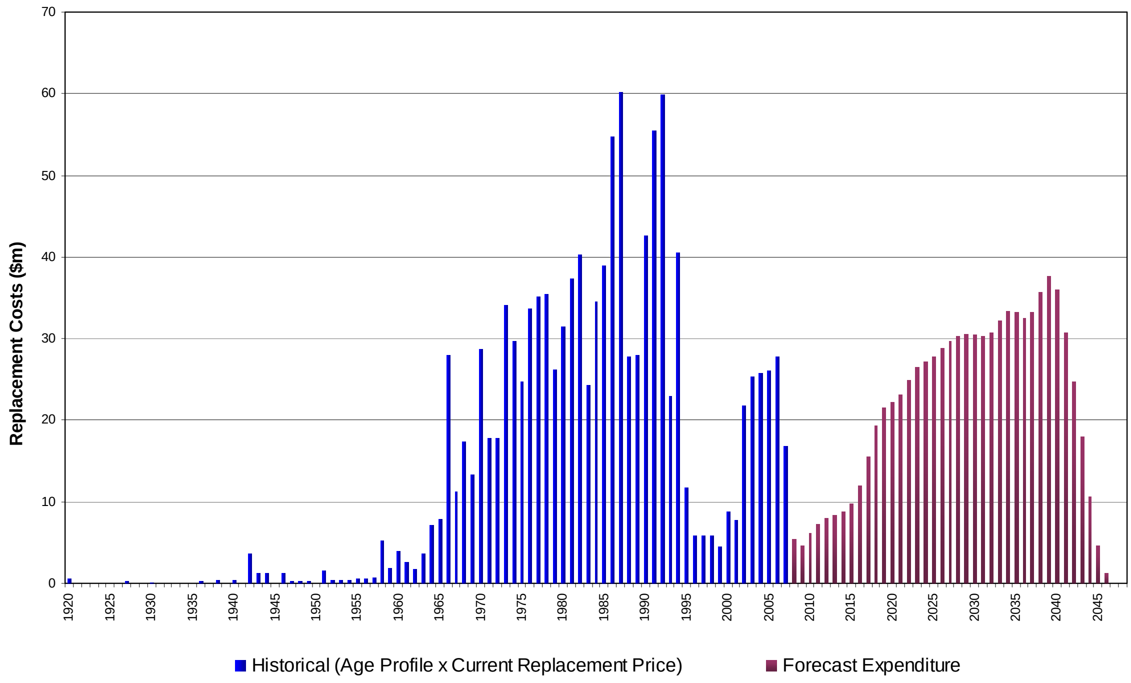
The modelling was a tool used to assess capital expenditure requirements and to consider implications of the age profile of existing network assets.

6.7.1 Asset age

As part of the Network Model, SKM has undertaken extensive age profiling of ActewAGL Distribution's network assets on an individual asset category basis. An age profile for the overall network (excluding poles) is shown in Figure 6.3. The figure also includes the projected expenditure on asset replacement derived from the age profile. The distribution poles were considered in a separate Pole Replacement/Refurbishment Model.

The modelling demonstrates that the majority of ActewAGL Distribution's electricity network assets were installed over the period from 1965 onwards, with the largest proportion installed during the period 1985–95. While a small amount of targeted refurbishment took place over time, the portfolio of assets continued to accumulate and progressively age. As the portfolio of assets progressively reach the end of their service life, it will become necessary to allocate an increasingly larger amount of capital expenditure for asset refurbishment and replacement purposes. It should be noted that this modelling has been done primarily on the basis of asset age, nominal asset life and the statistical distribution of expected lives for various asset categories.

Figure 6.3 ActewAGL Distribution weighted age profile (excluding pole replacement)



The model also allowed for the estimates of the average age and comparison with the typical expected operational life for each asset category. This comparison is shown in Table 6.3. In addition to the asset data derived from the Network Model, Table 6.2 also includes the distribution pole data based on ActewAGL Distribution records for poles.

Table 6.2 ActewAGL Distribution average asset age by category

Asset category	Weighted average age (2007/08)	Average expected life
Sub-transmission overhead lines	28.88	50
Sub-transmission underground	5.00	50
Zone substations	26.11	47
Distribution substation	23.92	41
Distribution underground	22.57	50
Distribution poles	31.00	43
Distribution overhead lines	22.48	50
Distribution other	22.29	31
Total weighted average system age	**24.88**	**-**
Total weighted average system life	-	46

It must be noted that the average ages and lives shown above are not numerical averages, but are weighted by the replacement cost (RC) value of each asset category. Table 6.2 shows that the weighted average age of assets in the ActewAGL Distribution network is estimated to be 24.88 years, compared with a weighted average life of 46 years for all network assets (that is, 54 per cent of weighted average network life has expired). The figures derived from the model were consistent with the assessment of asset age conducted by Meritec consultants before the 2004 regulatory review by the ICRC. At that time the asset age was assessed as part of the asset valuation report. Figure 6.4 shows the forecast weighted age of ActewAGL Distribution's network for the 2009–14 regulatory period.

Figure 6.4 Forecast weighted average age of network

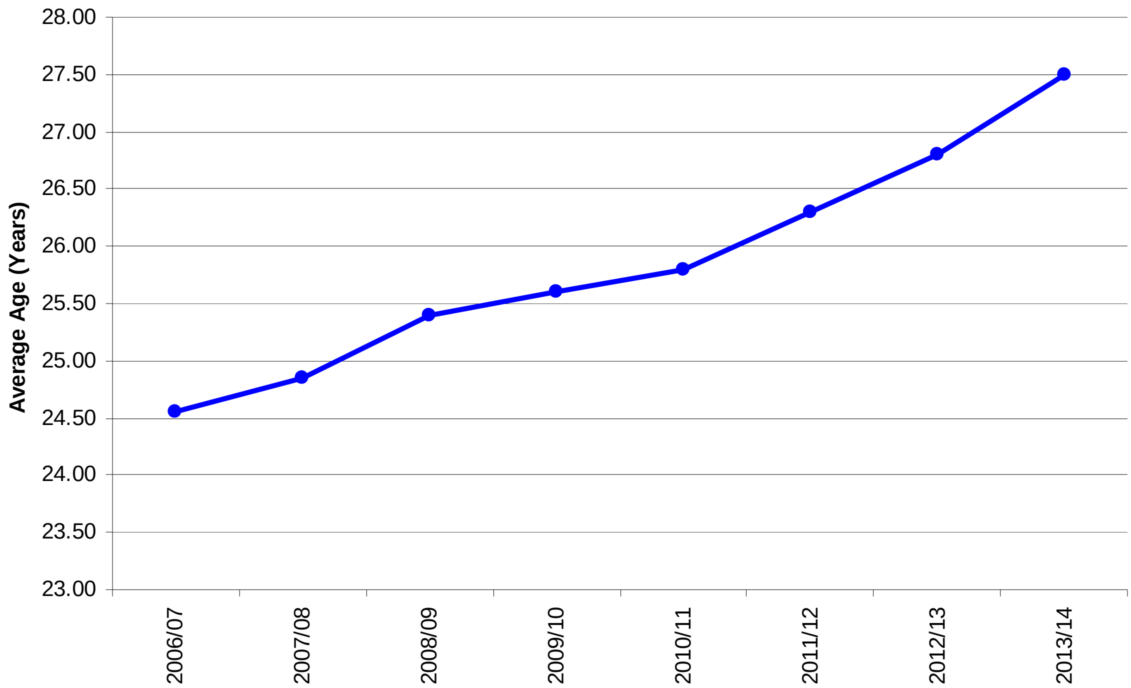


Figure 6.4 has been constructed assuming that the refurbishment/replacement capital expenditure proposed in this regulatory proposal is approved. Should the level of proposed capital expenditure be reduced, the system will age more rapidly requiring an associated increase in maintenance expenditures.

The average weighted age indicates that the ActewAGL Distribution's system is about the median average age when compared with other Australian utilities, as shown in Table 6.3. The implied weighted average ages for other utilities shown in this table have generally been sourced from previous asset valuations, and are *implied* because they are computed from the ratio of depreciated replacement cost (DRC) to RC. This is a reasonable approximation for weighted average age, even though it tends to slightly understate the average age of a system. In addition, it can be expected that for those companies where available data is from 2002 further ageing of their system by one or two years will have occurred since that time.

Even if the AER approves ActewAGL Distribution's expenditure proposals, the ActewAGL Distribution system will still continue to age (to 27.53 years) by the end of the 2009–14 regulatory period. This will continue to be within the range of normal system ages experienced by other utilities.

The main conclusion to be drawn from this analysis is that ActewAGL Distribution will need to continue to monitor system ageing and performance over the 2009–14 regulatory period, and will need to increase future refurbishment/replacement capital expenditure to maintain optimum system cost and performance.

Table 6.3 Weighted average asset age of various Australian utilities

Utility name	Implied weighted average age (years)	Effective date
Utility 1	17.35	2003
Utility 2	19.97	2005
Utility 3	20.25	2002
Utility 4	23.24	2002
Utility 4	23.66	2002
Utility 6	29.56	2002
Utility 7	31.56	2002

6.7.2 Capex/opex trade-offs

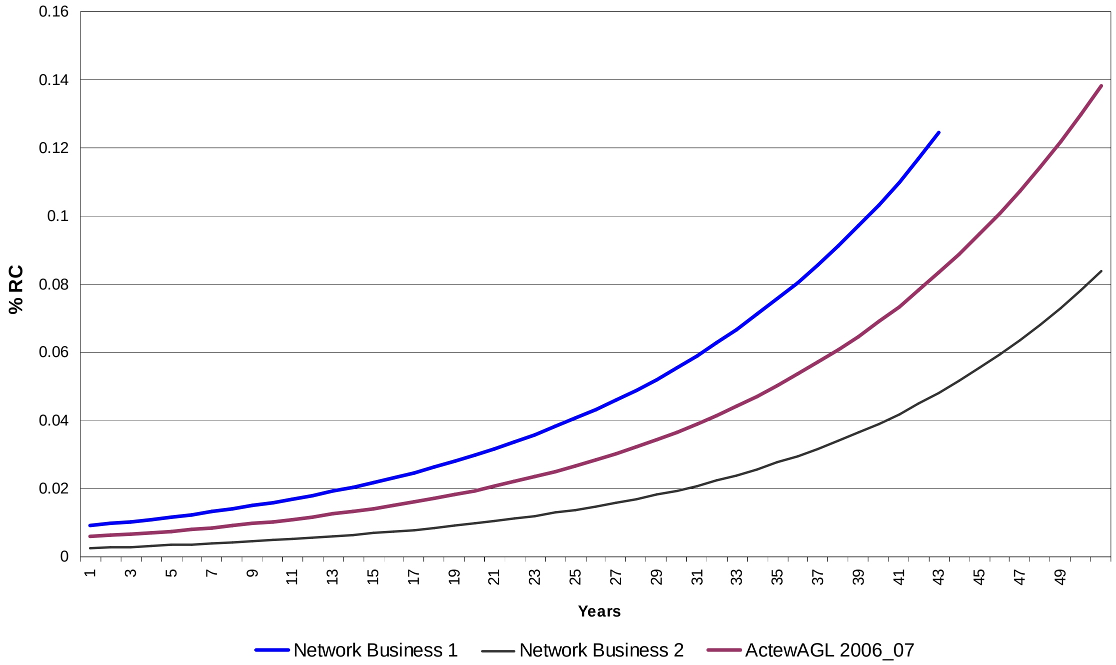
It is well understood that as an electricity distribution system ages, other things being equal, the level of operating and maintenance expenditure will increase. This is a consequence of deterioration of asset condition, the need for more frequent inspection and maintenance, and an increase in the failure rate of the assets in service.

As a result of work undertaken for a number of other Australian utilities, SKM has been able to construct for ActewAGL Distribution a model which reflects the profile of increasing maintenance expenditure with increasing asset age, for each different class of assets (for example, distribution overhead, distribution underground, substations).

Modelling the relationship between operating expenditure and age provides insight into the potential trade off issues between capital and operating expenditures. For specific projects where a trade-off between capital and operating expenditure exists, such as for asset maintenance and replacement, various options are considered with respect to achieving the lowest life cycle cost. These considerations can be quite specific to the project, and are usually undertaken through options analysis in the project justification process. The model assists this process by demonstrating the potential ongoing operating expenditure considerations of alternate maintenance approaches, where the cost implications (and potential trade offs with capital expenditure) may not be immediately evident.

The operating expenditure/age profile curve is different for each class of assets, and can be aggregated, on a weighted value basis to reflect the operating expenditure/age profile for the total system of each utility. To date, SKM has undertaken such analysis for two other distribution companies, in addition to ActewAGL Distribution, and this has resulted in the profile curves shown in Figure 6.5.

Figure 6.5 Typical opex/age relationship as a percentage of replacement cost



These curves are based on an exponential function between operating expenditure and age and have been developed using two *known* points - the actual current level of operating expenditure (expressed as a percentage of RC) and current age (for each utility individually), and an estimate of the level of operating expenditure applicable to new assets (that is, planned inspection and maintenance only, with no allowance for corrective or emergency maintenance). While this modelling can be disaggregated down to an asset class level, SKM found that very few utilities, including ActewAGL Distribution, collect operating and maintenance costs on an asset class basis to enable this to be done.

The additional operating and maintenance expenditure that is required each year to inspect and maintain new assets (that is, the point in Figure 6.5 at which the curve intersects the vertical axis) is modelled to be approximately 0.58 per cent of the value of new assets in the case of ActewAGL Distribution.

The average level of operating and maintenance expenditure that is currently spent on the inspection and maintenance of the system is given through its current age position on the curve. This is expressed as a percentage of the RC of the asset base, and in the case of

ActewAGL Distribution, this value is 2.76 per cent. It can also be demonstrated that as a system ages, it will require increasing corrective and emergency maintenance. In ActewAGL Distribution's case, the modelling suggests that this additional operating and maintenance expenditure amounts to approximately $1.4 million ($2007/08) on average per annum over the period from 2007/08 to 2013/14. As older assets are replaced, the required operating and maintenance declines.

Although these curves are unique to the relevant distributors and vary significantly with the mix of assets in service, ActewAGL Distribution's current situation has been plotted for comparison, and can be seen to lie directly between the other two distributors for which results are known. Figure 6.5 suggests that ActewAGL Distribution's current level of operating expenditure as a percentage of the asset replacement cost is comparable with the peer distributors used in this comparison.

6.7.3 Asset replacement and refurbishment expenditure based on modelling

Pole Refurbishment/Replacement Model

The Pole Modelling includes consideration of the whole population of distribution poles with the special emphasis on the timber poles and in particular natural wood poles.

The replacement/refurbishment capital expenditure required for distribution poles (all poles types) was modelled separately from the remainder of assets (for example, transformers, switchgear, pillars and cables). The model includes capital expenditure on pole refurbishment sometimes referred to either as pole "reinstatement" or "nailing".

The refurbishment/replacement modelling does not forecast capital expenditure requirements based solely on age, but takes into account a number of other condition based and operational factors which include:

- a condition based assessment based on routine inspections;
- known poor performing pole categories;
- different pole condemnation rates for different pole types (for example, natural round, creosote, tanalith, concrete etc.);
- an appropriate allowance for "over-aged assets" based on general industry and ActewAGL Distribution's experience;
- assets of technical obsolescence that may not reach their assigned design life; and
- life extension strategies such as pole nailing and chemical treatment.

The final outcome of the modelling of pole refurbishment and replacement results in the projection of capital expenditure shown in Table 6.4. The model predicts relatively stable expenditure levels on pole replacement and refurbishment over the 2009–14 regulatory period. The results from the Pole Model were used as the direct input into the capital expenditure program on poles.

Table 6.4 Pole Replacement/Refurbishment Model—projected capital expenditure on replacement and refurbishment

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Pole refurbishment/replacement cost	9.9	9.8	10.1	10.3	10.3	10.4

Network Asset Replacement/ Refurbishment Model

The Network Model assists the assessment of the asset refurbishment needs of ActewAGL Distribution's network. Based on the age profile of the existing network assets, this model is used as a general reference for assessing the expenditure required to refurbish assets in a prudent and efficient manner.

The Network Model includes major sub-transmission and distribution network asset categories, but excludes poles and several other secondary asset categories. The model is based predominantly on the age profiling of the assets.

SKM's modelling of general network refurbishment/replacement results in the following projection of capital expenditure outlined in Table 6.5. The model predicts increasing future asset refurbishment expenditure levels well above those proposed by ActewAGL Distribution for the 2009–14 regulatory period.

Table 6.5 General network refurbishment model—projected capital expenditure requirements for general network

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
General network refurbishment model (SKM)	19.4	16.9	15.4	14.9	15.8	10.3

Note: Excludes expenditure on poles, zone substation buildings, fences, services, meters and some electrical protection relays.

For the purposes of constructing the replacement/refurbishment capital expenditure requirements contained in this regulatory proposal, the modelling is used as a point of reference for the level of expenditure. This ensures that the average system age profile at both the asset class and total system level is defined and understood, and that the level of refurbishment/replacement capital expenditure being proposed is not excessive, nor deficient to the point of creating a future bow wave of maintenance and refurbishment costs.

The magnitude of expenditure being sought for the replacement/refurbishment of general network assets is based on the ActewAGL Distribution targeted programs rather than the SKM modelling. A number of targeted refurbishment and replacement programs were prepared on the basis of risk considerations, experience, current asset performance, and forecast maintenance requirements. When these programs are considered in aggregate the total forecast capital expenditure is less than the amount indicated in the SKM asset refurbishment modelling. These targeted programs also take account of what is considered to be practical and achievable in terms of resource availability and works programming.

As a consequence, the average age of ActewAGL Distribution's system (excluding poles) will continue to increase over the 2009–14 regulatory period as shown in Figure 6.2. This continued ageing will need to be carefully monitored in future regulatory periods to ensure that it does not become excessive.

The asset refurbishment modelling supported by the further modelling of capex/opex trade-offs therefore remain instructive in providing a ready methodology for understanding the relative relationship between capital and operating expenditure on a system wide or asset class basis. More references on the outcomes of this modelling are included in the AMP.

The comparison with the Network Model and the Pole Model indicates that the level of expenditure proposed by ActewAGL Distribution is below the levels anticipated by modelling.

The magnitude of expenditure required for the targeted replacement and refurbishment programs, compared with the SKM modelling is shown in Table 6.6.

Table 6.6 ActewAGL Distribution targeted network refurbishment/replacement versus SKM general asset refurbishment and pole refurbishment modelling

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14
Targeted Refurbishment/Replacement (capital expenditure proposed by ActewAGL)	18.1	19.4	16.8	16.5	17.6
SKM Modelled Network Refurbishment/Replacement (including poles and general network assets)	26.5	25.2	25.0	25.9	20.6

Note: Excludes expenditure on zone substation buildings, fences, services, meters and some electrical protection relays

7. Forecast capital expenditure

In the 2009–14 regulatory period ActewAGL Distribution's capital expenditure will significantly increase from current period levels. The increase will be most pronounced in the early years of the next period, after which capital expenditure will fall back to a level approximately equivalent (in real terms) to the actual and forecast levels of the current period.

The forecast increase is largely attributable to four relatively substantial augmentation projects that are planned for the early years of the period. The small size of ActewAGL Distribution's electricity network relative to those of most other DNSPs means that its capital program is more prone to pronounced peaks and troughs of expenditure. Pole replacement expenditure will continue to be a significant driver of capital expenditure outcomes in the 2009–14 regulatory period.

In summary the main drivers of capital expenditure forecasts for the 2009–14 regulatory period are:

- the requirement for zone substation augmentation due to urban expansion;
- regulatory, safety and security requirements that will continue to drive asset renewal and replacements costs, such as the pole replacement/reinforcement program and 132 kV connection assets to the new Southern Bulk Supply Point; and
- high forecast levels of new residential and commercial development in the beginning of the 2009–14 regulatory period.

7.1 Overview of historic capital expenditure

The Independent Competition and Regulatory Commission (ICRC) released its Final Decision on prices for electricity distribution services in the ACT from 2004/05 to 2008/09 in March 2004. The ICRC's Final Decision included the capital expenditure allowance shown in Table 7.1 (in both the original 2002/03 dollars and escalated to 2008/09 dollars to assist comparison).[57]

Table 7.1 ICRC 2004 final decision—capital expenditure

$ million	2004/05	2005/06	2006/07	2007/08	2008/09	**Total**
2002/03 dollars	20.6	20.1	22.4	19.4	20.3	**102.8**
2008/09 dollars	24.1	23.8	26.4	22.9	23.9	**121.1**

The capital expenditure forecasts submitted to the ICRC for the current regulatory period were based on ActewAGL Distribution's 10-year Capital Investment Plan, and as such were best

[57] All dollar values in this chapter, unless otherwise specified, are expressed in constant 2008/09 terms.

estimates of the efficient and prudent capital expenditure requirements for each year of the regulatory period. The ICRC's Final Decision incorporated a capital expenditure allowance over the period 5 per cent below ActewAGL Distribution's forecast capital expenditure on all programs except pole replacement. Pole replacement expenditure was allowed in the decision at the value initially forecast by ActewAGL Distribution in September 2003.

As detailed in Table 7.2, ActewAGL Distribution's actual capital expenditure for the current period will exceed by $41.6 million or 34 per cent that determined by the ICRC in 2004. Table 7.2 shows that the major component of the additional capital expenditure has been pole-related expenditure.

Poles inspected since 2003 have been condemned at a significantly higher rate than anticipated creating an urgent priority both to replace poles, and to minimise risk by pole reinforcement. ActewAGL Distribution's 2003 forecast expenditure of $16.7 million on pole-related expenditure over the 2004–09 regulatory period is substantially below the $52.8 million that is currently expected to be spent on pole-related expenditure over this period.

Box 7.1 sets out the circumstances of pole-related expenditure during the current period.

Table 7.2 Actual and forecast capital expenditure versus ICRC decision 2004–09

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	**Total**
Asset renewal/replacement	11.4	12.3	16.5	16.5	18.6	**75.2**
Customer initiated	14.4	11.3	15.9	17.6	21.8	**81.0**
Augmentation	1.5	3.4	1.1	3.2	4.7	**13.9**
Reliability and quality improvements	0.0	0.0	0.1	0.6	0.4	**1.2**
Network IT Systems	0.5	0.8	0.8	1.8	2.2	**6.1**
Less Capital Contributions	(6.3)	(3.7)	(4.4)	(5.1)	(7.9)	**(27.3)**
Non-system assets	0.4	0.5	0.4	0.5	0.5	**2.3**
Corporate Services Business Support	2.4	1.0	0.8	3.7	2.4	**10.3**
ActewAGL Distribution Total capital expenditure	**24.3**	**25.6**	**31.3**	**38.9**	**42.7**	**162.7**
ICRC 2004 decision	24.1	23.8	26.4	22.9	23.9	**121.1**
Expenditure above decision	**0.1**	**1.8**	**4.9**	**16.0**	**18.8**	**41.6**
Over (under) spend excluding pole related	**(5.4)**	**(3.9)**	**(4.4)**	**6.7**	**12.4**	**5.5**

Other drivers of the higher capital expenditure over the 2004/05 to 2008/09 period than allowed in the 2004 decision are:

- costs of $1 million arising from the requirement, introduced in 2006, to connect the ACT distribution network to a new Southern Bulk Supply Point;

- increased network augmentation expenditure as the result of a higher than anticipated incidence of Development Approvals for high-voltage cable construction requiring boring rather than open trenching to meet requirements of the *Tree Protection Act 2005*;[58]

- increased metals prices impacting on the price of copper and aluminium cables;

- high real wages growth in the general construction sector due to labour and skill shortages throughout Australia out-stripping movements in the Consumer Price Index (CPI) and that assumed in the 2004 final decision;

- materials cost growth greater than movements in the CPI (see section 7.3.3); and

- significantly increased customer initiated expenditures resulting from residential and commercial development on a scale above that expected, particularly in Civic, South Canberra Parliamentary Triangle, Canberra International Airport, Gungahlin and Kingston Foreshore.

Box 7.1 Pole-related expenditure during the current period

Additional requirements for pole inspection and replacement became apparent in 2003/04 concurrent with the ICRC's review of ActewAGL Distribution forecast expenditures for the current regulatory period. ActewAGL Distribution forecasts up to September 2003 identified pole replacement capital expenditure of $15 million (2003/04 dollars) over the five years. This requirement was based on a historical condemning rate of 2.5 per cent.

The ICRC's consultant on capital and operating cost forecasts for the review leading up to the 2004 decision was Burns and Roe Worley Pty Ltd (BRW). BRW's report to the ICRC commented on what it considered to be relatively high rates of pole condemnation already being experienced and possible solutions available to ActewAGL Distribution to address the issue: essentially more extensive use of chemical preservatives and pole reinforcement.[59] ActewAGL Distribution strongly refuted these conclusions based on knowledge of the comparable pole condemnation rates elsewhere where preservatives had been used extensively over the long term. The application of external chemical treatments to poles situated in private back yards is also problematic due to safety concerns. ActewAGL Distribution had already adopted pole reinforcement where possible within the limitations of machinery and plant access.

By February 2004, ActewAGL Distribution's revised forecasts were that $22 million (2003/04 dollars) would be spent in pole replacement capital expenditure over the five years covered by the pricing determination. This was based on a condemning rate of 10 per cent, which was the rate being experienced in the older suburbs. At the public hearings, ActewAGL Distribution advised the ICRC that revised forecasts were significantly in excess of the forecasts used in the Commission's draft decision[60] and raised the issue of the emerging backlog of pole replacements in the context of safety and reliability.

The ICRC's November 2003 draft decision proposed a five per cent efficiency dividend on ActewAGL Distribution's total forecast capital expenditure, including pole replacement. However, pole expenditure was exempted from this requirement in the final decision and the originally proposed $15 million was allowed. In accepting ActewAGL Distribution's September 2003 forecasts for pole replacement, the ICRC cited the need

[58] Boring is much more expensive than trenching, often around double the price or more depending on installation method, ground conditions etc.

[59] Burns and Roe Worley with Halcrow Group and McLennan Magasanik Associates 2003, Report to the Independent Competition and Regulatory Commission, *Review of Expenditure, Demand Forecasts and Cost Attribution for the Electricity And Water Services in the ACT* (Quantitative Version) 28 August, pp 179-180

[60] ICRC 2004, *Transcript of proceedings, Inquiry into pricing for electricity distribution services in the ACT, Thursday 5 February*, p 27, lines 20-28

for caution to avoid discouraging additional investment on "needed capital expenditure, such as pole replacements".[61] The ICRC also noted that "… the latest available evidence indicated that ActewAGL Distribution would spend at least all of its projected capital investment on pole replacements" and that "… unless exceptional circumstances prevailed, [this would] be accepted as prudent capital expenditure".[62]

The pole condemning rate continued to increase over the period and it has been prudent and necessary for ActewAGL Distribution to increase its capital expenditure on replacing and reinforcing condemned poles. There are a number of issues associated with this increased condemning rate, but the two major drivers are changes to pole inspection procedures and the progressive ageing of the *natural round* wood poles installed in ActewAGL Distribution's network.

More stringent processes for pole inspections and pole inspection audits (prompted by several pole failures that resulted in house fires, vehicle damage and a pole collapsing with an ActewAGL Distribution employee aloft) include inspectors removing tree roots, concrete backfill, fences, paving, retaining walls etc as required to fully excavate around the pole circumference; more accurate measurement and assessment of pole strength; and improved training for detecting rot, especially white rot.

Natural round wood poles were installed in the Canberra network up until the early 1970s. The quality of available timber diminished over the period during which Canberra's suburbs were built with the effect that these poles in older suburbs have a longer realised life than in more recently developed suburbs. Consequently, *natural round* poles in both older and newer suburbs across a large area of Canberra are concurrently reaching the end of their useful lives. This added to the frequency of finding decayed poles, with condemning rates for *natural round* poles of up to 40 per cent experienced in a significant number of Canberra suburbs. In 2006, the condemning rate of *natural round* wood poles across Canberra averaged around 30 per cent that is, approximately 300 per month. ActewAGL Distribution examined options for addressing the increased risk imposed by the short to medium-term backlog of poles needing inspection and condemned poles, and has implemented a risk mitigation strategy involving increased pole inspection, replacement and reinforcement. ActewAGL Distribution is currently reinforcing around 60 per cent of condemned poles to improve their safety until they can be replaced.

During the 2004–09 period, ActewAGL Distribution kept the ICRC informed with regard to capital expenditure on poles. During the transition to national regulation of electricity distribution, the ICRC advised ActewAGL Distribution of current and intended communication with the AER on this matter advocating the rolling into the regulatory asset base of additional expenditure on pole replacement and reinforcement.[63]

7.2 Overview of capital expenditure forecasts 2009–14

ActewAGL Distribution's proposed capital expenditure program complements and builds on that of the current regulatory period. Several of the drivers of increasing capital expenditure during the current regulatory period are expected to apply in the next, and are therefore factored into the proposed capital expenditure program.

ActewAGL Distribution forecasts a significant step increase in capital expenditure from the current regulatory period, largely due to four large augmentation projects required in the 2009–14 regulatory period.

Figure 7.1 provides an analysis of the sources of variation between ActewAGL Distribution's current period and proposed capital expenditure programs. The main points to be drawn from Figure 7.1 in addition to the significant increase in total capital expenditure from that of the current period, are the following.

[61] ICRC 2004, *Final decision - Investigation into prices for electricity distribution services in the ACT*, March, p xix

[62] ICRC 2004, *Final decision - Investigation into prices for electricity distribution services in the ACT*, March, p 47

[63] Letter of 10 May 2007 from ICRC to ActewAGL Distribution

- The major change in the composition of the program is the increase in the share of *Augmentation* capital expenditure (25 per cent of the total in 2009–14, up from 7 per cent in current period) due to required zone substation augmentations and the Southern Supply Project. Augmentation accounts for more than half of the total increase in capital expenditure.

- While the share of total capital expenditure forecast for the *Asset replacement program* will decline from 40 per cent in the current period to 32 per cent in the next as a result of the increased augmentation capital expenditure, these expenditures will increase in absolute terms by almost one-third.

- *Customer initiated* capital expenditure will remain a major component of ActewAGL Distribution's total capital program, accounting for 31 per cent of the total expenditure in the 2009–14 regulatory period, and total costs are increasing in absolute terms by 16 per cent.

- The three categories of *Asset renewal/replacement*, *Customer initiated* and *Augmentation* will together comprise 88 per cent by value of the ActewAGL Distribution's capital program during 2009–14.

- Expenditure on *Network IT systems*, though only seven per cent of the capital program, is to more than double from current period to provide integrated support systems for the business.

Figure 7.1 Components of current and next period capital expenditure

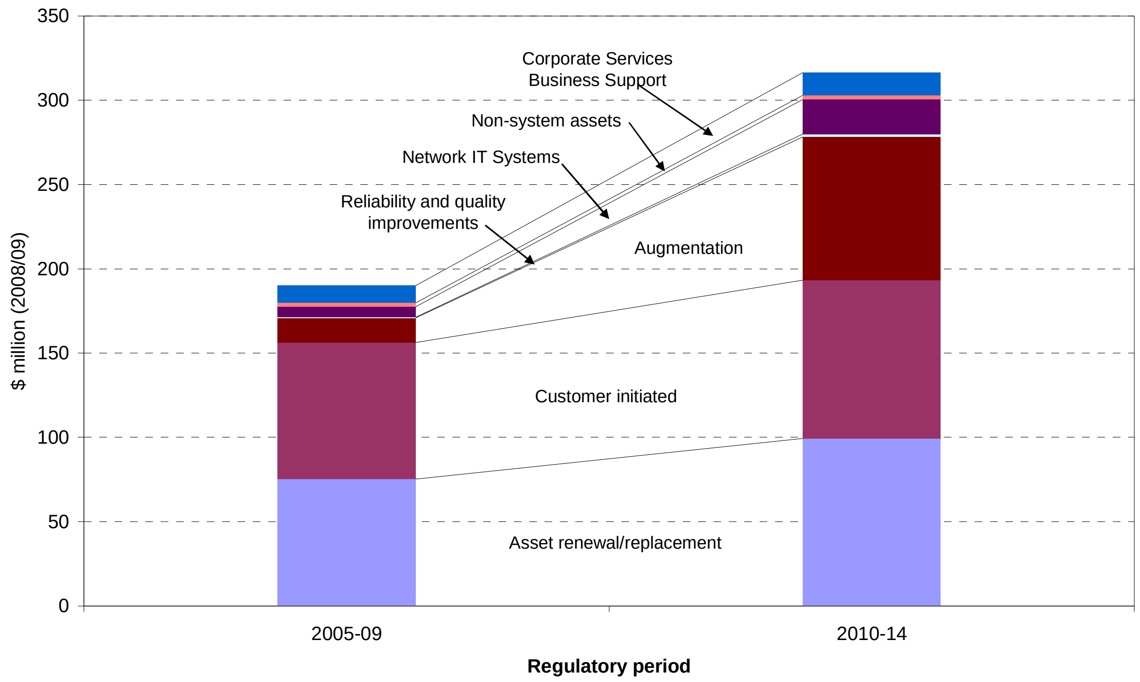


Table 7.3 presents ActewAGL Distribution's forecast capital expenditure for the 2009–14 regulatory period in greater detail. While total capital expenditure is forecast to increase sharply at the start of the period, by 2013/14 it will return to approximately the level of 2008/09.

Table 7.3 Forecast capital expenditure 2009–14

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	**Total**
Asset renewal/replacement	*18.6*	20.2	21.5	18.9	18.8	19.3	**98.6**
Customer initiated	*21.8*	21.7	23.9	20.3	15.2	12.9	**94.0**
Augmentation	*4.7*	29.9	14.6	13.9	15.4	2.7	**76.5**
Reliability and quality improvements	*0.4*	0.2	0.4	0.4	0.3	0.3	**1.5**
Network IT Systems	*2.2*	4.3	4.1	3.5	3.5	5.1	**20.5**
Less Capital Contributions	*(7.9)*	(5.8)	(8.2)	(7.5)	(4.2)	(3.7)	**(29.4)**
Non-system assets	*0.5*	0.5	0.5	0.5	0.5	0.5	**2.6**
Corporate Services Business Support	*2.4*	7.4	1.5	1.6	1.4	1.5	**13.3**
Total Capital expenditure	***42.7***	**78.3**	**58.3**	**51.7**	**50.9**	**38.5**	**277.7**

7.2.1 Augmentation

The substantial increase in augmentation capital expenditure needs to be seen in the context of a low base, with the last significant augmentation investment being the Gold Creek Zone Substation built in 1994. During the intervening period, ActewAGL Distribution has sought to achieve higher performance from existing major assets to keep costs at a minimum.

However there are implications of working assets in this way and the Fyshwick Zone Substation provides a useful case study. Built in 1982 and the single remaining 66 kV substation in the ActewAGL Distribution network, Fyshwick Zone Substation was resourced with transformers from other locations as they were replaced by 132 kV equipment. This arrangement proved problematic, with three major transformer failures being experienced in the past eight years. As a result, two new (second hand) transformers were brought into operation, while the remaining transformer underwent major refurbishment. In addition to power transformer failures, all 11 kV switchgear needed replacement in 2000 requiring a purpose built structure. The capacity of Fyshwick Zone Substation is to be progressively replaced over the life of these new assets following commissioning of the proposed Eastlake Zone Substation.

Overwhelmingly, the forecast increase in augmentation-related capital expenditure will result from the 4 largest augmentation projects in the 2009–14 capital program shown in Table 7.4. These are 132 kV connection assets the new Southern Bulk Supply Point, 2 new zone substations at Molonglo and Eastlake, and installation of a third transformer at the Civic Zone Substation. Expenditure on the latter three projects is required to meet forecast demand growth in Canberra, in the case of the Molonglo Zone Substation, to serve the development of a new satellite town in the Molonglo Valley, and for the others, respectively, the substantial development taking place at the Kingston Foreshore (Eastlake) and in the Canberra City Centre (Civic).

Table 7.4 ActewAGL Distribution's four largest augmentation projects 2009–14

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Eastlake Zone Substation and associated feeders	9.4	9.8	0.6	1.4	0.8	**22.0**
Civic Zone Substation	3.7	3.1	0.0	0.0	0.0	**6.8**
Molonglo Zone Substation and associated feeders	0.0	0.3	7.3	7.4	0.0	**15.0**
Southern Supply Point	14.2	0.0	3.9	4.4	0.0	**22.5**
Capital expenditure major programs/projects	**27.3**	**13.2**	**11.9**	**13.1**	**0.8**	**66.3**

7.2.2 Renewal and replacement

Asset renewal and replacement expenditure will also increase in 2009/10 by $1.6 million from 2008/09 levels due to the replacement of the Civic Switchboard and continuation of the pole replacement program. These projects are required to ensure that ActewAGL Distribution meets safety obligations under *Management of Electricity Network Assets Code* as well as to ensure the reliability and security of supply for standard control services in accordance with the *Electricity Distribution (Supply Standards) Code*.

Capital and operating expenditure trade-offs have been assessed in developing the forecasts. As described in chapter 6, ActewAGL Distribution's capex/opex trade-off model indicates that if capital expenditure is reduced below the proposed level, maintenance costs for existing assets will increase such that overall expenditure would be higher in NPV terms.

7.2.3 Corporate services business support

Capital expenditure on *Corporate services business support* is also forecast to increase in 2009/10 due mainly to the impending relocation of ActewAGL's Corporate Headquarters. The expenditure for the relocation has been subject to detailed internal review and will result in lower total cost than at the current site.

7.3 Forecasts, methodology and assumptions 2009–14

The following sections explain ActewAGL Distribution's broad approach to capital expenditure forecasting and how the elements of the approach relate to the capital expenditure objectives and factors in the transitional *Rules*. Section 7.3.3 then provides a detailed discussion of cost escalation factors. The remaining sections provide the forecasts for each component of ActewAGL Distribution's capital expenditure and a discussion of the particular assumptions and methodologies adopted for each category.

7.3.1 Requirements of the AER

The transitional *Rules* set out the framework for the AER's assessment of capital expenditure proposals and the necessary components of the regulatory proposal. The requirements are supplemented by the AER's Regulatory Information Notice (RIN). In deciding whether to accept a service provider's forecasts, the AER is required to have regard to the *capital expenditure factors* set out in 6.5.7(e). These factors include information provided by the DNSP in its building block proposal and analysis by the AER.

A building block proposal by a DNSP is required by clause 6.5.7(a) of the transitional *Rules* to include the total forecast capital expenditure for the relevant regulatory control period that the DNSP considers is required to achieve each of the *capital expenditure objectives*. The *capital expenditure objectives* are as follows:

- to meet or manage the expected demand for *standard control services* over that period;
- to comply with all applicable *regulatory obligations or requirements* associated with the provision of *standard control services*;
- 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* through the supply of *standard control services*.

Clause 6.5.7(c) of the transitional *Rules* requires the AER to accept the DNSP's capital expenditure forecast if it is satisfied that the forecast reasonably reflects:

- the efficient costs of achieving the *capital expenditure objectives;*
- the costs that a prudent operator in the circumstances of the relevant *Distribution Network Service Provider* would require to achieve the *capital expenditure objectives*; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the *capital expenditure objectives*.

Clause S6.1.1 of the transitional *Rules* sets out the information and matters relating to capital expenditure that the DNSP must provide in its building block proposal in order for the AER to determine whether it will accept or reject the capital expenditure forecasts provided by the DNSP. ActewAGL Distribution has provided the required information in respect of current period actual and forecast capital expenditure in the attached pro forma 2.2.1, and the remaining requirements of S6.1.1 are met in this chapter and attachments as indicated where appropriate.

The RIN specifies the information that the AER requires, in addition to the requirements set out in clause S6.1.1 of the transitional *Rules*, to allow it to assess the forecast capital expenditure. The additional requirements include the following:

- Information on proposed material projects and programs as well as material projects and programs undertaken in the current regulatory control period (RIN 1.2.3)—these are covered in pro forma 2.2.3;
- An organisational overview (RIN 1.3.1)—this is covered in chapter 1 and attachment 2 of this regulatory proposal;
- Information on relationships with entities other than the provider (RIN 1.3.2). This is covered in pro forma 2.3.2 and in chapter 1 and attachment 2 of this regulatory proposal;
- Details on the cost estimation process, including the unit rates and escalators that have been used (RIN 1.3.10)—this is covered in section 7.3.3 below and in pro forma 1.3.10;
- Information on service standard obligations, and regulatory and legislative obligations (RIN 1.3.4 and 1.3.5)—these are covered in chapters 3 and 4 of this regulatory proposal;
- Plans, policies and procedures that underpin the development of the forecasts (RIN 1.3.6)—these are listed in the pro forma 2.3.6. The role of the key documents of the network planning and management process underpinning the capital expenditure forecasts is described in chapter 6 of this regulatory proposal;
- Details on network planning and management (RIN 1.3.7)—this is covered in chapter 6 of this regulatory proposal;
- Information on transactions with persons other than the provider, in both the current and forecast regulatory period (RIN 1.3.12)—this is covered in pro forma 2.3.12;
- Information on capital contributions (RIN 1.3.13)—this is covered in section 7.3.11 below and in pro forma 2.2.1; and
- Explanation of significant variations in capital expenditure in the 2009–14 regulatory period compared with 2006/07 as calculated in pro forma 2.2.4. ActewAGL Distribution has provided reasons for the variations in attachment 16.

ActewAGL Distribution has a structured and fully integrated business planning process, described in chapter 6 of the regulatory proposal, to ensure that expenditure is prudent. In accordance with clause S6.1.1 of the transitional *Rules*, the following sections describe the methodology used in developing ActewAGL Distribution’s capital expenditure forecasts and the key underlying assumptions that have been made.

7.3.2 Capital expenditure objectives and factors

The principal drivers of ActewAGL Distribution’s capital expenditure program, referred to in the transitional *Rules* as the *capital expenditure objectives*, broadly encompass:

- service standard obligations, as described in chapter 3;
- regulatory obligations, as described in chapter 4; and

- demand and energy forecasts, as described in chapter 5.

Clause 6.5.7(a) of the transitional *Rules* stipulates that the DNSP must include the total forecast capital expenditure that is required to achieve the *capital expenditure objectives*. Chapter 6 of this regulatory proposal outlines ActewAGL Distribution’s approach to planning future expenditure in order to meet the requirements in a prudent and strategic manner. Proposed expenditures are based on a realistic expectation of the demand forecast as described in chapter 5 and cost inputs as described in section 7.3.3 below.

When forecasting the capital expenditure for the 2009–14 regulatory period, ActewAGL Distribution has also considered the *capital expenditure factors* as set out in clause 6.5.7(e). ActewAGL Distribution's expenditure forecasts reflect the efficient cost of service provision. This is demonstrated through:

- the execution of long term plans, strategies and procedures (see chapter 6) to ensure the optimal project solution is chosen, thereby ensuring that expenditure is prudent;
- option analyses, including assessment of non-network alternatives, where appropriate (following the process outlined in chapter 6 and described in attached project justifications);
- the use of cross industry standard estimates/escalators of input cost growth for major capital inputs as described below;
- analysis of the actual and expected capital expenditure for each asset category in the current and past regulatory periods (see sections 7.3.4 to 7.3.9 for further details);
- consideration of the relative prices of different capital and operating inputs; and
- a total system level assessment of the trade-off between capital and operating expenditures, as described in Chapter 6 of this regulatory proposal, as well as consideration on a project by project basis where such a trade-off may be possible.

According to clause 6.5.7(c) of the transitional *Rules*, the AER must accept a forecast of required capital expenditure that is included in a building block proposal if the AER is satisfied that the expenditures reflect efficient costs, the costs are prudent and are based on a realistic expectation of the demand forecast. ActewAGL Distribution has carefully considered the proposed capital expenditure to ensure that it fulfils these requirements.

7.3.3 Method and input cost escalation

ActewAGL Distribution has adopted a zero-base approach to forecasting future capital expenditure requirements. Costs associated with ActewAGL Distribution’s identified capital expenditure have been developed using bottom-up estimates of expenditure in 2007/08 dollars, escalated by the relevant factors described below. The actual unit rates used by ActewAGL Distribution can be found in the project justifications of the asset management and augmentation plans at attachment 21. ActewAGL Distribution has engaged Sinclair Knight Merz (SKM) to provide an independent and systematic assessment of the estimation of the ten most important unit rates used in ActewAGL Distribution's regulatory proposal. The key unit rates can be found in Attachment 17.

ActewAGL Distribution has not included contingencies in its forecasts. The capital expenditure is based on a tendering process to secure the lowest life cycle costs for ActewAGL Distribution in accordance with the ActewAGL Distribution procedure for purchasing of goods and services.

ActewAGL Distribution commissioned Sinclair Knight Merz (SKM) to provide an independent and systematic assessment of the escalation factors that apply to capital programs and projects for the period from 2007/08 (the base year) to 2013/14.

In recent years it has become more complex to escalate future costs, as the factors influencing the different cost components fluctuate more widely. For a prolonged period, cost components associated with the development of capital expenditure forecasts could be expected to move in line with increases in the Consumer Price Index (CPI). Particularly over the past four years, the costs of inputs have been growing substantially in excess of the CPI.

The resources boom has seen commodity prices rise to levels in December 2007 that were 200-400 per cent above 2003 levels. In addition, wages growth in the electricity industry has continued to outpace CPI. Since 2002, average weekly income and the Australian Bureau of Statistics (ABS) Energy, Gas and Water Index have both exceeded CPI, by 6.5 per cent and 10.8 per cent respectively (as at December 2007). Market price surveys conducted by SKM show that power transformer costs increased by more than 20 per cent in two years (2004 to 2006), while aluminium cable and overhead conductor costs rose by 27 per cent and copper cable by 46 per cent over the same period.

SKM has examined the rapidly increasing cost of capital infrastructure works, particularly in the Australian electricity industry. Many Australian transmission and distribution network companies have reported rapidly increasing costs for both individual projects (substations and overhead distribution lines), and annual and five year capital works programs covering the full range of capital expenditure. Peaks in oil prices above $100/barrel in 2008 are likely to add further price pressure to parts of the electricity industry supply chain.

As part of this research, SKM conducted a multi-utility strategic procurement study in which nine Australian transmission and distribution companies provided confidential contract information on the purchase of their main items of plant, equipment and materials (such as power transformers, switchgear, cables and conductors) over the period 2002 to 2006. SKM has also developed a database of contract cost information for a number of turnkey substation and transmission line projects, including plant equipment, materials, construction, testing and commissioning.

SKM's research indicates that there are several factors driving the rapid rises in capital infrastructure costs, including:

- acute increases in world-wide commodity market prices since 2002/03;

- subsequent increases in the purchase price of plant, equipment and materials, both locally-produced and imported, although these increases lag behind increases in commodity prices by a period of between 6 and 24 months;

- widespread increases in the market price for contracted works in Australia caused by the current demand/supply imbalance of skilled labour and other construction resources.

SKM has studied relevant historic and forecast data and has developed a comprehensive cost escalation modelling process that captures the likely impact of input cost drivers on future electricity infrastructure pricing.

Having identified these common cost drivers, SKM examined each of the main items of plant equipment and materials within its database to establish a percentage contribution of the individual cost components of a completed item. Once assigned, these individual cost weightings show how changes in the price of each cost driver could be expected to affect the overall cost of an item.

ActewAGL Distribution used SKM's weighting of materials in its plant and equipment costings. The weightings of the commodities for ActewAGL Distribution were assigned according to the findings of the 2006 SKM strategic procurement study described above. Using the procurement databases of the companies in the study, SKM established underlying cost drivers for the prices of specific capital items.

SKM has also relied upon contract price information provided under confidentiality arrangements for switchgear, transformers, overhead conductor and underground cable. A number of the cost drivers associated with the pricing of capital infrastructure are associated with materials traded on world commodity markets. Four of the most important cost components are copper, aluminium, steel and oil.

In developing cost escalation factors for ActewAGL Distribution, SKM utilised in its calculations the unadjusted long-term Consensus Economics commodity pricing levels. The Consensus *long-term 5 to 10-year forecast* indicates that world market conditions will cause the price of a commodity to move towards the level indicated at some stage during the next 5 to 10 years.

Although such long term forecasts have limitations, it is SKM's view that the most suitable method to include data points contained in a 5 to 10-year forecast in calculations involving linear interpolation would be to consider the points to lie in the middle of the time period listed, in this example at 7.5 years hence. This results in a lower value than using a 10-year approach, since commodity prices are assumed to decrease (see appendix B in attachment 18). SKM therefore considers Consensus Economics' long-term price predictions represent the cost of these commodities at a period of 7.5 years from the date of the Consensus report.

It is also of interest to note from the price trends that there appears to be a significant time lag between the rapid increases in commodity prices (which occurred for copper and aluminium between late 2003 and mid-2005) and the time at which finished product prices began to rise. This suggests that the contract prices for finished product, such as transformers, cables and conductors, will continue to rise well beyond what were considered to have been the peaks in commodity prices occurring in late 2007, rising through 2008, and probably into 2009. Current buoyant activity in the construction and resources sectors helps to sustain price increases in heavy equipment. In developing the capital expenditure escalation factors, a one-year time lag between the movements in commodity prices and their flow-on influence to the price of finished goods has been used.

Currency exchange rates affect the actual price paid in Australia. Within its December 2007 *Australian National State and Industry Outlook* publication (updated quarterly), Econtech provides a long-term forecast for the Australian Dollar. Econtech's report has been used to develop Australian Dollar prices for commodities, at the corresponding $USD to $AUD exchange rates for each relative time period.

A summary of the escalation factors developed by SKM for ActewAGL Distribution using the above methodology is provided in Table 7.5.

Table 7.5 Escalation factors for capital expenditure (nominal)

Index: 2007/ 08 =1.00	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Substation Civil Engineering	1.000	1.018	1.025	1.030	1.040	1.057	1.082	1.107
Substation Transformer	1.000	1.045	1.048	1.053	1.056	1.059	1.062	1.062
Substation Switchgear	1.000	1.055	1.091	1.119	1.150	1.180	1.208	1.233
Substation Electronics/Other	1.000	1.034	1.068	1.105	1.142	1.181	1.220	1.255
Substation Overhead/Labour	1.000	1.057	1.137	1.217	1.294	1.371	1.448	1.520
O/H Lines	1.000	1.040	1.084	1.130	1.172	1.214	1.254	1.294
U/G Cables (Cu.)	1.000	1.052	1.092	1.136	1.174	1.212	1.249	1.281
U/G (Al.)	1.000	1.054	1.114	1.172	1.225	1.279	1.332	1.382
Substations	1.000	1.049	1.077	1.105	1.132	1.159	1.185	1.208
O/H Lines	1.000	1.045	1.104	1.163	1.218	1.274	1.329	1.382
U/G Cables (Cu.)	1.000	1.049	1.076	1.107	1.135	1.162	1.187	1.207
U/G (Al.)	1.000	1.049	1.069	1.094	1.115	1.135	1.154	1.167
Relays	1.000	1.042	1.094	1.147	1.200	1.253	1.306	1.357
Meters	1.000	1.042	1.094	1.147	1.200	1.253	1.306	1.357
Other	1.000	1.027	1.052	1.078	1.106	1.135	1.164	1.193

The escalators have been estimated based on future input prices, the cost shares of labour and commodities and subject to the time lag described above. Because the prices of input commodities are expected to decrease or be stable and the price of labour is expected to increase, escalators with the highest weighting of labour will show the largest increases. For example, the Substation Overhead/Labour escalator relates only to labour and therefore shows the largest increase of all the escalators in Table 7.5. Four different labour escalators have been used depending on the relevant sector. For details see attachment 18 to this regulatory proposal.

7.3.4 Customer initiated expenditure—methodology and forecasts

Section 79 of the *Utilities Act 2000* (ACT) requires ActewAGL Distribution, on the request of a customer, to connect, vary the capacity of a connection, or allow another authorised person to connect or vary capacity of a connection, in line with the standard customer contract. Customer initiated capital expenditure is therefore correlated with the level of new residential and commercial development.[64]

An overview of the actual and estimated total customer initiated capital expenditure during the 2004–09 regulatory period is set out in Table 7.6. The review of current period expenditures helps to identify drivers that are relevant for the 2009–14 regulatory period.

Table 7.6 Customer initiated capital expenditure program 2004–09

$ million 2008/09	2004/05	2005/06	2006/07	F2007/08	F2008/09	**Total**
New Urban Development	4.4	1.4	2.9	3.6	6.3	**18.6**
Urban Infill Development	1.4	1.3	2.1	2.0	1.5	**8.3**
Rural Development	0.1	0.2	0.5	0.5	1.4	**2.7**
Commercial Development	3.9	4.7	6.9	5.9	6.4	**27.8**
Special Customer Requests	0.8	1.3	0.8	0.6	0.6	**4.2**
Relocations	2.3	1.0	1.2	1.0	1.6	**7.2**
Community and Associated	0.0	0.0	0.0	2.2	1.8	**4.0**
Customer Initiated Replacement	0.0	0.0	0.0	0.1	0.1	**0.1**
Services	1.4	1.4	1.6	1.7	1.9	**8.2**
Total Customer Initiated Costs	**14.4**	**11.3**	**15.9**	**17.6**	**21.8**	**81.0**

Customer initiated costs have increased significantly during the current regulatory period due to new urban development (mainly Gungahlin and Macgregor), commercial development (for example, in the Canberra CBD) and rural development (Mount Tennent). In 2008/09, customer initiated expenditure is forecast to increase significantly in the *New Urban Development* category as land releases are brought forward by the ACT Government in response to current housing availability and affordability concerns. *Rural Development* is forecast to peak in 2008/09 as a result of the further delay in the rebuilding of the Uriarra Forestry Settlement, destroyed in the 2003 bushfires.

Major customer initiated programs in the 2004–09 regulatory period were:

- Gungahlin Drive Extension 132 kV and high-voltage Relocations;
- City - Section 84 Developments; and
- Cotter Pump Station Upgrade.

[64] *Commercial* here includes any *light industrial* load. There are no examples of *heavy industry* in the ACT.

Methodology for estimating customer initiated costs

The process for determining forecast customer initiated capital expenditure takes account of:

- direct customer or developer enquiries;
- major public and private development initiatives identified through public/media announcements;
- future development activity identified through the ACT Government planning, preliminary assessment and agency liaison/consultation processes;
- future development activity identified through discussions with the ACT Government on land release programs;
- investigation and reconciliation with ACT Government land release programs and the BIS Shrapnel Pty Ltd 2007 report *Building in Australia 2007–2022;* and
- historic expenditure in the various customer initiated work categories, adjusted to reflect the anticipated broader short-term economic environment.

ActewAGL Distribution's Customer Initiated Capital Investment Program has been prepared in the context of:

- anticipated housing demand of 2,185–2,385 dwellings per year for the next three years, and around 1,500 dwellings from 2011 to 2014;
- supply of the anticipated housing demand to be sourced primarily from residential greenfield developments for the period of the investment plan, with urban infill or redevelopment contributing in the order of 20 to 30 per cent of the demand;
- limited greenfield development opportunities existing in neighbouring Queanbeyan for the short to medium term, resulting in the housing demand of the ACT/Queanbeyan region being fulfilled predominantly within the ACT;
- housing availability and affordability gaining increasing political prominence; prompting a significant increase in ACT Government residential land development programs and a policy change to allow limited private sector Greenfield residential land development;
- increasing greenfield developer demands for improved aesthetics and reduced street furniture, particularly in areas of proposed higher density housing, potentially resulting in less efficient servicing arrangements and therefore higher servicing costs per dwelling;
- the ongoing development/redevelopment of:
    - the Kingston Foreshore;
    - the Canberra CBD (Civic);

- individual sites in the Gungahlin, Tuggeranong, Belconnen and Woden town centres; and
- commercial sites such as the Canberra International Airport (including Fairbairn)

- the emerging development of Fyshwick Section 48 (*EpiCentre*);
- the continuing lower than average rainfall in ACT water catchments, resulting in the emergence of several significant water supply security initiatives, such as a proposed water purification plant in the Belconnen District, that will require significant electricity network infrastructure works; and
- an increasing number of purpose-built data-centre developments involving high electrical load densities.

Several of these are subject to considerable uncertainty, particularly in the latter part of the period, and so ActewAGL Distribution has decided not to include any provision for “expected but unknown developments”, as discussed further below.

ActewAGL Distribution’s forecast customer initiated capital expenditures for the 2009–14 regulatory period are set out in Table 7.7.

Major customer initiated programs proposed to be undertaken in the 2009–14 regulatory period are as follows.

- In the Belconnen District, the proposed water purification plant, including a new feeder will be initiated. This project was approved by the ICRC in its April 2008 final decision on water and wastewater prices in the ACT. The total cost for this project is $9.7 million.
- In Russell, Commonwealth Government High-Voltage Reticulation and Substations. The total cost for this program is estimated to be $1.1 million; and
- In Parkes, Proposed Department of Finance and Administration (DOFA) Development. The total cost for this program is $4.2 million.

Table 7.7 Forecast customer initiated capital expenditure programs (excluding capital contributions) 2009–14

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	Total
New Urban Development	*6.3*	6.3	6.8	6.3	4.7	3.8	**27.9**
Urban Infill Development	*1.5*	1.8	2.1	1.1	1.3	1.9	**8.0**
Rural Development	*1.4*	0.1	0.1	0.1	0.1	0.1	**0.6**
Commercial Development	*6.4*	7.3	5.7	3.7	4.7	3.4	**24.8**
Special Customer Requests	*0.6*	0.7	0.8	0.9	0.8	0.5	**3.7**
Relocations	*1.6*	1.1	1.0	0.9	0.8	0.7	**4.5**
Community and Associated Development	*1.8*	2.2	5.3	5.5	0.6	0.5	**14.1**
Customer Initiated Replacement	*0.1*	0.2	0.2	0.2	0.2	0.2	**0.8**
Services	*1.9*	2.0	1.9	1.8	2.0	1.8	**9.6**
Total Customer Initiated Costs	***21.8***	**21.7**	**23.9**	**20.3**	**15.2**	**12.9**	**94.0**

In 2009/10, customer initiated capital expenditure is expected to decrease by 0.5 per cent in real terms. In 2010/11, it is expected to increase by 10.2 per cent mainly due to $0.5 million of New Urban Development expenditure from reticulation of the and the new suburbs of Molonglo, Casey, Lawson and Bonner and Community and Associated Development expenditure of $3.1 million for the proposed water purification plant facility. ActewAGL Distribution has assessed as optimistic the claimed development timeframes for several other major developments and adjusted the forecasts accordingly.

The emergence of dedicated data centre developments involving very high electrical load densities will have flow-on effects to asset augmentation works as additional feeder capacity becomes necessary for the supply of these high load sites.

Considerable effort has been made to ensure that all major development initiatives currently being considered have at least been identified. However, uncertainty in land release plans makes it impossible to forecast with a great degree of confidence detailed customer initiated capital investment requirements beyond the first one or two years of the 2009–14 regulatory period. As a result of this uncertainty, forecast customer initiated expenditure decreases in 2011/12 to 2013/14. It could be expected that some unanticipated projects would emerge in this period. At this stage, however, proposed expenditure cannot be directly linked to projects as stipulated in clause 6.5.7 of the transitional *Rules*. ActewAGL Distribution has not included any allowance or contingency factor for “expected but unknown” developments that could arise based on experience.

About 31 per cent of the total customer initiated program will be recovered as capital contributions in accordance with the ACT *Capital Contributions Code*. Capital contributions are discussed further in section 7.3.11 of this regulatory proposal.

7.3.5 Network augmentation expenditure—methodology and forecasts

An overview of *network augmentation* capital expenditure during the 2004–09 regulatory period is set out in Table 7.8.

Table 7.8 Historic augmentation capital expenditure programs 2004–09

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	**Total**
Sub-transmission	0.0	0.6	0.3	0.1	0.7	**1.7**
Distribution system	1.5	2.8	0.8	2.7	2.6	**10.5**
Zone substations	0.0	0.0	0.0	0.3	1.4	**1.7**
Total	**1.5**	**3.4**	**1.1**	**3.2**	**4.7**	**13.9**

Network augmentation expenditure has increased from $1.5 million to $4.7 million in the current regulatory period.

The major programs completed, or to be completed, during the current regulatory period include:

- major high-voltage network augmentation projects to provide new capacity and rectify low reliability or supply quality problems;
- sub-transmission system projects such as the Southern Supply Point Project; and
- zone substation augmentation projects and project development work for new zone substations.

ActewAGL Distribution has not needed to invest in a new zone substation for more than 10 years. Network constraints and consumption trends, however, mean that load is now approaching maximum capacity at Civic and Fyshwick Zone Substations. New urban development will also take place in the Molonglo District. As a result, significant augmentation capital expenditure has become necessary to ensure ongoing security and reliability of supply.

Methodology for estimating augmentation capital expenditures

When forecasting augmentation capital expenditure, ActewAGL Distribution considers:

- system load requirements with particular reference to ‘hot spots’, system capacity issues and other points of potential vulnerability;
- load forecasts;
- forecasts of land development;
- the assessed condition of critical assets and asset failure rates;
- risks and priorities;

- compliance with requirements of the Technical Regulator and technical standards;
- achievement of service standards;
- health, safety and environmental issues; and
- non-network alternatives.

ActewAGL Distribution's forecast *augmentation* capital expenditure for the 2009–14 regulatory control period is set out in Table 7.9.

Table 7.9 Forecast augmentation capital expenditure programs 2009–14

$ million (2008/09)	2009/10	2010/11	2011/12	F2012/13	F2013/14	**Total**
Sub-transmission	14.2	0.0	3.9	4.4	0.0	**22.5**
Distribution system	2.6	2.8	2.6	3.6	2.7	**14.4**
Zone substations	13.1	11.9	7.3	7.4	0.0	**39.7**
Total Electricity Augmentation	**29.9**	**14.6**	**13.9**	**15.4**	**2.7**	**76.5**

ActewAGL Distribution forecasts a significant increase in augmentation expenditure in 2009/10 due to the new zone substations and the transformer at Civic Zone Substation. ActewAGL Distribution will also incur capital costs associated with the construction of the 132 kV connection assets to the Southern Supply Point mandated by the ACT Government.[65]

Demand forecasts described in chapters 5 and 6 of this regulatory proposal show that 5 of the 11 zone substations will have insufficient capacity to meet the demand within the next 10 years. New zone substations will be required in Eastlake and Molonglo to meet increasing demand and to relieve capacity pressures on existing sub-stations.

Zone substation capacity shortages in Canberra Central District (that is, Inner North and Inner South Canberra) are forecast to occur unless augmentation is undertaken. This necessitates investment in the City East, Civic, Telopea Park and Woden zone substations and the new Eastlake Zone Substation in the next 10 years. Without investment, a shortage is expected to occur before the end of the 2009–14 regulatory period at Fyshwick and Civic Zone Substations. This will seriously put at risk the supply security currently provided by the ACT electricity network unless augmentation is undertaken.

Four main augmentation projects have been planned and incorporated into capital expenditure forecasts:

- establishment of a new zone substation in Eastlake to provide initially 50MVA new capacity, with provision to increase to 100MVA in the future. This will provide the urgently required capacity for the major developments in the surrounding areas, and allow progressive retirement of the temporary Fyshwick Zone Substation beyond the 2009–14

[65] *Utilities Exemption 2006 (No1)* made under the *Utilities Act 2000*

regulatory period. East Lake Zone Substation will also take over a portion of Telopea Park Zone Substation load and enable Telopea Park Zone Substation to supply new government and commercial developments on both sides of the lake;

- installation of a third transformer and high-voltage switchboard at Civic Zone Substation. This will increase Civic Zone Substation capacity by 50MVA to meet demand requirement in City and City West, and postpone the need of augmentation of City East Zone Substation;
- a new zone substation in the Molonglo district is required for the provision of power to the new Molonglo District. The new zone substation will be able to take over some load in Weston Creek from Woden Zone Substation and therefore defer the need for Woden Zone Substation capacity augmentation for many years; and
- construction of 132 kV lines from the Southern Bulk Supply Point (operated by TransGrid) to provide the ACT with the second 132 kV connection point to the NSW transmission network as required by a regulation introduced in 2006 by the ACT Government. For regulatory purposes the lines have been considered by the ICRC and assessed to meet the definition of a distribution network (see attachment 13).

These augmentation projects are expected to meet the network demand and reliability requirements for the 2009–14 regulatory period. Forecasts show that Mitchell Zone Substation should not be required in the next 10 years unless development in the Canberra Central District is higher than expected. No augmentation expenditure is therefore included for Mitchell Zone Substation in the 2009–14 regulatory period.

Table 7.10 presents an overview of the expenditure for the four main augmentation programs. In summary, the key drivers of forecast augmentation expenditure are growth in urban and commercial development in Canberra, and the fact that load at multiple zone substations will reach or exceed the capacity in the next few years.

Table 7.10 Forecast main augmentation capital expenditure 2009–14

$2008/09 million	2009/10	2010/11	2011/12	F2012/13	F2013/14	**Total**
Eastlake Zone Substation and associated feeders	9.4	9.8	0.6	1.4	0.8	**22.0**
Civic Zone substation	3.7	3.1	0.0	0.0	0.0	**6.8**
Molonglo Zone Substation and associated feeders	0.0	0.3	7.3	7.4	0.0	**15.0**
Southern Supply Point 132 kV lines	14.2	0.0	3.9	4.4	0.0	**22.5**
Total	**27.3**	**13.2**	**11.9**	**13.1**	**0.8**	**66.3**

These projects account for 87 per cent of the proposed augmentation program and are described in further detail in the following sections. Details of these projects are provided in the Network Ten Year Augmentation Plan 2008/09 that forms part of this proposal, and in specific project justifications, which are outlined in the boxes below. The remaining augmentation capital expenditure is related to distribution systems such as feeders and cable upgrades due to increased demand.

Box 7.2 Eastlake Zone Substation

The South Canberra area has a large number of government offices and major commercial facilities including the Australian Parliament House, Federal Government departmental offices, national institutions, the Canberra International Airport, major hospitals, and the Defence Communication Centre. About one quarter of ACT residents live in this area.

There has been a sustained high level of land development and redevelopment in South Canberra. In particular, land development in the past few years has led to rapid diminution of zone substation spare capacity. Based on known current and future development, it is anticipated that load demand in South Canberra will exceed zone substation secure capacity by 2011.

When demand exceeds Fyshwick Zone Substation capacity, a zone substation transformer outage would lead to a prolonged outage. Power restrictions during the entire summer peak load period (or at any time) would lead to enormous and unacceptable economic losses.

Each of the existing zone substations has reached its design capacity and cannot be further expanded. The magnitude of capacity shortage and timing requirements also precludes other solutions, such as demand side management and distributed generation. A new zone substation is assessed as the only practical solution to address the capacity shortage.

Sites in the Narrabundah and Fyshwick areas have been examined in the past for the new zone substation. Presently two sites have been identified by the ACT Planning and Land Authority (ACTPLA) as suitable: one in the Eastlake area, and the other in Narrabundah. The Narrabundah site has been earmarked for a major electricity substation in the Territory Plan. Both sites have the potential to accommodate a combined zone substation and switching station facility. The Eastlake site was identified in 2006 by ACTPLA as a preferred site for the Causeway Switching Station relocation.

A set of planning objectives has been established and a planning study carried out for both sites. The study concludes that the Eastlake option provides marginally better outcomes than the Narrabundah option at a similar cost. It also accommodates the ACT Government’s desire for the Causeway Switching Station to be relocated away from the Kingston Foreshore.

The proposed Eastlake Zone Substation and associated high-voltage network includes:

- a 50MVA zone substation by 2011
- 132 kV line work by 2011
- provision for a zone substation capacity upgrade to 100 MVA at a later date
- $11 million for rolling out high-voltage network over a period of 15 years.

Box 7.3 Civic Zone Substation

Civic Zone Substation is located to the North West of Canberra city centre and supplies predominantly commercial and residential buildings located in the city. The substation was built in 1986 and has two 55 MVA 132/11 kV transformers installed with associated 132 and 11 kV switchgear.

The *Electricity Distribution (Supply Standards) Code 2000* (ACT) requires ActewAGL Distribution to maintain sufficient network capacity to meet customer demand. Following common industry practice, ActewAGL Distribution's electricity network is designed to have sufficient supply capacity under most single contingency events in the high-voltage and extra high-voltage networks. The high-voltage network in urban areas is designed to satisfy N-1 or N criteria through adequate equipment rating and network configurations. The general principle has been to maintain network secure capacity above the maximum demand in all parts of the networks.

Based on demand forecasts, the cyclic rating at Civic Zone Substation would have been exceeded in 2008 summer in a one in ten year weather condition, and the emergency rating will be exceeded by summer 2012. ActewAGL Distribution must augment the Civic Zone Substation in order to meet this demand.

The preferred solution to meet the expected demand is the installation of a third transformer.

Box 7.4 Molonglo Zone Substation

The ACT Government is planning a new Molonglo District between Weston Creek and Belconnen districts, along the Molonglo River. The intended population of this district is around 50,000 to 75,000. A new Molonglo Zone Substation will be required to service this new district, and to provide capacity relief to Woden Zone Substation.

There are four existing zone substations within 10km of the proposed Molonglo zone substation location. These are Latham (8.5km), Belconnen (7.2km), Civic (5.3km) and Woden (5km). Latham and Belconnen have been discounted due to their distance from the new development and their existing demand and forecast demand growth. Black Mountain lies between the Civic Zone Substation and the proposed development at Molonglo and makes the installation of 11 kV cables impractical. Based on the forecast load growth, Woden Zone Substation will reach its summer emergency capacity of 95MVA by 2014. Woden Zone Substation cannot cover the entire Molonglo District development and several major developments are expected to contribute to the Woden substation load growth.

As a result, a new zone substation is required to meet the demand of the Molonglo area by 2013.

This new substation will initially provide 50 MVA capacity to supply the Molonglo District, the southern end of Belconnen District, the northern parts of the Weston Creek and Stromlo districts.

Box 7.5 Southern Supply to the ACT 132 kV lines stage 1

In 2006, the ACT Government created a statutory network performance regulation requiring TransGrid to establish a second supply point to the ACT with a capability of at least 375 MVA. Utilisation of the supply point capacity requires ActewAGL Distribution to develop and connect 132 kV lines to the supply point.

Two feasible augmentation options for transmission connection to Williamsdale covering the planning horizon have been jointly developed by TransGrid and ActewAGL Distribution. TransGrid and ActewAGL Distribution have applied the regulatory test to these two options. The option that was chosen is the establishment of the Williamsdale 330/132 kV Bulk Supply Point (BSP), the option that had the lowest present value of costs in all cases.

ActewAGL Distribution is required to undertake work to connect Williamsdale BSP into the ActewAGL Distribution sub-transmission system including:

- construction of two high capacity 132 kV circuits from Williamsdale to the Gilmore/Theodore area at least six months prior to 330 kV supply being required at Williamsdale
- any works necessary to upgrade the network capacity within the ActewAGL Distribution sub-transmission network to match the supply capability of the Williamsdale BSP.

The total cost of stage 1 is currently estimated to be $14.9 million (including easement acquisition and compensation costs).

7.3.6 Reliability and quality improvements

Reliability and quality improvements were not considered as a separate category in ActewAGL Distribution’s 2004 submission to the ICRC, however some reliability and quality improvements expenditures have occurred in the 2004–09 regulatory period. An overview of the expenditures in the current regulatory period is provided in Table 7.11.

Table 7.11 Historic reliability and quality improvements capital expenditure programs 2004–09

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	**Total**
Sub-transmission	0.0	0.0	0.0	0.0	0.0	**0.0**
Distribution system	0.0	0.0	0.1	0.6	0.3	**1.0**
Zone substations	0.0	0.0	0.0	0.0	0.1	**0.2**
Total Electricity Reliability and Quality Improvements	**0.0**	**0.0**	**0.1**	**0.6**	**0.4**	**1.2**

There was only minor expenditure under the reliability and quality improvements category during the current regulatory period, mainly relating to feeder ties and under-frequency relays. The increased cost for distribution system in 2007/08 is due to construction of a feeder tie in Hume and re-conducting of a feeder in Majura.

As noted in chapter 3, ActewAGL Distribution has only limited forecast expenditure specifically targeted at reliability improvements. The expenditure focuses instead on rectifying localised reliability problems rather than improve system wide network performance as the current analysis of the costs of reliability improvements (through installation of reclosers on 11 kV lines) outweigh customer willingness to pay at this stage. Planned augmentations as outlined in the previous section, however, will contribute to security and reliability of supply..

When estimating future reliability and quality improvement expenditures, ActewAGL Distribution has identified specific programs that have been estimated considering the capital expenditure factors (clause 6.5.7). The costs for the 2009–14 regulatory period are presented in Table 7.12.

Table 7.12 Forecast reliability and quality improvements capital expenditure programs 2009–14

$ million (2008/09)	2009/10	2010/11	2011/12	F2012/13	F2013/14	**Total**
Sub-transmission	0.0	0.0	0.0	0.0	0.0	**0.0**
Distribution system	0.1	0.3	0.3	0.3	0.3	**1.2**
Zone substations	0.1	0.1	0.1	0.0	0.0	**0.3**
Total Electricity Reliability and Quality Improvements	**0.2**	**0.4**	**0.4**	**0.3**	**0.3**	**1.5**

Reliability and quality improvement capital expenditure is forecast to remain between $0.2 million and $0.4 million during the 2009–14 regulatory period. The expenditure will be targeted at projects related to reliability and quality of supply. While not a significant expenditure, the program will help to maintain the long-term performance of the network and compliance with ActewAGL Distribution's regulatory obligations in specific locations.

7.3.7 Electricity asset replacement and renewal

Asset replacement and renewal programs are necessary to maintain the performance of the network and ensure ActewAGL Distribution complies with its regulatory obligations, particularly in respect of network reliability and safety. For example, safety and reliability concerns drive projects such as zone substation 11 kV transformer cable sealing ends and replacement of capstan nut switchboards, as personal injuries to ActewAGL Distribution staff have occurred. The asset replacement category covers expenditure on the existing network assets that is capitalised as part of the capital expenditure budget. The assessment of potential trade-offs between capital expenditure and operating expenditure is described in chapter 6 of this regulatory proposal.

The main drivers for the current asset replacement program are replacement of defective equipment (for example condemned wooden poles), and replacement of equipment that cannot meet the current operational requirements (for example certain types of switchgear, and protection relays).

An overview of the total Electricity asset replacement and renewal capital expenditure in the current regulatory period is set out in Table 7.13.

Table 7.13 Historic replacement and renewal capital expenditure programs 2004–09

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	**Total**
Zone Substations	0.4	0.9	1.4	1.0	2.4	**6.1**
Sub-transmission	0.0	0.0	0.0	0.0	0.0	**0.0**
Distribution Substations	1.4	1.5	1.5	2.0	2.2	**8.5**
Distribution Overhead	9.5	9.7	13.4	13.2	12.9	**58.7**
Distribution Underground	0.1	0.2	0.1	0.3	1.1	**1.8**
Buildings	0.0	0.0	0.0	0.1	0.0	**0.1**
Total Electricity Replacement and Renewal	**11.4**	**12.3**	**16.5**	**16.5**	**18.6**	**75.2**

Asset replacement and renewal expenditure has increased by 13.1 per cent per annum during 2004–09. This is mainly because costs in the zone substations, *Distribution Overhead* and *Distribution Underground* asset classes have increased substantially as described below.

During the current regulatory period, expenditure on zone substations has increased from $0.4 million to a projected $2.4 million. The gradual increase in expenditure observed over the period reflects a steady increase in the need to undertake condition-based replacements of assets to ensure compliance with regulatory obligations. The targeted activities include the upgrade of perimeter fencing and replacement of switchboards, relays, cable sealing ends, instrument transformers, isolators and battery chargers before failure. Relevant regulatory obligations include the need to:

- enhance the security of critical infrastructure;
- ensure compliance with reliability standards; and
- ensure the safety of employees.

Distribution overhead costs have increased due to an increased need to replace poles that have been condemned. In 2003, ActewAGL Distribution enhanced its pole inspection program following several pole failures that resulted in house fires, vehicle damage and a pole collapsing with an ActewAGL Distribution employee aloft and causing extensive injuries (see Box 7.1 for further details).

This pole inspection program has led to an increase in the condemnation rates of poles, and therefore the pole replacement program. ActewAGL Distribution's network includes a high percentage of natural round poles compared to other Australian distribution businesses. The majority of pole condemnations relate to these poles.

Distribution underground expenditure will increase in 2008/09 by $0.8 million. In order to meet obligations and manage risks associated with the operation of the electrical network (eg address issues of safety and reliability as recently identified by the Technical Regulator or actual failures), replacement will be required for various high voltage and low voltage mains and pilot cables and associated joints and terminations, service cables and distribution pillars or Tee joints.

Methodology for estimating asset replacement and renewal costs

Asset renewal investment is mainly driven by the ageing of the assets, and compliance requirements relating to safety, reliability and asset protection. The objective of asset replacement is to manage risks and requirements relating to:

- maintaining electricity supply and reliability;
- maintaining operational functionality of the network;
- providing a safe work environment for ActewAGL Distribution’s employees and contractors;
- ensuring public safety;
- environmental compliance;
- avoiding property damage;
- legal and regulatory obligations; and
- optimising the balance between capital and operating expenditures.

Forecast expenditures are determined after consideration of:

- historic trends;
- escalation of material costs as described in section 7.3.3 above;
- the assessed condition of the assets;
- assessment of asset failure rates;
- risk management review and prioritisation;
- unit rates ;
- pole replacement and refurbishment modelling;
- the requirements of the Technical Regulator;
- the need to achieve and comply with service and technical standards;
- assessment of Health, Safety and Environmental issues; and
- assessment of operating expenditure/capital expenditure trade-offs.

As noted in chapter 6 of this regulatory proposal, assets are generally replaced either as a result of equipment failure or deteriorating condition of an asset indicating imminent failure.

Other asset replacement considerations include the added value that new assets may provide, because of integrated features through new technology.

For the 2009–14 regulatory period, the asset replacement strategy focuses on critical assets where a reasonable failure probability exists and its impact would potentially result in high financial, reliability, safety or environmental risks.

The average age of ActewAGL Distribution's assets at June 2009 is modelled to be 25.6 years. The proposed replacement and renewal program will slow down the rate of increase in the average age of the assets. In June 2014, the average age of the assets is expected to be 27.5 years as described in chapter 6 of this regulatory proposal, based on ActewAGL Distribution's capital expenditure proposal.

ActewAGL Distribution's forecast asset replacement and renewal capital expenditures for the 2009–14 regulatory period are set out in Table 7.14.

Table 7.14 Forecast Replacement and Renewal capital expenditure programs 2009–14

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Zone Substations	*2.4*	3.9	5.0	2.2	2.3	2.0	**15.4**
Sub-transmission	*0.0*	0.0	0.0	0.0	0.0	0.0	**0.0**
Distribution Substations	*2.2*	2.2	2.3	1.8	1.6	1.7	**9.5**
Distribution Overhead	*12.9*	12.9	13.3	14.0	14.0	14.7	**69.0**
Distribution Underground	*1.1*	1.1	0.9	0.9	0.9	0.9	**4.8**
Buildings	*0.0*	0.0	0.0	0.0	0.0	0.0	**0.0**
Total Electricity Replacement & Renewal	***18.6***	**20.2**	**21.5**	**18.9**	**18.8**	**19.3**	**98.6**

Forecast asset replacement program expenditures will increase by $1.6 million in 2009/10 and by a further $1.3 million in 2010/11 but then decrease by $2.6 million in 2011/12. The increase in 2009/10 is due to the Civic Zone Substation switchboard replacement, battery charger replacement and increased overhead costs due to requirements for vegetation management and bushfire mitigation, including the effect of the new *Tree Protection Act 2005*.

Where the requirement under the *Utilities Act* to manage vegetation to protect overhead assets conflicts with obligations under the *Tree Protection Act*, ActewAGL Distribution develops capital expenditure programs to underground overhead conductors or install aerial-bundled low-voltage overhead cables. ActewAGL Distribution expects that the need to underground assets to protect registered trees will increase over the coming regulatory period as trees are placed on the tree register, and more trees meet minimum size requirements for regulation under the *Tree Protection Act*.

The further increase in expenditure in 2010/11 is mainly due to the Civic Switchboard replacement ($0.8 million). With the expected completion of this project in 2010/11, replacement and renewal expenditures will decrease. Distribution Overhead expenditure (due to pole replacement) is expected to remain high and increase over the 2009–14 period due to a predicted increase in condemned poles. Further information about the pole replacement program is provided below.

In summary, key drivers of the replacement and renewal program are ActewAGL Distribution's ageing assets requiring replacement and renewal for reliability, security and safety reasons, in combination with regulatory obligations.

The major replacement and renewal programs that will be undertaken are presented in Table 7.15. These programs explain 78 per cent of the proposed asset replacement and renewal program. Detailed project justifications are contained in the Network Ten Year Augmentation Plan and Asset Management Plan.

Table 7.15 Major replacement and renewal programs 2009–14

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	**Total**
Pole replacement and reinforcement programs	9.8	10.1	10.3	10.3	10.4	**51.1**
Civic Switchboard Replacement	1.4	2.2	0.0	0.0	0.0	**3.6**
Zone Fence Upgrades	0.7	0.7	0.7	0.7	0.4	**3.3**
Over-current & Distance Protection Relay Replacements	0.5	0.6	0.6	0.7	0.4	**2.8**
Ground Substation Replacement	1.6	1.9	1.4	1.6	1.7	**8.1**
Reactive and Planned Zone Substation Equipment Replacement	0.7	0.9	0.3	0.3	0.6	**2.8**
Underground Network Replacement	1.1	0.9	0.9	0.9	0.9	**4.8**
Capital expenditure major programs/projects	**16.0**	**17.3**	**14.2**	**14.5**	**14.5**	**76.5**

Pole replacement and reinforcement programs

Power pole replacements are forecast to dominate the asset replacement program for the 2009–14 regulatory period. ActewAGL Distribution estimates that 5,492 poles will be replaced in the 2009–14 regulatory period. Pole reinforcement is also a significant expenditure and is a prudent method of extending pole life thereby deferring capital expenditure.

ActewAGL Distribution's network incorporates approximately 53,000 power poles, the majority of which (approximately 39,000) are wooden. Almost half of the poles in the network are untreated natural round wood poles which are particularly susceptible to deterioration of their structural integrity over time.

Failure of power poles has lead to a significant number of incidents including damage to property and injury to people. A serious injury to a linesman occurred when a pole failed in December 2002. At this time, ActewAGL Distribution’s pole failure rate was at least three times higher than for other electricity network companies (with similar poles) that were represented on the then Electricity Supply Association of Australia Power Poles committee.

ActewAGL Distribution is compelled to appropriately manage the risks associated with its power pole population for a number of reasons. These include Health, Safety and Environment (HSE) legislation, disclosure and risk management for insurance purposes, meeting the Technical Regulator’s requirements, and meeting the *Utility Networks (Public Safety) Regulation 2001* requirements.

The pole replacement and reinforcement program deals with condemned wooden power poles. This program of works is required to meet the transitional *Rules* capital expenditure objective to “maintain the safety and security of the distribution system through the supply of standard control services.”

As a result of the pole failures, ActewAGL Distribution reviewed the pole inspection cycle and replacement/reinforcement policy, and implemented an enhanced pole inspection and management regime in order to manage the pole population in accordance with “good electricity industry practice”. The main revisions of the process and procedure focused on:

- provision of improved Geographic Information System (GIS) and defect recording facilities;
- increased rigour in the management of adherence to the documented inspection cycle for every pole;
- numbering of every pole;
- dealing with access and obstruction issues; and
- revision of the procedure to include improved tools, abaxial treatment of wood poles and inspection holes to control fungal attack, standardised inspection depths and enhanced inspection around hard surfaces, concrete collars etc.

During the period from May 2003 to November 2007, 13,050 condemned poles were rectified, 4,297 by replacement and 8,753 by reinforcement. Most wooden poles are condemned because of a loss of strength in the buried section of the pole near ground level. This loss of strength is typically the result of rot, termites or bushfire. Natural round wood poles have no preservative treatment carried out prior to being installed in the ground, which increases the risk of rot and or termites. As a result of this, the condemning rate for natural round poles is approximately 10 times greater than the other types of wood poles (Creosote and Tanalith (CCA) hardwood poles which are no longer used due to scarcity and expense).

In addition to the main reasons for condemning a pole, it is estimated that at least half of the natural round poles have cross-arms attached with a non-galvanised (black) *kingbolt*. These bolts are more than 35 years old and are corroding. The resultant rust is causing the pole heads to split which leads to moisture ingress and rot spores. Many of these poles will require replacement because of severe loss of strength in the pole head.

While there has been a high condemning rate over the last four years, 68.5 per cent of these poles that were condemned have been reinforced and remain in the network. This ratio is forecast to remain the same in the 2009–14 regulatory period.

ActewAGL Distribution and consultants SKM have developed a pole replacement and reinforcement model to provide a forecast for the requirements of managing the pole population over the next two regulatory periods. This model provides separate forecasts of condemnation rates for different pole types (for example, natural round, creosote, tanalith, etc.), as well as forecasts for future replacement of reinforced poles and poles with kingbolt damage and rot above ground.

The following points summarise the key drivers in the model, and the basis on which the model was developed:

- ActewAGL Distribution has a comparatively high condemning rate with respect to other network providers due to the age, condition and type of poles in the network. The high condemning rate is being addressed by implementing a higher reinforcement rate and a modest replacement rate which is in line with other utilities;
- the overall forecast condemnation rate for all types of poles is expected to drop from the current level of 27 per cent, to 21 per cent over the period 2008/09 to 2011/12, and 15 per cent thereafter; and
- reinforcing poles allows for the prudent deferral of capital expenditure and results in the life of the existing network assets being extended.

If the program is not completed the risk to the public and ActewAGL Distribution would increase dramatically as the proportion of reactive replacement increases. This also results in significantly higher costs than those of a similar planned replacement. The cost difference is estimated to be $5,000 per pole, though fewer poles would be involved in the reactive replacement approach.

As a result of the potentially problematic access arrangements at each site (as described in chapter 2), the average cost of pole replacement/reinforcement is higher for ActewAGL Distribution than other utilities.

Resulting from a four-way competitive tender, ActewAGL Distribution's pole reinforcement price is reflective of the current market price. Quantities of poles forecast to require replacement and reinforcement over the 2009–14 regulatory period are shown in Table 7.16.

Table 7.16 Forecast quantities of pole replacements and reinforcements 2009–14

Number	2009/10	2010/11	2011/12	2012/13	2013/14
Pole replacements	1,095	1,095	1,095	1,105	1,102
Pole reinforcements	700	700	700	360	360

Ground substation replacement

A range of equipment items is installed in ground mounted substations and switching stations. Replacements of components or complete substations may be required due to intrinsic failure, failure from external factors, safety or environmental issues or obsolescence. This program is to enable the replacement of ground mounted substation equipment and its associated ancillary equipments.

Replacement will be necessary to ensure compliance with regulatory obligations associated with the provision of electrical services and to maintain the reliability, safety and security of the distribution system.

Civic switchboard replacement

This project is required to replace the potentially unreliable switchboards at Civic Zone Substation and therefore meets the capital expenditure objective to maintain the quality reliability and security of the distribution system. The Zone Substation's switchroom hosts two high-voltage switchboards both of which have been in continuous service since 1967 and are in need of replacement owing to the condition of each switchboard, lack of spare parts, and concurrent reliability issues.

7.3.8 Network IT Systems and Communications

An overview of Network Information Technology (IT) Systems and Communications capital expenditure over the current regulatory period is set out in Table 7.17.

Table 7.17 Historic Network IT Systems and Communications capital expenditure programs 2004–09

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	**Total**
Other non system assets	0.4	0.5	0.4	0.5	0.5	**2.3**
Network IT systems	0.5	0.8	0.8	1.8	2.2	**6.1**
Total Network Non-system Capital Expenditure	**0.9**	**1.2**	**1.2**	**2.3**	**2.7**	**8.4**

Network IT Systems expenditures have increased from $0.9 million to $2.7 million during the current regulatory period. The main increase has occurred during 2007/08 due to investment in the upgrade of the Trunk Mobile Radio (TMR) and Very High Frequency (VHF) Operational Radio Systems. The ageing TMR network requires the replacement of system hardware that is well beyond the end of its 10-year projected life. The expenditure on other non-system assets has been stable during the current regulatory period.

Methodology for estimating Network IT Systems and Communications

Key underlying documents to the Network IT Systems and Communications capital expenditure programs are the:

- Technology and Information Management Strategy;
- Ten Year Network Capital Investment Projects – Technology and Information Management; and
- SCADA & Information Systems Strategy.

As noted in chapter 6 of this regulatory proposal, the key goal of expenditure on IT Systems and Communications is to ensure continued support of the current business requirements and the known business future directions using the technology most suited to meeting these ends.

A key objective of expenditure on IT is to achieve integrated support systems such that information that supports other business functions and processes is available to related and unrelated systems when it is required and be readily accessible to allow data mining for the production of decision making information. A further objective is compliance with regulatory requirements (for example, maintaining the. outage database) as well as safety and operational considerations via Supervisory Control and Data Acquisition (SCADA). The number of systems currently containing similar information is large and is counter-productive to the aims of minimising data entry.

ActewAGL Distribution aims to reduce the number of systems to an efficient level. This will be dictated in a large part by the functionality provided by the applications that interface with the various databases. The means of achieving this is to consolidate and amalgamate the current databases into a manageable number of systems, and to integrate these systems in such a way that duplication of data entry is minimised.

Capital expenditure forecasts are determined by the following process:

- Review of the business requirements;
- Assessment of data requirements for operational, regulatory and financial purposes;
- Review of the data model and systems integration including data access issues;
- Review of data security;
- Assessment of requirements arising from the expansion of the network;
- Review of the assessed condition of existing systems and data bases;
- Assessment of the timing of obsolescence;

- Risk management review and prioritisation;
- Consideration of the need to be able to respond to business needs and external regulatory compliance requirements;
- Consideration of efficiency improvements;
- Integration with corporate strategies;
- Compliance with corporate and networks technical standards; and
- Assessment of health, safety and environmental factors.

ActewAGL Distribution's forecast IT System and other non system asset capital expenditures for the next regulatory control period are set out in Table 7.18.

Table 7.18 Forecast Network IT Systems and Communications capital expenditure programs 2009–14

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	**Total**
Other non system assets	0.5	0.5	0.5	0.5	0.5	0.5	**2.6**
Network IT systems	2.2	4.3	4.1	3.5	3.5	5.1	**20.5**
Total Network Non-system Capital Expenditure	**2.7**	**4.8**	**4.7**	**4.0**	**4.1**	**5.6**	**23.1**

The step increase in expenditure in 2009/10 of $2.1 million is due to investments and replacements in the Network IT Systems. Other non systems assets expenditures are expected to be stable throughout the 2009–14 regulatory period. The main reason for the step increase in Network IT system capital expenditures is as follows:

- replacement of protection intertrip and SCADA communications pilot cables with an estimated cost of $1.9 million in 2009–14 due to decline in their electrical characteristics as some "pairs" in some cables do not meet defined criteria for protection circuit operation, which has caused unplanned outages. Pilot cables have been *in situ* in some cases for 40 years.
- IT system replacements are undertaken on a 7- to10-year basis according to normal practise. The cost for IT system replacement will be $7.2 million in 2009–14. Major IT system replacements in the regulatory period include the Asset and Works Management and GIS systems. In 2013/14 preliminary work is expected to commence on a replacement SCADA system.
- zone substation Remote Terminal Unit replacement due to equipment failure of some RTUs. The oldest of this type of equipment has been in service for over 20 years and replacement parts for the RTU models in these substations are not available through the manufacturer which necessitates replacements.

- three network automation programs: Enhancement of high-voltage Switchgear to Allow Remote Operation, Upgrade of Key Distribution Substation to Remote Operability, and Enhancement of the Fault Passage Indicator Monitoring to improve fault location through the installation of Fault Passage Indicators (FPI) linked to the SCADA system and thereby reduce unplanned customer outage duration.

7.3.9 Corporate Services Business Support capital expenditure

Corporate Services Business Support capital expenditures arise from Facilities Management and Business Systems areas of ActewAGL Distribution.

Corporate capital expenditure is allocated following a direct allocation linked to the business (Electricity Network, Water division, ActewAGL Retail etc). For example, refurbishment/security upgrade at Greenway depot is directly allocated to Electricity Networks. Corporate Services has allocated 54.75 per cent of the forecast capital expenditure for the new corporate headquarters. This adopts the same method as in the last regulatory decision, in accordance with clause 6.15.8(b)(1) of the transitional *Rules*.

An overview of the current period Corporate Services Business Support capital expenditure is set out in Table 7.19.

Table 7.19 Historic Corporate Services Business Support capital expenditure 2004–2009

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	**Total**
Corporate Services Business Support	2.4	1.0	0.8	3.7	2.4	**10.3**
Total Corporate Services Business Support	**2.4**	**1.0**	**0.8**	**3.7**	**2.4**	**10.3**

The increased expenditure in 2007/08 is related to refurbishments in Greenway (locker room conversion) and the AER price review. In 2008/09 the costs relate to security improvements and refurbishments in Greenway and the costs associated with the current regulatory price review process. From 1 July 2009, ActewAGL Distribution proposes to harmonise the regulatory treatment of these costs, currently capitalised, with general accounting practice where they are expensed.

Forecasts are determined by the following process:

- Review of the business requirements;
- Assessment of data requirements for operational, regulatory and financial purposes;
- Review of data security;
- Review of the assessed condition of existing buildings and IT systems;

- Assessment of the timing of obsolescence;
- Risk management review and prioritisation;
- Consideration of the need to be able to respond to business needs and external regulatory compliance requirements;
- Consideration of efficiency improvements;
- Integration with Corporate strategies;
- Compliance with Corporate and Networks technical standards;
- Assessment of health, safety and environmental factors; and
- The capital expenditure for corporate services has been escalated using CPI.

Forecast Corporate Services Business Support capital expenditure is outlined in Table 7.20.

Table 7.20 Forecast Corporate Services Business Support capital expenditure 2009–14

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	**Total**
Corporate Services Business Support	*2.4*	7.4	1.5	1.6	1.4	1.5	13.3
Total Corporate Services Business Support	***2.4***	**7.4**	**1.5**	**1.6**	**1.4**	**1.5**	**13.3**

The forecast incorporates capital expenditure for existing properties and the relocation of ActewAGL Corporate Headquarters to 6 Mort Street. Due to the relocation in 2009/10 there will be a considerable increase in capital expenditure in both Facilities Management and Business Systems and Commercial Development, but the overall operating expenditure will thereafter decrease. The Regulatory Asset Base will decrease in 2008/09 to reflect disposal of the asset as discussed in section 7.3.10 below.

Major Corporate Services Business Support projects to be undertaken are:

- relocation of the corporate headquarters (further described in chapter 8 of this regulatory proposal);
- maintenance and refurbishments of buildings;
- security enhancements; and
- IT development and telecommunications enhancement.

7.3.10 Disposals

ActewAGL Distribution expects to have one asset disposal with cash effect during the current regulatory period. During 2009/10, ActewAGL's Corporate Headquarters will move from the current ActewAGL House at 221 London Circuit to a new, leased building at 6 Mort Street, Canberra City. As a result, ActewAGL House will be sold resulting in a disposal which has been accounted for in the 2008/09 forecasts.

7.3.11 Capital Contributions and Relocation Capital Contributions

Under the *Electricity Networks Capital Contributions Code* (ACT) (the *Code*), an electricity distributor may charge, and a customer must pay, a capital contribution charge for the development or augmentation of the distributor's electricity network undertaken at the request of the customer. ActewAGL Distribution's Electricity Networks 10-year Capital Investment Plan provides the basis for determining when *Capital Contributions* and *Relocation Capital Contributions* are likely to occur.

To forecast the value of capital contributions, ActewAGL Distribution applies the provisions of Code to the various categories of customer initiated works under the code. In categories where contributions can be less than 100 per cent of the total project, historical data for that category are used, in consultation with ActewAGL Distribution's project design branch. The value of capital contributions in Table 7.22.

Table 7.21 Capital contributions 2004–09

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	Total
Customer contributions	3.8	2.5	3.1	3.6	6.1	**19.1**
Relocation contributions	2.5	1.2	1.3	1.6	1.8	**8.3**
Capital contributions	**6.3**	**3.7**	**4.4**	**5.1**	**7.9**	**27.3**

Table 7.22 Forecast capital contributions 2009–14

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Customer contributions	4.7	7.0	6.5	3.3	2.9	**24.4**
Relocation contributions	1.2	1.2	1.0	0.9	0.8	**5.0**
Capital contributions	**5.8**	**8.2**	**7.5**	**4.2**	**3.7**	**29.4**

7.4 Major supply contracts

The RIN requires ActewAGL Distribution to describe the top ten transactions with an entity other than the provider for the supply of goods and/or services over the current and the next regulatory control period. These major contracts pertain to the supply of vehicles (via leases), cables, galvanised 3-piece poles, pole replacement services, concrete poles and padmounts and ground mounted transformers. Details are provided in pro forma 2.3.12.

The contracts are awarded to contractors following a tendering process with selection on the basis of best value. For the current regulatory period, the top ten transactions represent about

$75 million. It is difficult to measure the expected value of the top ten transactions in the 2009–14 regulatory period since suppliers could be changed and/or ActewAGL Distribution may decide to use more or fewer contractors for the specific services to optimise value. Based on the information available at the time of the regulatory proposal, ActewAGL Distribution expects the total value of the top ten transactions in the 2009–14 regulatory period to be approximately $105 million.

7.5 Variance justification

ActewAGL Distribution has, in attachment 16, provided reasons for variations greater than 10 per cent in the 2009–14 regulatory period compared with the baseline 2006/07 for respective cost category.

There are many components of capital and operating costs that will increase by more than 10 per cent against the baseline. This is due to the low augmentation levels since 1994 (when the last zone substation was built), the pressures on wages, and increased commodity prices.

7.6 Summary of forecast capital expenditure

ActewAGL Distribution's proposed capital expenditure program continues and builds on the completed program for the current regulatory control period. The proposed program is aimed at ensuring ongoing network reliability, meeting demand growth, and minimising the total life cycle cost of providing network services. Table 7.23 summarises the total proposed capital expenditure program for 2009–14 including capital contributions and disposals.

Table 7.23 Forecast capital expenditure including contributions and disposals 2009–14

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Asset renewal/replacement	20.2	21.5	18.9	18.8	19.3	**98.6**
Customer initiated	21.7	23.9	20.3	15.2	12.9	**94.0**
Augmentation	29.9	14.6	13.9	15.4	2.7	**76.5**
Reliability and quality improvements	0.2	0.4	0.4	0.3	0.3	**1.5**
Network IT Systems	4.3	4.1	3.5	3.5	5.1	**20.5**
Less Capital Contributions	(5.8)	(8.2)	(7.5)	(4.2)	(3.7)	**(29.4)**
Non-system assets	0.5	0.5	0.5	0.5	0.5	**2.6**
Corporate Services Business Support	7.4	1.5	1.6	1.4	1.5	**13.3**
Total Capital expenditure	**78.3**	**58.3**	**51.7**	**50.9**	**38.5**	**277.7**
Net disposals	-	-	-	-	-	**-**
Net Capital expenditure	**78.3**	**58.3**	**51.7**	**50.9**	**38.5**	**277.7**

ActewAGL

ActewAGL Distribution believes that, should the AER consider reducing the value or scope of ActewAGL Distribution’s capital expenditure proposals, its regulated network operating expenditure would need to be correspondingly increased to compensate for the increased maintenance costs that would undoubtedly arise.

8. Forecast operating expenditure

ActewAGL Distribution's operating expenditure is forecast to increase moderately over the 2009–14 regulatory period. The key drivers contributing to the operating expenditures in the 2009–14 regulatory period are as follows.

- Wage increases – labour costs are rising at faster than the general increase in prices in the economy due to shortages of skilled labour and consequent requirement for strategies to engage and retain staff. Wages typically comprise around 70 per cent of operating expenditure.
- Taxation – inclusion of the ACT Government's Utilities Network Facilities Tax (UNFT) in operating expenditure (treated as a pass through in the current regulatory period).
- Self-insurance costs, not previously claimed for recovery, for risks faced by the business, where insurance cover is impractical or unavailable.
- Planned maintenance – higher expenditure levels for pole inspections and vegetation management will continue into the next period as major drivers of planned maintenance, but other planned overhead maintenance costs will increase due to required pole-top and cross-arm maintenance and installation of vibration dampers and low-voltage network line spreaders. Reactive maintenance is forecast to remain nearly constant at current period levels.
- Relocation of the ActewAGL Corporate Headquarters. This will result in a step increase in the category of *Other expenditures*. The Electricity Networks business bears a significant share of the operating costs of ActewAGL Distribution's existing corporate headquarters. The existing building dates from the 1960s, is expensive to operate and maintain and would require a major refit to bring it up to a suitable modern standards. The new building will be constructed to an accredited five-star Greenhouse rated design and cost significantly less to operate and maintain. However, since ActewAGL Distribution owns the current building and intends to lease the new one, operating costs will increase (the Regulatory Asset Base will be reduced by the sales proceeds from the current building).

Cost drivers are described in further detail under respective cost category.

Figure 8.1 shows the composition of ActewAGL Distribution's actual and forecast operating expenditure for the 2009–14 regulatory period. Figure 8.2 breaks down actual and forecast maintenance costs into planned and reactive segments.

Figure 8.1 Actual and forecast operating expenditure 2009–14

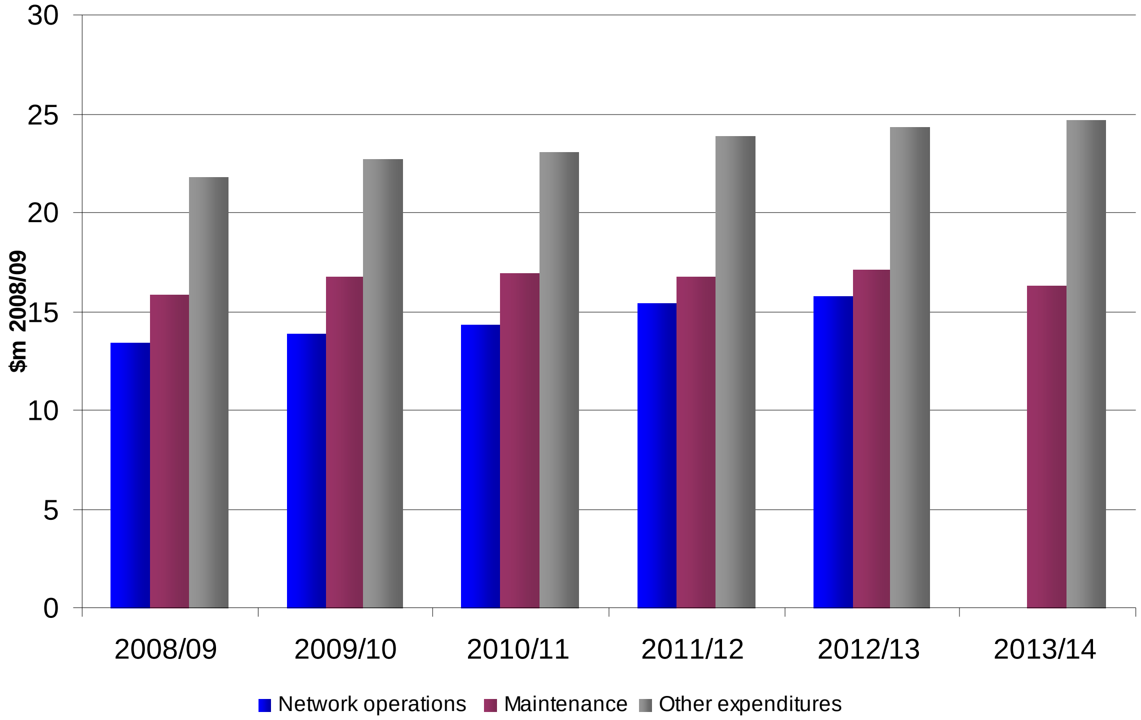
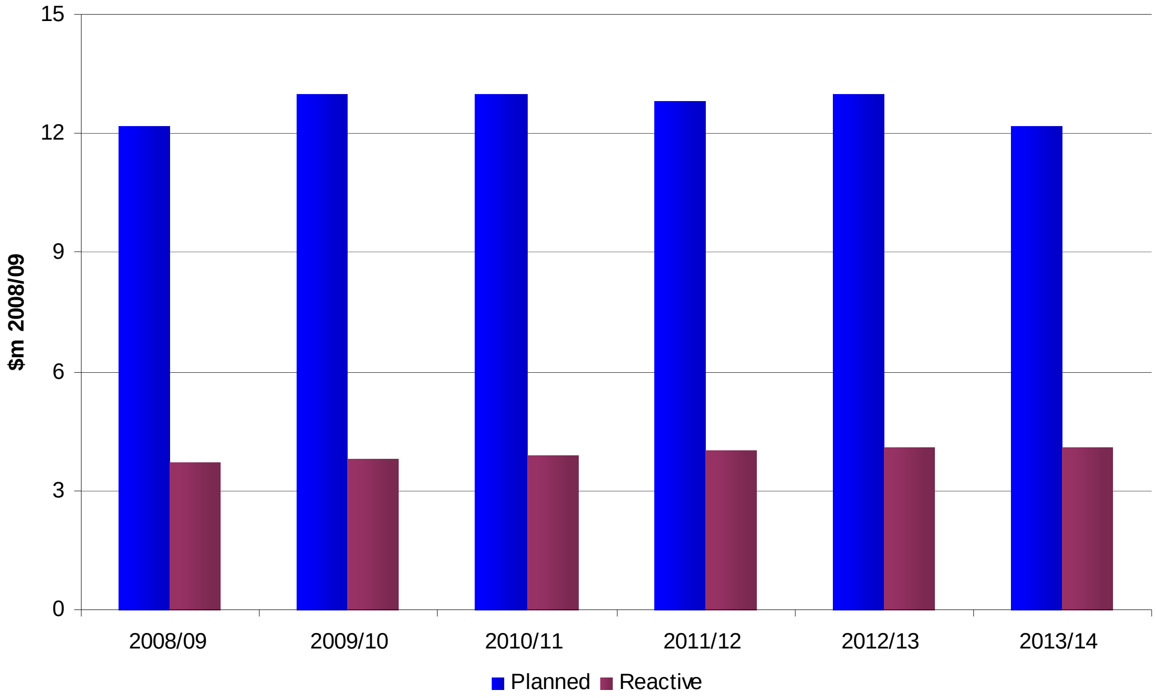


Figure 8.2 Actual and forecast maintenance costs 2009–14



8.1 Overview of historic regulated network operating expenditure

8.1.1 ICRC 2004 Final Decision

In March 2004, the ICRC released its Final Decision on prices for electricity distribution services in the ACT for 2004–09. The Final Decision included the regulated network operating expenditure shown in Table 8.1 (both in the 2002/03 constant dollars of the 2004 decision and inflated to 2008/09 constant dollars for ease of comparison).[66]

Table 8.1 ICRC 2004 Final Decision for operating expenditure

$ million	2004/05	2005/06	2006/07	F2007/08	F2008/09	Total
2002/03 dollars	37.8	37.7	37.4	38.5	39.6	190.9
2008/09 dollars	44.4	44.6	44.2	45.3	46.6	225.0

The ICRC accepted ActewAGL Distribution's proposed regulated network operating expenditure for the regulatory period, except for:

- the removal of a proposed provision for the disposal of obsolete stock; and
- the deduction of a progressive 1 per cent per annum compounding efficiency factor.

8.1.2 Cost pass throughs 2004–08

The ICRC approved two pass-throughs of costs in the current regulatory period. These were in relation to the network costs involved in the introduction of Full Retail Contestability in electricity passed through in 2004/05 and for the introduction of the Utilities Network Facilities Tax (UNFT) in 2005/06. The Full Retail Contestability cost pass through amount is reflected in Table 8.2.

8.1.3 ActewAGL Distribution's actual operating expenditure 2004–09

ActewAGL Distribution now expects its total operating expenditure for the current period to exceed that determined by the ICRC by $1.4 million or 0.6 per cent over the five-year period. The comparison between operating expenditure in the 2004 ICRC Final Decision and ActewAGL Distribution's actual and forecast operating expenditure in the current period is provided in Table 8.2.

The operating expenditure outcome primarily reflects ActewAGL Distribution's costs of meeting its safety and reliability obligations in an environment of generally rising costs.

[66] All dollar values in this chapter, unless otherwise specified, are expressed in constant 2008/09 terms.

Table 8.2 Comparison of ICRC decision and actual and forecast operating expenditure

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	Total
Network operations	11.3	11.9	11.8	13.1	13.0	**61.2**
Planned Maintenance	*7.6*	*8.0*	*8.4*	*9.5*	*12.2*	***45.7***
Reactive Maintenance	*2.7*	*3.8*	*3.5*	*3.6*	*3.7*	***17.4***
Maintenance expenditures	10.3	11.8	12.0	13.1	15.9	**63.0**
Other expenditures	20.9	19.9	20.5	21.4	21.8	**104.5**
Total operating expenditure	**42.5**	**43.6**	**44.3**	**47.6**	**50.7**	**228.7**
ICRC decision	44.4	44.6	44.2	45.3	46.6	**225.0**
Approved cost pass throughs	1.2	1.1	0.0	0.0	0.0	**2.3**
Over (under) spend	**(3.1)**	**(2.1)**	**0.1**	**2.3**	**4.1**	**1.4**

Note: Figures exclude the UNFT. See pro forma 2.2.2 AA opex for the UNFT in the current regulatory period.

There has been a general growth in operating expenditure over the 2004–09 regulatory period, driven by:

- real wages growth in the general construction sector throughout Australia has out-stripped movements in the Consumer Price Index (CPI) due to skill shortages impacting on utilities across Australia;
- growth in the costs of materials used in operations and maintenance has significantly exceeded movements in CPI;
- growth in the number of the assets as ActewAGL Distribution responds to increasing development demands in the ACT;
- an ageing asset base has resulted in increased corrective and emergency maintenance;
- planned maintenance needed to increase to contain and reduce reactive maintenance;
- the requirement for an enhanced pole inspection program to deal with increased risks to safety from the aging asset base;
- additional vegetation and bushfire mitigation inspection and management programs to address and mange the risks to electricity supply and the environment;
- additional overhead line maintenance for example on pole tops, low conductors, and cross-arms to address backlogs;
- additional distribution substation and mini-pillar maintenance to address safety and access requirements raised by ActewAGL Distribution’s Technical Regulator;

In addition there were emerging operational priorities during the period.

- A significant increase in required pole inspection and tree clearing expenditure The forecast for the current regulatory period was $11.8 million but actual and expected expenditures have risen to $23.3 million over the regulatory period;
- An increase in the apprenticeship, trainee, cadet and graduate program from 33 staff in 2003/04 to 85 staff in 2008/09. At the time of the last final decision ActewAGL Distribution's forecast over the current regulatory period was $6.7 million. The actual and estimated expenditure is $18.1 million. These costs represent an investment in developing loyal and committed staff against the high costs of recruitment and retention in a tight labour market;
- Inclusion in the 2005 Enterprise Bargaining Agreement (EBA) of a *retention allowance* for all electrical workers. The retention allowance provided an incentive for electrical workers to remain with ActewAGL Distribution as the electrical workers labour market became tighter and competition for skilled labour in the electricity industry increased. This measure resulted in a total increase of $2.4 million in direct operating costs, albeit saving costs that would have otherwise been incurred in recruitment and training; and
- Increased scope of the Life Guard health, safety and environment (HSE) management system to ensure and improve environmental protection, safety and the wellbeing of staff through effective compliance with obligations. The total cost of this measure has increased in total by approximately $0.5 million ($ nominal). The introduction of Life Guard to ActewAGL has brought about a marked improvement in the safety performance of the company. A substantial reduction in time lost due to injuries has itself been a boost to productivity.

Despite the cost pressures and the emerging operational pressures arising during the period, ActewAGL Distribution has been able to re-prioritise and manage the costs, resulting in financial outcomes close to the regulatory allowance

8.2 Overview of forecast operating expenditure

ActewAGL Distribution's forecast operating expenditure for the 2009–14 period is set out in Table 8.3. The operating expenditure forecast is prepared with the objective of providing sufficient funds to:

- maintain levels of average network reliability for customers as required by the jurisdictional regulator;
- meet current and known future compliance obligations; and
- achieve good asset management practices.

The operating expenditure forecasts assume that:

- the capital program, discussed in chapter 7 of this regulatory proposal, is accepted in full;

- increases in commodity prices will moderate and labour costs will increase in line with those of the sector as a whole;
- increased economies of scale in operations and management will absorb some of the impact of asset growth; and
- current efficiency gains from ActewAGL's multi-utility status will continue to be realised.

Table 8.3 Overview of forecast operating expenditure 2009–14

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	**Total**
Network operations	*13.0*	13.4	13.9	14.3	15.4	15.8	**72.8**
Planned maintenance	*12.2*	*13.0*	*13.0*	*12.8*	*13.0*	*12.2*	***64.1***
Reactive maintenance	*3.7*	*3.8*	*3.9*	*4.0*	*4.1*	*4.1*	***19.8***
Maintenance expenditures	*15.9*	16.8	16.9	16.8	17.1	16.3	**83.9**
Other expenditures	*21.8*	22.7	23.1	23.9	24.3	24.7	**118.6**
Total operating expenditure	***50.7***	**52.9**	**53.9**	**54.9**	**56.7**	**56.8**	**275.3**

Note: Figures exclude debt raising, self-insurance costs and the ACT's Utilities Network Facilities Tax (UNFT). These costs are described in sections 8.5, 8.6 and 8.7 and included in the Post Tax Revenue Model (PTRM).

The forecast average annual increase in operating expenditure over the 2009–14 regulatory period is 1.8 per cent, compared with 4.5 per cent in the current regulatory period. The average annual increase in forecast operating expenditure between 2008/09 and 2013/14 is 2.3 per cent, below the average annual increase between 2004/05 and 2008/09.

This increase is a result of:

- continuing labour cost pressures arising from shortages of skilled resources in Canberra, particularly in the commercial construction sector;
- significant growth in the size of the network; and
- the ageing of network assets over the 2009–14 regulatory period.[67]

ActewAGL Distribution forecasts a $2.2 million increase in total operating expenditure in 2009/10. This change is mostly due to increases in *Planned maintenance* and *Other expenditures* categories.

In 2009/10, *Network operations* expenditure is forecast to increase by $0.4 million. Thereafter, it is forecast to slightly increase due to increasing scope of operations and wage increases in line with the market. In 2012/13 there will be a step increase in the costs associated with requirements for the next regulatory review. Network operations expenditure is further described in section 8.3.4 below.

[67] Based on the capital program proposed by ActewAGL Distribution for the 2009-14 period, the weighted average age of the stock of network assets will increase from 25.6 years in 2009/10 to 27.5 years by 2013/14.

Maintenance Expenditure: The increase in planned maintenance expenditures is a continuation of a trend of increased costs in the maintenance program for overhead distribution assets. In addition, new obligations such as the *Tree Protection Act 2005* (ACT) and further safety measures will increase maintenance costs**.** Maintenance expenditure is further described in section 8.3.5 below and new or changing regulatory obligations in chapter 4 of this regulatory proposal.

Other Expenditures: ActewAGL Distribution expects the category *Other expenditures* to increase by $0.9 million, or 3.9 per cent, in 2009/10. This is because of the higher corporate management fee ($1.3 million) due to the relocation of the ActewAGL's Corporate Headquarters to leased facilities. *Other expenditures* are further analysed in section 8.3.6.

The methodology and assumptions underlying operating expenditure forecasts for the 2009–14 regulatory period are described in the following sections.

8.3 Forecasts, methodology and assumptions 2009–14

The following sections explain broadly ActewAGL Distribution's approach to forecasting operating expenditure and how elements of the approach relate to the operating expenditure objectives and factors in the transitional *Rules*. Section 8.3.3 below provides detailed discussion of cost escalation factors. The remaining sections discuss the forecasts for each component of ActewAGL Distribution's operating expenditure and the particular assumptions and methodologies adopted for each category.

8.3.1 Requirements of the AER

The regulatory requirements for operating expenditure largely mirror those for capital expenditure in chapter 7 of this regulatory proposal.

The transitional *Rules* set out the framework for the AER's assessment of ActewAGL Distribution's operating expenditure forecasts and the necessary components for the regulatory proposal. The requirements of the transitional *Rules* are supplemented by the AER's Regulatory Information Notice (RIN). In deciding whether to accept a service provider's forecasts, the AER is required to have regard to the operating expenditure factors set out in clause 6.5.6(e) of the transitional *Rules*. These factors include information provided by the DNSP in its building block proposal and analysis by the AER.

A building block proposal by a DNSP is required by clause 6.5.6(a) of the transitional *Rules* to include the total forecast operating expenditure for the relevant regulatory control period that the DNSP considers is required to achieve each of the *operating expenditure objectives*. The *operating expenditure objectives* are to:

- meet or manage the expected demand for *standard control services* over that period;
- comply with all applicable regulatory obligations or requirements associated with the provision of 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* through the supply of *standard control services*.

Clause 6.5.6(c) of the transitional *Rules* requires the AER to accept the DNSP's operating expenditure forecast if it is satisfied that the forecast reasonably reflects:

- the efficient costs of achieving the *operating expenditure objectives*;
- the costs that a prudent operator in the circumstances of the relevant *Distribution Network Service Provider* would require to achieve the *operating expenditure objectives*; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the *operating expenditure objectives*.

Clause S6.1.2 of the transitional *Rules* sets out the information and matters relating to operating expenditure that the DNSP must provide in its building block proposal in order for the AER to determine whether it will accept or reject the operating expenditure forecasts provided by the DNSP. ActewAGL Distribution has provided the required information in respect of current period actual and forecast operating expenditure in the attached pro forma 2.2.2.

The RIN specifies the information required by the AER in addition to that set out in clause S6.1.2 of the transitional *Rules*. This includes:

- actual operational expenditure for each of the past regulatory years of the *previous regulatory control period* and *current regulatory control period* (the expected operating expenditure for each of the last two regulatory years of the *current regulatory control period*) and the forecast of required operating expenditure by expenditure type for the *next regulatory control period*;
- the total amounts of operating expenditure requested and operating expenditure approved for each year of the current regulatory control period (including any approved pass through amounts); and
- an explanation of significant variations in the regulated network operating expenditure in the 2009–14 regulatory period compared with 2006/07 as calculated in pro forma 2.2.4. ActewAGL Distribution provides reasons for these variations in Attachment 16 to this regulatory proposal.

Each of these matters are addressed in the following sections and accompanying templates.

8.3.2 Operating expenditure objectives and factors

When forecasting operating expenditure for the 2009–14 regulatory period, ActewAGL Distribution has considered the *operating expenditure objectives* set out in clause 6.5.6(a) of the transitional *Rules*, as well as the *operating expenditure factors* set out in clause 6.5.6(e) of the transitional *Rules*. ActewAGL Distribution has:

- forecast operating expenditure consistent with regulatory obligations (and changing obligations) as described in chapter 4, and consistent with the long term plans, strategies and procedures set out in chapter 6, to ensure that the most prudent options are adopted;
- used reputable and considered estimates for escalating cost forecasts (see section 8.4.3); and
- considered and analysed the actual and expected regulated network operating expenditure for each asset category in the current and past regulatory periods (see section 8.5 for further details);
- at a total system level, examined the trade off between capital expenditure and operating expenditure as described in chapter 6; and
- A Contract Management Procedure that ensures that contract arrangements reflect arm's length terms through the implementation of sound business rules and practices; and
- A Procurement of Goods and Services Procedure that ensures that all goods and services provided to ActewAGL Distribution meet specified performance requirements and minimise the total acquisition and life cycle cost of purchased goods and services.

According to clause 6.5.6(c) of the transitional *Rules*, the AER must accept the forecast of required operating expenditure that is included in a building block proposal if it is satisfied that the expenditure reflects efficient costs, the costs are prudent and are based on a realistic expectation of the demand forecast. ActewAGL Distribution has carefully considered the expenditures to ensure that the proposed total regulated network operating expenditure below fulfils these requirements.

8.3.3 Operating expenditure methodology and assumptions

This section describes the common methodology used for developing operating expenditure presented in this regulatory proposal and the key underlying assumptions that ActewAGL Distribution has made and applied to each category of expenditure, in accordance with clause 6.1.2 of the transitional *Rules*.

The forecast approach adopted by ActewAGL Distribution for future regulated network operating expenditure requirements is a combination of two techniques referred to as the *base year* and *zero-base* methods.

- The *base year* approach assumes a business-as-usual scenario and forecasts future regulated network operating expenditure requirements by escalating known and efficient historical expenditure levels.
- Where ActewAGL Distribution identifies operating expenditure step changes not reflected in the historical expenditure levels, it develops bottom-up estimates of the costs associated with the required change. The *zero base* method refers to this bottom-up approach. This approach applies equally to new activities added to the operating expenditure forecast and to the removal from forecasts of any activities included in the historical expenditure that are

no longer applicable to the forecast years. ActewAGL Distribution has applied the zero base method on planned maintenance expenditure in operating expenditure.

ActewAGL Distribution has escalated labour expenditures and other costs with the factors as described below. The proportion of labour costs in total operating expenditure is approximately 70 per cent. Some unit rates have been used as a base for estimating planned maintenance expenditures, but no single unit rate materially affects operating expenditure forecasts.

Selection of a base year

The latest year for which audited ActewAGL Distribution accounts are available is 2006/07. ActewAGL Distribution believes that the expenditure in this year represents an efficient level of regulated network operating expenditure given the asset mix, age profile and size of the ActewAGL Distribution network.

The base-year forecasting methodology requires:

- the removal from the base year of costs that are not indicative of future requirements;
- adding costs for any step changes required for future years, for example, new assets, ageing system, replaced assets, new operating and maintenance activities; and
- escalating costs for wages and materials.

When setting the base year, ActewAGL Distribution has adjusted for the increase in the apprentice training program, regulatory price review process (previously capitalised) and the employment of staff and contractors for increased scope of planned maintenance in response to the recommendations of the audit undertaken by the ACT Technical Regulator in 2007. No costs have been removed since each of the other activities of the base year are expected to continue throughout the next period, though some efficiencies have been assumed (see below).

Cost escalation

In preparing its operating expenditure forecasts for the next period, ActewAGL Distribution has not directly adjusted for growth in customer numbers. Other parameters such as inflation, general wage levels and demand and energy growth better explain the movements operating expenditure on a year-by-year basis.

There is, of course, over the longer term a clearer relationship between number of customers and the changes in operating expenditure that occurs through augmentation capital expenditure. The size of the network (and the number of assets in service) will grow over the 2009–14 regulatory period, however ActewAGL Distribution is not proposing to increase staffing on account of this, assuming that it will capture some economies of scale.

ActewAGL Distribution commissioned Sinclair Knight Merz (SKM) to construct robust cost escalation forecasts. The forecast considers the labour/material split by expenditure category and applies separate escalators as detailed below.

Labour costs

There has been considerable discussion amongst economic and industry commentators regarding Australia's current skills shortage. Most recently, the ACT Skills Commission and research by the ACT Chamber of Commerce predict that the ACT will continue to be the worst affected of the Australian States and Territories from a shortage of skilled and unskilled workers.[68]

Figure 8.3 shows the historical trend in average Australian hourly wage rates and *Electricity, Gas and Water* sector hourly rates (provided by the Australian Bureau of Statistics), compared with CPI.

Figure 8.3 Australian normalised labour rate index

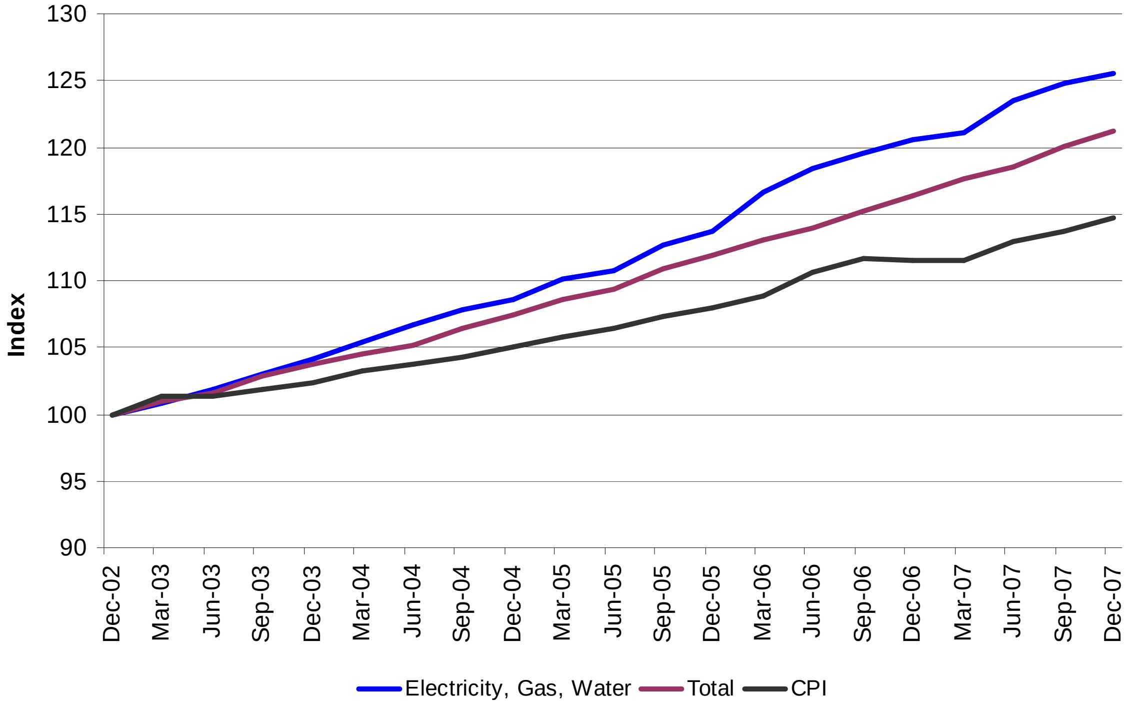


Figure 8.3 shows that, as at December 2007, growth in hourly rates of pay of employees in the *Electricity, Gas and Water* sector and across all Australian industries have exceeded CPI by 10.8 and 6.5 percentage points, respectively, since December 2002.

A number of studies dealing with the escalation in Labour costs within the Australian Electricity Industry have recently been commissioned, most notably:

- the April 2007 Access Economics forecast labour cost indices[69], developed for the AER during the Powerlink review;

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[68] Thistleton, John 2008, "Recruitment crisis on boomer exodus", *The Canberra Times*, 1 May, p 1
[69] Access Economics 2007, *Labour Cost Indices for the Energy Sector*, 12 April

- the April 2007 BIS Shrapnel report[70] commissioned by ElectraNet to establish an outlook for future wages growth over the Transmission Network Service Provider's (TNSP) forthcoming regulatory period; and

- the August 2007 Econtech wages growth forecast report commissioned by the AER as part of the SP AusNet review process.[71]

SKM's advice to ActewAGL Distribution is that, while the three forecasts use slightly different forecasting methodologies, all are based on robust methodologies for developing state and industry specific wage forecasts, including consideration of the movements in the underlying drivers of wage growth within specific industries, and why in recent years, the annual wage growth recorded in the electricity, gas and water sector has been higher than the that in the economy as a whole.

The three major drivers of wages growth are inflation, economic growth, and underlying supply of appropriately skilled labour. Each report includes an assumption of increased productivity, although at varying rates. All three Reports consider that the ongoing tightness within the labour market will cause wages to escalate more than would have happened due to CPI and productivity factors alone. Labour market tightness is exacerbated by the fact that many of the skills required within the electricity, gas and water industries are held in common with the mining and resources sectors, which continue to expand and exert pressure on utilities' ability to attract and retain sufficient numbers of skilled employees. The three reports listed above generally describe a downturn in the rate of growth of wages over the medium term to 2013, though the timing and magnitude of the respective downturns differ.

Table 8.4 presents labour cost growth forecast by Access Economics, BIS Shrapnel and Econtech for the Electricity, Gas and Water sector at the national level.

Table 8.4 Forecasts for nominal wage growth within the Australian utilities sector

Per cent	Access Economics	BIS Shrapnel	Econtech
2007/08	5.7	6.2	5.2
2008/09	5.1	5.4	5.7
2009/10	3.6	5.1	7.6
2010/11	3.9	6.1	7.0
2011/12	4.4	5.9	6.3
2012/13	4.5	5.8	6.0
2013/14	4.3	5.0	5.6
2014/15	3.6	5.4	5.0
2015/16	3.9	6.1	4.8

[70] BIS Shrapnel 2007, *Outlook for Labour Markets and Costs to 2016/17: Electricity, Gas and Water Sector Australia and South Australia*, April
[71] Econtech 2007, *Labour Costs Growth Forecasts* (available for download from the AER website)

The Access Economics report has been criticised because it “expects wages in the utility sector to grow more slowly than the rest of the economy.”72 Econtech is of the opinion that wages in the utilities sector will increase by one per cent above average growth in labour, providing a national average growth rate for utilities of 5.7 per cent which Econtech translates into a real growth figure for the Electricity, Gas and Water sector over the period 2006–16 of 3.2 per cent.[73] The BIS Shrapnel report also notes that Access Economics has “underestimated nominal wages growth” stating that “the main source of the difference between BIS Shrapnel and Access Economics is that BIS Shrapnel believes the labour market for the utilities, mining and construction sector will remain relatively tight for longer than [Access Economics].”[74]

BIS Shrapnel[75] also states that wages in the Electricity Gas and Water sector are predicted to grow more rapidly than overall wages. BIS Shrapnel’s figures show nominal annual growth rates over the period 2008 to 2012 of 5.2 per cent for overall wages, and 5.8 per cent for the Electricity, Gas and Water sector. For the period 2013 to 2017 the nominal annual growth rates are 5.1 per cent and 5.7 per cent, respectively.

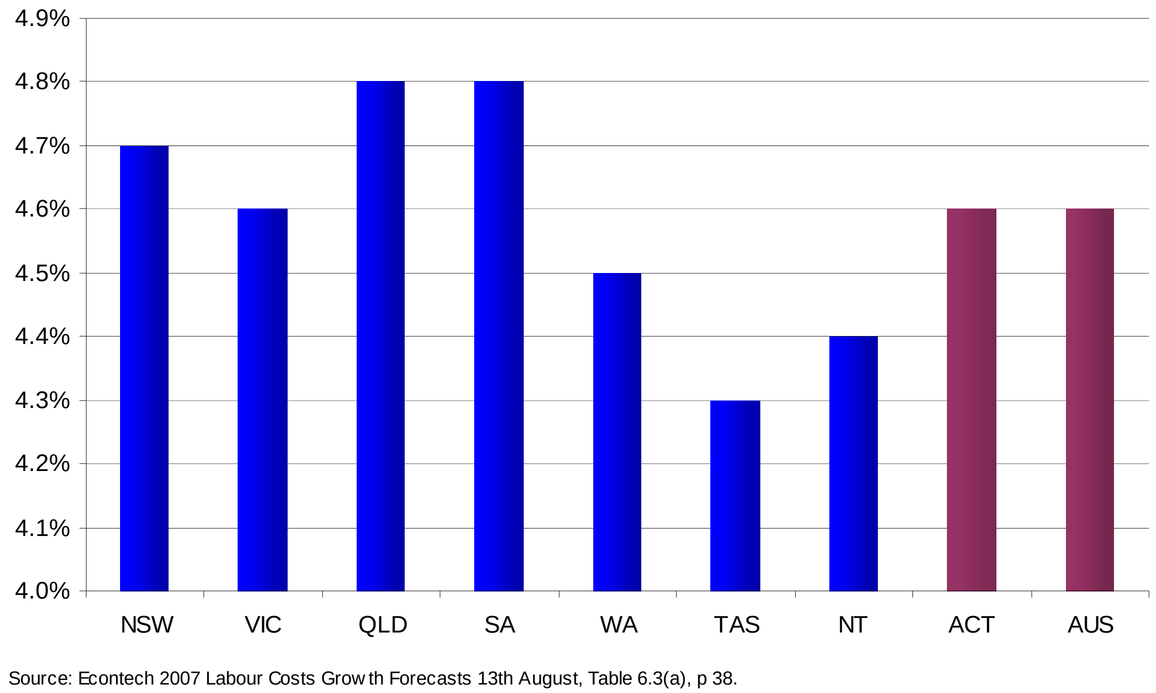
The August 2007 Econtech report made use of more recent economic data in predicting movements in the underlying drivers of wage growth. This was evident in the comparatively lower Econtech forecast CPI figures, which in turn related to Econtech’s consideration of updated movements in the underlying drivers of inflationary pressure, such as the Australian Dollar remaining above US$0.80. SKM has concluded that figures provided within the more recent Econtech Report have more credibility for predicting future labour costs.

In its recent Powerlink decision[76], the AER indicated a preference for state-specific forecasts of labour costs based on thorough macroeconomic modelling. As a result, ActewAGL Distribution also reviewed a more recent Econtech report of 18 April 2008. This report forecasts general state-specific wage movements rather than those at an industry level. According to Econtech, forecast real wage level increases in the ACT are expected to be between 3.9 per cent and 5.9 per cent: within Econtech’s August 2007 expectations. However ActewAGL Distribution believes that Econtech’s previously identified 1 percentage point differential between expectations for general wages and those of the Electricity, Gas and Water sector is also relevant in determining expected wage growth in ActewAGL Distribution.

On this point, ActewAGL Distribution notes the information provided in Chart 6.1 of Econtech’s August 2007 report and reproduced as Figure 8.4 below. It shows that Econtech is predicting that ACT labour cost growth will be in line with the national average.

[72] Econtech 2007 *Labour Costs Growth Forecasts,* 13 August, p 43
[73] Econtech 2007 *Labour Costs Growth Forecasts,* 13 August, Table 6.3(a), p 38
[74] BIS Shrapnel 2007, *Outlook for Labour Markets and Costs to 2016/17,* section 6.1 p 57
[75] BIS Shrapnel 2007, *Outlook for Labour Markets and Costs to 2016/17,* table 4, p 26
[76] AER 2007, *Powerlink Queensland Transmission Network Revenue Cap: Decision*, 14 June

Figure 8.4 Econtech nominal national and state labour cost growth rates, 2005/06 to 2015/16



Source: Econtech 2007 *Labour Costs Growth Forecasts* 13th August, Table 6.3(a), p 38.

ActewAGL Distribution proposes that this correlation between the predicted movements in labour costs within the ACT and Australia as a whole could be extrapolated to other national labour cost growth factors, such as those provided by Econtech for the utilities sector, for their use as ACT specific cost escalators. On this basis, ActewAGL Distribution has used the figures presented within Econtech's National Forecasts for Wage Growth within the Australian Utilities Sector in Table 8.4 as the labour cost escalation rates that can be expected to be experienced in the Electricity, Gas and Water sector in the ACT.

Other expenses

The other key component of operating expenditure forecasts after labour is the cost of materials. Regulators have traditionally considered the non-labour elements of maintenance activities as being principally consumable items, and have used forecast inflation (CPI) as the appropriate escalator. ActewAGL Distribution has followed this practice, using the CPI forecasts provided in chapter 10 of this regulatory proposal.

It should be noted that:

- miscellaneous materials consist partly of products used in capital expenditure, which are expected to increase significantly more than CPI and

- the costs of certain services categorised as ‘other expenses (for example insurance and consulting services) are growing at a higher rate than the growth in CPI.

ActewAGL Distribution therefore believes that using CPI for escalation of miscellaneous (other) materials represents a reasonable approach.

8.3.4 Network operations expenditure

Network operations expenditure consists of those costs associated with network management, network systems operation and control, network support systems and planning and control. An overview of this expenditure in the current regulatory period is set out in Table 8.5.

Table 8.5 Historic Network operations expenditure 2004–09

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	**Total**
Network Control	3.6	3.7	3.5	3.7	3.8	**18.3**
IT Planning and Operations	1.0	0.9	0.8	0.9	1.0	**4.5**
Network Systems Operations	2.1	2.5	2.7	2.7	2.9	**13.0**
Quality, Environmental and Safety Systems	0.9	1.2	1.0	1.0	0.7	**4.7**
Executive & Financial Management	1.5	1.5	1.3	1.9	1.6	**7.8**
Other Network Operating Costs	2.2	2.1	2.6	2.9	3.1	**12.9**
Total network operations expenditure	**11.3**	**11.9**	**11.8**	**13.1**	**13.0**	**61.2**

Total Network operations expenditure has increased during the current regulatory period by approximately 3.5 per cent per annum. In that time, annual Network Systems Operations costs and Other Network Operating Costs have increased by $0.8 million and $0.9 million respectively. The cost increase in Network Systems Operations is largely explained by the requirement for additional staff to deal with a significant increase in general customer enquires for customer initiated works: mainly network connection and modification advice for commercial and residential developments. There has also been an increase in expenditure on system switching due to the increase in capital expenditure on customer initiated works and asset replacement programs. Other Network Operating Costs have increased due to the implementation of full retail contestability with additional operating costs, such as those associated with the management of transfers. There has also been a significant increase in the annual licence fee from ICRC and the implementation of energy industry levy in 2007/08 by the ACT Government.

Expenditure in the remaining cost categories has been relatively steady across the current period.

Forecasts for Network Operations expenditure

The forecasting approach adopted by ActewAGL Distribution for future operating expenditure requirements is that outlined in section 8.3.3 above. The split between labour and miscellaneous costs expenditures is forecast to be the same as for the completed years of the current regulatory period. Consideration has been given to compliance with all applicable legislation and the existing and new requirements of the ACT Technical Regulator, the ICRC and the AER that could have an impact on the costs. When forecasting the costs, ActewAGL Distribution has:

- reviewed historic costs and trends;
- determined escalation factors as described in section 8.3.3;
- reviewed regulatory requirements;
- made adjustments where specific event/costs drivers are likely to have an impact; and
- adjusted for growth in the network taking account of economies of scale.

ActewAGL Distribution's forecast network operations expenditure for the 2009–14 regulatory control period is set out in Table 8.6.

Table 8.6 Forecast Network Operations expenditure 2009–14

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Network Control	*3.8*	3.8	3.9	4.0	4.1	4.2	**20.0**
IT Planning and Operations	*1.0*	0.8	0.9	0.9	0.9	0.9	**4.4**
Network Systems Operations	*2.9*	3.0	3.1	3.1	3.2	3.3	**15.6**
Quality, Environmental and Safety Systems	*0.7*	1.3	1.3	1.3	1.4	1.4	**6.6**
Executive and Financial Management	*1.6*	1.8	1.8	1.9	2.0	2.0	**9.5**
Other Network Operations Costs	*3.1*	2.9	3.0	3.0	3.8	3.9	**16.6**
Total Network operations expenditures	***13.0***	**13.4**	**13.9**	**14.3**	**15.4**	**15.8**	**72.8**

Total network operations expenditures in 2009/10 and going forward are expected to increase in line with the wage and CPI increases. In 2012/13 Other Network Operations expenditures are expected to increase by $0.8 million due mainly to costs associated with the next AER price review process. Expenditure associated with the price review was capitalised in the current regulatory period, but ActewAGL Distribution has decided to follow industry and general accounting practice and include this as operating expenditure from 1 July 2009.

Though the network will grow considerably, ActewAGL Distribution is not expecting to increase employee numbers within total network operating expenditure. ActewAGL Distribution believes that it will achieve economies of scale in the 2009–14 regulatory period, particularly considering that regulated network capital expenditure on augmentation and customer initiated projects will increase by 80 per cent over the 2009–14 regulatory period.

8.3.5 Network maintenance expenditures

Network maintenance expenditure is largely driven by the mix of assets in service and their condition. The number of assets needing to be maintained increases with customer growth. The condition of assets is dependent both on their age and how well they have been maintained. The estimated average age of the ActewAGL Distribution's electricity distribution assets in July 2009 will be 25.6 years.

Network maintenance can be divided into two main categories: planned and reactive. Planned maintenance accounted for 72 per cent of total maintenance during the 2004–09 regulatory period. Overhead planned is the largest single component. An overview of the total Network Maintenance expenditures is set out in Table 8.7.

Table 8.7 Historic Network Maintenance operating expenditures

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	**Total**
Zone Substation Planned	1.6	1.5	1.5	1.6	2.0	**8.2**
Sub-transmission Planned	0.1	0.2	0.1	0.2	0.6	**1.2**
Underground Planned	0.2	0.0	0.0	0.0	0.3	**0.6**
Overhead Planned	4.8	5.6	6.1	6.8	7.3	**30.6**
Distribution Station Planned	1.0	0.7	0.6	0.9	2.0	**5.1**
Total Planned Maintenance Expenditures	**7.6**	**8.0**	**8.4**	**9.5**	**12.2**	**45.7**
Zone Substation Reactive	0.1	0.1	0.2	0.1	0.2	**0.7**
Sub-transmission Reactive	0.0	0.0	0.0	0.0	0.0	**0.1**
Underground Reactive	1.1	1.6	1.2	1.3	1.3	**6.4**
Overhead Reactive	1.4	2.0	2.0	2.0	2.1	**9.3**
Distribution Station Reactive	0.1	0.1	0.2	0.3	0.2	**0.9**
Total Reactive Maintenance Expenditures	**2.7**	**3.8**	**3.5**	**3.6**	**3.7**	**17.4**
Total Network Maintenance Expenditures	**10.3**	**11.8**	**12.0**	**13.1**	**15.9**	**63.0**

Annual total network maintenance expenditures have increased from $10.3 million in 2004/05 to $15.9 million in 2008/09. The significant increase in the final two years of the regulatory period is due to increased planned maintenance costs for overhead distribution, distribution substations and zone substations.

There is a number of reasons why these costs are increasing relative to the base year.

- The ACT Technical Regulator's July 2007 audit of various ground-mounted distribution assets (substations and distribution pillars) persuaded ActewAGL Distribution that, due to asset maturity, a generally reactive approach to maintenance is no longer acceptable. ActewAGL Distribution has instead sought to develop a condition-monitoring approach based around a five-yearly inspection and maintenance cycle. As a result, ActewAGL Distribution has engaged additional contract resources and as well as additional in-house expertise through apprenticeships. These resources are to support activities that are recognised as necessary to discharge obligations against the *Management of Electricity Network Assets Code* and will result in a step increase in planned maintenance costs in 2008/09 and 2009/10.

- Overhead planned maintenance expenditure has increased throughout the current regulatory period due to costs associated with pole inspections and a program for restoring access tracks to a usable condition after being damaged during the major bushfires in December 2001 and January 2003.

- Planned maintenance for distribution and zone substations is forecast to increase in 2008/09 as ActewAGL Distribution must comply with a wide range of obligations to ensure employee safety (as outlined in chapter 4). Developments in OHS standards are such that previously acceptable work methods or installation arrangements, for example, substation pole platforms and substations without protective personnel barriers, are no longer considered to provide a safe work environment. A variety of changes specific to individual activities/locations, has resulted in modified access procedures, work methods and engineering controls such as indoor substation safety rails and barriers, earthing tests on substations and *Earthmat* repairs and extensions.

- Reactive maintenance has increased by $1 million during the current regulatory period as a result of asset condition.

Forecast Network Maintenance expenditure

ActewAGL Distribution's maintenance strategy is set out in the Asset Management Plan (AMP). The AMP is the outcome of ongoing planning and analysis and is supported by other more specific and detailed planning and analytical work discussed in chapter 6 of this regulatory proposal. The AMP and supporting documents form the basis of all maintenance cost forecasting and are the key underlying documents for maintenance expenditure approval processes.

The AMP is the basis for ensuring compliance with applicable legislation, including the *Utilities Act 2000* (ACT), the *Consumer Protection Code*, occupational health and safety legislation, public safety and environmental legislation and other regulatory requirements. The AMP is also the basis for the level of the regulated network maintenance expenditure forecast.

In forecasting maintenance expenditure, ActewAGL Distribution has used 2006/07 as the base year and relied on Econtech data (as described above) for wage increases and CPI for other expenditures. Planned maintenance expenditures have been estimated based on historic rates and some non-material unit rates. Maintenance expenditure forecasts also involve:

- review of historic trends;
- review of the assessed condition of the assets and failure rates;
- risk management review and prioritisation;
- consideration of outcomes from a pole replacement model;
- review of the requirements of the Technical Regulator;
- review to ensure compliance with service and technical standards;
- assessment of health, safety and environmental (HSE) issues; and
- assessment of the impact of new legislation such as the *Tree Protection Act 2005*.

ActewAGL Distribution's forecast network maintenance expenditure for the 2009–14 regulatory period is set out in Table 8.8.

Table 8.8 Forecast network maintenance expenditures 2009–14

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	**Total**
Zone Substation Planned	*2.0*	2.0	2.1	2.1	2.2	2.1	**10.4**
Sub-transmission Planned	*0.6*	0.6	0.5	0.3	0.2	0.2	**1.8**
Underground Planned	*0.3*	0.3	0.4	0.4	0.4	0.4	**1.8**
Overhead Planned	*7.3*	8.1	8.0	7.9	8.0	7.5	**39.5**
Distribution Station Planned	*2.0*	2.0	2.1	2.1	2.2	2.1	**10.5**
Total Planned Maintenance Expenditures	***12.2***	**13.0**	**13.0**	**12.8**	**13.0**	**12.2**	**64.1**
Zone Substation Reactive	*0.2*	0.2	0.2	0.2	0.2	0.2	**0.9**
Sub-transmission Reactive	*0.0*	0.0	0.0	0.0	0.0	0.0	**0.1**
Underground Reactive	*1.3*	1.3	1.3	1.3	1.4	1.4	**6.6**
Overhead Reactive	*2.1*	2.1	2.2	2.2	2.3	2.3	**11.1**
Distribution Station Reactive	*0.2*	0.2	0.2	0.2	0.2	0.2	**1.1**
Total Reactive Maintenance Expenditures	***3.7***	**3.8**	**3.9**	**4.0**	**4.1**	**4.1**	**19.8**
Total Network Maintenance Expenditures	***15.9***	**16.8**	**16.9**	**16.8**	**17.1**	**16.3**	**83.9**

As can be seen from Table 8.8, ActewAGL Distribution forecasts that total Network Maintenance expenditures will remain more or less stable annually, slightly decreasing by the end of the 2009–14 regulatory period. The increase in 2009/10 of $0.9 million is a result of the increased effort in the planned overhead maintenance due to higher expenditure for pole inspections, required pole-top and cross-arm maintenance and installation of vibration dampers and low-voltage network line spreaders. The increase in overhead planned maintenance is further described in Box 8.1.

After the benefits of the step increase in planned overhead maintenance are realised, these costs are forecast to stabilise and even decrease towards the end of the 2009–14 regulatory period. The maintenance expenditures for sub-transmission assets are expected to decrease after the completion of major track maintenance works. Planned maintenance costs for zone substations, distribution substations and underground assets are forecast to be stable throughout the 2009–14 regulatory period.

Reactive maintenance expenditures will increase as the asset base ages, but only by $0.3 million in the 2009–14 regulatory period as reactive maintenance is replaced by less costly planned maintenance.

Box 8.1 Planned overhead maintenance

Planned overhead distribution maintenance is a significant component of the planned maintenance forecast. These expenditures have increased in the current regulatory period, mainly due to increased scope of pole inspections and vegetation management.

Over the 2009–14 regulatory period, the real costs of the pole inspection program are expected to increase slightly due to wage escalation.

Since the 2003 Canberra Bushfires, dedicated access tracks to distribution lines in the National Parks and rural areas have suffered significantly from erosion and in many places have become unusable. They require major repair in some areas to permit vegetation inspection and clearing. These tracks are also used for line patrols, inspections and pole replacement. An increase in maintenance expenditure is required to restore the tracks to a usable condition. The fires also killed many substantial trees immediately outside the line easements. The distribution lines are in danger from these trees that could fall across them. Dead trees cannot be accessed for removal by climbing and can only be trimmed from an Elevated Work Platform or the more expensive option of being felled (where approval has been granted) after the line has been isolated and temporarily removed. They must also be carted away owing to fuel hazards from dead timber.

At present, tree-related problems are the major single cause of customer outages. Increased effort in vegetation control is expected to decrease the incidence of tree-related outages. Without access to trim or clear these trees there is a very significant risk of the trees collapsing across the high-voltage network necessitating their removal in emergency conditions.

Increased costs of planned overhead maintenance are also the result of an increase in air break switch and high-voltage link maintenance due to condition-related defects. Air break switches are failing to operate correctly, resulting in large area outages or delays in programmed works. Their readjustment and realignment is required to prolong their serviceable life and to reduce the incidence of failure. Electrical connections on air breaks switches and links are also failing.

Hand ties on insulators and hand splices on conductors have failed, and this has the potential to start fires. Programs are being developed for the live line crews to replace suspect items with more modern solutions to mitigate the risk to public safety and the environment in bushfire prone areas. These types of maintenance events are becoming more common as external assets begin to reach their design life limits and deteriorate through weathering, usage, loading etc.

In urban areas the implementation of the *Tree Protection Act 2005* (ACT) has seen a steady increase in the listing of protected and significant trees (see chapter 4). There are also other trees that are heritage protected. Generally, permission may be granted to trim trees listed under this Act. However, it has become increasingly difficult to reach agreement for the removal of particular trees. Such restrictions increase maintenance costs as trimming has to occur on a more regular basis in order to maintain clearances dictated under the *Public Safety Code*. This has resulted in permanently increased costs for vegetation management during 2007 to 2009

The increased expenditure in other overhead maintenance in the 2009–14 regulatory period is due to many smaller projects. Past pole top construction utilised black steel (non-galvanised) bolts in their construction. Over 4,900 cases have been identified to date where they are suspected to have rusted to the point of being dangerous and are in need of replacement. This will increase Other Overhead maintenance costs in 2009/10 by $0.5 million, which explains the largest part of the step increase. Low conductor clearances will also be targeted for rectification to meet regulatory obligations. ActewAGL Distribution's 132 kV transmission assets will require closer inspections by helicopter to check mid span compression connections, spacers, vibration dampers and connections. The costs for vibration dampers in 2009/10 will increase by $0.1 million and decrease in 2013/14 by the same amount once the program of installation is complete. ActewAGL Distribution will also increase expenditure by $0.1 million in 2009/10 to 2013/14 for low-voltage spreaders to prevent wires clashing and sparking in windy weather. This has become necessary because of the increase in the risk of fire both in bushfire areas and now within urban backyards due to water restrictions. The 132 kV assets also require significant vegetation clearing following pine plantation regrowth. Track and fence maintenance is also necessary due to the damage from the 2003 fires. A trial of bird diverters on the 132 kV towers is programmed to prevent short duration outages experienced in recent years during the nesting season.

A summary of the forecast costs of planned overhead maintenance in the 2009–14 regulatory period is provided in Table 8.9.

Table 8.9 Forecast expenditure for planned overhead maintenance

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Vegetation Management*	2.7	2.7	2.8	2.6	2.6	2.7
Pole and Line Inspection	3.0	3.1	3.1	3.2	3.2	3.3
Other Overhead	1.5	2.3	2.1	2.1	2.1	1.5
Overhead Distribution Asset Maintenance	**7.3**	**8.1**	**8.0**	**7.9**	**8.0**	**7.5**

* Does not include sub-transmission easement management costs.

In summary, key drivers of network maintenance expenditures in the 2009–14 regulatory period will be the combination of an ageing asset base, which necessitates replacement and renewal for reliability, security and safety reasons, and compliance with existing and new regulatory obligations. Particularly when considering the increasing size of the network in the 2009–14 regulatory period, ActewAGL Distribution believes that its proposed maintenance expenditure forecasts are realistic and reflect a careful consideration of the operating expenditure *objectives* and *factors*.

8.3.6 Other expenditure

The category *Other Expenditure* comprises costs incurred via allocation of a share of corporate services costs, direct network-related costs such as the apprentice training program and services provided by ActewAGL Retail, such as customer service and billing. An overview of the total other expenditures for the 2004–09 regulatory period is set out in Table 8.10.

Table 8.10 Historic other expenditures

$ million (2008/09)	2004/05	2005/06	2006/07	F2007/08	F2008/09	Total
Advertising and Marketing	1.3	1.2	1.1	1.3	1.1	**6.0**
Corporate Management Fee	11.4	9.9	9.9	9.3	9.5	**50.1**
Business Services	2.0	2.1	2.1	1.9	2.1	**10.3**
Apprentice Training Program	1.4	2.6	3.9	5.2	4.9	**18.1**
Business Overheads	3.6	3.0	2.4	2.4	3.0	**14.3**
Costs of services in connection with Regulated Miscellaneous Charges	1.2	1.1	1.2	1.1	1.1	**5.7**
External Business Expenditure	(0.0)	0.1	(0.0)	0.1	0.1	**0.1**
Total other expenditures	**20.9**	**19.9**	**20.5**	**21.4**	**21.8**	**104.5**

Total *Other expenditures* have increased by $0.9 million in the current regulatory period. This is due to the increased scope of the apprentice & graduate/engineers training program which has increased by 52 staff and $3.5 million during 2004–09. Business overheads have decreased from $3.6 million to $3.0 million in the current period due to a $0.4 million ($ nominal) reduction in insurance premiums.

Other expenditures in this category have been stable.

Forecasts of Other operating expenditures

When forecasting other expenditure, ActewAGL Distribution has:

- reviewed historic costs and trends;
- applied escalation factors as described in section 8.3.3; and
- assessed regulatory requirements.

The forecasting approach adopted by ActewAGL Distribution for future other expenditures is that outlined in section 8.3.3 above. The shares of labour and miscellaneous costs are expected to remain the same as for the completed years in the current regulatory period. Apart from increased apprentice training costs, ActewAGL Distribution has not made any other specific adjustments to the base costs.

ActewAGL corporate services undertakes a range of processes and services on behalf of TransACT Communications, ACTEW Corporation and the business units within ActewAGL Distribution. These services comprise of:

- the Office of the Chief Executive;
- Internal Audit;
- Human Resources;

- Facilities Management;
- Legal and Secretariat;
- Corporate Finance;
- Business Systems; and
- Business Development and Strategy.

Network Logistics resides within the Networks Business and provides purchasing and accounts payable, warehousing and fleet management services to both the Networks business and other ActewAGL group users.

An allocation of all applicable joint costs is undertaken annually of all applicable costs arising from these shared services, using the methodology as approved by the AER. This allocation is achieved through a Fixed Price Service Charge.

ActewAGL Distribution has used a 5.5 per cent wage escalation factor for corporate services. This is due to ActewAGL Distribution facing skill shortages, which place additional pressure on providing remuneration incentives to attract and retain skilled staff. In addition, some positions require national recruitment to obtain the necessary skills. ActewAGL Distribution has escalated other operating expenditure with the CPI as described in section 8.3.3.

As a multi-utility, ActewAGL Distribution is able to realise economies of scale and scope that would not otherwise be available to the business entities standing alone. The efficiencies generated by this arrangement were accepted by the ICRC in its April 2008 Final Decision on prices for water and wastewater services provided by ACTEW Corporation (ACTEW) in the ACT. ActewAGL Distribution's Water Services business[77] operates and maintains the water and wastewater infrastructure under contract to ACTEW Corporation, the asset owner. The decision acknowledged, based on cost information derived from research by CRA International,[78] that ActewAGL Distribution was able to perform the functions significantly more cheaply than ACTEW as a stand-alone entity. It is reasonable to assume that similar efficiency gains are being realised by the ActewAGL Distribution Electricity Networks business since the corporate expenditures are being shared with other parts of the ActewAGL joint venture.

These shared efficiency savings are important to the Electricity Networks business considering its small size when compared with other similar DNSPs.

An overview of forecast other expenditures is set out in Table 8.11.

[77] ActewAGL Water is a business within the ActewAGL Distribution joint venture partnership.
[78] CRA International 2008, *Efficiencies in the Utilities Management Agreement*, A report for ACTEW Corporation, 14 February

Table 8.11 Forecast other operating expenditures 2009–14

$ million (2008/09)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Advertising & Marketing	*1.1*	1.1	1.1	1.1	1.1	1.2	**5.6**
Corporate Management Fee	*9.5*	10.8	11.0	11.5	11.8	12.0	**57.0**
Business Services	*2.1*	2.2	2.2	2.2	2.3	2.3	**11.2**
Apprentice Training Program	*4.9*	5.0	5.2	5.3	5.4	5.5	**26.4**
Business Overheads	*3.0*	2.4	2.4	2.4	2.4	2.4	**11.8**
Costs of services in connection with Regulated Miscellaneous Charges	*1.1*	1.3	1.3	1.3	1.3	1.4	**6.6**
External Business Expenditure	*0.1*	0.0	0.0	0.0	0.0	0.0	**0.0**
Total other expenditures	***21.8***	**22.7**	**23.1**	**23.9**	**24.3**	**24.7**	**118.6**

Total other expenditures are expected to increase by $0.9 million in 2009/10. The reason for this is an increase of $1.3 million in the Corporate Management Fee to reflect higher operating costs in relation to ActewAGL's proposed new corporate headquarters. This impact arises primarily because the new corporate headquarters will be leased, rather than owned by ActewAGL as is the case for the current corporate headquarters. Attachment 23 provides details of the intended relocation.

The cost of the Apprentice Training Program is expected to increase by $0.1 million in 2009/10 due to wage increases in line with the market. Expenditure on this program will continue to grow in the 2009–14 regulatory period, but at a significantly lower rate than in the current regulatory period. Further details of the program are provided in Box 8.2.

Apart from the apprentice training program and the step increase in corporate management fee due to the corporate headquarters relocation, total other expenditures are expected to be in line with that estimated for 2008/09, even though the size of ActewAGL Distribution's network will continue to grow.

Box 8.2 Apprentice training program

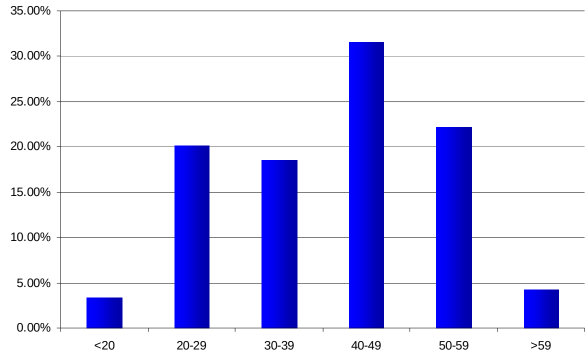
ActewAGL Distribution has found it increasingly difficult to recruit staff, particularly experienced staff both to field and professional positions. In 2005, it was decided to increase the investment in developing future tradespeople locally by increasing the apprentice intake. An audit conducted within the ActewAGL Distribution Electricity Networks business at that time highlighted that a more strategically focused approach was required for succession planning activities across the whole business to ensure the adequate resourcing of key roles.

The figure below provides a summary of the age distribution of the Networks business staff as at the end of February 2008. The findings of age demographic analysis, together with national demographic data, suggest that the age profile of Australian organisations will continue to increase. Combined with national skills shortages, it will become increasingly important for organisations to attract people and train them with the skills they require, as well as to retain employees in all age cohorts.

Key findings of the ActewAGL Distribution Networks business demographic study of February 2008 were that:

- 26.4 per cent of staff are aged 50 years or older;
- 16 staff members are aged 59 years or older;
- the oldest branch has 46.4 per cent of staff aged 50 years or older; and
- 100 staff members within Networks are aged 30 years or younger.

Demographic profile of the ActewAGL Distribution Electricity Networks business



It is strategically important to secure a healthy demographic mix and prepare for management succession. ActewAGL Distribution's costs for apprentice, office trainee and graduate training have increased significantly from $1.4 million in 2004/05 to $4.9 million in 2008/09. In the 2009–14 regulatory period, the scope of the apprentice program will increase from $5.0 million in 2009/10 to $5.5 million in 2013/14. ActewAGL Distribution will continue with the same levels of trainees and graduates in the 2009–14 regulatory period due to an increased number of staff planning retirement and increased maintenance and capital investment activities as described in this regulatory proposal.

8.4 Factors influencing operating costs

Comparison against other DNSPs is often used to gain insight into the efficiency of a business's operating expenditure. However, the conclusions that can be drawn from such comparisons are often limited as no two distribution networks are identical. It is important to recognise the unique cost environment in which different utilities operate.

Operating costs are influenced by the number and types of assets in service and the condition of those assets. Age is often used as a *de facto* measure of asset condition. The link between operating expenditure and output measures such as energy supplied or system demand is relatively weak. ActewAGL Distribution therefore believes that benchmarking operating expenditure against these measures provides limited insight into the efficiency of a distribution entity.

To compare ActewAGL Distribution's comparatively small Electricity Networks business, which has many unique attributes, with much larger DNSPs will inevitably give rise to flawed outcomes. The ActewAGL Distribution Electricity Networks business has to maintain core functions such as Regulatory Affairs, Billing, Financial Management, Systems and Procedures, the cost of which has to be carried by a much smaller network, customer base and revenue base than other DNSPs. ActewAGL Distribution is subject to significant planning and operating restrictions and inherent network issues not applicable to other utilities.

In past benchmarking exercises, there has been an attempt to 'normalise' the results by adjusting for the unique pressures affecting ActewAGL Distribution. However, the process of normalisation has been necessarily very subjective requiring identification and quantifying the impact of the unique attributes. As a consequence, the benchmarking results were flawed and of very limited usefulness.

ActewAGL Distribution believes that there is no single indicator that would provide a meaningful benchmark outcome and that benchmarking would have limited merit in establishing the prudency of ActewAGL Distribution's cost forecasts.

8.4.1 Unique cost drivers for ActewAGL Distribution

ActewAGL Distribution faces some unique cost drivers. These drivers have been outlined in chapter 2, and can be summarised as:

- backyard reticulation results in significant access problems and much higher costs of supply;
- access issues are exacerbated by screen vegetation planted by lessees around the boundaries of properties significantly increases susceptibility to outages and increases the complexity of carrying through maintenance and non co-operating lessees which incurs a large administrative cost through the requirement of the *Utilities Act*;
- planning authorities in the ACT aim to minimise the amount of street furniture and keeping the sub-transmission network out of sight and on the fringe of urban development increasing both capital expenditure and maintenance expenditure; and
- The role of Canberra as the national capital has implications for the requirements and expectations of ActewAGL Distribution's customers. The requirements for a relatively high level of supply security have resulted in additional capacity being built into the network.

8.4.2 Analysis

In the following comparisons, actual ActewAGL Distribution expenditure in 2006/07 has been used after removal of metering costs. It has been compared with the latest actual expenditure data available in the public domain for the comparator organisations escalated to comparable dollars. Typically, 2003/04 actual expenditures have been used for the comparison base; this has been escalated to 2006/07 dollars. The escalation factors used reflect the movements in real wages and material costs. The operating expenditure used in these comparisons is total regulated network operating expenditure including all overheads.

In the following comparisons and associated discussions, reference will be made to the relative size of the distribution networks and customer densities. Table 8.12 provides some of the typical parameters used to compare electricity distribution networks. The parameters are generally based on data in the public domain and may not be current to the latest financial year, but still give a reasonable indication of the relative sizes of the networks being serviced. On all parameters, ActewAGL Distribution is considerably smaller than its peers.

Where reference is made to comparable rural and urban utilities, the names have been removed but the identifiers are available to the AER on request.

Table 8.12 Relative size of Australian distribution utilities (approximate values)

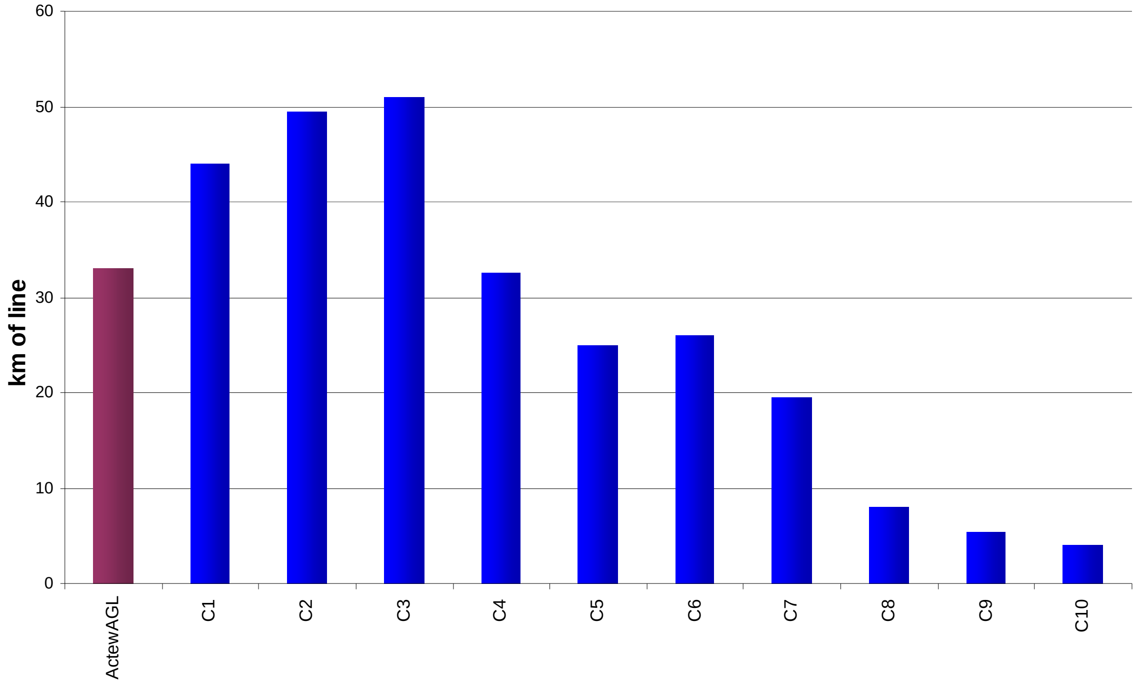
Utility	Length of line (km)	Number of Customers	Demand (MW)
ActewAGL Distribution	4,696	156,360	573
Citipower	6,488	286,107	1,699
United Energy	12,308	609,585	2,392
Alinta	5,579	286,085	1,106
Energy Australia	47,144	1,539,030	5,165
Integral Energy	33,863	822,446	3,246
Energex	48,115	1,217,193	3,835
SP AusNet	29,397	573,766	1,777
Powercor	80,577	644,113	2,394
Ergon Energy	142,793	736,710	2,231
Country Energy	182,023	734,074	2,082

Source: Line length and customer numbers from AER 2007 *State of the Energy Market*. Data on maximum demand are 2004 data collated by SKM from publicly available sources.

Relative size is a significant issue. Overheads in terms of support systems (e.g. financial, billing, asset management, and geographical information systems), customer contact centres, control centres and corporate functions are expected to represent a larger proportion of operating costs for a smaller business when compared to larger entities.

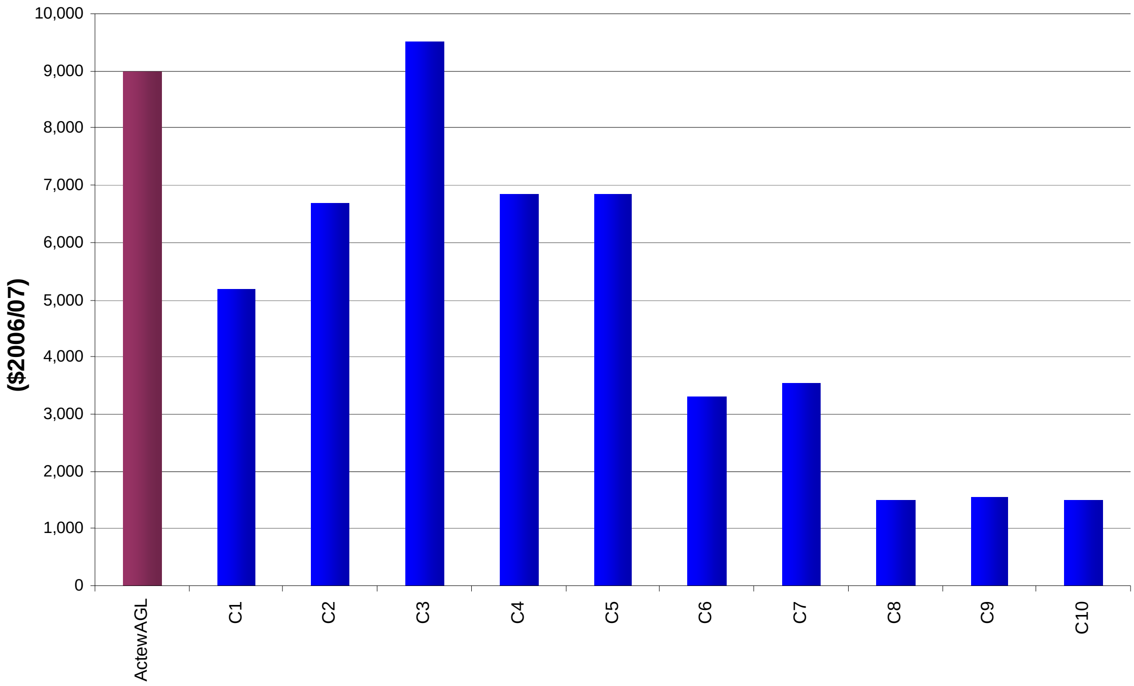
The comparable customer densities are presented in Figure 8.5.

Figure 8.5 Comparable customer densities



This figure indicates that ActewAGL Distribution has an intermediate customer density—below the major city suppliers but well above the rural distributors.

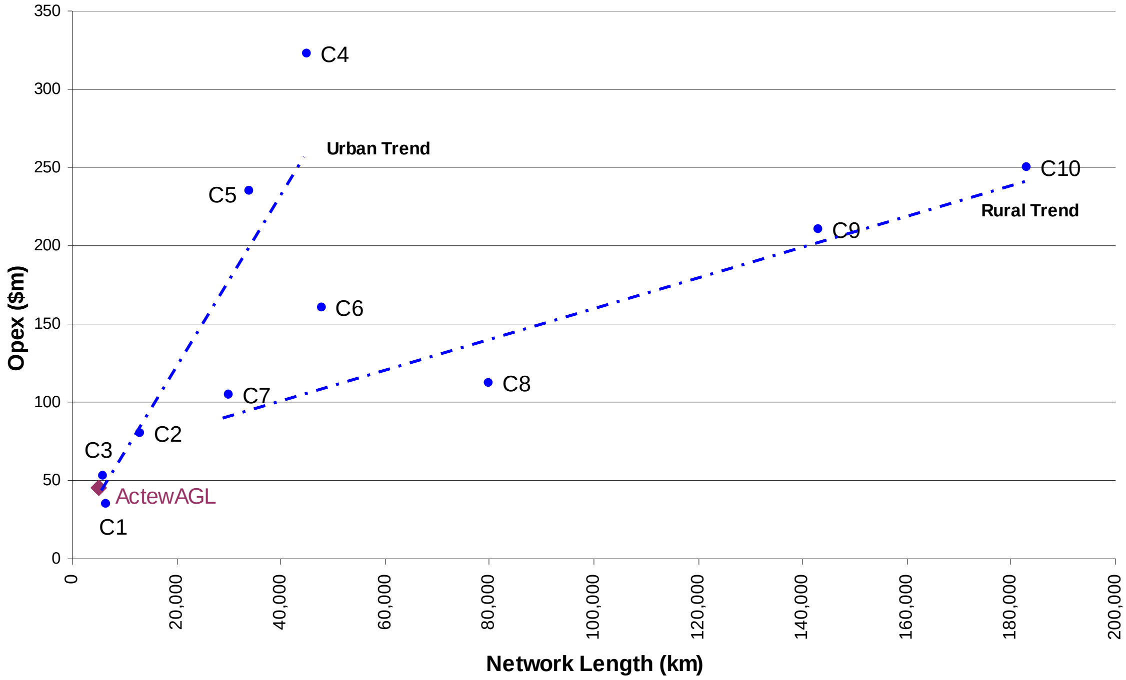
Figure 8.6 Comparative regulated network operating expenditure per kilometre of line ($2006/07)



The measure of total regulated network operating expenditure per kilometre of line (Figure 8.6) tends to favour rural distributors with long lengths of overhead line and low customer density, though costs *per customer* in these instances is likely to be higher. The measure tends to disadvantage smaller compact networks where line length is limited and the bulk of the assets in service are made up of other asset categories. ActewAGL Distribution ranks closest to some urban distributors of comparable size. The remaining networks are, on average, an order of magnitude larger as such economies of scale are a major influencing factor.

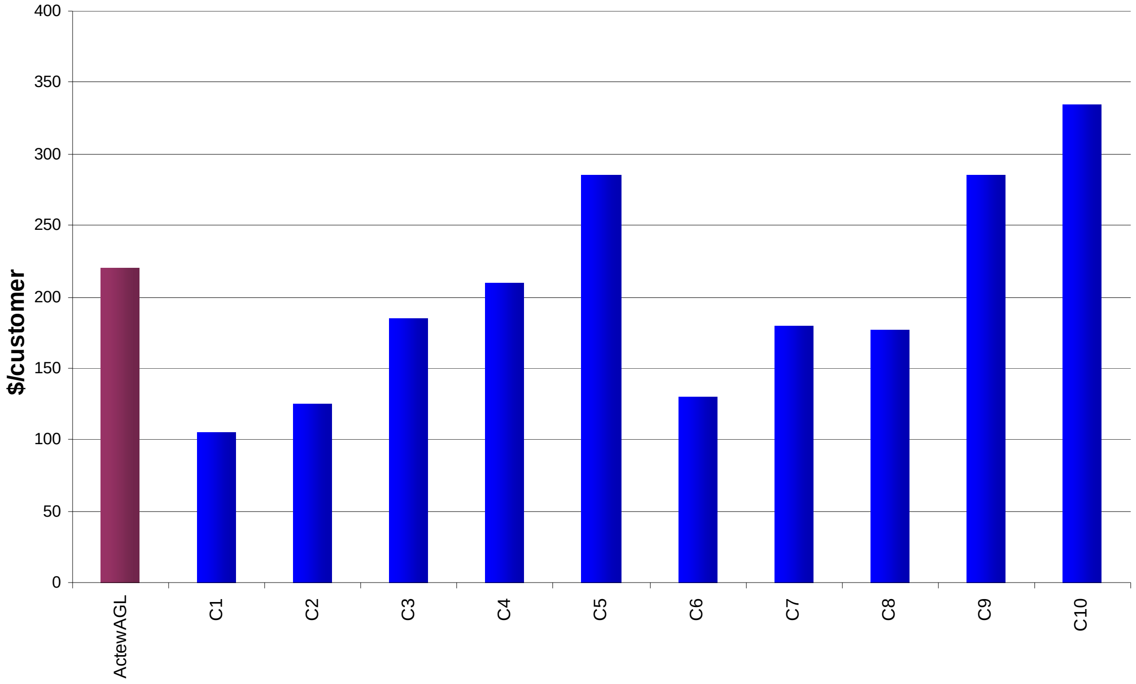
An alternative view of these data, as shown in Figure 8.7, demonstrates the effect of the scale factor. There are two distinctly different trend lines for urban and rural distributors. ActewAGL Distribution's expenditure sits on the urban trend line comparable with other urban distributors.

Figure 8.7 Regulated network operating expenditure per kilometre trend lines



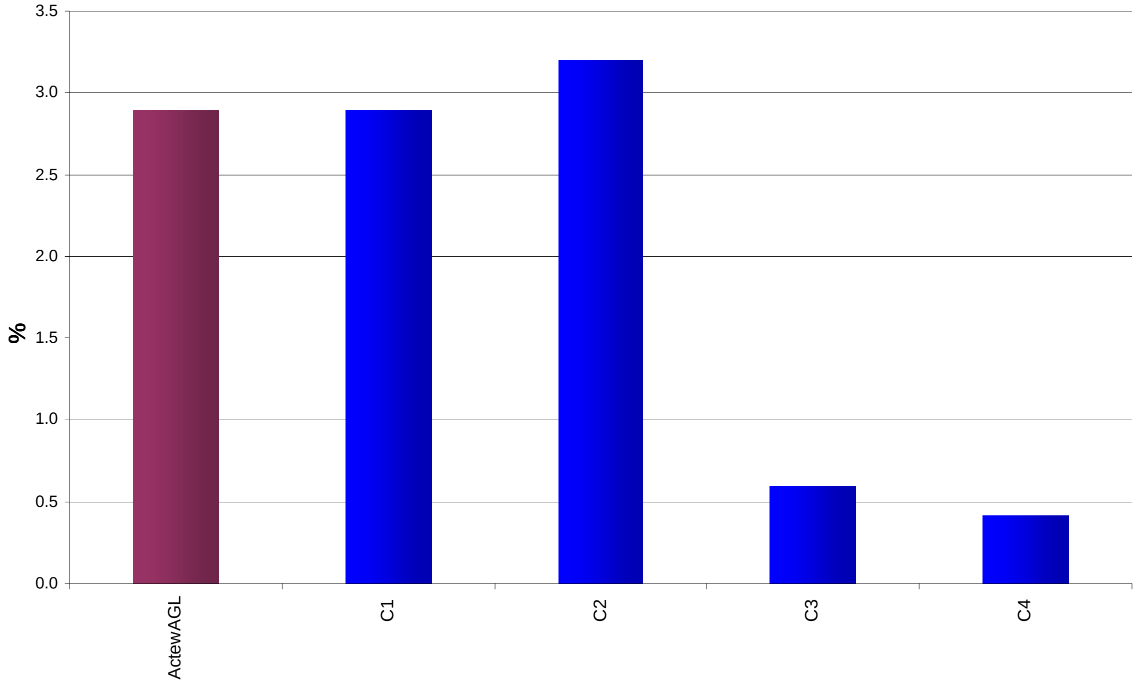
In terms of total regulated network operating expenditure per customer serviced, ActewAGL Distribution is comparable with the rural distributors and an urban distributor. It should be noted that ActewAGL Distribution has approximately half the customers of the next smallest distributor in this comparison. The average number of customers of the remaining distributors is a factor of five times that of ActewAGL Distribution. The issue of scale is, again, critical when considering this measure.

Figure 8.8 Comparative regulated network operating expenditure per customer ($2006/07)



Replacement cost (RC) might be considered to be a better base for the comparison of regulated network operating expenditure than regulatory asset base (RAB) especially for maintenance expenditure which is specifically related to the assets to be maintained. However, RC data is not readily available in the public domain. The comparators used in Figure 8.9 are Australian east coast distributors for which data was available from previous operating expenditure reviews carried out by SKM. The work was done on a confidential basis and for this reason the distributors have not been identified. The comparison is based on total regulated network operating expenditure, including overheads, as asset maintenance specific expenditure is also not readily available in the public domain.

Figure 8.9 Comparison of total operating expenditure as percentage of replacement cost



8.4.3 Summary of comparisons

None of the comparisons in the figures presented in the previous section account for the condition of the assets being maintained.[79]

As already discussed, each electricity distributor is unique in some aspect. The specific considerations that are unique to ActewAGL Distribution, and which would tend to distort comparisons, are as follows:

- ActewAGL Distribution is a relatively small distributor—smallest by a significant factor in terms of customer numbers, energy and demand supplied and is the second smallest in terms of kilometres of line. It is difficult to estimate the impact of economies of scale on operating expenditure requirements, but it is likely to be significant, especially in corporate and business overheads, support infrastructure such as customer systems, asset databases, maintenance management systems, outage management, and system control. ActewAGL Distribution seeks to overcome cost disadvantages in corporate and support services through the ActewAGL multi-utility structure.

- ActewAGL Distribution has a much larger proportion of natural (untreated) hardwood poles remaining in service than is typical in the electricity supply industry. Natural poles represent over 50 per cent of the ActewAGL Distribution pole population. A more typical level

[79] Age is often used as a *de facto* measure of condition. Typical curves of operating expenditure versus average age of an asset in service for two Australian distribution utilities, including a trade off between capital and operating expenditures, are shown in chapter 6 of this regulatory proposal.

throughout the industry would be around or below 10 per cent. The higher proportion increases the maintenance cost of reticulation assets. The location of poles in backyards historically limited ActewAGL Distribution's ability to use chemical treatment. Expenditures include an increased intensity of pole inspections and management as part of a successful proactive strategy to address pole failure rates.

- The asset management strategy adopted for the large population of natural hardwood poles has resulted in a large and growing number of reinforced poles (approximately 20 per cent of the pole population). There are increased maintenance costs associated with reinforced poles due to unions having imposed climbing bans in respect of these poles.
- ActewAGL Distribution has inherited an urban network with the bulk of low-voltage reticulation in the rear of residential housing blocks. This generates unique maintenance issues ranging from access difficulties to interference with poles including attached structures, fencing, vegetation, pavements etc. In particular, the lack of access for elevating work platforms in combination with the large number of staked poles in these situations results in higher maintenance and capital costs for management of these assets.
- Comparison of unplanned reliability statistics suggest that ActewAGL Distribution is performing better than other DNSPs.[80] This suggests that the level of maintenance undertaken by ActewAGL Distribution has been effective in this regard.
- SKM has reviewed the asset management principles and maintenance cycles/strategies of all of ActewAGL Distribution's major asset categories and has concluded that they are generally consistent with sound industry practice.
- Regulatory requirement for notification to land occupiers prior to entering land for works/inspections also adds to cost base, given that a large percentage of assets are on customers' properties.

ActewAGL Distribution believes that it is vital that all these considerations be taken into account in assessing attainable efficient costs of service provision and that simplistic comparisons of costs in the absence of precise information on the operating environment must be actively avoided.

8.5 Equity and debt raising costs

8.5.1 Equity raising costs

ActewAGL Distribution is proposing an increased regulated network capital expenditure program, but the program will not exceed the AER threshold that would trigger an allowance for equity raising costs. ActewAGL Distribution does therefore not seek to be compensated for equity raising costs for its future regulated network capital expenditure program.

[80] See discussion of service performance in chapter 3 of this regulatory proposal.

8.5.2 Debt raising costs

Many businesses raise debt to partly fund the capital investment programs. Unlike equity raising costs (which only occur once), debt raising costs occur not only when the debt is initially raised, but also when the debt is rolled over. For the regulated DNSPs, the transitional *Rules* stipulate that for the purposes of estimating debt raising costs the businesses are assumed to have a gearing of 60 per cent. In the regulatory framework the regulated businesses must be compensated for the legitimate expense for the gearing.

In the Post Tax Revenue Model developed by the AER, the debt raising costs are added to the operating expenses.

There is a strong regulatory precedent for credit ratings of BBB+ and debt raising costs of 12.5 basis points (bp). The AER has since 2004 relied on the Allen Consulting Group Report in determining the debt raising costs. However in the 2007 Powerlink decision, the AER changed the methodology to first determine how many multiples of the benchmark median bond issue size ($200 million) comprise the benchmark debt share (60 per cent) of the RAB in each year. The AER then matched the number of multiples with the corresponding debt raising cost benchmark, which is presented below.

The concept behind the decreasing benchmark is that the relative cost of raising debt is expected to decrease with higher levels of debt raised, due to the spread of company credit rating costs across the multiples of bonds being issued.

ActewAGL Distribution's debt share of RAB for the 2009–14 regulatory period will be between $390 million and $436 million, as shown in Table 8.13.

Table 8.13 Debt share of RAB and associated costs in basis points 2009–14

	2009/10	2010/11	2011/12	2012/13	2013/14
Debt share of RAB ($ million nominal)	387	405	418	429	432
Debt raising costs (basis points)	10.4	9.1	9.1	9.1	9.1

The average debt raising cost for the 2009–14 regulatory period for ActewAGL Distribution's is 9.36bp, calculated using the AER's approach for Powerlink. Considering that ActewAGL Distribution is a relatively small utility it is reasonable that the debt raising costs will be higher than for a larger company.

The debt raising costs for the 2009–14 regulatory period are shown in Table 8.14.

Table 8.14 Total debt raising costs 2009–14

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14
Debt raising costs	0.32	0.35	0.37	0.38	0.39

8.6 Self-insurance

Certain risks borne by ActewAGL Distribution in the provision of electricity distribution services in the ACT are not compensated through the WACC or elsewhere in this regulatory proposal. As such, ActewAGL Distribution proposes a self-insurance allowance for this purpose.

An allowance for self-insurance risk is supported by regulatory precedent. The acceptance of such an approach, and the reasoning behind it, is evident in the AER's *Statement of Regulatory Principles for Transmission Businesses*. This statement specifically canvasses the inclusion of self-insurance and other regulatory mechanisms to mitigate the risk of certain events on electricity transmission businesses, as follows.

> The ACCC considered the option of self-insurance, in addition to external insurance, should generally be available to Transmission Network Service Providers (TNSPs) to allow them to select the most efficient approach. Alternatively, it is suggested that where a risk is not controllable by the TNSP, it may be appropriate to include (as an alternative to receiving an allowance in the cash flows) a mechanism in the revenue cap that allows the TNSP to pass through to users the costs of certain events.[81]

The AER's guidance to transmission businesses in January 2007 specifically allowed for the inclusion of a self-insurance risk premium, as long as certain conditions were met, for example, actuarial sign-off. In its recent electricity transmission decision for SP AusNet, the AER allowed the inclusion of a self-insurance risk premium.

> For risks associated with the provision of prescribed transmission services that are not compensated for through the WACC or elsewhere in its revenue proposal, a TNSP may propose to "self-insure", and seek a self-insurance allowance for this purpose.[82]

ActewAGL Distribution believes that, for self-insurance, the principles espoused by the AER apply equally to a distribution business as they do to transmission businesses. ActewAGL Distribution therefore engaged SAHA International (SAHA) to undertake a valuation of its self-insured risks. The objectives of the consultancy were to:

- Identify the key risks it faces as a regulated electricity distribution business;
- Assess whether those risks were business risks that would be faced by an efficient electricity distributor, having regard to the relevant circumstances facing ActewAGL Distribution; and
- Quantify where possible those business risks and recommend a preferred regulatory treatment for recovery of the identified costs.

In estimating ActewAGL Distribution's self-insurance risk premium, SAHA identified all the other risk mitigation strategies that ActewAGL Distribution will have in place for the 2009–14 regulatory period, including external insurance, capital and operating programs (with the latter being a function of the costs that were assumed to be included in the base year) and any

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[81] ACCC 2004, *Statement of principles for the regulation of electricity transmission revenues–background paper*, 8 December, p 65

[82] AER 2008, *Final decision, SP AusNet transmission determination 2008-09 to 2013-14*, January, p 137

regulatory risk mitigation mechanisms. The risks assessed and their quantification is summarised in Table 8.15.

Table 8.15 Quantification of ActewAGL Distribution self-insured risk premium

$ '000 (2007/08)	Quantification for five years	Annual quantification
Bushfire	890.0	178.0
Earthquake	51.5	10.3
Theft of Assets	70.0	14.0
Key Asset Failures	1,400.0	280.0
Pole and Wires	5,245.0	1,049.0
Counter-party Credit	72.5	14.5
General Public Liability	5.3	1.1
Total	7,734.3	1,546.9

Specific information on risks covered and calculation of the self-insurance premium are provided in pro forma 2.3.11. SAHA's confidential report to ActewAGL Distribution forms attachment 20 to this regulatory proposal.

Based on SAHA's report, ActewAGL Distribution's proposed self-insurance costs for the 2009–14 regulatory period are shown in Table 8.16.

Table 8.16 Self-insurance costs 2009–14

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14
Self-insurance costs	1.6	1.6	1.6	1.6	1.6

Note: This table refers to the total self-insurance cost before allocation to Standard and Alternative Control Services.

Since in general the risks identified apply to or are associated with all of ActewAGL's assets, self-insurance cost has been split between Standard Control Services and Alternative Control Services based on, for simplicity, the proportionate size (by value) of the respective opening RABs.

In regard to acceptance of the ActewAGL Joint Venture Board of the risks quantified, ActewAGL Distribution has in place a process of continual identification and management of the key risks faced by the business. This comes under the auspices of the Board's Audit and Risk Management Committee. Each February, as part of the process, the Board is advised of and endorses the insured and uninsured risk position of ActewAGL. The position is reaffirmed in June each year when the Board accepts (or rejects) the terms and conditions of insurance quotations. As part of the preparation of this regulatory proposal, the Board has considered and signed off on a set of assumptions, including that of self-insuring for a number of risks at the values assessed by SAHA.

8.7 The Utilities Network Facilities Tax (UNFT)

In 2006, the ACT Government introduced a Utilities Network Facilities Tax (UNFT). Having been introduced during the 2004-09 regulatory period, ActewAGL Distribution sought and was granted a cost pass through for the cost of the tax under the tax change event provision of ICRC's 2004 Final Decision.[83]

For the 2009–14 regulatory period, ActewAGL Distribution has included in its operating expenditure forecasts an estimate of the UNFT payable to the ACT Government. The inclusion of this tax results in a step increase of $4 million in operating expenditure in 2009/10.

It is difficult to estimate future UNFT liabilities. Each year, the ACT Government provides the rate to apply for the coming year, but does not set the rate to apply to future years. The 2008/09 ACT Budget includes estimates for total UNFT revenue for each year to 2011/12. ActewAGL Distribution has used the forecast growth in UNFT revenue from this source as a basis for estimating the UNFT applying to its electricity network.

Estimated UNFT expenditures for the 2009–14 regulatory period are shown in Table 8.17.

Table 8.17 Forecast UNFT expenditures 2009–14

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14
UNFT expenditures	4.0	4.1	4.2	4.3	4.4

8.8 Fixed and variable costs

Clause S6.1.2 of the transitional *Rules* requires the proposal to identify "to what extent that forecast expenditure is on costs that are fixed and to what extent it is on costs that are variable".

Fixed costs are those that are incurred to keep the business alive and irrespective of the level of business activity. *Variable costs,* on the other hand, are those that vary with activity levels. In the medium to long term, all costs can be varied depending on the stage in the investment cycle to the extent chosen in the trade-off between capital and operating expenditure. Also, there is potentially a number of ways in which the activity of an electricity distribution business can be defined, for example, demand or customers served. The transitional *Rules* provide no further guidance on the definition of 'variable costs'.

The relationship between ActewAGL Distribution's operating costs and activity is complex. The only significant short-term relationship between growth, or changes in scale, and operating costs is via growth driven capital expenditure, which results in additional assets and in turn additional maintenance costs. In this sense, operating expenditure may be linked to various

[83] The 2004 decision, having included only Commonwealth taxes in a *tax change event* was amended to include an appropriate provision by ICRC 2007, *Final Decision Electricity Distribution Services: Proposed Amendment to the 2004 Pricing Direction*

growth measures, such as new land releases if the new assets are associated with connection of new customers, or growth in peak demand if the new assets are associated with network augmentation. However, as stated, the relationship is complex, depending on such factors as the type of asset involved and the type of customer connected, and is hard to estimate on a year-by-year basis.

A further potential link between growth and operating expenditure is through the impact of customer numbers on the costs of providing customer services such as billing and revenue collection. However, for ActewAGL Distribution, changes in electricity network customer numbers have a very small impact on customer costs, particularly billing systems that incur a large fixed cost and minimal variable costs. As explained in ActewAGL Distribution's approved cost allocation methodology, customer costs are calculated on the basis of the share of electricity network customers in the total electricity and water customer base. This share remains very stable (as most electricity customers are also water customers). Furthermore, the retail costs represent a small proportion (4 per cent in 2007/08) of ActewAGL Distribution's total operating costs.

Given that changes in scale are not significant direct drivers of ActewAGL Distribution's operating cost forecasts, output measures such as customer numbers, throughput and the number of assets have not been used as inputs into the operating cost forecast methodology. As described throughout this chapter, the methodology essentially involves input cost escalation from the efficient base year considering parameters such as inflation, wage and material changes that, on a year-by-year basis, have a more direct impact on operating expenditures. Where there are step changes, the specific drivers such as new Technical Regulator requirements relating to certain maintenance and operating practices (not broad measures such as customer numbers or throughput) are identified and incorporated.

8.9 Efficiency benefit sharing scheme

In accordance with clause 6.5.8 of the transitional *Rules*, the AER has published an efficiency benefit sharing scheme (EBSS) to apply from the start of the 2009–14 regulatory period. An EBSS attempts to share efficiency gains and losses between DNSPs and distribution network users. The aim of an EBSS is to provide a DNSP with a constant incentive to improve the efficiency of its operating expenditure.

In its Final Decision on the EBSS for the 2009 ACT and NSW determinations, the AER sets out the information that must be provided as part of this regulatory proposal:

- A description of its capitalisation policy including any proposed changes to the policy and a calculation of the impact of those policy changes on forecast operating expenditure;
- The proposed method for accounting for demand growth to be used at the end of the regulatory control period to adjust forecast operating expenditure for outturn demand growth (that is, to adjust for any changes in scale). The method proposed must be the same method as used to produce the operating expenditure forecasts;

- Any proposed cost category exclusions for uncontrollable costs; and
- Forecast operating expenditure for the 2009–14 regulatory control period including disaggregated forecasts for non-network alternatives and cost categories proposed to be excluded.

8.9.1 Capitalisation policy

ActewAGL Distribution's capitalisation policy is set out in attachment 21 to this regulatory proposal.

ActewAGL Distribution does not propose any changes to the capitalisation policy during the 2009–14 regulatory period.

8.9.2 Demand growth and operating expenditure

As discussed in several parts of this regulatory proposal, demand growth can have an impact on operating expenditure in a number of ways. However, it is difficult to determine the strength of the relationship with any precision. For example, there is no simple relationship between customer numbers and operating and maintenance expenditure. While the connection of one large commercial customer may result in some additional operating and maintenance costs, the connection of a smaller customer or even many smaller customers may have no impact. As a result, demand parameters such as customer numbers are not direct inputs into ActewAGL Distribution's operating cost forecast methodology.

The most significant way in which demand influences operating expenditure is through the impact on assets in service. Increased demand may increase the costs of maintaining those assets and eventually require their augmentation.

Growth-driven capital expenditure results in additional assets in service and then a corresponding increase in maintenance costs. Modelling by SKM has shown that the increased operating and maintenance for new assets is approximately 0.58 per cent of the value of new assets (chapter 6 of this regulatory proposal refers). For some assets it is possible to quantify the increase in operating and maintenance costs. For example, a new pole results in increased pole inspection costs. However, in general there is no direct relationship.

One option for quantifying a relationship may be to analyse the long-term high level relationship between operating expenditure and growth in the asset base. However, such an analysis would be complicated by the changes in scope and practice over time that have resulted in step changes in operating expenditure (for example, the start of the National Electricity Market and changed practices arising from the deterioration of backyard reticulation).

ActewAGL Distribution is therefore unable to propose a robust method for adjusting operating expenditure to account for unforeseen demand growth. In requiring ActewAGL Distribution to formulate a relationship, the AER should note the considerable burden of proof this places on ActewAGL Distribution.

- While it may be theoretically possible to form a relationship between demand and operating expenditure, it is an exceptionally complex task and the relationship will differ between utilities, for the reasons outlined above.

- The application of a relationship to operating expenditure forecasting (as required by the AER Final Decision) would require ActewAGL Distribution to recast its long-established and ICRC-approved forecasting methodology, as well as to revise its 2009–14 forecasts and regulatory proposal content.

- These modifications would have been bound by considerable time constraints, as the AER released its Final Decision on 29 February 2008 and RNSP proposals were due on 2 June 2008.

ActewAGL Distribution understands the desire for operating expenditure increases associated with higher than forecast growth in demand to be excluded from the operation of the EBSS. However, further consideration needs to be given to how this excluded expenditure is to be estimated accurately and specifically for the circumstances of ActewAGL Distribution. ActewAGL Distribution seeks the AER's assessment of options on this issue for its consideration and response.

8.9.3 Proposed cost category exclusions

In its Final Decision on the EBSS, the AER states that:

> … it is appropriate for the EBSS to focus on controllable costs but notes that it is a difficult exercise to adequately define in advance all costs that may, or may not, be included in the EBSS. The AER will, therefore, permit a DNSP to propose a range of additional cost categories to be excluded from the operation of the EBSS. These categories must be specific to the business, involve an identifiable reason for being excluded and should not involve an ongoing business activity. A DNSP must propose cost categories to be excluded from the scheme in their regulatory proposal for the 2009–14 regulatory control period."

ActewAGL Distribution proposes the exclusion of the following costs from the operation of the EBSS:

- self-insurance costs;

- debt raising costs;

- costs of agreed pass throughs; and

- UNFT payable to the ACT Government.

ActewAGL Distribution has proposed the exclusion of these cost categories because they are not correlated with the underlying efficiency of the business processes and service provision.

ActewAGL Distribution proposes, for EBSS purposes, the operating expenditure forecasts as provided in Table 8.18. Apart from the *National Electricity Rule* requirements, there is no ACT specific framework for the consideration of non-network alternatives (e.g. a demand-side management code). Therefore ActewAGL Distribution assesses non-network and network options using the same criteria. As such, ActewAGL Distribution does not separately forecast non-network expenditure.

Table 8.18 Forecast operating expenditure 2009–14 for EBSS purposes

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14
Total regulated network operating expenditure	**58.7**	**59.8**	**61.0**	**62.9**	**63.0**
Debt raising costs	0.3	0.4	0.4	0.4	0.4
Self-insurance costs	1.5	1.5	1.5	1.5	1.5
UNFT	4.0	4.1	4.2	4.3	4.4
Total operating expenditure for EBSS purposes	**52.9**	**53.9**	**54.9**	**56.8**	**56.8**

8.10 Summary of forecast regulated network operating expenditure

ActewAGL Distribution's proposed operating expenditure program continues and builds on the completed program for the current regulatory control period. The proposed program is aimed at ensuring ongoing network reliability, and minimising the total lifecycle cost of providing network services. Table 8.18 summarises the total proposed regulated network operating expenditure program for 2009–14 including debt raising costs, self-insurance and the UNFT.

Table 8.19 Forecast operating expenditure 2009–14 including debt raising costs, self-insurance and UNFT

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Network operations	13.4	13.9	14.3	15.4	15.8	72.8
Planned maintenance	13.0	13.0	12.8	13.0	12.2	64.1
Reactive maintenance	3.8	3.9	4.0	4.1	4.1	19.8
Maintenance expenditures	16.8	16.9	16.8	17.1	16.3	83.9
Other expenditures	22.7	23.1	23.9	24.3	24.7	118.6
Regulated network operating expenditure	**52.9**	**53.9**	**54.9**	**56.7**	**56.8**	**275.3**
Debt raising costs	0.3	0.4	0.4	0.4	0.4	1.8
Self-insurance costs	1.5	1.5	1.5	1.5	1.5	7.5
UNFT	4.0	4.1	4.2	4.3	4.4	20.9
Total regulated network operating expenditure	**58.7**	**59.8**	**61.0**	**62.9**	**63.0**	**305.5**

9. Opening regulatory asset base

In accordance with clause 6.12.1(6) of the transitional *Rules*, a distribution determination is predicated on the AER making a decision on ActewAGL Distribution's Regulatory Asset Base (RAB) as at 1 July 2009 in accordance with clause 6.5.1 and clause S6.2.

Consistent with clause 6.5.1 of the transitional *Rules*, the AER has developed a Roll Forward Model (RFM), which ActewAGL Distribution has used to calculate its RAB value as at 1 July 2009. Clause 6.5.1(g) of the transitional *Rules* provides that the RFM for ActewAGL Distribution must apply the approach adopted by the Independent Competition and Regulatory Commission (ICRC) in the current determination, but taking into account any written representations by the ICRC to ActewAGL Distribution before the commencement date of the amendments to the *National Electricity Rules* (NER).

Under clause S6.1.3(10) of the transitional *Rules* each DNSP is required to submit a completed RFM to the AER as part of its building block proposal.

9.1 Roll Forward Model

The RFM sets out the calculation of the RAB from the beginning of one regulatory period to the beginning of the next period, as well as from year to year within each period, on an actual basis.[84] In the ACT, the closing RAB value from the RFM forms an input into the Post Tax Revenue Model which is then rolled forward from year to year on an indicative basis, and used in the calculation of annual revenue requirements.

In determining the opening asset base for the 2009–14 regulatory period, ActewAGL Distribution must:

- determine the opening asset base in 2004 by using the values specified in clause S6.2.1(c), and adjusting for any difference between estimated capital expenditure and actual capital expenditure in the previous regulatory control period;
- add actual capital expenditure incurred during the 2004–09 period and where actual is not available, add estimated capital expenditure to the 2004 opening asset base;
- reduce the previous value of the asset base by the amount of depreciation of the RAB during the previous regulatory control period according to the approach determined by the ICRC;
- reduce the previous value of the RAB by the disposal value of any assets disposed; and

[84] ActewAGL Distribution notes that at this time, data for 2007/08 and 2008/09 are estimates. Before the AER's final decision (scheduled for April 2009), ActewAGL Distribution will be able to provide actual figures for 2007/08.

- make adjustments for any reclassification of services or change in the use of assets that affects the classification of the services provided by the assets.

9.2 Roll forward calculation

The opening RAB at 1 July 2004, as set out in clause S6.2.1 of the transitional *Rules*, is $510.54 million ($ nominal). This value has been rolled forward and adjusted for actual capital expenditure, depreciation, capital contribution/disposals, and inflation as set in Table 9.1.

Depreciation has been calculated according to the approach determined by the ICRC in the previous regulatory control period using the average remaining life as at June 2004 and assigning a standard life of 40 years to all new assets and 21.77 years to all existing assets. The expected sale proceeds of ActewAGL House have been included and reduced the RAB value according to the corporate services cost allocation.

As discussed in chapters 7 and 8, ActewAGL Distribution believes that its capital expenditure in the current regulatory period represents the prudent and efficient cost of service provision.

ActewAGL Distribution has rolled forward its current regulatory period RAB consistent with the methodology described above and using the RFM constructed by the AER. ActewAGL Distribution has applied the approach adopted by the ICRC in the current determination, taking into account any written representations by the ICRC to ActewAGL Distribution before the commencement date of the amendments to the NER. ActewAGL Distribution notes the following written representations that are relevant to the roll forward calculation:

- the letter to the CEO of ActewAGL Distribution dated 25 August 2006 relating to expenditure on the Southern Supply Point;
- the letter to the CEO of ActewAGL Distribution dated 10 May 2007 relating to additional expenditure of poles; and
- the letter the CEO of ActewAGL Distribution dated 28 March 2008 relating to expenditure on the Southern Supply Point.

These representations are supplied as attachments 13 and 14 and 15 to this regulatory proposal.

After making the required adjustments, the rolled forward value of the RAB as at 30 June 2009 is calculated to be $593.0 million ($ nominal). The roll forward calculation is presented in Table 9.1. The completed Excel Model is provided at attachment 6.

Table 9.1 Roll Forward of ActewAGL Distribution's Regulatory Asset Base

$ million (nominal)	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Opening RAB	506.8	516.7	530.6	546.5	579.3	**593.0**
Net Capital Expenditure	21.7	23.4	29.5	37.8	30.1	
Depreciation	24.1	25.4	26.7	28.7	30.1	
Indexation	12.4	15.9	13.1	23.7	16.0	
Closing RAB	516.7	530.6	546.5	579.3	595.4	
2003/04 adjustment					*(2.3)*	

10. Cost of capital and forecast inflation

10.1 Cost of capital

Clause 6.12.1(5) of the transitional *Rules* directs the AER to make a decision in relation to the rate of return in accordance with clause 6.5.2. Clause 6.5.2(b) states that the rate of return is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar degree of non-diversifiable risk as that faced by the RNSP.

The return on capital is the financial return that investors seek when considering and assessing investments. The return on capital should represent the opportunity cost of capital. Clause 6.5.2(b) states that the rate of return must be calculated as a nominal post-tax weighted average cost of capital (WACC) using the following formula:

$$WACC = k_E \frac{E}{V} + k_D \frac{D}{V}$$

where:

- k_E is the nominal return on equity, or $r_f + \beta_e \times MRP$

where:

r_f is the nominal risk free rate
β_e is the equity beta
MRP is the market risk premium

- k_D is the nominal return on debt, or r_f + DRP

where:

r_f is the nominal risk free rate
DRP is the debt risk premium

- $\frac{E}{V} =$ equity share in total value
- $\frac{D}{V} =$ debt share in total value

Clause 6.5.2 (b) of the transitional *Rules* prescribes the value of the following parameters:

- $\beta e = 1.0$
- MRP = 6.0 per cent
- $\frac{D}{V} =$60 per cent

Therefore, the following parameters must be estimated by ActewAGL Distribution.

- The nominal risk free rate, according to clause 6.5.2 (c);
- The debt risk premium, as per clause 6.5.2 (e); and
- Forecast inflation

10.1.1 Nominal risk free rate

The risk free rate is an integral component of the WACC framework as it represents a return investors would earn on assets with no volatility and no default risk, or in other words an asset with zero default risk.

Clause 6.5.2(c) of the transitional *Rules*, prescribes that the nominal risk free rate for a regulatory control period is the annualised yield on Commonwealth Government Securities (CGS) with a maturity of 10 years. If there is no CGS with a maturity of 10 years on any day in the period, the nominal risk free rate for the regulatory control period must be determined on a straight line basis from the two CGS closest to the 10-year term and which also straddle the 10 year expiry date.

There is a standard convention for quoting yields in Australia including that used for corporate bonds. The standard convention is to quote an X per cent per annum yield when the semi-annual yield (the return received at the end of a six month period) is ½ X (half the per annum yield). However, clause 6.5.2(c) requires the use of an annualised yield, ie, the percentage return that an investor would receive at the end of a 12-month period. In calculating the annualise yield any payment received within a year is reinvested, which is akin to the accepted use of accumulation indexes to calculate the market risk premium.

For example, a 10-year government bond with a quoted rate of 5.72 per cent per annum actually means that a lender will earn a half of this, or 2.86 per cent return over six months. As a result a lender would reinvest the semi-annual yield of 2.86 per cent for the remaining six months of the year, resulting in a lender earning a 5.80 per cent return over a full year (that is, 5.80 per cent = $(1+2.86\%)^2$ -1). The need to annualise the risk free rate has been accepted by the Australian Competition and Consumer Commission (ACCC) in previous regulatory determinations.[85] ActewAGL Distribution proposes that this approach should be applied and therefore, when setting the risk free rate, has annualised the risk free rate.

For the purpose of this regulatory proposal ActewAGL Distribution has proposed a value for the nominal risk free rate in accordance with transitional *Rules*. This value will change due to capital market developments. For the purpose of determining the risk free rate to apply in the Final Decision, ActewAGL Distribution has nominated a period in accordance with clause 6.5.2 (c)(2)(i) of the transitional *Rules*.

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[85] For example, ACCC 2005, *NSW and ACT Transmission Network Revenue Cap TransGrid 2004-05 to 2008-09*, 27 April, p 138

The value used in this proposal for the nominal risk free rate is 6.272 per cent. ActewAGL Distribution notes that the AER will determine the nominal risk free rate to be used in its revenue cap determination, in accord with a sample period, and ActewAGL Distribution has proposed a sample period at attachment 23.

10.1.2 Debt risk premium

The debt risk premium is what a business must pay to secure debt financing on top of the nominal risk free rate. The debt risk premium a business pays depends on the perceived riskiness of the business. Low risk companies will be able to secure debt financing at a cheaper rate than more risky companies. The gearing of a company is one parameter when measuring the risk of the company.

Clause 6.5.2(e) of the transitional *Rules* defines the debt risk premium as the margin between the 10-year Commonwealth annualised bond rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity of 10 years and a credit rating of BBB+ from Standard and Poor's.

In estimating the debt risk premium the AER's standard practise has been to use data sourced from Bloomberg's 10-year yield. In the 2008 SP AusNet Final Decision, the AER used an eight-year Bloomberg BBB fair yield plus the spread between the 8- and 10-year Bloomberg A fair yields to replicate a 10-year benchmark because Bloomberg discontinued the 10-year BBB yield.

ActewAGL Distribution considers the approach to using Bloomberg's 10-year BBB predicted yield as reasonable. However, ActewAGL Distribution notes the discontinuation of Bloomberg's 10-year BBB fair-yield index creates some additional complexity. In its Final Decision in January 2008 on SP AusNet, the AER used Bloomberg's eight-year BBB rated yield and added the spread between an 8 and 10-year A rated Bloomberg index. ActewAGL Distribution is concerned that by estimating the spread of an 8- and 10-year A rated index, the spread will be underestimated since it is more risky holding a less favourably rated bond over a longer time. Another method which has been used in regulatory decisions has been data from CBASpectrum for BBB+ rated bonds. However, it has been demonstrated that the CBASpectrum contain a downward bias and an underestimation in the order of 20-25 basis points (as discussed in ACTEW Corporation's regulatory submission to the ICRC on 31 July 2007). ActewAGL Distribution proposes that the AER also should consider using data from CBASpectrum for BBB+ rated bonds to compare with the method used in estimating the debt risk premium for SP AusNet.

ActewAGL Distribution proposes to calculate the debt risk premium by reference to the Bloomberg's 10-year BBB predicted yield. However, in the event that the Bloomberg 10-year BBB predicted yield is unavailable during the sample period we propose to use the highest value from either the:

- 10-year CBASpectrum BBB+ predicted yield; or
- 8-year Bloomberg BBB predicted yield plus the spread between an 8- and 10-year A rated Bloomberg predicted yields.

As discussed, ActewAGL Distribution believes that both these alternate approaches are likely to result in a conservative estimate of the debt risk premium.

ActewAGL Distribution proposes that the same sample period should be used as for the risk free rate. For the purposes of this regulatory proposal, ActewAGL Distribution has used the risk premium from the CBASpectrum BBB+ of 3.376 per cent. ActewAGL Distribution notes that the AER will determine the nominal risk free rate to be used in its revenue cap determination for a sample period and ActewAGL Distribution has proposed a sample period at attachment 23.

10.1.3 Debt and equity raising costs

Debt and equity raising costs are discussed in chapter 8.

10.1.4 Proposed WACC Parameters

ActewAGL Distribution has calculated a post-tax nominal vanilla WACC of 10.70 per cent in accordance with the requirements of the transitional *Rules* and using current market parameters. The key parameters and variables underlying the cost of capital calculation are summarised in Table 10.2.

Table 10.1 ActewAGL Distribution’s proposed WACC parameters

Parameter	Value
Nominal risk free rate	6.272%
Expected inflation	2.51%*
Equity beta	1.0
Market risk premium	6.0%
Proportion of Debt Funding	60%
Debt risk premium	3.376%
Utilisation of Imputation Credits	50%
Nominal cost of equity (post tax)	12.27%
Nominal cost of debt (post tax)	9.65%
Nominal vanilla WACC	10.70%

Note: See section 10.2 for calculation of the inflation value.

10.2 Forecast inflation

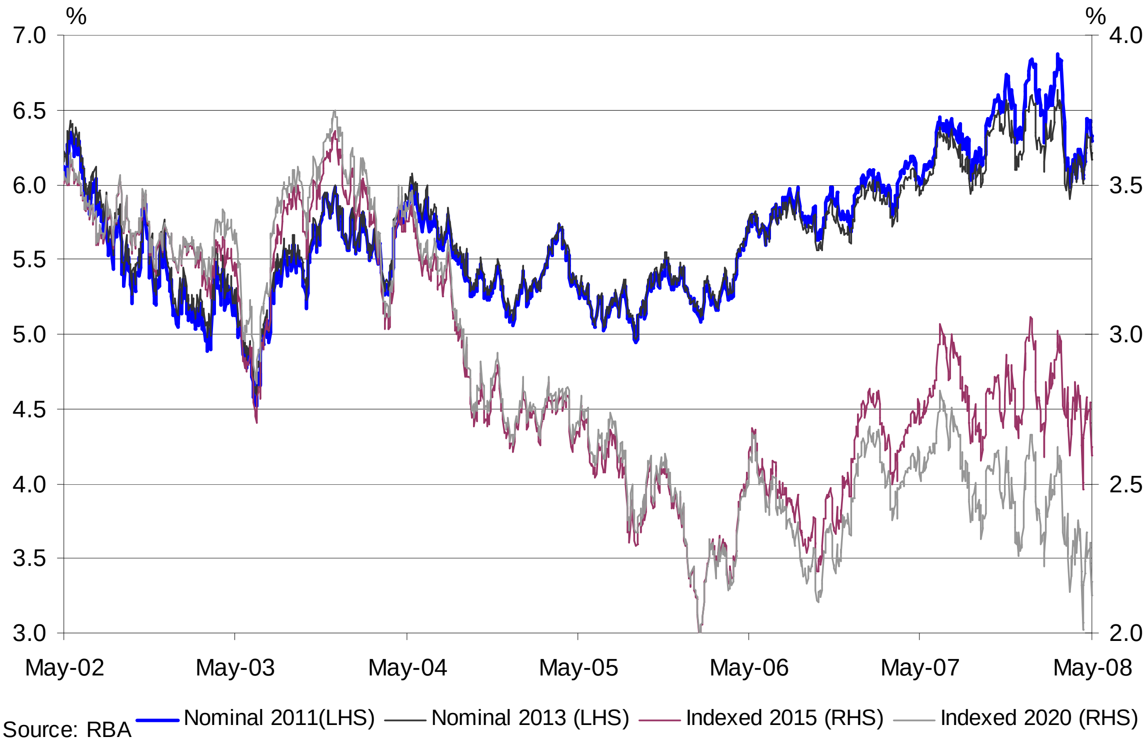
Clause 6.4.2 (b)(1) of the transitional *Rules* states that the contents of the PTRM must include a method that the AER determines is likely to result in the best estimates of expected inflation.

The Consumer Price Index (CPI) has traditionally been calculated using the Fischer equation as the difference between the nominal risk free rate and the real risk free rate. The Fischer equation is based on accepted theory and is therefore a non-arbitrary method for calculating CPI.

$$CPI = \frac{1 + r_f}{1 + rr_f} - 1$$

However, there is strong market evidence that the difference in yields between nominal and indexed CGS results in an overestimate of expected inflation. As can be seen in Figure 10.1, the yields on indexed CGS have fallen dramatically between 2004 and 2008.

Figure 10.1 Yield on nominal and indexed CGS from 2002 to April 2008



Source: RBA

In January 2008, the AER's Final Decision for SP AusNet used the Reserve Bank of Australia (RBA) as a source for its estimation of inflation. In March 2008, the Essential Services Commission engaged Allen Consulting Group who confirmed the bias, but the ESC decided to use historical inflation estimations for forecasting inflation. The new regulatory consensus that has emerged in Australia is therefore that inflation should be estimated directly due to the evidence in the downward bias in the indexed CGS.

Consistent with the AER approach in the SP AusNet Final Decision, ActewAGL Distribution has utilised figures for projected inflation in order to develop appropriate capital and operating expenditure escalation factors and adopted figures from credible forecasters as far out as is possible, thereafter (that is, in 2013/14) the mid-point of the RBA target range, being 2.5 per cent. A recent credible long-term forecast for CPI has been presented in a Competition Economists Group (CEG) report.[86] Table 10.2 outlines ActewAGL Distribution's proposed inflation forecast based on this report.

Table 10.2 Expected inflation in the 2009–14 regulatory period

	2009/10	2010/11	2011/12	2012/13	2013/14
Consumer Price Index	2.4%	2.5%	2.6%	2.6%	2.5%

At the time of compiling this regulatory proposal headline inflation was expected to be tracking above 3 per cent, which is above the very top of the Reserve Bank of Australia's (RBA's) target band of two to three per cent. However, the RBA has stated that the inflationary pressure is expected to peak in 2008 and "would then probably moderate during 2009, in response to the forecast slowing in demand".[87] Market indications therefore suggests that the inflation pressure will decrease. This supports the conclusion that ActewAGL Distribution's inflation forecast is reasonable.

Consistent with the AER's approach in the SP AusNet Final decision, ActewAGL Distribution has averaged the forecasts in Table 10.2 and used the RBA's range of 2.5 per cent for a further five years (until 2018/19). This produces a best estimate of 10-year forecast of annual inflation of 2.51 per cent.

[86] See CEG 2008, *A methodology for estimating expected inflation*,17 January
[87] RBA 2008, *Minutes of the Monetary Policy Meeting of the Board*, Sydney, 4 March

11. Corporate income tax

11.1 Background

Clause 6.4.3 of the transitional *Rules* states that ActewAGL Distribution's cost building blocks include the estimated cost of corporate income tax for each regulatory year. As a result, clause 6.12.1(7) of the transitional *Rules* states that a distribution determination is predicated on a decision by the AER on the estimated corporate income tax to the provider for each regulatory year of the regulatory control period in accordance with clause 6.5.3.

Clause 6.5.3 stipulates that the estimated cost of corporate income tax for each regulatory year (ETC_t) must be calculated in accordance with the following formula:

$$ETC_t = (ETI_t \times r_t)(1 - \gamma)$$

Where:

- ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than the Distribution Network Service Provider, operated the business of the Distribution Network Service Provider, such estimate being determined in accordance with the post-tax revenue model.
- r_t is the expected statutory income tax rate for that regulatory year as determined by the AER to be 30 per cent.
- γ (the assumed utilisation of imputation credits) is deemed to be 0.5.

The estimate must take into account the estimated depreciation for that regulatory year for tax purposes, for a benchmark efficient Distribution Network Service Provider, of assets where the value of those assets is included in the regulatory asset base for the relevant distribution system for that regulatory year.

Section 2.4.5 of the RIN specifies the information that ActewAGL Distribution must provide to the AER in order for it to make a constituent decision on the estimated cost of corporate income tax for each regulatory year of the regulatory control period:

- the Australian Taxation Office's assessments of tax payable under the National Tax Equivalent Tax Regime (NTER);[88]
- NTER values for the RAB to be applied in the post tax revenue model (that is, standard control services only); and

[88] It should be noted that ActewAGL Distribution is a partnership for tax purposes and therefore is not liable to pay corporate income tax.

- NTER values for assets not within the RAB.

11.2 Estimated tax depreciation

Determining the cost of corporate tax facing the regulated business requires an assessment of the tax concessions available to that business.

Consistent with the *Income Tax Assessment Act 1936* and the *Income Tax Assessment Act 1997*, ActewAGL Distribution deducts from its annual assessable income any loss or outgoing to the extent that it is necessarily incurred in carrying on a business for the purpose of gaining or producing your assessable income. Included in this deduction is the decline in value of depreciating assets held from any time during that year.[89] This decline is generally measured by reference to an evaluation of the tax asset base (TAB), which is influenced by:

- the value of assets in each asset class
- the effective life, for tax purposes, of the asset class.

Under the pre-tax approach previously applied to ActewAGL Distribution by the ICRC, the allowance for tax was embedded within the return on equity calculation. Therefore there was no existing TAB used for calculating the depreciation tax deduction. The AER's approach to this requires an assessment of:

- the date ActewAGL Distribution was first subject to tax (or the NTER)
- the tax value of assets at that date, in sufficient details to distinguish RAB assets from non-RAB assets
- the vintage, or age, profile of the RAB assets when first subject to the NTER.

ActewAGL Distribution notes that, as acknowledged by the AER in its issues paper on this subject, *a degree of judgement* is required in establishing the initial tax base. For example, assumptions may be required to separate non-RAB assets if they are not separately identified in tax accounts.

11.2.1 Transfer to NTER

On 14 June 2007 the AER released an Issues Paper *Transition of energy businesses from pre-tax to post-tax regulation,* which proposed an approach by which the TAB could be established for the transition to post-tax regulation. As noted in the Issues Paper, the AER's proposed approach is to roll forward the tax value of the asset base from "the date the business was first subject to tax (or the NTER)"[90]. The AER has endorsed ActewAGL Distribution's proposal to roll forward its TAB to the commencement of the upcoming regulatory period from the date that ACTEW Corporation was first subject to the NTER.[91]

[89] *Income Tax Assessment Act 1997* (Cwth), Division 40.
[90] AER 2007, *Issues Paper—Transition of energy businesses from pre-tax to post-tax regulation*, June, p 12
[91] Letter from AER, 17 March 2008 and provided as attachment 22.

ACTEW Corporation and its subsidiary entities were first recorded on the NTER Entity Register on 1 July 2001. ACTEW Corporation Limited and its current subsidiary entities continue to be part of the NTER and are recorded in the current NTER Entity Register maintained by the NTER Administrator.

11.3 Tax Asset Base Roll Forward 2001–09

ActewAGL Distribution's TAB was $405.55 million as at 1 July 2001. The value of these assets includes assets in the divisional tax asset register as well as an allocation of central corporate assets consistent with "the approach adopted by the ICRC in the distribution determination for the regulatory control period 2004-2009".[92] Treatment of combined "meter and connection" assets involves exercise of judgement as metering assets need to be excluded from the TAB for standard control services. Based on the ratio of capital expenditure on meters to capital expenditure on connection assets over the current regulatory period, ActewAGL Distribution has split the value of these assets on a 50:50 basis. Table 11.1 provides a breakdown of opening tax asset values for each category of assets in the TAB.

Table 11.1 Opening tax value of assets 2001/02

Asset Category	Opening Tax Value ($m nominal)
Sub-transmission	22.4
Zone substations	64.9
Substations	69.9
Distribution reticulation (including connection assets)	223.5
Land	6.8
Buildings type 1	2.9
Buildings type 2	1.9
Business support systems – Networks	5.3
Business support systems – Corporate Services	4.0
Buildings - Corporate Services	4.0

Standard lives for the various asset classes for the roll forward to the commencement of the 2009–14 regulatory period are shown in Table 11.2. Commissioning dates for individual assets were obtained from tax asset registers, and the standard and remaining lives attributed to each class were weighted based on individual asset values within these categories. Standard tax lives as at 31 June 2001 have been based on depreciation rates and remaining lives calculated from the difference between the standard tax life and estimated age. However, for some assets, standard tax lives have been assigned in accordance with the Australian Master Tax Guide. Depreciation has been calculated on a straight-line basis.

[92] Transitional *Rules* clause 6.5.1(g). ActewAGL Distribution notes that this calculation is undertaken in the NSW Roll Forward Model and so applies, where relevant, the requirements found in clause 6.5.1 of the transitional *Rules*.

Table 11.2 Standard tax lives of assets

Asset Category	Standard Life
Sub-transmission	46.0
Zone substations	38.9
Substations	42.7
Distribution reticulation (including connection assets)	47.5
Land	n/a
Buildings type 1	n/a
Buildings type 2	99.4
Business support systems - Networks	12.3
Business support systems - Corporate Services	5.7
Buildings - Corporate Services	n/a

ActewAGL Distribution has rolled forward its TAB from 1 July 2001 to 30 June 2009 using the relevant worksheet in the NSW Roll Forward Model.[93] ActewAGL Distribution submits a TAB value of $472.52 million for the start of the 2009-14 regulatory period. The completed TAB Roll Forward Excel Model can be found in attachment 7.

11.4 Tax depreciation concessions

ActewAGL Distribution has calculated the tax depreciation concessions available to the business from in the 2009–14 regulatory period, which can be found in Table 11.3.

Table 11.3 Tax depreciation concessions

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Tax Depreciation Concessions	18.8	20.7	22.3	23.7	25.2

11.5 Corporate income tax building block

Consistent with the calculation methodology found in clause 6.5.3 of the transitional *Rules*, ActewAGL Distributions' proposed corporate tax building block is as set out in Table 11.4.

[93] ActewAGL Distribution has used the same capital expenditure data as used in the Roll Forward Model. However, ActewAGL Distribution notes that, in accordance with general industry practice, in its *actual* Tax Asset Register pole replacements are not being capitalised. The *actual* Tax Asset Base is therefore lower than the Tax Asset Base that is being rolled forward in the Tax Asset Base Roll Forward Model.

Table 11.4 Corporate income tax building block 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Tax Payable	11.0	12.8	13.4	12.8	13.3
Value of Imputation Credits	(5.5)	(6.4)	(6.7)	(6.4)	(6.7)
Tax Allowance	**5.5**	**6.4**	**6.7**	**6.4**	**6.7**

12. Revenue requirement

12.1 Background

Clause 6.12.1(2) of the transitional *Rules* states that a distribution determination is predicated on a decision regarding ActewAGL Distribution's building block proposal, in which the AER must either approve or refuse to approve the proposed annual revenue requirement for each regulatory year of the regulatory control period.

Pursuant to clause 6.4.3(a) of the transitional *Rules*, the building blocks are (for each regulatory year):[94]

- regulatory depreciation;
- return on capital;
- corporate income tax; and
- operating expenditure.

12.2 Regulatory depreciation

Clause 6.12.1 of the transitional *Rules* requires the AER to make a decision on whether or not to approve the depreciation schedules submitted by ActewAGL Distribution and, if it decides against approving them, a decision determining depreciation schedules in accordance with clause 6.5.5(b). Pursuant to this clause:

- 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;
- the sum of the real value of the depreciation that is attributable to any category of the economic life of that category must be equivalent to the value at which that category of asset was first included in the regulatory asset base; and,
- the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.

In its 2004 Final Decision the ICRC adopted a straight-line approach to depreciation, which was supported by ActewAGL Distribution in its submissions to the ICRC. In the interests of consistency with the previous decision, simplicity and transparency, ActewAGL Distribution

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[94] The AER has decided that neither a service target performance incentive scheme nor a demand management incentive scheme is to apply in the ACT for the 2009–14 regulatory control period. Indexation of the Regulatory Asset Base is included in ActewAGL Distribution's calculation of the return on capital.

proposes the continuation of the straight-line depreciation calculation. ActewAGL Distribution believes that this approach conforms to the requirements in clause 6.5.5(b) of the transitional *Rules*. Depreciation has been calculated consistent with the approach adopted in the Roll Forward Model, using the average remaining life as at 31 June 2009 of 20.45 years. The mechanics of this calculation can be found in ActewAGL Distribution's Roll Forward Model—Standard Control at attachment 6. This Model categorises the relevant assets for depreciation purposes by reference to an asset class and also demonstrates the schedules' conformity with clause 6.5.5(b) of the transitional *Rules*.

ActewAGL Distribution's depreciation schedule for the regulatory period is outlined in the post tax revenue model (PTRM) at attachment 8. The PTRM calculates the regulatory depreciation cost building block for ActewAGL Distribution for the 2009–14 regulatory period. This building block is summarised in Table 12.1.

Table 12.1 Regulatory depreciation 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Regulatory depreciation	14.8	16.0	17.3	18.6	20.0

12.3 Return on capital

The movements in the value of the RAB over the 2009–14 regulatory period are set out in Table 12.2.

Table 12.2 Roll forward of RAB 2009–14

$ million ($2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening RAB	593.0	645.4	675.0	696.1	715.1
Net capital expenditure	81.4	60.6	53.7	52.9	40.0
Depreciation	29.0	31.0	32.6	33.9	35.2
Closing RAB	645.4	675.0	696.1	715.1	719.9

ActewAGL Distribution notes that it has maintained one asset class in the PTRM. The decision to maintain one asset class has been decided separately from the fact that the Roll Forward Model produces an opening asset valuation in one class.[95] ActewAGL Distribution believes that maintaining consistency with the ICRC's previous treatment of the RAB is important to ensure that all assets are depreciated using a consistent approach over their entire economic lives. ActewAGL Distribution believes splitting assets into classes in the PTRM, and assigning

[95] Consistent with the PTRM Handbook, p 5, footnote 3, the AER has not required ActewAGL Distribution to split its opening RAB, perceivably as a transitional initiative. ActewAGL Distribution would, however, consider splitting forecast capital expenditure into classes if the AER believes that this strikes a more appropriate balance in the transition to a national regulatory framework.

them standard economic and remaining economic lives that were not used when the assets were first included in the RAB, would be inconsistent with clauses 6.5.5(b)(1) and 6.5.5(b)(2) of the transitional *Rules*.

ActewAGL Distribution's proposed nominal vanilla weighted average cost of capital is 10.70 per cent. This proposal is based on the discussion found in chapter 10.

The return on capital has been calculated in accordance with clause 6.5.2 of the transitional *Rules*. The return on capital building block is reproduced below in Table 12.3.

Table 12.3 Return on capital 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Return on equity	29.1	32.5	34.8	36.8	38.8
Return on debt	34.3	38.3	41.1	43.4	45.7
Return on capital	**63.4**	**70.8**	**75.9**	**80.2**	**84.5**

12.4 Corporate income tax

The estimated tax allowance is described in chapter 11 and outlined in Table 12.4.

Table 12.4 Corporate income tax 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Tax payable	11.0	12.8	13.4	12.8	13.3
Value of imputation credits	(5.5)	(6.4)	(6.7)	(6.4)	(6.7)
Tax allowance	**5.5**	**6.4**	**6.7**	**6.4**	**6.7**

12.5 Operating expenditure

The calculation of operating and maintenance costs has been detailed in chapter 8. ActewAGL Distribution's operating expenditure forecasts for the 2009–14 regulatory period are shown in. Table 12.5.

Table 12.5 Operating expenditure 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Operating expenditure	60.2	62.9	65.7	69.4	71.4

12.6 Revenue requirement, X factors and price path

In accordance with clause 6.12.3(3)(d) of the transitional *Rules*, the AER must approve ActewAGL Distribution's proposed total revenue requirement and the annual revenue requirement for each year of the period if it is satisfied that those amounts have been properly calculated using the PTRM on the basis of amounts calculated, determined or forecast in accordance with the requirements of Part C of the transitional *Rules*.

A completed Post Tax Revenue Excel Model is provided as attachment 8.

The control mechanism applied to standard control services in the ACT is a maximum average revenue cap. This constraint is expressed as the maximum allowed annual revenue for network services, per kWh.

Table 12.6 Revenue requirement and X factors 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Regulatory depreciation	14.8	16.0	17.3	18.6	20.0
Return on capital	63.4	70.8	75.9	80.2	84.5
Tax allowance	5.5	6.4	6.7	6.4	6.7
Operating expenditure	60.2	62.9	65.7	69.4	71.4
Unsmoothed revenue requirement	144.0	156.1	165.5	174.7	182.6
Energy forecasts (GWh)	2,878.3	2,925.1	2,971.7	3,018.3	3,066.3
Revenue yield ($/kWh)	0.05049	0.05279	0.05520	0.05772	0.06035
Smoothed revenue requirement	145.3	154.4	164.0	174.2	185.0
X factor (%)	***20.37***	***2.00***	***2.00***	***2.00***	***2.00***

Consistent with general regulatory practice, ActewAGL Distribution proposes a different X factor in the first year of the regulatory control period to account for the increase in revenue requirements from 2008/09 to 2009/10. ActewAGL Distribution proposes an X factor of 20.37 per cent in 2009/10 and 2.00 percent in subsequent years. This proposal is consistent with the requirements set out in clause 6.5.9 of the transitional *Rules*. It provides ActewAGL Distribution with sufficient funds in the early years of the regulatory period to manage the step changes in expenditures, while also:

- creating a minimal variance between expected revenue in the last regulatory year of the regulatory period and the annual revenue requirement in that last year; and
- equalising (in terms of net present value) the revenue to be earned over the regulatory period with the total revenue requirement for the regulatory period.

In the current regulatory period, the Utilities Network Facilities Tax (the UNFT) is treated as a cost pass through. ActewAGL Distribution has forecast UNFT liability in the 2009–14 regulatory period. Removing the effect of the UNFT, the "underlying" X factor in 2009/10 would be 17.07 per cent.

ActewAGL Distribution provides indicative prices for the 2009–14 regulatory control period in chapter 13.

13. Indicative prices and control mechanisms

The transitional *Rules* and the Regulatory Information Notice (RIN) contain several requirements relating to pricing and the control mechanisms for direct control services.

The transitional *Rules* require ActewAGL Distribution to include in its regulatory proposal indicative prices for direct control services for each year of the regulatory control period.[96] The prices are indicative only, and a full pricing proposal must be submitted annually to the AER.[97] The pricing proposal for the first year is required within 15 business days of the publication of the AER's distribution determination. In subsequent years, the pricing proposal is to be submitted at least 2 months before the commencement of the relevant regulatory year.

In addition, section 2.2.5 of the RIN sets out the following information on services and indicative prices that must be provided as part of the regulatory proposal:

- the name and a description of each individual standard control service; alternative control service; and negotiated distribution service provided by the *RNSP* that is the subject of the *regulatory proposal*;
- actual customer numbers for each individual prescribed service, excluded service and negotiated distribution service in each year of the *current regulatory control period* (provide an estimate for the final two years of the *current regulatory control period*);
- the revenue earned for each individual prescribed service, excluded service and negotiated distribution service in each year of the *current regulatory control period* (provide an estimate of revenues for the final two years of the *current regulatory control period*);
- the prices for each individual prescribed service and excluded service in each year of the *current regulatory control period* (provide an estimate for the final two years of the *current regulatory control period*); and
- indicative prices for each individual standard control service and alternative control service in each year of the *next regulatory control period*.

The information requested above is provided in pro forma 2.2.5. Further discussion of the services and indicative prices is provided in section 13.1, while section 13.2 explains ActewAGL Distribution's tariff structures and initiatives and their role in demand management.

The transitional *Rules* also require the AER to make a determination on how compliance with the control mechanisms is to be assessed. This is addressed in section 13.3.

[96] RIN, section 2.2.5.
[97] Transitional *Rules*, clause 6.18.2

13.1 ActewAGL Distribution's services and indicative prices

ActewAGL Distribution's main standard control service is to receive electricity at 132 kV and 66 kV from the sub-transmission system, and transform and distribute it to consumers at 11 kV in the case of high voltage consumers and to low voltage consumers at 415/240 volts. Associated with this are a number of services related to:

- energising and de-energising premises;
- temporary connections;
- modifying services;
- issuing copies of electrical drawings; and
- maintaining connections and shared networks of embedded generators.

ActewAGL Distribution's alternative control service is its electricity metering service. This includes the provision of meters and meter reading services for consumers with loads of less than 160 MWh per annum. Metering for consumers larger than 160 MWh per annum is contestable. ActewAGL Distribution is not an accredited service provide of metering for meters of types 1–4.

The charges for standard control services are listed in pro forma 2.2.5. There is a description of the distribution use of system charges below in sections 13.2.1 and 13.2.2, together with a description of how the main charges within the residential and non-residential groups are prepared as a suite of tariffs, designed to complement, not compete with each other.

13.1.1 Indicative prices

ActewAGL Distribution's indicative prices for standard control and alternative control services are shown in tables 13.1 and 13.2 below. These are based upon the structure of network charges existing in 2008/09 and forecast loads and customer numbers. Transmission Use of System (TUOS) charges are excluded from the indicative prices.

The transitional *Rules* place a side constraint on average revenue from each tariff class. This is a new requirement for ActewAGL Distribution, as no side constraints are applied under the ICRC's 2004 determination. The structure of the network charges is unlikely to change significantly over the regulatory period as the side constraint reduces pricing flexibility. The form of regulation to apply in the ACT for the 2009–14 regulatory period, in accordance with the transitional *Rules* and the AER's guideline,[98] means that prices are adjusted, not only for CPI – X, but for the variation in average price due to changes in the load profile used to set prices from year to year.

Table 13.1 and Table 13.2 provides a list of ActewAGL Distribution's current prices and indicative prices for standard control services.

[98] AER 2008, *Final Decision on Control Mechanisms for Standard Control Services for the ACT and NSW 2009 distribution determination, February*

Table 13.1 Current and indicative prices for standard control services

		Current prices		Indicative prices				
Service	Unit	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
010 Residential Standard Network Charge								
Residential Standard Network Access	c/day	14.30	14.35	17.46	18.24	19.03	19.87	20.73
Residential Standard Network Energy	c/kWh	3.70	3.37	4.10	4.29	4.48	4.68	4.89
060 Residential Off-Peak Night Network	c/kWh	0.32	0.15	0.18	0.19	0.20	0.21	0.22
070 Residential Off-Peak Day & Night Network	c/kWh	0.90	0.50	0.61	0.64	0.67	0.70	0.73
015 Residential Time-of-Use (TOU) Network Charge								
Residential TOU Network Access	c/day	14.30	14.35	17.46	18.24	19.03	19.87	20.73
Residential TOU Network Max Energy	c/kWh	5.10	5.00	6.00	6.20	6.40	6.60	6.80
Residential TOU Network Mid Energy	c/kWh	3.50	3.05	3.70	3.80	3.90	4.00	4.10
Residential TOU Network Economy Energy	c/kWh	2.60	2.60	3.10	3.20	3.30	3.40	3.50
Residential TOU Network Controlled Economy Energy	c/kWh	2.60	2.60	0.61	0.64	0.67	0.70	0.73
020 Residential 5,000 Network Charge								
Residential 5000 Network Access	c/day	34.30	34.35	37.46	38.24	39.03	39.87	40.73
Residential 5000 Network Energy to 60 kWh per day	c/kWh	2.10	2.27	3.00	3.19	3.38	3.58	3.79
Residential 5000 Network Energy greater than 60 kWh per day	c/kWh	3.70	3.37	4.10	4.29	4.48	4.68	4.89
030 Residential Heat Pump Network Charge								
Residential Heat Pump Network Access	c/day	77.30	77.35	80.46	81.24	82.03	82.87	83.73
Residential Heat Pump Network Energy to 165 kWh per day	c/kWh	0.60	0.77	1.50	1.69	1.88	2.08	2.29

Service	Unit	Current prices		Indicative prices				
		2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Residential Heat Pump Network Energy greater than 165 kWh per day	c/kWh	3.70	3.37	4.10	4.29	4.48	4.68	4.89
Network Solar Energy								
Solar Energy	c/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00
040 General Network Charge								
General Network Access	c/day	26.00	25.90	32.00	33.35	34.80	36.19	37.99
General Network Energy to 330 kWh per day	c/kWh	6.00	5.95	7.30	7.57	7.86	8.17	8.53
General Network Energy greater than 330 kWh per day	c/kWh	7.76	7.95	9.30	9.57	9.86	10.17	10.53
060 Non-Residential Off-Peak Night Network	c/kWh	0.37	0.15	0.18	0.19	0.20	0.21	0.22
070 Non-Residential Off-Peak Day & Night Network	c/kWh	0.95	0.50	0.61	0.64	0.67	0.70	0.73
080 Streetlighting Network Charge								
Streetlighting Network Access	c/day	26.00	25.90	32.00	33.35	34.80	36.19	37.99
Streetlighting Network Energy	c/kWh	3.48	3.12	3.80	3.95	4.09	4.28	4.43
090 General TOU Network Charge								
General TOU Network Access	c/day	26.00	25.90	31.50	33.35	34.80	36.19	37.99
General TOU Network Business Time Energy	c/kWh	8.65	8.8	10.71	11.21	11.73	12.27	12.83
General TOU Network Evening Energy	c/kWh	4.70	4.80	5.84	6.11	6.39	6.68	6.99
General TOU Network Off-peak Energy	c/kWh	2.60	2.65	3.22	3.37	3.53	3.69	3.86
135 Small Un-metered Loads Network Charge								
Small Un-metered Loads Network Access	c/day	26.00	26.00	32.00	34.00	35.00	36.00	38.00
Small Un-metered Loads Network Energy	c/kWh	8.00	7.84	9.58	10.06	10.28	10.67	11.13
141 Internal Network Charge								

Service	Unit	Current prices		Indicative prices				
		2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Internal Network Access	c/day	4.00	3.20	3.85	3.98	4.13	4.33	4.53
Internal Network Energy	c/kWh	0.33	0.33	0.39	0.40	0.41	0.43	0.45
101 Low Voltage TOU Demand Network Charge								
Low Voltage TOU Demand Network Access	c/day	36.00	35.00	43.00	45.00	47.00	49.00	51.00
Low Voltage TOU Demand Network Maximum Demand	c/kVA/d	28.60	29.00	35.00	37.00	39.00	41.00	43.00
Low Voltage TOU Demand Network Business Energy	c/kWh	1.90	2.31	2.81	2.94	3.08	3.22	3.37
Low Voltage TOU Demand Network Evening Energy	c/kWh	1.60	1.87	2.28	2.39	2.50	2.61	2.73
Low Voltage TOU Demand Network Off-peak Energy	c/kWh	1.25	1.30	1.58	1.65	1.73	1.81	1.89
103 Low Voltage TOU Capacity Network Charge								
Low Voltage TOU Capacity Network Access	c/day	na	35.00	43.00	45.00	47.00	49.00	51.00
Low Voltage TOU Capacity Network Maximum Demand	c/kVA/d	na	13.60	16.40	17.40	18.30	19.20	20.20
Low Voltage TOU Capacity Network Capacity	c/kVA/d	na	13.60	16.40	17.40	18.30	19.20	20.20
Low Voltage TOU Capacity Network Business Energy	c/kWh	na	2.31	2.81	2.94	3.08	3.22	3.37
Low Voltage TOU Capacity Network Evening Energy	c/kWh	na	2.00	2.28	2.39	2.50	2.61	2.73
Low Voltage TOU Capacity Network Off-peak Energy	c/kWh	na	1.30	1.58	1.65	1.73	1.81	1.89
121 High Voltage TOU Demand Network Charge - Customer low-voltage								
High Voltage TOU Demand Network Access	c/day	1200	1200	1500	1600	1700	1800	1900

Service	Unit	Current prices		Indicative prices				
		2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
High Voltage TOU Demand Network Maximum Demand	c/kVA/d	11.00	11.60	14.20	14.75	15.30	15.95	16.65
High Voltage TOU Demand Network Maximum Capacity	c/kVA/d	11.00	11.60	14.20	14.75	15.30	15.95	16.65
High Voltage TOU Demand Network Business Energy	c/kWh	1.40	1.80	2.20	2.30	2.40	2.50	2.60
High Voltage TOU Demand Network Evening Energy	c/kWh	1.30	1.55	1.90	1.95	2.00	2.10	2.20
High Voltage TOU Demand Network Off-peak Energy	c/kWh	1.10	1.13	1.39	1.44	1.49	1.55	1.62
122 High Voltage TOU Demand Network Charge - Customer high-voltage and low-voltage								
High Voltage TOU Demand Network Access	c/day	1200	1200	1500	1600	1700	1800	1900
High Voltage TOU Demand Network Maximum Demand	c/kVA/d	10.00	10.60	13.20	13.75	14.30	14.95	15.65
High Voltage TOU Demand Network Maximum Capacity	c/kVA/d	10.00	10.60	13.20	13.75	14.30	14.95	15.65
High Voltage TOU Demand Network Business Energy	c/kWh	1.40	1.80	2.20	2.30	2.40	2.50	2.60
High Voltage TOU Demand Network Evening Energy	c/kWh	1.30	1.55	1.90	1.95	2.00	2.10	2.20
High Voltage TOU Demand Network Off-peak Energy	c/kWh	1.1	1.13	1.39	1.44	1.49	1.55	1.62
111 High Voltage TOU Demand Network Charge								
High Voltage TOU Demand Network Access	c/day	1200	1200	1500	1600	1700	1800	1900
High Voltage TOU Demand Network Maximum Demand	c/kVA/d	11.00	11.60	14.20	14.75	15.30	15.95	16.65
High Voltage TOU Demand Network Maximum Capacity	c/kVA/d	11.00	11.60	14.20	14.75	15.30	15.95	16.65

		Current prices		Indicative prices				
Service	Unit	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
High Voltage TOU Demand Network Business Energy	c/kWh	1.65	2.05	2.45	2.55	2.65	2.75	2.85
High Voltage TOU Demand Network Evening Energy	c/kWh	1.5	1.75	2.10	2.15	2.20	2.30	2.40
High Voltage TOU Demand Network Off-peak Energy	c/kWh	1.2	1.23	1.49	1.54	1.59	1.65	1.72
112 High Voltage TOU Demand Network Charge - Customer high-voltage								
High Voltage TOU Demand Network Access	c/day	1200	1200	13.20	13.75	14.30	14.95	15.65
High Voltage TOU Demand Network Maximum Demand	c/kVA/d	10.00	10.60	2.20	2.30	2.40	2.50	2.60
High Voltage TOU Demand Network Maximum Capacity	c/kVA/d	10.00	10.60	1.90	1.95	2.00	2.10	2.20
High Voltage TOU Demand Network Business Energy	c/kWh	1.65	2.05	1.39	1.44	1.49	1.55	1.62
High Voltage TOU Demand Network Evening Energy	c/kWh	1.50	1.75	1500	1600	1700	1800	1900
High Voltage TOU Demand Network Off-peak Energy	c/kWh	1.20	1.23	13.20	13.75	14.30	14.95	15.65

Note: ActewAGL Distribution offers a Low Voltage Time-of-Use kW Demand Network Charge (102) but it is not used.

Table 13.2 Current and indicative prices for miscellaneous standard control services

	Current prices		Indicative prices				
Service	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
For a visit to re-energise or de-energise a premises							
501 Business Hours - re-energise	$43.64	$44.55	$46.36	$48.64	$50.91	$53.18	$55.45
502 After Hours - re-energise	$94.55	$97.27	$101.82	$106.36	$111.36	$116.36	$121.82
503 Business Hours - de-energise	$40.00	$40.91	$42.73	$44.55	$46.36	$48.64	$50.91
505 De-energise premises for non-payment	$73.64	$75.45	$78.64	$82.27	$85.91	$90.00	$94.09
508 Field Visit read only (for de-energisation non-payment)		$54.55	$56.82	$59.55	$62.27	$65.00	$67.73
Temporary Connections							
520 Overhead	$313.64	$322.73	$337.27	$352.27	$368.18	$385.00	$402.27
521 Standard underground	$454.55	$468.18	$489.09	$511.36	$534.55	$558.64	$583.64
522 Free-standing underground	$554.55	$568.18	$593.64	$620.45	$648.64	$677.73	$708.18
Modify Service Connection							
530 Overhead: remove, reposition or disconnect service, per site visit	$227.27	$231.82	$242.27	$253.18	$264.55	$276.36	$288.64
531 Underground: remove, reposition or disconnect service, per site visit	$545.45	$559.09	$584.09	$610.45	$638.18	$666.82	$696.82
Upgrade service from single to three phase							
532 Overhead	$290.91	$300.00	$313.64	$327.73	$342.73	$358.18	$374.55
533 Underground-service cable replacement not required	$290.91	$300.00	$313.64	$327.73	$342.73	$358.18	$374.55
533 Underground-service cable replacement required	$545.45	$559.09	$584.09	$610.45	$638.18	$666.82	$696.82
Other Miscellaneous services							
540 Installation defect (applied where a revisit to a site is necessitated by obstructed access or non-compliance with the Service and Installation Rules)	$150.00	$154.55	$161.36	$168.64	$176.36	$184.09	$192.27
550 Issue of copies of electrical drawings (per sheet or electronic equivalent)	$11.82	$12.09	$12.73	$13.18	$13.64	$14.09	$14.55

Service	Current prices 2007/08	2008/09	Indicative prices 2009/10	2010/11	2011/12	2012/13	2013/14
560 De-energising wires (to allow safe approach, for example, for tree pruning, plant operation, oversize loads, construction activities)	$363.64	$372.73	$389.55	$407.27	$425.45	$444.55	$464.55
570 Operational and maintenance services for small embedded generators (other than residential photovoltaic)							
connection assets- a charge of 2% of value of connection assets per annum		2%	2%	2%	2%	2%	2%
shared network assets - a charge of 2% of value of customers share of shared assets per annum (if applicable)		2%	2%	2%	2%	2%	2%

Table 13.3 provides a list of ActewAGL Distribution‘s current prices and indicative prices for alternative control services.

Table 13.3 Current and indicative prices for alternative control services

Service	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Meter provision, meter reading and data processing (cents/day)							
Quarterly basic metering (resident consumers)	9.70	9.75	13.94	14.01	14.07	14.13	14.22
Monthly basic metering (small non-resident consumers)	17.00	17.10	24.50	24.65	24.70	24.81	25.01
Monthly time-of-use metering (small to medium sized non-resident consumers)	17.00	17.10	24.50	24.65	24.70	24.81	25.01
Monthly manual interval metering (medium sized non-resident consumers)	$1.64	$1.65	$2.36	$2.37	$2.38	$2.39	$2.41
Internal metering (ActewAGL)	5.00	6.00	9.09	9.51	8.79	8.78	8.43
Other metering services							
504 Meter test during business hours (deposit)	$54.55	$56.36	$58.18	$60.00	$61.82	$63.64	$65.45
506 Special meter reading for example check read (second in a billing period)	$28.18	$29.09	$29.82	$30.55	$31.27	$32.09	$32.91
507 Install interval meter at customer's request	$136.36	$140.00	$143.64	$147.27	$150.91	$154.55	$158.18

13.2 Network pricing and demand management

ActewAGL Distribution’s residential and commercial tariff structures are explained in the following sub-sections. ActewAGL Distribution has developed a suite of tariffs which effectively meet the diverse needs of customers while at the same time encouraging more efficient use of the network. As discussed in chapter 6 and noted by the ICRC and the AER, price is a primary tool used by ActewAGL Distribution to manage demand and influence a demand side response.

In certain circumstances demand management can provide an efficient alternative to network augmentation. Demand management refers to any instrument or mechanism which changes energy usage behaviour.

13.2.1 Residential Network Charges

One of the constituent decisions the transitional *Rules* require the AER to make is “a decision on the procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another (including any applicable restrictions).”[99]

ActewAGL Distribution offers residential customers a choice of four network charge options plus two off-peak network services:

- The *Residential Standard Network* charge comprises a fixed charge per day, a metering charge per day and a flat rate energy charge;
- The *Residential 5,000 Network* charge has a lower energy charge and a higher fixed daily charge than the Home Network charge. Customers selecting this option do not qualify for access to off-peak network charges. The *Residential 5,000 Network* charge was designed for customers who have continuous loads, such as electric hot water systems and consume over 5,000 kWh per annum. The lower energy rate is limited to consumption up to 60 kWh per day. This is sufficient to cover the energy requirements of many residential consumers;
- The *Residential Heat Pump Network* charge is only available to customers with a reverse cycle air conditioner. The energy rate is set to recover the incremental cost of energy load on the network as a demand management tool to lower winter peak loads and improve utilisation of the residential network in summer;
- The *Residential Time-of-Use (TOU) Network* charge is available to residential customers with a time-of-use or interval meter. It uses three time periods:
    - Max (7.00 am to 9.00 am and 5.00 pm to 8.00 pm EST daily);
    - Mid (9.00 am to 5.00 pm and 8.00 pm to 10.00 pm EST daily); and
    - Economy (10.00 pm to 7.00 am EST daily).

[99] Transitional Rules, Clause 12.6.1 (17).

- In addition, it offers a Controlled Economy Network charge for appliances that would qualify for the off-peak tariff if the consumer were on the Residential Standard Network charge;

- The *Off-peak Night Network* charge is available only to existing installations receiving this service. It provides energy for between 6 and 8 hours per day between the hours of 10.00 pm and 7.00 am and
- The *Off-peak Day & Night Network* charge is available to residential customers on the Residential Standard Network charge (and to non-residential customers on the General Network charge) for appliances such as hot water storage units and underfloor heating systems. It provides power up to 13 hours per day between 10.00 pm and 7.00 am and again between 9.00 am and 5.00 pm.

Consumers are able to select whichever network charge they prefer, subject to any qualifying requirements. ActewAGL Distribution applies sophisticated modelling processes to synchronise charges across consumption levels and load profiles to ensure that charges best reflect system costs and manage demand to keep supply costs as low as possible.

13.2.2 Commercial Network Charges

ActewAGL Distribution has completed significant reform of its non-domestic network charges. The emphasis has been placed on designing charging structures and levels that focus primarily on specific load profiles, rather than the type of end-user or the end-use of the electricity.

Changes made during the reform process have made tariffs easier to understand, more economically sound and introduced much greater choice to better meet the needs of customers. As far as possible, ActewAGL Distribution has designed its network charges so customers can choose the charging structure that is most appropriate for their needs.

There are now four main network charging options available to commercial customers:

- The General Network charge;
- The General Time-of-use (TOU) Network charge;
- The Low Voltage Demand Network charges; and

The Low Voltage Demand, Low Voltage Capacity and High Voltage Demand Network charges are the most cost reflective network charges. They combine fixed, time-of-use and demand charges plus a capacity charge for the High Voltage and Low Voltage Capacity network charges. The Low Voltage Capacity charge is intended for low voltage customers with embedded generation but it may be an attractive option to other low voltage customers with consistent loads. The Low Voltage Capacity charge provides an incentive for customers with embedded generation to manage their output and their down-times so as to minimise their demand on the network.

The General Time-of-use Network charge has time-of-use price signals but does not have maximum demand charges. It is particularly suitable to small commercial customers with a discretionary or relatively large off-peak load such as bakers and for irrigation. The General Network charge is suitable for small commercial consumers operating in regular business hours or larger customers with poorer load factors (peaky loads).

In effect, the General and General Time-of-use Network charges form a cap on the amount that can be charged to commercial customers with a poor load factor. It is for this reason that the General Network charge has a higher energy charge for consumption over 330 kWh per day (about 120 MWh per annum) to reflect the higher network supply costs. A customer consuming 120 MWh per annum with a better load factor would find the Low Voltage Demand Network charge more attractive than the General Network charge. Any customer consuming more than 120 MWh and choosing to remain on the General Network charge can be assumed to have a poor load factor that imposes relatively higher network supply costs. The General Network charge has a step at 330 kWh per day to make this charge reflect system costs.

Similarly, the General Time-of-use Network charge has a higher energy price for energy consumed in business hours so that it synchronises with the Low Voltage Demand Network charge for customers with a high peak time load. The low voltage demand charge is a more appropriate network charge for these customers and any large customer choosing the General Time-of-use Network charge can be assumed to have a poorer load factor.

Non-residential consumers are able to select the charges that suit their load. Only low voltage consumers with embedded generation do not have a choice and are required to use the low voltage capacity network charge. To qualify for the high voltage demand network charges, consumers must take their energy at high voltage and make a capital contribution towards their connection assets and transformers. High voltage consumers do have the option of owning and operating their own high voltage assets. However, no consumers in the ACT have selected this option. Also, there is an option within the high voltage network charges for ActewAGL to own and manage the low voltage assets beyond the consumer's meter. Furthermore, customers taking their energy at high voltage have the option of selecting the network charges available to low voltage consumers.

Incentives Created – Customer with a Poor Load Factor

Figure 13.1 plots the network charges over a range of consumption levels and a range of consumption profiles from all peak to all off-peak with only one commercial network charge – the general network charge. In this case the average network charge is independent of the distribution of consumption across peak and off-peak times i.e., there are no incentives for consumers to manage the timing of their use of the network to improve the utilisation of the network.

Figure 13.1: Average network charge for commercial customers on general network charge

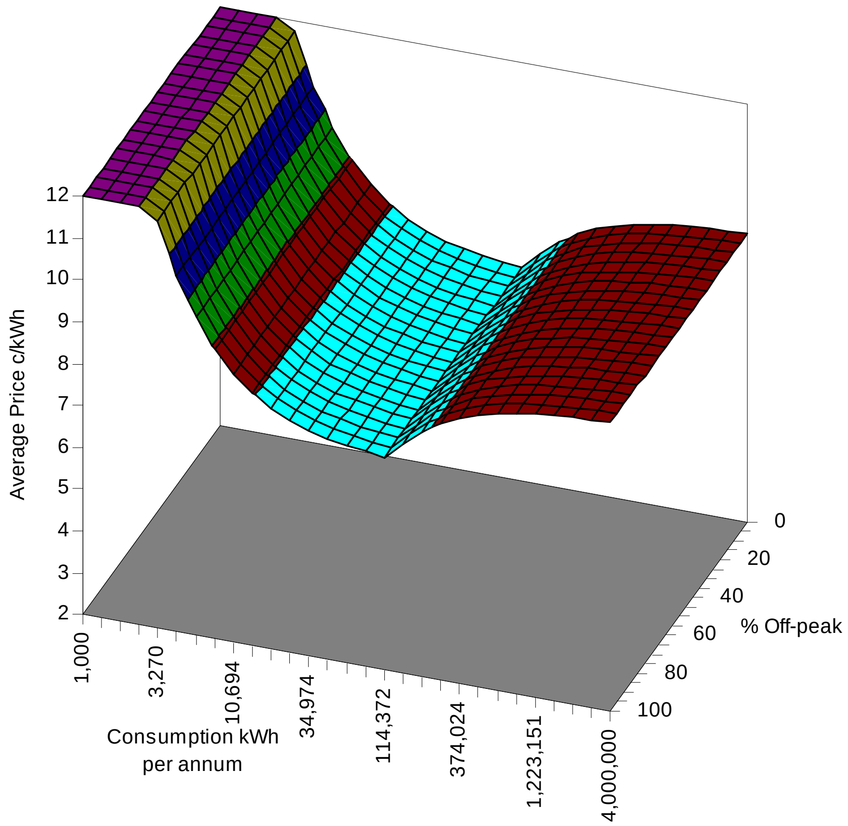


Figure 13.2 adds general time-of-use network charge to the model of commercial prices. It reveals that commercial customers can benefit from an incentive to shift their load from peak to off-peak times, where this reflects the network cost savings from doing so.

Figure 13.2: Price profile for general and general time-of-use network charges

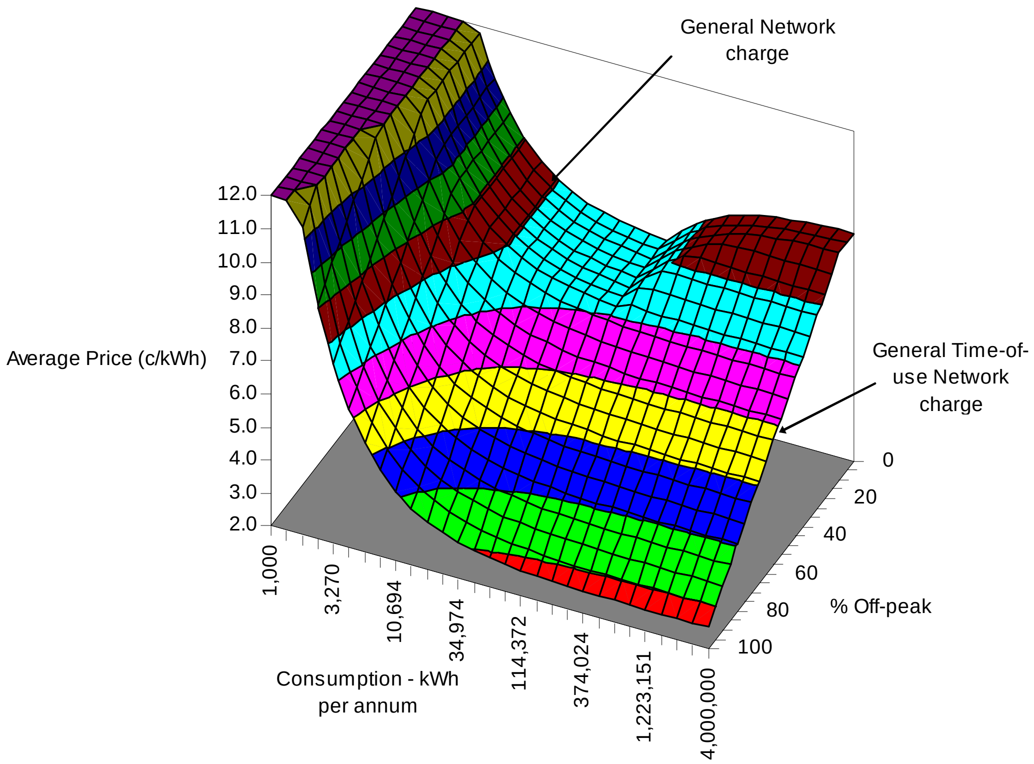
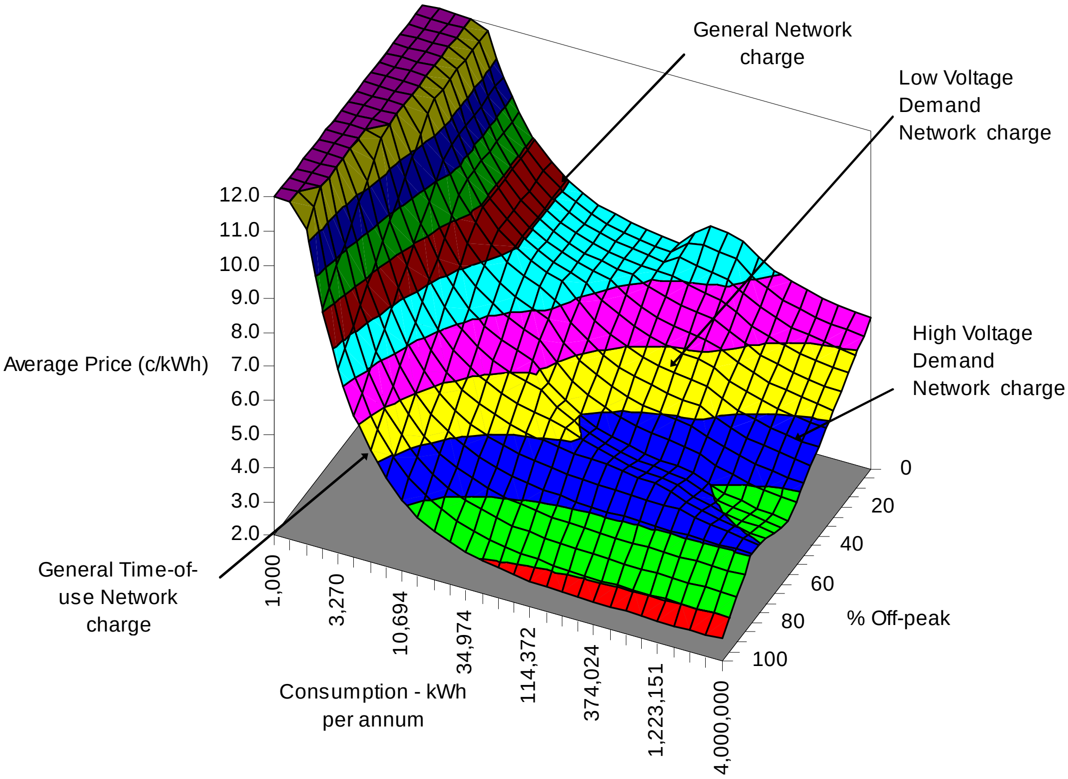


Figure 13.3 represents the full suite of network charges available to commercial customers, including demand charges. As in the above examples, it plots the network charges over a range of consumption levels and a range of consumption profiles from all peak time (business and evening) to all off-peak. It shows how the General Network charge suits most small customers while those with a high off-peak load can be rewarded be selecting the General Time-of-use Network charge. Also, it demonstrates how the low voltage and high voltage demand tariffs align with the non-demand tariffs. Larger customers with good load profiles are able to choose a demand charge based option and reduce overall network supply costs and their average network charges.

Figure 13.3: Average network charge for commercial customers with a good load factor



13.2.3 Impact of tariffs on consumption patterns

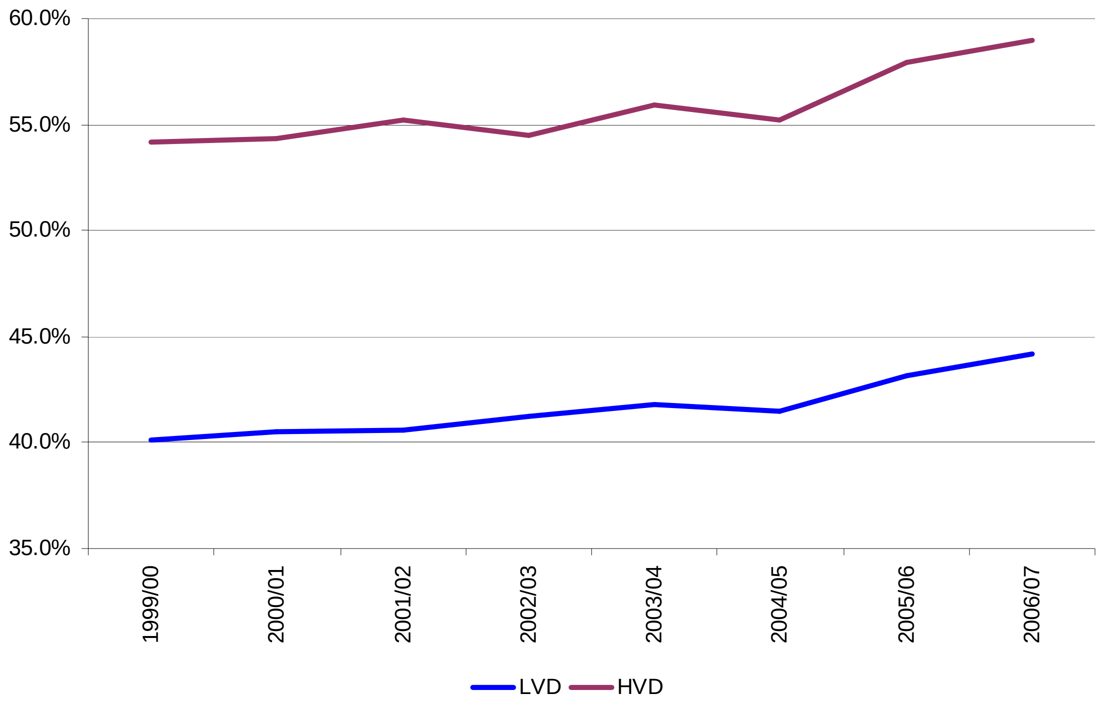
The ability to use price as a tool for demand management is possible because ActewAGL Distribution has had the flexibility to set prices and price structures to meet customer needs, while at the same time promoting efficient outcomes. ActewAGL Distribution reviews and develops new and innovative price options on an annual basis. ActewAGL Distribution notes that side constraints are now to be imposed on price changes for standard control services. While this will provide some ongoing flexibility as they are based on the average total bill rather than for particular customers, in general they may limit the flexibility to allow prices and charging structures to properly reward consumer behaviour that helps to minimise overall network costs.

Figure 13.4 shows the improvement of network utilisation. Between 1999/00 and 2006/07 customers on the low voltage demand network charge improved their load factor and therefore their utilisation of the network by 10 per cent, increasing the average energy consumed per hour relative to the average of their monthly maximum demands from 40 per cent to 44 per cent utilisation. Over the same period, high voltage demand customers increased their load factor and therefore their utilisation of the network by 9 per cent, from 54 per cent to 59 per cent utilisation.

ActewAGL Distribution has been able to absorb the extra electricity load on its network at much lower cost to all its customers than would have been the case. More than 50 per cent of the load in the ACT is now subject to time-of-use or controlled load (off-peak) charges.

Consumers have benefited from the opportunity to react to pricing signals that promote efficient long-run investment. This success confirms the benefit from promptly and continually evaluating the suite of network charges to manage demand and create incentives to reward customers for improving their load factors and load profiles.

***Figure 13.4**: Consumer utilisation of the network 1999–2007*



13.3 Compliance with the control mechanisms

The transitional *Rules* require the AER to include in its determination a decision on how compliance with a relevant control mechanism is to be demonstrated.[100] As noted above, in accordance with the transitional *Rules*[101] and the AER's guideline, the control mechanism for standard control services for the 2009–14 regulatory period must substantially be the same as that determined by the ICRC for prescribed distribution services in the regulatory control period 2004–09.

[100] Transitional *Rules*, clause 6.12.1 (13)
[101] Transitional *Rules*, clause 6.2.5

The AER is also required to make a decision on how TUOS charges are to be recovered and how adjustments for over or under recovery are to be made.[102]

In the following sections ActewAGL Distribution sets out its proposal for how compliance will be checked and annual adjustments made. This is consistent with the description set out in the AER's guideline.[103]

13.3.1 Standard control services

ActewAGL Distribution's prices for 2009–14 will be regulated under a Maximum Average Revenue (MAR) cap applied to the actual sales in the previous calendar year. The revenue when prices proposed for the next financial year are applied to the sales quantities in the previous calendar year should not exceed the revenue cap determined by multiplying the energy sales in kilowatt hours in the previous calendar year by the MAR.

To show compliance, ActewAGL Distribution first calculates the MAR. The MAR in 2008/09 is $0.04092 per kWh. To identify the MAR for 2009/10, ActewAGL Distribution inflates the MAR for 2008/09 by CPI – X that the AER determines for 2009/10. The MAR determined for each year becomes the base MAR to which CPI – X is applied in the next year.

The total energy sales for the previous calendar year comprise ActewAGL Distribution's:

- consumption data for the year where the metering data is read as interval data; and
- billing data for the year where the metering data is read as accumulation data.

Although this data is not audited, it is independent data that can be verified.

The determined revenue cap for standard control services is the total energy sales from these sources multiplied by the MAR for the year. The total revenue cap for standard control services comprises the determined revenue cap for standard control services plus any pass through costs for standard control services.

The revenue cap for distribution use of system services is the total revenue cap for standard control services less the revenue from miscellaneous standard control services (applying prices for the next financial year to the quantities in the previous calendar year).

Table 13.4 sets out the procedure for calculating the revenue cap for the distribution use of system (DUOS) charges using 2009/10 as an example. In the following example, the forecast energy sales in 2009/10 is 2,818,223,585 kWh.

[102] Transitional *Rules*, Clause 6.12.1 (19)

[103] AER, *Guideline on control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations*, February 2008

Table 13.4 Calculation of Distribution Use of System revenue cap for 2009/10

Maximum Average Revenue 2008/09	0.04092	c per kWh
CPI	2.51%	
X factor	+20.37%	
Maximum Average Revenue 2009/10	0.05049	c per kWh
Electricity sales ACT 2008	2,818,223,585	kWh
Determined revenue cap for standard control services	**$142,292,109**	
Plus UNFT under recovered in 2007/08 adjusted	$24,808	
Less UNFT over recovered in 2008/09 adjusted	$306,978	
Total revenue cap for standard control services	$142,009,938	
Less Miscellaneous Services Revenue	$1,191,681	
Distribution Use of System Charges Revenue Cap	**$140,818,257**	

To comply with the maximum average revenue cap, ActewAGL Distribution ensure that the revenue from the distribution use of system charges for each financial year, when applied to the actual sales volumes in the previous calendar year, does not exceed the distribution use of system charges revenue cap calculated using the procedure outlined above.

In addition, for each year after the first, side constraints apply to the weighted average revenue to be raised from a tariff class. Pursuant to clause 6.18.6 of the transitional *Rules*, the permissible percentage increase is the greater of CPI – X plus 2 per cent or CPI plus 2 per cent and increases to accommodate pass through and TUOS costs are excluded from the operation of the side constraint.

13.3.2 Transmission use of system (TUOS) charges

ActewAGL Distribution proposes to calculate TUOS charges using the same load profile that it uses for DUOS charges. Forecast TUOS charges will be adjusted for the difference between forecast sales in the coming financial year and the actual energy sales in the previous calendar year (the load profile used to set distribution use of system charges). It is necessary to have separate TUOS charges so that the amount of TUOS charges recovered can be determined.

13.3.3 Reporting TUOS charge recovery

ActewAGL Distribution proposes to report its TUOS charge recovery each financial year in its Annual Pricing Report. TUOS charges recovered in 2009/10 will be reported in the Annual Pricing Report for 2011/12 prices.

The amount reported will be calculated by determining the ratio of TUOS charges to NUOS charges for each component of network charges and applying that ratio to the amount of revenue recorded against each component of relevant network charges in ActewAGL Distribution’s accounts for each financial year.

For example, in 2006/07 the energy component of the standard residential network charge was 3.9 c/kWh, of which the TUOS component was 0.5 cents per kWh. Hence, TUOS was 12.82 per cent of the NUOS charge. In 2006/07, revenue from the energy component of the standard residential charge was $33,194,833.48. Therefore, TUOS revenue from this source was $4,255,747.88.

ActewAGL Distribution would apply this process to each component of network revenue that contains a TUOS component. Total TUOS revenue would be the sum of the TUOS revenues from each component of network charges.

13.3.4 Adjustment to pricing proposals for over/under recoveries

TUOS adjustments

To calculate the TUOS charge recovered each year ActewAGL Distribution will adjust the total amount to be recovered in the following year by the amount of over or under recovery in the previous financial year. For example, if TUOS charges in 2011/12 were estimated to be $25 million and ActewAGL Distribution had under recovered in 2009/10 by $1 million, then TUOS charges for 2011/12 would be set to recover $26 million.

Where there is an adjustment from a previous year, that adjustment will be carried forward and included, for the purpose of future adjustments, in the actual amount of TUOS charges paid in the next year. The amount paid in a financial year will be the amount payable with respect to TUOS services provided during a financial year, including amounts accrued at the end of the financial year less amounts paid during the financial year but with respect to services in another financial year (i.e., on an accrual basis).

Following on from the above example, assume that the actual cost of TUOS payable to TransGrid in the 2011/12 financial year were $24.5 million and ActewAGL Distribution's actual revenue from TUOS charges in 2011/12 (including accrued revenues) were $26.25 million. The actual amount paid to TransGrid for 2011/12 would be adjusted upward by the $1 million under recovered in 2009/10. Therefore, the amount over recovered in 2011/12 would be $0.75 million; an amount which would be repaid in an adjustment to network prices in the 2013/14 financial year.

In its Annual Pricing Report for 2008/09 submitted to the ICRC,[104] ActewAGL Distribution noted that it proposes to make an adjustment for any variation in TUOS charges for 2008/09 in the following year, once the actual amount had been determined.

ActewAGL Distribution will recover or refund the difference between the estimated TUOS costs used for pricing ($20,558,836) and TransGrid's proposed TUOS charges for 2008/09. To do this, it will add the difference in TUOS charges for 2008/09 to the estimated TUOS charges to be recovered in 2009/10. That amount will be treated as an actual expenditure on TUOS for 2009/10 for the purpose of making future adjustments.

[104] ActewAGL Distribution, *Annual Pricing Report 2008-09 Electricity Distribution Services*, 3 March 2008

UNFT adjustments 2009/10

In 2007/08 prices, ActewAGL Distribution forecast that the Utilities Network Facilities Tax (UNFT) recoverable in that period was $5.574 million. The actual amount paid was $5.600 million. The difference of $25,337 was under recovered in prices in 2007/08. Network prices were submitted to the ICRC for approval on 3 March 2008. This was before the amount of the UNFT for 2007/08 was known. Hence, the difference needs to be recovered in 2009/10 prices. After adjustment for energy sales volumes between 2009/10 forecast and 2008 actual sales, the amount claimed in 2009/10 prices is $24,808.

In 2008/09 prices, ActewAGL Distribution forecast that the UNFT payable in 2008/09 would be $4.150 million. It is anticipated that ActewAGL Distribution will know the amount of UNFT payable in 2008/09 before it is required to submit its annual pricing report for 2009/10 to the AER. If the actual amount payable is $3.836 million, there will be an over recovery of $0.314 million. The amount is refunded 2009/10 prices using the 2008 sales profile is $0.307 million.

UNFT adjustments 2010/11 – 2013/14

There are most likely to be differences between the forecast UNFT liability and the actual tax paid to the ACT Government. It is proposed that adjustments would be made for those differences once they are known. Hence, the difference between the forecast tax payable in 2009/10 and the actual tax paid in 2009/10 would be made in 2010/11 prices.

It is still possible that there will be differences between the amount of these adjustments and the amount collected or repaid. Such differences arise from the differences between the sale quantities and profiles used to set prices and the actual sale quantities and profiles. These differences are likely to be small amounts. Without setting separate charges for the adjustments, it is not possible to precisely calculate the amount of the differences. Hence it is proposed that no adjustment be made for any difference between the actual amount paid and the actual amount collected.

13.3.5 Alternative control services

Metering services in the ACT are treated as alternative control services. Prices for alternative control services are regulated using a maximum revenue cap. This cap is applied to metering revenue that would have been earned from the proposed prices for the coming financial year if they had been applied to the quantities sold in the services provided in the previous calendar year.

In 2008/09, the revenue cap for alternative control services was $5,666,539 before adjustments. In the first year of the 2009–2014 regulatory period, this cap would be set using a CPI + X adjustment. With an X factor of 41.01 per cent and a CPI of 2.51%, the revenue cap for alternative control services in 2009/10 would be $8,190,945. In subsequent years, the revenue cap will be raised by CPI.

To demonstrate compliance, ActewAGL Distribution would prepare a schedule of metering charges showing the revenue from each charge if that charge had applied in the previous calendar year. The revenue from these charges is not to exceed the revenue cap for alternative control services. Table 13.5 provides an example of the how compliance would be demonstrated.

Table 13.5 Demonstration of compliance with control mechanism for alternative control services

	2008/09 Price* ($ per day or per event)	2009/10 Price ($ per day or per event)	2008 meters billed (number)	Revenue
Residential accumulation meters	$0.0975	$0.1394	137,939	$7,018,461
Residential interval meters	$0.480	$0.5220	0	$0
Business accumulation meters	$0.171	$0.2450	11,183	$1,000,080
Internal accumulation meters	$0.060	$0.0909	109	$3,616
Business time of use meters	$0.171	$0.2450	74	$6,611
Business interval meters	$1.65	$2.36	187	$160,868
Special meter reading	$29.09	$29.82	40	$1,193
Meter test (deposit)	$56.36	$58.18	2	$116
Install interval meter (by request)	$140.00	$143.64	0	$0
Total			**149,492**	**$8,190,945**

14. Negotiable components

This chapter sets out ActewAGL Distribution's proposal in relation to those components of direct control services that may be *negotiable components* and discusses the negotiating framework that ActewAGL Distribution proposes to apply to such components.

The proposed negotiating framework is set out in attachment 9 to this regulatory proposal. Attachment 9 also includes a summary of the requirements of the transitional *Rules* in relation to the negotiating framework, together with appropriate cross-references to where these requirements have been included in the proposed negotiating framework.

14.1 Identification of negotiable components

Under the transitional *Rules* applying to ActewAGL Distribution for the 2009–14 regulatory period, a distribution service provided by ActewAGL Distribution that was previously determined by the ICRC to be a prescribed distribution service (for the purposes of the regulatory control period 2004–09) is deemed to be classified as a *direct control service* and further classified as a *standard control service*.[105]

A distribution service provided by ActewAGL Distribution that was previously classified as an excluded service by the ICRC is also deemed to be classified as a *direct control service* and further classified as an *alternative control service*.[106]

The ICRC in its 2004–09 regulatory decision determined that all regulated distribution services provided by ActewAGL Distribution were prescribed services, with the exception of the provision of and service of meters for customers consuming less than 160 MWh per annum.[107] The latter services were determined by the ICRC to be excluded distribution services.

As a result, all of the distribution services provided by ActewAGL Distribution (with the exception of those services related to metering as noted above) are classified as standard control services under the transitional *Rules* for the purposes of the 2009–14 regulatory period. The provision of and service of meters for customers consuming below 160 MWh per annum is classified as an alternative control service. However, both standard control services and alternative control services are classified as direct control services under the transitional *Rules*.

The transitional *Rules* permit ActewAGL Distribution to identify as part of its regulatory proposal whether any components of direct control services should be *negotiable components* and, if so, which components should be identified as negotiable.[108] A negotiable component may be a particular component of a direct control service or may relate to the terms and

[105] Transitional *Rules*, Part B, Division 1, 6.2.3C(a)
[106] Transitional *Rules*, Part B, Division 1, 6.2.3C(b)
[107] ICRC 2004, *Final Decision: Investigation into Prices for Electricity Distribution Services in the ACT*, March, section 4.2
[108] Transitional *Rules*, Part E, 6.8(c)(7)

conditions on which a direct control service or a component of a direct control service is provided.[109]

The AER's distribution determination for the 2009–14 regulatory period must include a constituent decision as to which, if any, of the components of ActewAGL Distribution's direct control services are negotiable components.[110]

ActewAGL Distribution recognises that the intent of the provisions in the transitional *Rules* is to foster a greater degree of negotiation between itself and its customers in relation to the provision of some components of direct control services (or elements of the terms and conditions associated with components of direct control services), where such negotiation is feasible without compromising the service delivered to other customers and without endangering ActewAGL Distribution's ability to comply with its regulatory obligations.

In general, ActewAGL Distribution considers that there is only a very limited scope for such negotiation in relation to its direct control services, given the need to ensure system security and operation is maintained within tight parameters. However, ActewAGL Distribution considers that some components of its direct control services have the potential to be negotiable. This is particularly the case with non-standard or above standard customer connection requirements, where changes to technical or performance related components can have a direct impact on ActewAGL Distribution's costs of providing a connection.

Special requirements are predominantly imposed by developers or planning agencies for major commercial or residential developments and may typically include additional conditions relating to security of supply, aesthetics, connection configuration or location of ActewAGL Distribution network components (e.g. minipillars or substations). ActewAGL Distribution typically considers these special requirements and, where regulatory obligations, the level and cost of service to other customers, and network operations would not be compromised by a decision to depart from the standard arrangements, they are agreed. In addition, some aspects of connection services provided to embedded generators are already subject to negotiation provisions under NER 5.5(f), and therefore would appear to also fall under the scope of negotiable components. In such circumstances ActewAGL Distribution considers that there are benefits from identifying such components as negotiable and applying a transparent negotiating framework to the discussions between itself and the relevant customer.

Notwithstanding the above, ActewAGL Distribution considers that it is often difficult to isolate in advance the 'negotiable' component of the direct control service from the rest of the service provided. ActewAGL Distribution therefore proposes that the following *criteria* be adopted in order to identify negotiable components of direct control services:

A negotiable component of a direct control service is any component of that service (including the terms and conditions on which that component is provided) where some variability can be applied to the provision of the direct control service without interfering with ActewAGL

[109] Transitional *Rules* Part DA, 6.7A(b)
[110] Transitional *Rules* Part E 6.12.1(16A), also Part DA, 6.7(a).

Distribution's ability to comply with any regulatory obligation or requirement, including those in the *NER.*

For illustration, ActewAGL Distribution has identified the following components of its direct control services as potentially satisfying the above criteria:

- the location of a substation to support customer load;
- the location of a customer's connection to ActewAGL Distribution's distribution network;
- the voltage level of a customer's connection;
- the capacity of a customer's connection;
- distribution access charges for embedded generators; [111] and
- any increase (or decrease) in the security or reliability of the shared distribution service requested by a customer in excess of that which would otherwise be provided at that customer's point of supply;[112]
- provision of standby network connections capacity (often applicable to embedded generation projects);
- special aesthetic requirements in relation to ActewAGL Distribution network equipment; and
- non-standard substation configuration or use of non-standard equipment.

This list is intended to be indicative and does not preclude the identification either by ActewAGL Distribution or a customer (or potential customer) of other components of direct control services that also satisfy the criteria set out above. Nor does it presuppose that all instances of the components of direct control elements identified above will be potentially negotiable components, as this is likely to depend on the particular circumstances applying in each case.

14.2 Negotiating framework

The transitional *Rules* require that where ActewAGL Distribution's proposal identifies components of direct control services that it proposes should be classified as negotiable

[111] The negotiable components principles set out in Transitional *Rules* Part DA 6.7A.1(9) contemplate negotiable components being related to access charges for embedded generators, including the compensation payable by the DNSP to the embedded generator in the event that it is constrained off or constrained on, and from the embedded generator to the DNSP in the event that its dispatch causes other generators to be constrained off or constrained on. (ie, NER 5.5(f)(4)(i) and (ii)).

[112] The negotiable components principles set out in Transitional *Rules* Part DA 6.7A.1(4) and (5) contemplate negotiable components being related to the provision of a shared distribution service that either exceeds or does not meet the network performance requirements set out in jurisdictional electricity legislation or in schedules 5.1a and 5.1 of the NER.

components, its proposal must also include the proposed negotiating framework that applies to such components.[113]

ActewAGL Distribution's proposed negotiating framework is provided in attachment 9.

The transitional *Rules* set out the minimum provisions that are required to be reflected in the proposed negotiating framework.[114] ActewAGL Distribution has summarised in Table A9.1 the relevant requirements of the transitional *Rules* and where these are addressed in the proposed negotiating framework.

ActewAGL Distribution notes that the transitional *Rules* require the AER to approve the proposed negotiating framework where the AER is satisfied that the framework adequately complies with the requirements in Part DA.[115]

14.3 Negotiable component criteria

As part of its distribution determination for ActewAGL Distribution, the AER must determine ActewAGL Distribution's *negotiable component criteria*.[116] These criteria are to be applied by ActewAGL Distribution in negotiating terms and conditions of access to negotiable components of direct control services and by the AER in resolving any access disputes in relation to negotiable components.[117]

ActewAGL Distribution notes that the negotiable component criteria determined by the AER must give effect to and must be consistent with the negotiable component principles set out in the transitional *Rules* Part DA 6.7A.1.[118] As a result, ActewAGL Distribution's regulatory proposal is not required to include a proposal in relation to the applicable negotiable component criteria.

113 Transitional *Rules* Part E, 6.8(c)(8), also Part DA 6.7A.5(a)
114 Transitional *Rules* Part DA 6.7A(c)
115 Transitional *Rules* Part E, 6.12.3 (g)
116 Transitional *Rules* Part DA 6.7A.4(a)
117 Transitional *Rules* Part DA 6.7A.4(a)(1) and (2)
118 Transitional *Rules* Part DA 6.74(b)

15. Alternative control services

Clause 6.2.3C of the transitional *Rules* prescribe the provision and servicing of meters for customers consuming less than 160 megawatt hours per annum as alternative control services in the ACT. Meter servicing is taken to include meter testing, meter reading, meter checking, the processing of metering data and the provision of non-standard meters. Clause 6.2.5 of the transitional *Rules* sets out the forms of control the AER may apply, and the matters the AER must have regard to in considering the appropriate control mechanism for alternative control services.

In its *Final Decision - Control Mechanisms for Alternative Control Services for the ACT and NSW 2009 distribution determinations*, the AER concluded that it:

> …will maintain the total revenue control mechanism adopted by the ICRC during the current regulatory period. Under this approach, ActewAGL Distribution will propose a revenue allowance based on a building block analysis, with maximum allowable revenues to be escalated each year by CPI. The revenue allowance will be established based on the rolled forward value of the relevant metering assets, and an analysis of costs associated with providing the services.[119]

It is important to firstly note ActewAGL Distribution's interpretation of two elements of the AER's proposed control mechanism for alternative control services.

- The provision of metering data by ActewAGL Distribution is a service that falls outside of the AER classification of alternative control services in the ACT. It is categorised as forming part of ActewAGL Distribution's standard control services, and is included in the operating costs forecasts.
- The escalation of maximum allowable revenue "each year by CPI" will occur from 2010/11 to 2013/14. There will be a 'full P_0 adjustment' in the first year of the regulatory period to ensure the net present value of allowed revenue over the regulatory period is equal to the net present value of the revenue requirement over the regulatory period.

Consistent with clause 6.2.6(c) of the transitional *Rules*, the following building block analysis will utilise elements of Part C of the transitional *Rules*.

15.1 Regulatory obligations

Compliance with applicable regulatory obligations and requirements is one of the four objectives for capital and operating expenditure set out in the transitional *Rules*.[120] Many of the obligations referred to in chapter 4 of this regulatory proposal, for example obligations relating to occupational health and safety, will clearly drive costs for the provision of alternative control services in the ACT. To inform ActewAGL Distribution's cost building block analysis but avoid

[119] AER 2008, *Final Decision—Control mechanism for alternative control services for the ACT and NSW 2009 distribution determination*, February, p 20

[120] Transitional *Rules*, clauses 6.5.6(a)(2) and 6.5.7(a)(2)

repetition, this section outlines those additional regulatory obligations specific to the provision of alternative control services. ActewAGL Distribution notes that it does not face regulatory obligations that it would classify as ‘service standard’ obligations when providing alternative control services.

15.1.1 National Electricity Rules

Chapter 7 of the *National Electricity Rules* relates to metering. ActewAGL Distribution is the responsible person for Types 5, 6, and 7 meters. ActewAGL Distribution is also a metering provider for Types 5, 6, and 7 meters.

15.1.2 NEM Metrology Procedure

The *NEM Metrology Procedure* includes a summary of obligations of the responsible person in relation to second tier loads, and additional obligations of the responsible person in relation to the provision, installation and maintenance of metering installations for second tier loads, and where necessary for first tier loads for load profiling purposes. This includes measurement of electrical energy and the provision of data to facilitate the efficient operation of the market.

The *Procedure* sets out those obligations that are imposed on a Metering Provider as contained in chapter 7 of the *National Electricity Rules*. The *Procedure* also sets out obligations in relation to the conversion of consumption energy data into trading interval data to facilitate the efficient operation of the market and the obligations on Metering Providers in relation to the provision, installation, routine testing and maintenance of a metering installation.

The *Procedure* covers the full extent of a metering installation, from the connection point at one extreme to the boundary of the telecommunications network at the other extreme. It includes connection of the metering installation to the telecommunications network. The *Procedure* is a key driver of capital and operating expenditures.

15.1.3 Electricity Metering Code and ICRC decision on interval meters

The *Electricity Metering Code* (August 2003) *(*the *Code*) sets out minimum standards for meters installed in the ACT, and customer rights and responsibilities in respect of those meters, including information provision. The *Code* is complemented by the ICRC’s December 2005 *Final Decision—Review of Metrology Procedures* (the *Final Decision*) which requires the installation of interval metering on a new and replacement basis to all customers in the ACT, as well as on request.

Impacts on expenditure programs

The forecast incremental additional costs associated with the ICRC’s *Final Decision* on the installation of interval meters over the 2009-14 regulatory period are $0.5 million ($2008/09) in capital expenditure and $0.4 million ($2008/09) in operating expenditure. These costs are reflected in Table 2 of pro forma 2.3.4, regarding new obligations and incremental additions to existing obligations, as well as in Table 4.1 of this regulatory proposal.

15.1.4 Occupational health and safety

Section 37(d) of the *Occupational Health and Safety Act 1989* (ACT) requires ActewAGL Distribution to provide information to employees to enable them to work safely. In order to allow staff to monitor those customer meter boards that contain asbestos, ActewAGL Distribution will undertake a meter board survey in the upcoming regulatory period. ActewAGL Distribution intends to engage a consultant to work on the analysis, development and implementation of processes, technology and the roles and responsibility changes required to comply with asbestos obligations.

15.1.5 Possible mandated smart meters roll out

The MCE is currently considering a Regulatory Impact Statement (RIS) on a mandatory roll out of smart meters. This RIS is based on the outcomes of a cost benefit analysis (CBA) undertaken in 2007/08, which concluded that a mandated, distributor-led, roll out of smart meters offered the lowest net costs of the options investigated. The CBA also recommended that in some jurisdictions where the benefits were less clear, the roll out could be delayed and comprehensive pilots and trials may be appropriate to verify costs and benefits ahead of a roll out in those jurisdictions.

ActewAGL Distribution understands that the final decision on the mandate will be taken by the MCE, on the basis of the jurisdictional analysis. At the time of making this regulatory proposal, considerable uncertainty exists over:

- the roll out model (alternative arrangements were considered in the CBA);
- roll out scope and timing (mandated, national, jurisdictional or staged);
- regulatory arrangements;
- cost recovery; and
- timing and scope of pilots and trials.

These issues were not resolved at the time of lodgement of this regulatory proposal, and therefore an estimation of the potential costs associated with the final smart meters decision as not been possible. It is therefore expected that most obligations arising under a smart meter decision will be treated as a regulatory change pass through event. There is significant potential, however, for a decision and associated obligations with cost implications for ActewAGL Distribution to occur before the commencement of the 2009–14 regulatory period. ActewAGL Distribution is therefore seeking a transitional period pass through event to address these and other obligations with similar timing issues. Proposed pass through events are discussed further in chapter 16 of this regulatory proposal.

15.2 Asset management strategy

As at January 2008 ActewAGL Distribution owned 171,000 Type 6 meters and 2,000 Type 5 meters. ActewAGL Distribution also owns 1,800 transformer connected metering installations and a further 4,700 Type 5 meters that are currently being read as Type 6 meters.

As the responsible person for Types 5, 6 and 7 metering installations in the ACT, ActewAGL Distribution has developed a Meter Asset Management Plan (the MAMP) in accordance with the *National Electricity Rules* and subsequently approved by NEMMCO. The MAMP details a significant expansion by ActewAGL Distribution of both its meter testing and replacement programme.

15.2.1 Meter installation

ActewAGL Distribution has commenced an ongoing programme to install Type 5 meters as the standard meter on its network, programmed to be read as Type 6 Time Of Use. As mentioned above, the ICRC's December 2005 *Final Decision—Review of Metrology Procedures* resulted in ActewAGL Distribution commencing the installation of Type 5 meters in March 2007. This *Final Decision* required ActewAGL Distribution to install Type 5 interval meters on a new and replacement, (as well as customer requested) basis.

In March 2006 ActewAGL Distribution submitted its *Implementation Plan for the Introduction of Interval Meters in the ACT* to the ICRC. This *Plan* was requested by the ICRC in its December 2005 *Final Decision—Review of Metrology Procedures*. The *Plan* guides ActewAGL Distribution's approach to the installation of interval meters in the ACT.

15.2.2 Meter replacement

ActewAGL Distribution has formulated its domestic meter replacement programs and expenditure forecasts based on the NEMMCO approved MAMP. ActewAGL Distribution plans to replace 3,600 meters per annum. This is occurring against the backdrop of a possible mandate from the MCE to install smart metering infrastructure as part of a national roll out, currently proposed to commence in late 2008 and be completed in 2014.

ActewAGL Distribution is meter replacement program is designed the limit the potential for the stranding of meter assets that may not meet the national smart meters functionality and performance standards. It should be noted, however, that ActewAGL Distribution is currently installing interval meters that are capable of being upgraded for remote reading, and which can support an in-house display. This new and replacement policy is also undertaken in accordance with the ICRC decision on interval meters. Therefore ActewAGL Distribution requires that it not face stranded asset cost risks, and be appropriately compensated, if these meters have to be replaced as a result of a smart meter mandate.

Project MIMI

Advances in technology now mean that meters are no longer limited to measuring usage—they can also be communications channels into customers' homes and businesses, as well as informing network planning and management.

In 2007, in the context of securing the ACT water supply, the ACT government requested ACTEW Corporation to trial smart metering. The ICRC included funding to support this in its recent price determination for water and wastewater services in the ACT.[121]

After a completion of a full business case and engagement with stakeholders, ActewAGL Distribution has assessed that there is a net benefit in undertaking a Multi-Utility Integrated Metering Infrastructure feasibility study. This expanded project allows investigation of opportunities for multi-utility metering, as well as investigation of some of the organisational, communications and data management issues that may arise in a larger trial of electricity smart metering. The principal objectives of the Project MIMI are as follows.

- Improve understanding of how to design household demand management programs for water to achieve sustainable household water consumption. This includes identifying the attitudes, beliefs and perceptions behind a household's water use and linking that with their actual water consumption, as well as exploring smart metering as a compliance/non-compliance mechanism;
- Identify commercial and operational (that is, network performance and customer service) advantages and savings;
- Trial advanced metering infrastructure (AMI) technology (meters, communications, applications and software, IT infrastructure), identifying the deployment and integration risks, issues, constraints;
- Determine and test the costs, savings and benefits of deploying multi-utility intelligent grid technology across the ACT;
- Determine the change management issues for ActewAGL Distribution and ACTEW, their employees and work practices, customers, special interest groups, the ACT Government and the wider ACT community; and
- Gain experience in the implementation of smart metering technology.

Project MIMI is expected to deliver recommendations on the technology options best suited to ACTEW Corporation and ActewAGL Distribution, report the expected costs and savings in a business case, report on market acceptance and customer behavioural responses, and identify any change management and communication challenges in a full deployment of smart meters across the ACT. ActewAGL Distribution considers that a trial is prudent, given the considerable uncertainties in costs associated with smart metering, in particular communications, which may be specific to the ACT.

This Project is not directly linked to the MCE smart meters roll out decision outlined above, as it arises from investigations in securing the ACT's water supply. It also investigates the potential for multi-utility metering, which is not a functionality currently included in the smart meter minimum functionality. This project, however, will improve ActewAGL Distribution understanding of the costs and potential benefits associated with electricity smart metering,

[121] ICRC 2008, Water and wastewater price review: Final Report and Price Determination (forthcoming)

and therefore will assist ActewAGL Distribution in formulating its approach to smart meters, as well as its response to the development of a national smart metering regulatory framework. It will also allow ActewAGL Distribution to test elements of the national smart meter minimum functionality and performance levels. Project MIMI is not a substitute, however, for the broad scale integrated pilots and trials that would be required to test the future national smart meter roll out arrangements. These pilots and trials are likely to include a number of parties (including retailers and NEMMCO) and test the specific functionality and performance levels established under the yet to be formulated national smart meters regulatory framework.

The proposed treatment of the costs associated with Project MIMI is discussed in sections 15.3.1 and 15.4.

15.2.3 Meter testing

The test methodology used by ActewAGL Distribution is detailed in the document *Procedure No: EN 4.10 P2; In-service Meter Compliance Testing and Bulk Replacement*. All ActewAGL Distribution meter testing will be field testing.

Table S7.3.3 in the *Rules* requires Type 5 and 6 metering installations to be inspected when the meter is tested. A typical inspection may include: check the seals, compare the pulse counts, compare the direct readings of meters, verify meter parameters and physical connections, current transformer ratios by comparison.

All direct connected and low-voltage current transformer (CT) connected meters are sample tested per AS1284 13. All low-voltage CT installations that are not inspected as part of routine testing will be inspected as set out in Table S7.3.3 of the *Rules*. Inspection of all low-voltage CT sites will be undertaken from 2008 and re-inspected in 2013. As required by clause S7.3.1(f) of the *Rules*, the officer responsible for electricity meter maintenance will:

- provide the test results to NEMMCO (upon request);
- advise each affected Market Participant of the outcome of the tests; and
- provide the results of the test to each affected Registered Participant on request.

NEMMCO has directed ActewAGL Distribution to test meters by attributes rather than variables.

15.2.4 Meter reading

ActewAGL Distribution currently has meter reading contracts with Fieldforce Services Pty Ltd (Fieldforce) and Ecowise Services (Aust) Pty Ltd (Ecowise). ActewAGL Distribution's current contract with Fieldforce only applies to basic accumulation read meters, which includes Type 5 meters, programmed to be read as Type 6 Time of Use. ActewAGL Distribution's current contract with Ecowise only applies to interval read meters.

On expiry, these contracts will be renewed through appropriate tender processes which comply with the standard ActewAGL Distribution procedures for contracts with a possible value over the contract period in excess of $1 million. The structure of any future contractual requirement may be impacted by the requirements of any national roll out of smart meters, decisions made by ACT regulators, and commercial considerations associated with the continuation of existing processes.

15.3 Forecast capital expenditure

Table 15.1 summarises ActewAGL Distribution's proposed capital expenditure program for metering services in the ACT. It should be noted that the extra cost of installing and replacing interval meters in the 2009–14 regulatory period is incorporated in ActewAGL Distribution's cost forecasts, rather than as a pass through as is the case in the current regulatory period.[122] The methodology for forecasting alternative control services capital expenditure utilises the same general methodology and *meters* escalators as discussed in chapter 7 of this proposal. Unless otherwise stated all monetary values are in 2008/09 dollars.

Table 15.1 Forecast capital expenditure for alternative control services 2009–14

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
New meter installations	2.1	2.0	2.1	2.2	2.0	**10.3**
Meter replacements	3.8	1.2	1.2	1.2	1.2	**8.5**
Total metering capital expenditure	**5.9**	**3.2**	**3.2**	**3.4**	**3.2**	**18.8**

The 2007/08 ActewAGL Distribution Ten Year Customer Initiated Capital Investment Plan includes a forecast for new meter installations. The forecast is characterised by a relatively consistent level of expenditure across the ten-year period, with the one-off increase in meter replacement capital expenditure in 2009/10 explained in section 15.3.1.

The estimated expenditure has been based primarily on historical expenditure levels with nominal adjustments for domestic meter installation expenditure to reflect the anticipated level of activity in the residential based New Urban Development and Urban Infill Development. Commercial meter installation expenditure is also nominally adjusted to reflect anticipated activity in commercial and industrial development although this has less influence overall.

The 2007/08 ActewAGL Distribution MAMP includes the costs associated with a 3,600 Annual Domestic Meter Replacement Program. The expenditure is forecasted to be approximately $1.2 million per annum. This cost is considered to be prudent and efficient as ActewAGL Distribution can replace 3,600 meters per annum utilising in-house resourcing and will still be able to meet its NEMMCO approved MAMP targets up until 2013/14. ActewAGL Distribution's budget for commercial meter replacement is approximately $0.02 million per annum.

[122] As is its current practice, ActewAGL Distribution will propose pass through the extra costs of interval meters incurred in the 2008 calendar year in the 2009/10 metering charges. Also, ActewAGL Distribution will be proposing to pass through the extra cost of interval meters incurred between 1 January 2009 and 30 June 2009 in 2010/11 metering charges.

15.3.1 Project MIMI

The total cost of the Project MIMI is $7 million and the vast majority of this cost will be incurred in 2008/09 and 2009/10.

Recognising the ACT Government announcement in October 2007, the ICRC in its April 2008 Final Decision for ACTEW Corporation suggested cost recovery for Project MIMI on a 40:40:20 basis, that is, 40 per cent electricity, 40 per cent water, and 20 per cent gas. On this basis the ICRC made an expenditure provision for ACTEW Corporation of $2.8 million in expenditure for Project MIMI in 2008/09. [123]

Therefore ActewAGL Distribution proposes, consistent with the ICRC's decision for ACTEW Corporation, that the AER allow the recovery $2.8 million in expenditures for the 'electricity portion' of Project MIMI. ActewAGL Distribution notes that the ICRC decision for ACTEW Corporation incorporated $2.4 million ($2006/07) in capital expenditure and $0.4 million ($2006/07) in operating expenditure. Consistent with this treatment, ActewAGL Distribution proposes an additional $2.4 million ($2006/07) in meter replacement capital expenditure and $0.4 million ($2006/07) in operating expenditure for the electricity portion of the project. This cost will be incurred in 2009/10.

15.4 Forecast operating and maintenance expenditure

Table 15.2 summarises ActewAGL Distribution's proposed operating expenditure program for metering services in the ACT. Unless otherwise stated all monetary values are in 2008/09 dollars. The methodology for forecasting alternative control services capital expenditure utilises the same overall methodology as outlined in section 8.3 of this proposal.

Table 15.2 Forecast operating expenditure for alternative control services 2009–14

$ million (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	**Total**
Metering reading	0.9	0.9	0.9	0.9	0.9	**4.4**
Maintenance and repair	0.8	0.8	0.8	0.6	0.7	**3.7**
Other metering expenditures	0.4	0.0	0.0	0.0	0.0	**0.0**
Total metering operating expenditure	**2.1**	**1.7**	**1.7**	**1.5**	**1.6**	**8.5**

Note: Figures exclude self-insurance costs. This cost is described section 8.6 and included in the Post Tax Revenue Model (PTRM).

Meter reading costs have been increasing by the growth in the CPI. The above forecasts represent a continuation this trend. If the Council of Australian Governments (COAG) mandates the roll out of smart meters, ActewAGL Distribution expects this cost to be higher. ActewAGL Distribution will be seeking to claim this increased cost of service provision as a pass through. This mechanism is discussed in chapter 16.

[123] ICRC 2008, Water and wastewater price review: Final Report and Price Determination (forthcoming)

Following discussions with NEMMCO, ActewAGL Distribution has switched to testing Type 6 meters by attributes rather than variables. ActewAGL Distribution plans to test 1,500 domestic meters per annum at an annual cost of $0.35 million from 2008/09 to 2011/12 inclusive to comply with NEMMCO's meter testing direction. ActewAGL Distribution will then reduce testing to 400 meters per annum at a cost of $0.2 million per annum. This new NEMMCO direction has driven a step increase in meter maintenance and repair cost forecasts in the 2009–14 regulatory period.

Commercial metering maintenance costs are forecast to grow faster than CPI as ActewAGL Distribution is required to visually inspect all CT metering sites every 5 years and commence low-voltage CT testing at all sites. This regulatory obligation drives a cost forecast of $0.2 million per annum up until 2013/14.

As described in section 15.3.1, ActewAGL Distribution proposes $0.4 million ($2006/07) in operating expenditure for the electricity portion of Project MIMI. This cost will be incurred in 2009/10 and is classified as "other metering expenditures" in Table 15.2.

15.5 Regulatory Asset Base

15.5.1 Roll Forward to 2009

ActewAGL Distribution has rolled forward its alternative control services RAB using actual capital expenditure and inflation. ActewAGL Distribution's adjusted opening RAB as at 1 July 2009 is $38.3 million ($ nominal). A completed Roll Forward Excel Model is provided as attachment 10. Table 15.3 outlines the major elements of the Roll Forward calculation.

Table 15.3 Roll forward of alternative control services RAB to start of 2009/10

$ million (nominal)	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Opening RAB	32.9	33.0	33.5	34.3	36.6	38.3
Net Capital Expenditure	1.1	1.3	1.9	2.8	3.1	
Depreciation	1.7	1.8	1.9	2.0	2.2	
Indexation	0.8	1.0	0.8	1.5	1.0	
Closing RAB	33.0	33.5	34.3	36.6	38.5	
2003/04 adjustment					*(0.2)*	

15.6 Revenue requirement

Clause 6.12.1(2) of the transitional *Rules* states that a distribution determination is predicated on a decision regarding ActewAGL Distribution's building block proposal, in which the AER must either approve or refuse to approve the proposed annual revenue requirement for each regulatory year of the regulatory control period.

Pursuant to clause 6.4.3(a) of the transitional *Rules*, the building blocks are (for each regulatory year)[124]:

- regulatory depreciation;
- return on capital;
- corporate income tax; and
- operating expenditure.

15.6.1 Regulatory depreciation

ActewAGL Distribution's depreciation schedule for the 2009–14 regulatory period is outlined in the PTRM at attachment 12. The PTRM calculates the regulatory depreciation cost building block for ActewAGL Distribution for the 2009–14 regulatory period. This building block is summarised in Table 15.4.

Table 15.4 Regulatory depreciation for alternative control services 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Regulatory depreciation	1.2	1.3	1.4	1.5	1.6

15.6.2 Return on capital

The movements in the RAB over the 2009–14 regulatory period are set out in Table 15.5.

Table 15.5 Roll forward of alternative control services RAB 2009–14

$ million ($2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening RAB	38.3	42.3	43.3	44.2	45.2
Net capital expenditure	6.1	3.3	3.3	3.5	3.4
Depreciation	2.1	2.3	2.4	2.5	2.5
Closing RAB	42.3	43.3	44.2	45.2	46.1

In its *Final Decision on Control Mechanisms for alternative controls services for the ACT and NSW 2009 distribution determinations*, the AER concluded that it:

> …proposes to allow a return on capital for alternative control services, equal to that allowed for standard control services.[125]

[124] The AER has decided that neither a service target performance incentive scheme nor a demand management incentive scheme is to apply in the ACT for the 2009–14 regulatory period. Indexation of the RAB is included in ActewAGL Distribution's calculation of the return on capital.

[125] AER, *Final Decision – Control mechanism for alternative control services for the ACT and NSW 2009 distribution determination*, February 2008, p 20

Consistent with this proposal, ActewAGL Distribution submits a nominal vanilla weighted average cost of capital of 10.70 per cent for alternative control services.

The return on capital has been calculated in accordance with clause 6.5.2 of the transitional *Rules*. The return on capital building block is reproduced in Table 15.6.

Table 15.6 Return on capital for alternative control services 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Return on equity	1.9	2.1	2.2	2.3	2.5
Return on debt	2.2	2.5	2.6	2.8	2.9
Return on capital	**4.1**	**4.6**	**4.9**	**5.1**	**5.3**

15.6.3 Corporate income tax

ActewAGL Distribution's alternative control services TAB was $8.4 million as at 1 July 2001. The value of these assets includes assets in the divisional tax asset register. It should be noted that ActewAGL Distribution has not allocated central corporate assets to this asset base. The tax standard life for metering assets for the roll forward to the commencement of the 2009–14 regulatory period is 25 years. Commissioning dates for individual assets were obtained from tax asset registers. Depreciation has been calculated on a straight-line basis. ActewAGL Distribution has rolled forward its TAB from 1 July 2001 to 30 June 2009 using the relevant worksheet in the NSW Roll Forward Model. ActewAGL Distribution submits a TAB value of $13.7 million for the start of the upcoming regulatory control period. The completed TAB Roll Forward Excel Model is provided as attachment 11.

ActewAGL Distribution has rolled forward its TAB using the PTRM (provided as attachment 12) and has calculated the tax depreciation concessions available to the business from 2009/10 to 2013/14, which can be found in Table 15.7.

Table 15.7 Tax depreciation concessions for alternative control services 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Tax depreciation concessions	0.7	0.9	1.0	1.2	1.3

Consistent with the calculation methodology found in clause 6.5.3 of the transitional *Rules*, ActewAGL Distribution's proposed corporate tax building block for alternative control services is as set out in Table 15.8.

Table 15.8 Corporate income tax for alternative control services 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Tax payable	0.9	0.9	0.9	0.9	1.0
Value of imputation credits	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)
Tax allowance	**0.4**	**0.4**	**0.5**	**0.5**	**0.5**

15.6.4 Operating expenditure

The calculation of operating and maintenance costs has been detailed in section 15.4. ActewAGL Distribution's operating expenditure forecasts for the 2009–14 regulatory period are shown in Table 15.9.

Table 15.9 Operating expenditure for alternative control services 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Operating expenditure	2.2	1.9	1.9	1.8	1.9

15.6.5 Revenue requirement, X factor and price path

In accordance with clause 6.12.3(3)(d) of the transitional *Rules*, the AER must approve ActewAGL Distribution's proposed total revenue requirement and the annual revenue requirement for each year of the period if it is satisfied that those amounts have been properly calculated using the *Post Tax Revenue Model* on the basis of amounts calculated, determined or forecast in accordance with the requirements of Part C of the transitional Rules.

The control mechanism applied to alternative control services in the ACT is a maximum revenue cap. The X factors proposed by ActewAGL Distribution for alternative control services are shown in Table 15.10.

Table 15.10 Revenue requirement and X factors for alternative control services 2009–14

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Regulatory depreciation	1.2	1.3	1.4	1.5	1.6
Return on capital	**4.1**	**4.6**	**4.9**	**5.1**	**5.3**
Tax allowance	**0.4**	**0.4**	**0.5**	**0.5**	**0.5**
Operating expenditure	1.2	1.3	1.4	1.5	1.6
Unsmoothed revenue requirement	8.0	8.3	8.7	8.9	9.4
Smoothed revenue requirement	8.2	8.4	8.6	8.8	9.0
X factor (%)	***41.01***	***0.00***	***0.00***	***0.00***	***0.00***

ActewAGL Distribution's proposal is consistent with the requirements set out in clause 6.5.9 of the transitional *Rules* and the AER's proposed form of control for alternative control services in the ACT. It equalises (in terms of net present value) the revenue to be earned over the regulatory period with the total revenue requirement for the regulatory period.

15.7 Cost pass through

ActewAGL Distribution's proposal in relation to pass through events applicable to the 2009–14 regulatory period, including those relating to the provision of alternative control services in the ACT, are set out in chapter 16 of this proposal.

16. Cost pass through

The transitional *Rules* require ActewAGL Distribution to include in its regulatory proposal a pass through clause with a proposal as to the events that should be defined as *pass through events*.[126]

ActewAGL Distribution proposes that the following nine events be defined as pass through events:

1. A regulatory change event
2. A service standard event
3. A tax change event
4. A terrorism event
5. A major natural disaster event
6. A transitional period event
7. A smart meter event
8. An input price event, and
9. A supply curtailment event

The first four of these pass through events are as defined in chapter 10 of the *National Electricity Rules (NER)* and are discussed in section 16.3 below. The last five pass through events are proposed by ActewAGL Distribution in accordance with the transitional *Rules* and are defined in section 16.4.

In addition ActewAGL Distribution proposes that:

- The above pass through events apply to both standard control services and alternative control services; and
- Cost impacts be defined to include the cost of revenue forgone.

ActewAGL Distribution notes that, consistent with clause 6.18.6(d) of the transitional *Rules*, cost pass throughs fall outside of the operation of the side constraint.

[126] Transitional *Rules,* clause S6.1.3(2)

16.1 Transitional Rules provisions

The transitional *Rules* provide that a pass through event that has a material impact on the cost of providing direct control services may, subject to the AER's approval, be passed through to customers.

Where a *positive change event* occurs, a distributor may seek the approval of the AER to pass through a positive pass through amount.[127] A *positive change event* is a pass-through event that materially increases the cost of providing direct control services.[128]

Where a *negative change event* occurs, the AER may require the distributor to pass through to users a negative pass through amount, as determined by the AER in accordance with clause 6.6.1(b) of the transitional *Rules*. A *negative change event* is a pass-through event that materially reduces the cost of providing direct control services. [129]

A positive pass through amount is defined in the *NER* as an amount not exceeding the increase in the costs of provision of the direct control service that the distributor has incurred and is likely to incur up to the end of the regulatory control period as a result of the positive change event (as opposed to the revenue impact of that event).[130]

A negative pass through amount is defined in the *NER* as an amount not exceeding the costs that the distributor has saved and is likely to save up to the end of the regulatory control period as a result of the negative change event (as opposed to the revenue impact of that event).[131]

Pass-through events are defined in the *NER* as any one of the following:[132]

- A regulatory change event
- A service standard event
- A tax change event
- A terrorism event; and
- An event nominated in a distribution determination as a pass through event is a pass though event for the determination (in addition to those listed above).

Distributors are able to nominate additional events as pass through events for a particular determination.[133] The AER is required in making its determination to make a decision on the additional pass-through events that are to apply for the regulatory control period.[134]

[127] Transitional *Rules*, clause 6.6.1(a)
[128] NER, Chapter 10, Glossary
[129] NER, Chapter 10, Glossary
[130] NER, Chapter 10, Glossary, definition of *eligible pass through amount*
[131] NER, Chapter 10, Glossary, definition of *required pass through amount*
[132] NER, Chapter 10, Glossary; definition of *pass through event*
[133] NER, Chapter 10, Glossary, definition of *pass through events*
[134] Transitional *Rules*, clause 6.12.1(14)

16.2 Application to alternative control services

The cost pass through provisions in the transitional *Rules* fall under Part C: Building Block Determinations for standard control services.

Under the transitional *Rules*, clause 6.2.6(c) allows the control mechanism for alternative control services to utilise elements of Part C of the transitional *Rules*.

ActewAGL Distribution considers that the pass through events identified under Part C of the transitional *Rules* are equally applicable to alternative control services for the purposes of the 2009-14 regulatory period. The costs of alternative control services are equally open to uncertainty as a result of the pass through events set out in the *NER*, namely changes in applicable regulation, service standard requirements, changes in taxes and terrorism events. The costs of alternative control services are also open to uncertainty as a result of most of the additional pass through events nominated by ActewAGL Distribution in this proposal.

ActewAGL Distribution therefore proposes that the cost pass through arrangements in section 6.6.1 of the transitional *Rules* should apply to alternative control services as well as to standard control services. ActewAGL Distribution notes that the key definitions in the *NER* in relation to the cost pass through regime are all defined in relation to events that have a material impact on the costs of *direct control services*, which includes both standard control services and alternative control services.

16.3 Pass through events identified in the NER

As noted above, the NER makes explicit provision for four types of pass through event: a regulatory change event; a service standard event; a tax change event; and a terrorism event.

Regulatory change event

A *regulatory change event* is defined as a change in a *regulatory obligation* or *requirement* that occurs during the course of a regulatory control period and substantially affects the manner in which the distributor provides direct control services and materially increases or materially decreases the costs of providing those services.

A regulatory obligation or requirement has the meaning assigned in the National Electricity Law, namely:[135]

(a) In relation to the provision of an electricity network service by a regulated network service provider:
- A distribution system safety duty [..]; or
- A distribution reliability standard [..]; or
- A distribution service standard [..] ; or

(b) An obligation or requirement under:

i. [The National Electricity Law or the National Electricity Rules];

[135] NEL, Part 2D

ii. An Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, that levies or imposes a tax or other levy that is payable by a regulated network service provider' or

iii. An Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, that regulates the use of land in a participating jurisdiction by a regulated network service provider; or

iv. An Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, that relates to the protection of the environment' or

v. An Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, [..] that materially affects the provision by a regulated network service provider of electricity network services that are the subject of a distribution determination.

ActewAGL Distribution considers that the definition of regulatory obligation or requirement as set out in the NEL is sufficient to capture changes in regulatory policy that may occur during the 2009–14 regulatory period that may have a material impact on ActewAGL Distribution's costs of providing direct control services.

ActewAGL Distribution considers that the definition of a regulatory change event would capture the following events (but not be limited to these events):

- the imposition by the AER of new obligations on ActewAGL Distribution, as a result of AER guidelines, schemes, models or reporting requirements issued pursuant to the transitional *Rules* or *NER*;
- an MCE or ACT Government legislative instrument mandating the roll out of 'smart metering infrastructure' in the ACT, or requiring ActewAGL Distribution to undertake pilots or trials in relation to smart metering infrastructure;
- the imposition of new requirements or obligations associated with the transfer of non-economic distribution regulatory functions from jurisdictional regulators to the AER (the MCE phase 2 legislative package and associated reforms); and,
- the introduction of legislation in relation to carbon emissions, which has a material impact on ActewAGL Distribution's costs in delivering its services.

Service standard event

Service standard events are defined separately from regulatory change events, and relate to administrative acts and decisions as well as changes in applicable legislation.

A service standard event is defined as a legislative or administrative act, decision or requirement that has the effect of:

- substantially varying, during the course of a regulatory control period, the manner in which a distributor is required to provide a direct control service; or

- imposing, removing or varying, during the course of a regulatory control period, minimum service standards applicable to direct control services; or
- altering, during the course of a regulatory control period, the nature or scope of the direct control services provided by the service provider;

and where this materially increases or decreases the costs to the service provider of providing direct control services.

The current ICRC determination includes service standard events as part of the allowed cost pass through provisions.[136]

ActewAGL Distribution notes that a potential service standard event during the 2009–14 regulatory period is a decision on a phased program of undergrounding the existing overhead electricity reticulation network in the ACT. Depending on the nature of the administrative decision or requirement, the program is likely to have the effect of 'substantially varying, during the course of a regulatory period, the manner in which a distributor is required to provide direct control services', or 'altering, during the course of a regulatory control period, the nature or scope of the direct control services provided by the service provider'. The decision would therefore fall within the scope of a service standard event, and prima facie, be covered by the cost pass through provisions.

ActewAGL Distribution has undertaken preliminary analysis of the costs and benefits of a phased program of undergrounding the existing overhead reticulation network in the ACT, as outlined in Box 16.1. The undergrounding program would result in significant expenditure impacts for ActewAGL Distribution, as well as a range of benefits for customers and the wider community. As in other jurisdictions where undergrounding has been adopted, the program would require government support.

Tax change event

A *tax change event* is defined as occurring wherever there is a change in a relevant tax (including the rate of the tax, the official interpretation of the tax or the way in which the tax is calculated), the removal of a relevant tax or the imposition of a relevant tax, which has the consequence of materially increasing or decreasing the costs to the service provider.

Relevant taxes are defined to be any tax payable by a distributor other than income tax and capital gains tax, stamp duty, financial institutions duty, bank accounts debit tax; and penalties, charges, fees and interest on late payments, or deficiencies in payments relating to any tax.

ActewAGL Distribution notes the above definition allows cost pass through events to be triggered by both changes in Commonwealth taxes and changes in state and territory taxes.

[136] ICRC 2004, *Final Decision Investigation into prices for electricity services in the ACT*, p 136

This is consistent with the current pass through provisions applying to ActewAGL Distribution under the current ICRC determination (as amended April 2007).[137]

Box 16.1 Undergrounding overhead electricity wires in the ACT

Around 60 per cent of the low voltage electricity distribution network in the ACT consists of overhead lines. The vast majority of these lines are reticulated through residential backyards. Backyard reticulation significantly hampers ActewAGL Distribution's access to the network and increases the cost of inspecting and maintaining the system and replacing assets, such as poles. Also, consumers often resent the reduced amenity associated with electric wires over and around the perimeter of their back yard, their obligation to keep trees clear of wires and the need for ActewAGL Distribution staff to enter their property to inspect, and in some cases replace, its assets. ActewAGL Distribution or its contractors also enter properties as part of vegetation management activities.

All electricity distribution wires in new residential areas of the ACT are placed underground.138 Installing wires underground improves ActewAGL Distribution's access to the network as these are generally laid to the front of the block and reduces maintenance and replacement costs. Importantly, undergrounding also provides a higher level of reliability and amenity to consumers, and improves community safety. Undergrounding also substantially reduces the occupational health and safety and the public liability risks associated with overhead wires.

The direct financial benefits associated with conversion of overhead networks to underground, as well as environmental, health and safety benefits across the ACT would include:

- operating and capital expenditure savings to ActewAGL Distribution;
- cost savings to customers as a result of reduced tree clearing costs;
- reduction in lines losses;
- reduced planned supply interruptions related to tree clearing and pole repair and replacements;
- reduced unplanned supply interruptions due to wind, storm and asset failure events;
- the improved aesthetics from improved community views and vistas;
- fewer physical pole structures impeding use of yard space;
- improved use and development potential of yard space with removal of boundary perimeter wiring and the house service line;
- reduced visual pollution from overhead wiring;
- improved community safety, with reduced tree clearing activity and during storm events;
- improved utility staff safety with reduced need to climb poles and work at heights; and
- reduced interruption to home occupants from removing pets and making backyards accessible to utility staff.

There are a number of examples where substantive undergrounding programs are proceeding, for example in Western Australia and South Australia. These conversions are justified on the basis of the overall economic benefits, including social (health and safety) and environmental benefits to consumers. In the ACT, some of these benefits will be unique and potentially more substantial, as they would involve poles and wires being removed from suburban backyards.

ActewAGL Distribution has undertaken a preliminary cost benefit analysis that involves progressive undergrounding of the existing overhead distribution service in the ACT over a long term investment horizon. This requires various measures of the benefits as compared to the costs, where a large percentage of the benefits are not revealed in market transactions.

The early results from this review indicate a potential net economic benefit from an underground conversion program in the ACT, but these results need to be tested further, particularly to determine a staged program that would maximise the net benefits to the community.

[137] ICRC 2007, *Final Decision – Electricity Distribution Services: Proposed Amendment to the 2004 Price Direction*, April
[138] ACT Planning and Land Authority, *Territory Plan 2002*, Part B1, section 3.10

Terrorism event

A *terrorism event* is defined in the NER as an act (including but not limited to the use of force or violence or the threat of force or violence) of any person or group of persons which from its nature or context is done for political, religious, ideological, ethnic or similar purposes or reasons and which materially increases the costs to a distributor of providing direct control services.

ActewAGL Distribution notes that the current ICRC determination accommodates cost pass through applications following a terrorism event.[139]

16.4 Proposed additional pass through events for 2009–14

Under the transitional *Rules*, distributors are able to nominate additional events as pass through events for a particular determination.[140] The AER is required in making its determination to make a decision on the additional pass through events that are to apply for the regulatory control period.[141]

ActewAGL Distribution proposes that the following should also be determined to be pass-through events for the purposes of the 2009–14 determination:

- a major natural disaster event
- a transitional period event
- a smart meter event
- an input price event, and
- a supply curtailment event.

The rationale for the inclusion of these additional categories of pass through event is provided below.

16.4.1 Major natural disaster event

ActewAGL Distribution notes that the current ICRC determination included as a pass through event a 'terrorism or major natural disaster event'.

Under the NER, terrorism events are explicitly included as pass through events. However there is no automatic inclusion of natural disaster events. Where a natural disaster occurs there may be a material increase in the costs that ActewAGL Distribution faces.

The ICRC accepted in its previous determination that this risk should be addressed by including a natural disaster event as a pass through event.

[139] ICRC 2004, *Final Decision Investigation into prices for electricity services in the ACT*, March, p 136
[140] NER, Chapter 10, Glossary, definition of 'pass through events'
[141] NER, 6.12.1(14)

> The commission agrees that in the event of a major unforeseen event [..] there may be a need to adjust the price path to reflect additional costs imposed on ActewAGL Distribution. [..]
>
> The Commission's preference [..] is to allow a pass-through only for terrorism attacks and major natural disasters which have a material impact on ActewAGL Distribution's costs.[142]

ActewAGL Distribution notes that similar pass through provisions have also been applied by the ICRC to ACTEW's water business[143] and to ActewAGL Distribution's gas distribution business.[144]

The AER has noted that in developing its preliminary positions on aspects of the transitional regulatory regime that should apply to the distributors in NSW and the ACT it has generally considered whether the current approaches of IPART and the ICRC are appropriate:

> Unless there is sufficient time to consider and implement changes to existing arrangements, or there is a clear reason to change the existing arrangements, the AER has generally proposed to maintain the approaches taken by the [..] ICRC and [..] IPART in the current regulatory period.[145]

ActewAGL Distribution proposes that the 2009-14 determination should include the following as an additional pass through event, to ensure consistency with the current provisions applying across ActewAGL Distribution's regulated businesses:

> **A major natural disaster event:** Any major natural disaster (but excluding bushfire or an earthquake which registers less than or equal to 6 on the Richter scale) which results in costs incurred by ActewAGL Distribution which are materially different to those incorporated into the AER's determination for the 2009–2014 regulatory period and which would not have been incurred but for the occurrence of the event.

ActewAGL Distribution notes that, as it has proposed a self-insurance allowance that incorporates the cost risk associated with bushfires and earthquakes which register less than or equal to 6 on the Richter scale, these events have been explicitly excluded as triggers under this category.

16.4.2 Transitional period event

Events that result in material costs increases, but occur between 2 June 2008 (the submission date for ActewAGL Distribution's regulatory proposal) and 30 June 2009 (the end of the current regulatory period) would fall outside the scope of both the current ICRC provisions and the cost forecasts that are submitted for the 200914 regulatory period.

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[142] ICRC 2004, *Final Decision: Investigation into prices for electricity services in the ACT*, March, pp 117-118
[143] ICRC 2004, *Final Report and Price Direction: Investigation into prices for water and wastewater services in the ACT*, March
[144] ICRC 2004, *Final Decision: natural gas access arrangement*, October, p 217; ActewAGL Distribution 2004, *Access Arrangement for ActewAGL Distribution Gas Distribution System in ACT and Greater Queanbeyan*, November
[145] AER 2007, *Preliminary Position, Matters Relevant for Distribution Determinations for ACT and NSW distributors for 2009-2014*, December, p 5

Under the transitional *Rules*, ActewAGL Distribution is required to submit a regulatory proposal to the AER.[146] ActewAGL Distribution is only able to resubmit its proposal where it receives a notice from the AER that its regulatory proposal does not comply with a requirement in the NEL or the transitional *Rules*.[147] In this case ActewAGL Distribution can only make changes to its regulatory proposal to address deficiencies set out in the notice.

Following the AER's publication of its draft distribution determination, the transitional *Rules* permit ActewAGL Distribution to submit a revised regulatory proposal to the AER.[148] However, this revised regulatory proposal may only differ from the original proposal so as to incorporate the substance of any changes required to address matters raised by the draft determination or the AER's reasons for it.[149]

As a result, the transitional *Rules* provide only limited opportunities for ActewAGL Distribution to make revisions to its regulatory proposal as submitted on 2 June 2008. In particular, any event occurring after the 2 June 2008 that is expected to materially increase ActewAGL Distribution's costs is not able to be reflected in a revision of the operating and capital expenditure forecasts submitted by ActewAGL Distribution to the AER as part of its regulatory proposal.

Under the arrangements for the current regulatory period, ActewAGL Distribution is able to make a claim for a cost pass through event in relation to changes in tax events, terrorist events, major natural disasters and service standard events. However, ActewAGL Distribution is only able to claim a pass through in relation to these events for the costs imposed on ActewAGL Distribution as a result of the event for the remainder of the current regulatory period.

As a result, were any of these events to occur after 2 June 2008 but before 1 July 2009 (the 'transitional period'), then ActewAGL Distribution would only be able to claim for the costs implied by the event to the end of June 2009. Costs resulting from the event after 1 July 2009 would not be recoverable, either as part of a cost pass through in the current regulatory period or through an amendment to the expenditure forecasts for the 2009–14 regulatory period.

In addition, ActewAGL Distribution notes that in the current regulatory period, it is not able to lodge pass through applications in relation to a regulatory change event, as this is not included as a pass through event in the ICRC's determination. The cost imposed by any change in regulatory requirements which occur after 2 June 2008 will not be able to be reflected in the expenditure forecasts for the 2009–14 regulatory period. Given that regulatory change events are established in the NER as eligible pass through events, ActewAGL Distribution considers that it should be able to recover any additional costs to which it is exposed as a result of regulatory change events which occur in the transitional period.

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146 Transitional *Rules*, 6.8.2(a)
147 Transitional *Rules*, 6.9.2(a) and (b)
148 Transitional *Rules*, 6.10.3(a)
149 Transitional *Rules*, 6.10.3(b)

ActewAGL Distribution considers that it faces material risks in relation to increases in costs imposed by external events during the 'transitional period' between the lodging of its regulatory proposal and the beginning of the new regulatory period. In particular, it is possible that a policy decision on smart meters that requires ActewAGL Distribution to undertake pilots and trials, or a complete roll out, of smart meters may occur during this period. As noted in chapter 2, a Bill proposing the introduction of feed-in tariffs is due to be debated in the ACT Legislative Assembly in June 2008, after the submission date. The introduction of a feed-in tariff scheme would be expected to have financial implications for ActewAGL Distribution. The AER is also due to finalise the reporting requirements for its new service target performance incentive scheme, which may impose additional costs on ActewAGL Distribution in relation to the setting up of new systems and reporting frameworks (in addition to those that have been included within ActewAGL Distribution's forecast expenditure, as discussed in chapter 3).

In order to manage what is a material risk for ActewAGL Distribution, it is proposed that the AER should approve a 'transitional period' event as an eligible cost pass through event. A transitional period event should be defined as follows:

> **A transitional period event:** Any event that falls within the definition of a cost pass through event set out in the NER or which is approved as a cost pass through event by the AER in its final determination for ActewAGL Distribution for the 2009–2014 period, and which occurs during the period 2 June 2008 to 30 June 2009.

ActewAGL Distribution also notes that the transitional *Rules* include a time limit for submitting an application to the AER for the approval of a pass through event. Clause 6.6.1(c) of the transitional *Rules* states:

To seek the approval of the *AER* to pass through a *positive pass through amount*, a *Distribution Network Service Provider* must submit to the *AER*, within 90 *business days* of the relevant *positive change event* occurring, a written statement [..]

In the case of a transitional period event, it may not be possible to submit to the AER an application for a pass through within the required 90 business days, as the relevant pass through category, if accepted by the AER, would not be in place before 1 July 2009. Transitional period events that occur in 2008 and early 2009 may not meet the deadline for submission to the AER for consideration.

To address this issue, ActewAGL Distribution proposes that the time limit for submission of all transitional period pass through applications be extended to 90 business days after 1 July 2009. ActewAGL Distribution proposes two possible mechanisms for achieving this outcome:

- All transitional period events being taken to occur on 1 July 2009 ; or
- The AER invoking its power under clause 6.6.1(k) of the transitional *Rules* and stating that it will extend the time limit for submission of all transitional period pass through event applications to 90 business days after 1 July 2009.

16.4.3 Smart meter event

The key uncertainties in relation to the cost of metering services during the 2009-14 regulatory period arise from the likelihood of an MCE and/or ACT Government policy decision relating to smart meters.

At its meeting in April 2007, the Council of Australian Governments (COAG) endorsed a staged approach for the national mandated roll out of electricity smart meters[150] to areas where benefits for consumers outweigh costs.[151] ActewAGL Distribution notes that the decision as to whether to mandate a roll out of smart meters in the ACT, or whether pilots and trials will proceed, has not yet been taken. The form of this decision is also unclear, particularly whether it will adequately fall within the definition of a regulatory change event.

An MCE or ACT Government policy decision on smart meters in the ACT could include a number of possible outcomes, from no action, to support for pilots and trials, through to a mandatory, territory-wide roll out of smart meters. A decision to undertake a staged roll out in the ACT could also include pilots and trials ahead of a decision on a roll out, all undertaken within the 2009-14 regulatory period. There is also some uncertainty as to the regulatory framework that will apply to smart meters in the future.

As a result of this uncertainty, the cost estimates which underlie the pricing proposal for ActewAGL Distribution's alternative control (metering) services (as set out in chapter 15) have not assumed a mandated roll out of smart meters. Any decision by the MCE or ACT government to mandate a roll out of smart meters would therefore result in costs for ActewAGL Distribution's metering services being materially in excess of those presented in this proposal. In addition, the costs associated with ActewAGL Distribution's standard control services will also be affected. Similarly, any decision by the MCE or ACT government to require ActewAGL Distribution to undertake a pilot or trial project in relation to smart meters, or which would make pilots and trials prudent to inform a future government decision on a full roll out, would also result in additional costs being imposed on ActewAGL Distribution.

ActewAGL Distribution previously raised with the AER the need to explicitly address the possible need to pass through additional costs associated with the mandatory deployment of interval meters and the importance of the AER acknowledging in its determination that these costs may be fully recovered.[152] The issue raised is equally relevant to any mandated roll out of smart meters.

In its earlier position paper the AER commented that:

> The AER recognises the potential for ActewAGL Distribution to incur additional costs in meeting obligations to roll-out interval meters. It further acknowledges the intent of the

[150] *Smart meters* are capable of measuring and recording energy in short intervals and also have two-way communication capabilities. Smart meters are distinguished from *interval meters* which do not have two-way communication capabilities.

[151] COAG 2007, *Communiqué*, 13 April, p 1

[152] ActewAGL Distribution 2008, *Submission to AER*, January. Note that ActewAGL Distribution's query to the AER was made in the context of the ICRC decision to mandate an interval meter roll out, which would be superseded by any ACT Government-mandated roll-out of smart meters.

> ICRC in mandating the roll-out in the ACT, that the cost of interval meters would be recovered by ActewAGL Distribution through distribution charges. [..] The AER acknowledges this may have cost implications for ActewAGL Distribution during the next regulatory control period.
>
> Based on the information before it, the AER's preliminary view is that additional efficient costs incurred through meeting these obligations during the next regulatory control period, should be recovered through ActewAGL Distribution's charges. It is anticipated that the recovery of additional costs associated with alternative control services may be accommodated under clause 6.2.6(c) of the transitional *Rules*. This clause provides for elements of Part C of the transitional Rules - including cost pass through provisions - to be adopted in the control mechanism for alternative control services. [153]

The AER however noted that determining the arrangements for cost pass through for alternative control services is an issue to be addressed at the distribution determination.

The AER's view as set out in the position paper would appear to be equally applicable to any mandated roll out of smart meters (as opposed to interval meters). ActewAGL Distribution supports the AER's view that the additional costs imposed on ActewAGL Distribution associated with a decision in the ACT to mandate a roll out of a particular type of meter should be recovered via the cost pass through arrangements.

As discussed above, clause 6.2.6(c) of the transitional NER allows the control mechanism for alternative control services to utilise elements of Part C of the transitional NER, which includes the cost pass through provisions.

ActewAGL Distribution considers that the definition of a regulatory change event would capture the introduction of a mandated roll out of smart meters enacted through a legislative instrument. However, for the avoidance of doubt, and taking account of the potential form of an eventual MCE or ACT Government decision on smart meters, ActewAGL Distribution proposes that a smart meter policy decision on pilots and trials or a full roll out of smart meters should be specifically identified as a cost pass through event in the AER's determination.

ActewAGL Distribution notes that IPART's 2004 determination for the NSW distributors provides a precedent for this approach, in that it identified the imposition of a mandatory roll out of interval meters as a specific pass through event.[154]

ActewAGL Distribution therefore proposes that the following category of pass through event be identified for the 2009–2014 regulatory period:

> **A smart meter event:** The imposition of a requirement on ActewAGL Distribution to replace existing meters used to measure the consumption of electricity by distribution customers with meters that measure the consumption of electricity at specific time intervals and which are capable of being remotely read (commonly referred to as 'smart meters'), either on a pilot basis or as part of a wider roll out, which has a material impact on the cost of providing direct control services by ActewAGL Distribution which would not have occurred in the absence of the mandatory roll out.

[153] AER 2007, *Preliminary Position, Matters Relevant for Distribution Determinations for ACT and NSW distributors for 2009-2014*, December, pp 40-41

[154] IPART 2004, *NSW Electricity Distribution Pricing 2004-05 to 2008-09: Final Report*, June, p 41

ActewAGL Distribution notes that an MCE or ACT Government decision on smart meters is likely to relate both to the costs of the meters and also the cost of the associated infrastructure, including communications and IT infrastructure. As such, this decision will have implications for both the cost of metering services and also the cost of standard control services, and, hence, the proposed pass through arrangements should apply to both standard and alternative control services.

16.4.4 Input price event

Within a climate of strong demand for resource commodities, volatility in input prices beyond the control of ActewAGL Distribution is likely to occur in the 2009–14 regulatory period. As noted by the RBA in its April 2007 Bulletin:

> [A] unique feature of the current [commodity] price boom is its composition, and particularly the exceptional growth in metals prices compared with other commodity prices. At roughly 150 per cent over the past five years, the recent increase in real metals prices is by far the largest of the last century for these commodities and the level of real metals prices is now above its century average.[155]

The magnitude of possible input price variations is difficult to predict at the present time and the significant risk posed by these variations is not compensated for in this regulatory proposal.

ActewAGL Distribution notes, however, the AER's recognition of the "scope to nominate significant input cost variations as pass through events"[156] and considers that in the current climate of unprecedented volatility in input prices it is appropriate to add such an event.

ActewAGL Distribution proposes that the 2009–14 determination should include an additional pass through event to apply when input prices vary and result in a material variation in actual capital and operating expenditure incurred in the 2009–14 regulatory period:

> **An input price event:** Any variation in input prices which results in costs incurred by ActewAGL Distribution being materially different to those incorporated into the AER's determination for the 2009–2014 regulatory period and which would not have been incurred but for the occurrence of the event.

It is proposed that the definition of 'input' be limited to 'non-labour' inputs. ActewAGL Distribution notes that pass throughs are treated symmetrically and all pass-through applications are subject to a consideration of the prudency and efficiency of costs incurred. ActewAGL Distribution would consider, consistent with clause 6.10.3(b) of the transitional *Rules*, revising its cost forecasts should this pass through proposal be rejected by the AER.

ActewAGL Distribution also notes that the transitional period event proposed in section 16.4.2 above would cover an input price event during the transitional period between 2 June 2008 and 30 June 2009.

[155] RBA 2007, *Reserve Bank Bulletin—The Recent Rise in Commodity Prices: A Long-Run Perspective*, April, p 3

[156] AER 2007, *Final Decision – Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, February, p 13

16.4.5 A supply curtailment event

The ACT has no substantive electricity generation capacity, relying instead on the transmission of power from interstate generation facilities. The ACT is expected to remain heavily reliant on electricity transmission services and interstate electricity generation.

The ACT Government is party to power sharing arrangements at times of supply shortfalls. In agreed circumstances, the ACT is required to manage and ration supply in the ACT in accordance with an agreed protocol. In addition, Regulations under the *Utilities Act 2000* allow the responsible Minister to approve an Electricity restriction scheme if satisfied that the scheme is necessary to facilitate, as far as practicable, the provision of efficient, reliable and sustainable electricity services by utilities to consumers; protect the interests of consumers; manage the safety and security of the electricity network; or protect public safety.[157]

For these reasons, ActewAGL Distribution proposes a pass through event where:

- There is an event, in another Australian state in relation to power generation and its transmission to the ACT; and/or
- Where an electricity restriction scheme is introduced; and
- The event is outside the control of ActewAGL Distribution and it has a material impact on ActewAGL Distribution's costs or revenue stream.

This risk to ActewAGL Distribution's revenue stream is not compensated elsewhere in the regulatory proposal.

ActewAGL Distribution proposes that in the event that power is not delivered to the ACT to fully meet ACT demands as forecast in this regulatory proposal, including interstate transmission or generation failure or excess demand or supply constraints, or where a restriction scheme is introduced, and this supply shortfall is out of the control of ActewAGL and impacts the revenue earnings of the business relative to what would have been earned had that power been supplied as forecast, that this revenue forgone and any associated costs be subject to a pass through event.

ActewAGL Distribution proposes that a supply curtailment event should be defined as follows:

> **A supply curtailment event:** When power is not transmitted to the ACT or is rationed to or within the ACT and cannot be supplied to meet normal requirements, as represented by ActewAGL Distribution forecasts supplied in this regulatory proposal for the 2009–14 regulatory period, and the event is outside of the control of ActewAGL Distribution.

ActewAGL Distribution would be able to claim the full cost of foregone revenue[158] that is directly attributable to this supply curtailment event, plus the cost of any customer claims and the increased costs imposed on it for needing to meet priority demands within the ACT from other supply sources.

[157] *Utilities (Electricity Restrictions) Regulations 2004*, section 6

[158] ActewAGL Distribution notes that the ICRC has allowed ACTEW Corporation to pass through forgone revenue associated with the imposition of water restrictions in the ACT.

16.5 Materiality threshold

Clause 6.2.8(a)(4) of the transitional *Rules* provides that the AER may publish a guideline as to its likely approach to determining materiality in the context of possible pass through events. The guideline is not binding, but if the AER's distribution determination is not in accordance with the guideline, the AER will be required to state its reasons for departing from the guideline.

In November 2007 the AER released an issues paper covering materiality thresholds for cost pass-through.[159] A preliminary positions paper followed in December 2007.[160] While the AER indicates on its website that a guideline on materiality is to be released in the near future, the guideline has not been released prior to the submission of this regulatory proposal.

The AER's preliminary position is that an event is material if:

- the revenue impact in any one year exceeds 1 per cent of the respective DNSP's revenue for the first year of the regulatory period; or
- the proposed capital expenditure exceeds 5 per cent of the AARR in the first year of the regulatory period.

In response to the preliminary positions paper, ActewAGL Distribution raised several concerns about the AER's proposed revenue based threshold, and proposed an alternative more flexible approach. In summary, ActewAGL Distribution's position is that:

- The value of the threshold should be based on an estimate of the combined administrative cost of assessing a typical pass through claim;
- A cost impact measure is preferred to a revenue impact measure; and
- A materiality test which includes a safety net helps address the inequity associated with a uniform threshold.

ActewAGL Distribution believes that there are some additional cost pass through materiality threshold issues that need to be addressed by the AER as part of the 2009–14 determination.

16.5.1 No materiality threshold for scheduled events

As discussed in chapter 2, ActewAGL Distribution's regulatory proposal is submitted against the backdrop of significant ongoing development of the regulatory framework for RNSPs. Areas of major scheduled or anticipated regulatory changes are as follows:

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[159] AER 2007, *Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-14*, Issues Paper, November

[160] AER 2007, *Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-14,* Preliminary Positions Paper, December.

- In April 2007 the Council of Australian Governments (COAG) endorsed a staged approach for the national mandated roll out of electricity smart meters[161] to areas where benefits for consumers outweigh costs.[162] The MCE is currently considering the Regulatory Impact Statement and a decision is expected in June 2008.[163]

- The AER is currently developing several guidelines, models, schemes and reporting requirements. Some of these are due to be finalised by 30 June 2008, however other aspects, such as reporting requirements, will be subject to consultation later this year.

- The MCE's phase 2 legislative package, which will implement the transfer of non-economic distribution regulatory functions from jurisdictional regulators to the AER as well as new network planning and connection arrangements, are scheduled for introduction in the South Australian Parliament by no later than 30 September 2009.[164]

- New ARPANSA standard for Electric and Magnetic Fields (EMF), expected to be finalised by 1 January 2009, which may set stringent standards for EMF that lead to the need for new capital and operating expenditure.

- A Private Member's Bill on a feed-in tariff scheme has been introduced into the ACT Legislative Assembly. ActewAGL Distribution understands that the Bill is to be debated in June 2008, after the lodgement of this regulatory proposal.

- New ACT Workplace Safety Bill (anticipated name) expected to be introduced in the ACT Legislative Assembly towards the end of 2008. The Bill is expected to impose additional obligations on construction sites across all industries, including the utilities industry, affecting ActewAGL Distribution's capital works and maintenance programs and potentially leading to a significant cost impact on these programs.

ActewAGL Distribution proposes that no materiality threshold should apply to the above events. Given that the above are all foreseen or scheduled events, ActewAGL Distribution considers that it would not be appropriate to apply a materiality threshold to the pass through of costs associated with the events. If the timing and details of the events were certain, then the costs would be included in ActewAGL Distribution's regulatory proposal *in their entirety.* It is unreasonable to penalise ActewAGL Distribution, by potentially not allowing recovery of costs that fall below a threshold, because the policy details have not been finalised before the regulatory proposal submission date.

ActewAGL Distribution notes there is a regulatory precedent for applying no threshold to anticipated events. IPART in its 2004 determination for the NSW distributors considered that it

[161] *Smart meters* are capable of measuring and recording energy in short intervals and also have two-way communication capabilities. Smart meters are distinguished from *interval meters* which do not have two-way communication capabilities.
[162] COAG 2007, *Communiqué*, 13 April, p 1
[163] MCE Energy Market Reform Bulletin, no 117
[164] Ministerial Council on Energy Meeting Communiqué 13 December 2007, p 3

would be inappropriate to apply a materiality threshold to foreseen but uncertain costs, including the costs associated with any mandatory interval meter roll out.[165]

ActewAGL Distribution also notes that some of the above regulatory change events are scheduled to occur within the period between 2 June 2008 and 30 June 2009. These regulatory change events would therefore be covered by ActewAGL Distribution's proposed 'transitional period event', as described in section 16.4.

16.5.2 Separate materiality threshold for alternative control services

As outlined in section 16.2 above, ActewAGL Distribution proposes that the pass through arrangements apply to standard control services and alternative control services.

ActewAGL Distribution considers that, if a materiality threshold is to be applied, as indicated in the AER's preliminary positions paper, any threshold for alternative control services must be determined based on consideration of the specific circumstances applying to alternative control services in the ACT and should not be the same as any materiality threshold that the AER determines should be applied to standard control services.

[165] IPART 2004, *NSW Electricity Distribution Pricing 2004-05 to 2008-09: Final Report*, June, p 127

Attachment 1—Compliance with the RIN and the transitional Rules

The AER's Regulatory Information Notice (Attachment 2) sets out the minimum information that must be provided by the RNSP to assist the AER in its assessment of the RNSP's regulatory proposal. Throughout this regulatory proposal ActewAGL Distribution has referred to the relevant requirements and how they have been met. Table A1.1 below provides a checklist of the AER's requirements and where they are addressed in ActewAGL Distribution's regulatory proposal.

The transitional *Rules* also set out some explicit information requirements. Clauses S6.1.1 and S6.1.2 set out the minimum required information and matters relating to capital expenditure and operating expenditure. Clause S6.1.3 sets out the minimum additional information and matters that the regulatory proposal must contain. Table A1.2 below provides a checklist of the requirements and where they are met in ActewAGL Distribution's regulatory proposal.

Table A1.1: AER Regulatory Information Notice (RIN) requirements

RIN section	Title and requirements	Principal coverage in the proposal
2.1	Business details and regulatory period Trading name Australian Business Number Business and postal address Contact person(s) and details	Pro forma 2.1 Chapter 1
2.2.1	**Capital expenditure** (a) Capital expenditure actuals for each of the past regulatory years of the *previous regulatory control period* and *current regulatory control period* (the expected capital expenditure for each of the last two regulatory years of the *current regulatory control period*) and the forecast of required capital expenditure by asset class (for example, distribution lines, substations etc.) for the *next regulatory control period*; and/or (b) Capital expenditure actuals for each of the past regulatory years of the previous and *current regulatory control period* (the expected capital expenditure for each of the last two regulatory years of the *current regulatory control period*) and the forecast of required capital expenditure by category driver (for example, regulatory obligation or requirement, replacement, reliability (augmentation), business support etc.) for the *next regulatory control period.* (c) The total amounts of capital expenditure requested and capital expenditure approved for each year of the *current regulatory control period* (including any pass through amounts).	Pro forma 2.2.1 Chapters 7 and 15
2.2.2	**Operating expenditure** (1) Operational expenditure actuals for each of the past	Pro forma 2.2.2 Chapters 8 and 15

RIN section	Title and requirements	Principal coverage in the proposal
	regulatory years of the *previous regulatory control period* and *current regulatory control period* (the expected operating expenditure for each of the last two regulatory years of the *current regulatory control period*) and the forecast of required operating expenditure by expenditure type for the *next regulatory control period*. (2) The total amounts of operating expenditure requested and operating expenditure approved for each year of the *current regulatory control period* (including any approved pass through amounts).	
2.2.3	**Material projects and programs** For projects and programs have or are expected to be undertaken in the *current regulatory control period* or are forecast to be undertaken in the *next regulatory control period:* (1) project/program unique identifier, project name and a brief description (2) reason for project/program (with reference to the driver/purpose categories that are in the expenditure reporting pro formas) (3) proposed start date and commissioning date (4) the categories of distribution services which are to be provided by the projects/programs (5) the location of the project or program (6) an indication as to whether the forecast capital expenditure associated with the project or program has obtained business case approval (7) an indication as to whether any of the forecast capital expenditure is for an option that has satisfied the regulatory test (8) the anticipated or known cost of the project/program.	Pro forma 2.2.3, Chapter 7
2.2.4	**Variance justification** The *RNSP* must identify and explain significant variations in the proposed forecast expenditure from historical expenditure. The *AER* has defined the baseline as the actual expenditure outcome of the third year of the *current regulatory control period* (adjusted for inflation). The *AER* has also defined the term significant variation as a ten per cent variation between the baseline expenditure and the average of the five years forecast expenditure in the *next regulatory control period*.	Pro forma 2.2.4, Attachment 17
2.2.5	**Services and indicative prices** (1) the name and a description of each individual standard control service; alternative control service; and negotiated distribution service provided by the RNSP that is the subject of the regulatory proposal (2) actual customer numbers for each individual prescribed service, excluded service and negotiated distribution service in each year of the current regulatory control period (provide an estimate for the final two years of the current regulatory control period)	Pro forma 2.2.5, Chapters 1 and 13

RIN section	Title and requirements	Principal coverage in the proposal
	(3) the revenue earned for each individual prescribed service, excluded service and negotiated distribution service in each year of the current regulatory control period (provide an estimate of revenues for the final two years of the current regulatory control period) (4) the prices for each individual prescribed service and excluded service in each year of the current regulatory control period (provide an estimate for the final two years of the current regulatory control period) (5) indicative prices for each individual standard control service and alternative control service in each year of the next regulatory control period.	
2.3.1	**Organisational overview** (1) What are the current ownership arrangements (as well as any proposed changes to those arrangements over the *next regulatory control period*) and are any other businesses operated by the *RNSP*. (2) An overview of the *RNSP's* structure (for example, divisions and/or business units) as well as an organisational chart. (3) Explain how each division and/or business unit contributes to the provision of *standard control services*, *alternative control services*, *negotiated distribution services* and non-distribution services. (4) Current staffing numbers, including both employee and contractor numbers in each division and/or business unit of the organisation (note the *AER* is seeking information on labour hire numbers not labour provided under service contracts) and any expected change in staffing numbers over the *next regulatory control period* (and if a change is expected, the reasons this change). State the basis used for calculating staffing numbers. (5) Key information systems used by the *RNSP* to provide regulated network services (including network management systems and accounting systems). (6) Whether the *RNSP* provides any non-regulated services and the proportion of revenues recovered from these services as a proportion of total revenues earned by the *RNSP*. (7) An overview of the *RNSP's* customer base and the key customer considerations (for example, differential growth in regions of the network) that have impacted on the development of the *RNSP's* expenditure forecasts - with reference to the customer data provided by the *RNSP* in relation to the demand forecast pro forma. (8) Explain how environmental factors, including topographic and climatic considerations, affect the *RNSP's* efficient costs and how they have impacted on the *RNSP's* proposed expenditure forecasts. (9) Provide a high level overview of the *RNSP's* network (for example, historical development, geographical coverage, total line and cable length, etc) and a recent high level map of the network showing major network features including key forecast	Chapter 1, Attachment 2, Chapter 2, section 2.1

RIN section	Title and requirements	Principal coverage in the proposal
	augmentations.	
2.3.2	**Relationships with other entities** List the relationships that meet the criteria listed in the RIN section 2.3.2	Pro forma 2.3.2 Chapter 1,
2.3.3	**Key assumptions** For the assumptions used to develop expenditure forecasts: (1) a description of the assumption (2) the method used to develop the assumption (3) what information the assumption has been used to forecast (4) how the assumption has been applied to develop the relevant forecast. A certification of the reasonableness of the assumptions	Pro forma 2.3.3, Chapters 5, 7 and 8, Attachments 17 and 18
2.3.4	**Regulatory obligations and requirements** Provide the following information regarding the existing regulatory obligations or requirements relating to the provision of the *RNSP*'s *direct control services* and which have a material impact on its expenditure forecasts. Note that it is sufficient to reference the overarching obligation where this captures the elements that are central to the construction of the expenditure forecasts. • the authority or body enforcing the instrument and provision(s) • the relevant instrument and provision(s) relating to the particular regulatory obligation or requirement • a brief explanation of what is required to comply with the particular regulatory obligation or requirement • whether the regulatory obligation or requirement is apparent in the current and historic expenditures of the *RNSP*. For each new, anticipated or incremental regulatory obligation or requirement (or existing obligations which are expected to lead to changes in expenditures) relating to the *RNSP*'s *direct control services* and which are expected to have a material impact on its expenditure forecasts, provide the following information: • the authority or body enforcing the instrument and provision(s) • the relevant instrument and provision(s) relating to the particular regulatory obligation or requirement • a brief explanation of what is required to comply with the particular regulatory obligation or requirement • the estimated cost impact of the obligation or requirement • details of the methodology used to estimate the cost impact of the obligation or requirement.	Pro forma 2.3.4, Chapters 4 and 15
2.3.5	**Service standard obligations**	Pro forma 2.3.5,

RIN section	Title and requirements	Principal coverage in the proposal
	For each service standard obligation that relates to the provision of the *RNSP*'s *direct control services*, the *RNSP* must provide the following information: Details of any externally imposed obligations, including performance measures and, where applicable, relevant performance targets. Details of any internal programs, projects or initiatives aimed at maintaining or improving network reliability and customer service performance during the *next regulatory control period*, in order to satisfy the particular externally imposed obligation. The estimated impact of satisfying the externally imposed obligation on the *RNSP*'s capital and operating expenditures for the *next regulatory control period*. Note that for existing externally imposed service standard obligations the impact of satisfying the obligation is not required as these should already be reflected in the businesses cost structure. However, the estimated impact of new, proposed or incremental service standard obligations should be provided. Where internally imposed service performance standards have been developed to assist in satisfying externally imposed standards, provide: • Details of the internal performance measures and, where applicable, relevant internal performance targets. • An explanation of any internal programs, projects or initiatives aimed at maintaining or improving network reliability and customer service performance during the *next regulatory control period*, in order to satisfy the particular internally imposed target. • The estimated impact of satisfying the internally imposed obligation on the *RNSP*'s capital and operating expenditures for the *next regulatory control period*. • An explanation of how each internally imposed performance standard assists the business in satisfying the relevant externally imposed obligation.	Chapter 3
2.3.6	**Plans, policies, procedures** List and provide a brief description and a copy of key internal plans, policies, procedures or strategies that are used by the *RNSP* to plan and conduct its day to day operations and have been relied upon by the *RNSP* in the development of its *regulatory proposal*. Where a *RNSP*'s key internal plans, policies, procedures and strategies have changed in the *current regulatory control period* or will change before the *next regulatory control period* and that change has had a material impact on forecast expenditures for the *next regulatory control period*, identify: • the plan, policy, procedure or strategy that has changed • provide an explanation of the change and the reason for the change	Pro forma 2.3.6, Chapters 6 and 15

RIN section	Title and requirements	Principal coverage in the proposal
	• the impact on the *RNSP*'s forecast expenditures as a result of the change.	
2.3.7	**ACT network planning and management** Provide the following information describing the *RNSP*'s approach to network planning and management: details about network performance and/or utilisation and comparison with targeted levels an explanation of the approach to network planning, investment evaluation and operating and maintenance expenditure decision making copies of the key documents used to plan the *RNSP*'s system and develop capital and operating expenditure forecasts. an explanation of how the key documents support the capital and operating expenditure forecasts and relate to each other an explanation of the historic network capacity or performance levels and their impact on service levels at key points in the network an explanation of the target capacity or performance levels and how these meet external and internal performance standards an explanation of how network capacity in the *current regulatory control period* met actual demand relative to the demand forecasted for each period an explanation of how forecast capacity will meet performance standards and forecast demand based on the capital and operating expenditure proposed for the *next regulatory control period*.	Pro forma 2.3.7, Chapters 6 and 15
2.3.8	**Demand forecast** (a) Provide the following information relating to demand forecasts: (1) the demand forecasts that the RNSP has used to develop operating and capital expenditure forecasts (where applicable) for the next regulatory control period, including forecasts relating to total energy consumption, coincident peak (maximum) demand and customer numbers (2) an explanation of the key drivers likely to impact on the demand forecasts over the next regulatory control period (3) the methodology that has been used to prepare the demand forecasts, including the key assumptions and inputs which have been used (4) a detailed description of the model used by the RNSP to develop its demand forecasts (including the models key inputs and assumptions) (5) whether there has been any independent verification of the demand forecasts, and if so a copy of a report on that verification (6) an explanation of how the demand forecast has been used to	Pro forma 2.3.8 Chapter 5 Attachments 4 and 5

RIN section	Title and requirements	Principal coverage in the proposal
	develop the RNSP's capital expenditure and operating expenditure forecasts (7) if a consultant has developed the demand forecast for the RNSP, a copy the consultant's report.	
2.3.9	**Consideration of non-network alternatives** (a) The RNSP is require to provide the following information: (1) The extent to which the RNSP has considered and made provision for efficient non-network alternatives in developing its forecast operating and capital expenditures for the next regulatory period (2) The processes, procedures or policies that the RNSP has in place to ensure that efficiency non-network solutions are identified and, where appropriate, selected (3) A description of the types of non-network alternatives that the RNSP normally considers (4) A list of those non-network projects that have been selected during the current regulatory control period.	Chapter 6 (section 6.2)
2.3.10	**Expenditure estimation process** (a) Provide an overview of the expenditure estimation process used by the RNSP in developing its forecast capital and operating expenditures. (b) Provide information on the following aspects: (1) the unit rates adopted by the RNSP for key items of plant and equipment, how these have been developed (including source material) and evidence that they reflect efficient costs. (2) the key expenditure escalators (for example, labour, materials, land and other) used in developing the expenditure estimates, and for each expenditure escalator identified provide: (i) the specific escalator used in each year of the regulatory period (ii) whether the escalator is in real or nominal terms (iii) how the escalator has been developed (including source material). (3) whether the same expenditure escalators have been used in developing proposed capital and operating expenditures. If not provide justification and supporting evidence as to why different expenditure escalators should apply. (4) whether the expenditure estimation process involves the application of contingency factors, what risks they account for and how they have been calculated. (5) how the profile of expenditure for different types of projects and programs have been developed. (c) Not all expenditure estimations are derived from bottom-up unit rates and this approach may be more suitable to larger individually estimated projects. Where this is the case, the RNSP must provide details of the approach used to that a judgment can be formed about its reasonableness (for example, key	Chapters 7 and 8 Pro forma 2.3.3 Attachments 17 and 18

RIN section	Title and requirements	Principal coverage in the proposal
	assumptions used and inputs).	
2.3.11	**Self insurance** (a) If a RNSP proposes to self insure particular events, the self insurance expenditures for each year of the next regulatory control period should be included in the RNSP's regulatory proposal or included as a separate line item in the RNSP's operational expenditure forecasts. (b) For each event that is proposed to be self insured the RNSP is to provide the following information: (1) name and description of the event being self insured (2) whether the event is in relation to a particular asset or asset type (3) date of board resolution/management decision to self insure (4) the reason why the event is being self insured (5) whether the RNSP is aware of any external insurer/s who are able to insure the event (6) if the RNSP has obtained a quote from an external insurer, the annual amount of the premium so obtained (7) the insured value of each event that is to be self insured (8) the value of the annual self insurance premium for the event (9) a reference to the relevant area in the regulatory proposal that explains how the self insurance premium for the event was calculated and any consultant report relating to the self insurance proposal.	Pro formas 2.3.11 and 2.3.3 Chapter 8 (section 8.6)
2.3.12	**Expenditures with other persons** (a) In relation to expenditures with other persons which either directly or indirectly relate to, are or connected with, the provision of electricity distribution services the RNSP is to provide the following information: (1) List the top ten expenditures the RNSP has had with other persons for the supply of goods and/or services over the current regulatory control period. The top ten expenditures are to be determined on the basis of the total estimated value of transactions (excluding GST). Multiple transactions with the same person must be cumulated when determining the top ten expenditures. The RNSP should include transactions with both monetary and non-monetary consideration. Transactions do not include payments to electricity market participants. (2) For each transaction identified in (1) above: (i) the nature of the expenditure, including a description of the goods and/or services provided (ii) an estimation of the total value of the expenditure (excluding GST) (iii) a description of the procurement process undertaken in respect of the goods and/or services (iv) whether it is likely that the RNSP will have arrangements for	Pro forma 2.3.12, Chapter 7

RIN section	Title and requirements	Principal coverage in the proposal
	the supply of goods and/or services with the parties to these transactions in the next regulatory control period For each expenditure identified in section 2.3.12(a)(1), list each contract that: (i) has an end date after 30 June 2009; and (ii) the RNSP has factored into its capital and operating expenditure forecasts for the next regulatory control period. (4) For each expenditure identified in (3) above: (i) the nature of the expenditure, including a description of the goods and/or services to be provided (ii) an estimation of the total value of the proposed expenditures (excluding GST) and the amount that has been estimated for inclusion in forecast expenditures (iii) a description of the proposed procurement process to be undertaken in respect of the goods and/or services (iv) whether any of the proposed transactions are with a person identified in section 2.3.2 of this notice.	
2.3.13	**Capital contributions** (a) Provide information as to the basis on which capital contributions in the current regulatory control period (estimates for 2007-08 and 2008-09) and next regulatory control period have been determined and, if necessary, the process by which capital contributions have been allocated to the different asset classes in the PTRM.	Pro formas 2.3.3 and 2.3.13 Chapter 7 (section 7.3.11)
2.4.1	**Transitional issues** (a) Provide information on existing or potential transitional issues (expressly identified in the Rules or otherwise) which the RNSP expects will have a material impact on it and should be considered by the AER in making its distribution determination. For each issue, set out the following information: (1) the transitional issue (2) what has caused the transitional issue (3) how the transitional issue impacts on the RNSP (4) how the RNSP considers the transitional issue could be addressed (5) reference to the relevant area of the regulatory proposal. (b) A transitional issue is defined as an issue having a material impact on the RNSP which arises from the transition from the current regulatory control period to the next regulatory control period and the RNSP believes needs to be addressed in the AER's 2009-2014 distribution determination.	Pro forma 2.4.1 Chapter 2 (section 2.3)
2.4.2	**X factors** (a) Provide the following information regarding X factors: (1) an explanation of how the X factors have been set	Chapters 12 and 15, Attachment 8

RIN section	Title and requirements	Principal coverage in the proposal
	(2) an explanation of how the X factors satisfy the requirements of clause 6.5.9 of the Rules and guidance in the PTRM handbook (3) any other justifications that the RNSP considers are relevant.	
2.4.3	**Financial parameters for PTRM** (a) Provide the following financial parameters for the PTRM: (1) the proposed averaging period (in days) for bond rates (that is, the nominal risk free rate and debt risk premium) and the start of the averaging period (2) an indicative 10 year Commonwealth bond rate (3) an indicative 10 year debt risk premium (4) an inflation forecast for the next regulatory control period.	Chapter 10 Attachments 8, 12 and 23
2.4.4	**Review of procedures** (a) The AER's requirements in respect of historic expenditure information are set out at sections 2.2.1 and 2.2.2 of this notice. In summary, the AER requires actual historic capital and operating expenditure information for prescribed and excluded services for the following periods: (1) for each year ended 30 June 1999 to 30 June 2004. (2) for each year ended 30 June 2005 to 30 June 2007. (b) In providing the information in section 2.4.4(a)(2) the AER requires the RNSP to undertake certain procedures to review this information for: (1) consistency with the cost allocation methodology of the RNSP that existed at the time; and (2) arithmetic accuracy of the inputs used to develop the information and the accuracy of the process used to convert those inputs into actual outputs. and (c) The procedures in section 2.4.4(b) must be carried out in accordance with the Australian Auditing Standard AUS 904 or the updated auditing standard on related services, which relates to Engagements to Perform Agreed-Upon Procedures. (d) In respect of the information to be provided in section 2.4.4(a)(2) the RNSP must provide a report from an independent auditor of the findings of the agreed-upon procedures engagement for the matters outlined in section 2.4.4(b) and separately identify in that report any exceptions in reporting these findings. The report and any separate report developed for management in respect of the engagement should be provided as an attachment to the RNSP's regulatory proposal. (e) In respect of the information in section 2.4.4(a)(1) and (a)(2) the RNSP must provide details as to whether this information has been independently audited, for purposes connected with the economic regulation of network services, whether an opinion has been expressed about it and any other details about the procedures undertaken as component parts of this audit of the information. If the information has been audited the RNSP must	Attachment 19

RIN section	Title and requirements	Principal coverage in the proposal
	provide the audit report prepared by the independent auditor in respect of this information and any separate report developed for management in respect of the audit engagement. This information and any report must be attached to the RNSP's regulatory proposal. (f) The AER may require the independent auditor referred to in section 2.4.4(d) to present or explain its findings at a meeting with the AER.	
2.4.5	**Corporate income tax base** (a) Provide the following information: (1) The Australian Taxation Office's assessment of tax payable under the National Tax Equivalent Regime (NTER) (2) NTER values for the RAB to be applied in the PTRM (that is, standard control services only) (3) NTER values for assets not within the RAB.	Pro forma 2.4.5, Chapters 10 and 15
2.4.6	**Alternative control services** (a) Provide the following information in relation to alternative control services: (1) Information to support the application of the proposed control mechanism including: (i) an overview of metering services provided by the RNSP (ii) a demonstration of the application of the proposed control mechanism and any supporting information (iii) in the case of a departure from the AER's likely approach to the relevant control mechanisms for alternative control services, a statement of the reasons justifying the departure (2) Proposed revenue allowance, including: (i) a rolled-forward value of the relevant metering assets (ii) an analysis of expenditure associated with providing the services (iii) detail of the cost of each building block element.	Chapter 15 Pro forma 2.2.5 Chapter 13

Table A1.2: Transitional Rules clause S6.1 requirements

Rules section	Title and requirements	Principal coverage in the proposal
S6.1.1	**Information and matters relating to capital expenditure** A *building block proposal* must contain at least the following information and matters relating to capital expenditure: (1) a forecast of the required capital expenditure that complies with the requirements of clause 6.5.7 of the *Rules* and identifies the forecast capital expenditure by reference to well accepted categories such as:	Chapters 7 and 15 Pro forma 2.2.2

Rules section	Title and requirements	Principal coverage in the proposal
	(i) asset class (eg. *distribution lines*, *substations* etc); or (ii) category driver (eg. *regulatory obligation or requirement*, replacement, *reliability*, net market benefit, business support etc), and identifies, in respect of proposed material assets: (iii) the location of the proposed asset; and (iv) the anticipated or known cost of the proposed asset; and (v) the categories of *distribution services* which are to be provided by the proposed asset;	Pro forma 2.2.3
	(2) the method used for developing the capital expenditure forecast;	Chapter 7
	(3) the forecasts of load growth relied upon to derive the capital expenditure forecasts and the method used for developing those forecasts of load growth;	Chapter 5
	(4) the key assumptions that underlie the capital expenditure forecast;	Pro forma 2.3.3
	(5) a certification of the reasonableness of the key assumptions by the directors of the *Distribution Network Service Provider*;	Attachments 23 and 24
	(6) capital expenditure for each of the past *regulatory year*s of the previous and current *regulatory control period*, and the expected capital expenditure for each of the last two *regulatory year*s of the current *regulatory control period*, categorised in the same way as for the capital expenditure forecast;	Pro forma 2.2.1
	(7) an explanation of any significant variations in the forecast capital expenditure from historical capital expenditure.	Attachment 16
S6.1.2	**Information and matters relating to operating expenditure** A *building block proposal* must contain at least the following information and matters relating to operating expenditure:	Chapters 8 and 15 Pro forma 2.2.2
	(1) a forecast of the required operating expenditure that complies with the requirements of clause 6.5.6 of the *Rules* and identifies the forecast operating expenditure by reference to well accepted categories such as: (i) particular programs; or (ii) types of operating expenditure (eg. maintenance, payroll, materials etc), and identifies in respect of each such category: (iii) to what extent that forecast expenditure is on costs that are fixed and to what extent it is on costs that are variable; and (iv) the categories of *distribution services* to which that forecast expenditure relates;	
	(2) the method used for developing the operating expenditure forecast;	Chapters 8 and 15

Rules section	Title and requirements	Principal coverage in the proposal
	(3) the forecasts of key variables relied upon to derive the operating expenditure forecast and the method used for developing those forecasts of key variables;	Chapters 8 and 15 Attachment 18
	(4) the method used for determining the cost associated with planned maintenance programs designed to improve the performance of the relevant *distribution system* for the purposes of any *service target performance incentive scheme* that is to apply to the *Distribution Network Service Provider* in respect of the relevant *regulatory control period*;	Chapter 8
	(5) the key assumptions that underlie the operating expenditure forecast;	Chapters 8 and 15
	(6) a certification of the reasonableness of the key assumptions by the directors of the *Distribution Network Service Provider*;	Attachments 23 and 24
	(7) operating expenditure for each of the past *regulatory year*s of the previous and current *regulatory control period*, and the expected operating expenditure for each of the last two *regulatory year*s of the current *regulatory control period*, categorised in the same way as for the operating expenditure forecast;	Pro forma 2.2.2
	(8) an explanation of any significant variations in the forecast operating expenditure from historical operating expenditure.	Attachment 16
S6.1.3	**Additional information and matters**	
	A *building block proposal* must contain at least the following additional information and matters:	
	(1) an identification and explanation of any significant interactions between the forecast capital expenditure and forecast operating expenditure programs;	Chapter 6
	(2) a proposed pass through clause with a proposal as to the events that should be defined as *pass through events*;	Chapter 16
	(3) a description, including relevant explanatory material, of how the *Distribution Network Service Provider* proposes the *efficiency benefit sharing scheme* should apply for the relevant *regulatory control period*;	Chapter 8
	(4) a description, including relevant explanatory material, of how the *Distribution Network Service Provider* proposes the *service target performance incentive scheme* should apply for the relevant *regulatory control period*;	Chapter 3
	(5) a description, including relevant explanatory material, of how the *Distribution Network Service Provider* proposes the *demand management incentive scheme* (if applicable) should apply for the relevant *regulatory control period*;	Chapter 6
	(6) the provider's calculation of revenues or prices for the purposes of the control mechanism proposed by the provider together with: (i) details of all amounts, values and inputs (including X factors) relevant to the calculation; and (ii) an explanation of the calculation and the amounts, values	Chapters 5, 7, 8, 9, 10, 11, 12, 13 and 15 Attachments 4, 5, 6, 7, 8, 10, 11, 12

Rules section	Title and requirements	Principal coverage in the proposal
	and inputs involved in the calculation; and (iii) a demonstration that the calculation and the amounts, values and inputs on which it is based comply with relevant requirements of the Law and the *Rules*;	
	(7) the provider's calculation of the regulatory asset base for the relevant *distribution system* for each *regulatory year* of the relevant *regulatory control period* using the *roll forward model* referred to in clause 6.5.1 of transitional Chapter 6, together with: (i) details of all amounts, values and other inputs used by the provider for that purpose; and (ii) a demonstration that any such amounts, values and other inputs comply with the relevant requirements of Part C of transitional Chapter 6; and (iii) an explanation of the calculation of the regulatory asset base for each *regulatory year* of the relevant *regulatory control period* and of the amounts, values and inputs referred to in subparagraph (i);	Chapters 9 and 15 Attachments 6 and 10
	(8) the commencement and length of the period nominated by the *Distribution Network Service Provider* for the purposes of clause 6.5.2(c)(2) of transitional Chapter 6;	Chapter 1
	(9) the provider's calculation of the proposed rate of return;	Chapters 10 and 15
	(10) the *post-tax revenue model* completed to show its application to the *Distribution Network Service Provider* and the completed *roll forward model*;	Attachments 6, 8, 10, 12
	(11) the provider's estimate of the cost of corporate income tax for each *regulatory year* of the *regulatory control period*;	Chapter 11, Attachment 7
	(12) the depreciation schedules nominated by the *Distribution Network Service Provider* for the purposes of clause 6.5.5 of transitional Chapter 6, which categorise the relevant assets for these purposes by reference to well accepted categories such as: (i) asset class (eg *distribution lines* and *substations*); or (ii) category driver (eg *regulatory obligation or requirement*, replacement, *reliability*, net market benefit, and business support), together with: (iii) details of all amounts, values and other inputs used by the provider to compile those depreciation schedules; and (iv) a demonstration that those depreciation schedules conform with the requirements set out in clause 6.5.5(b) of transitional Chapter 6; and (v) an explanation of the calculation of the amounts, values and inputs referred to in subparagraph (iii);	Chapter 12, Attachments 8 and 12.

Attachment 2—Organisational overview

Section 2.3.1 of the RIN requires that ActewAGL Distribution provide certain information regarding its organisational structure and characteristics. Most of the required information has been provided in chapters 1 and 2 of this regulatory proposal. The RIN requirements and ActewAGL Distribution's responses are summarised below.

A2.1 Ownership structure

The ownership structure of ActewAGL Distribution is illustrated in Figure 2.2 in chapter 2 of this regulatory proposal. As explained in chapter 2, following October 2006 business dealings between AGL and Alinta, ownership of ActewAGL's distribution arm was shared equally between Alinta Limited and ACTEW Corporation Limited. Further changes to the distribution partnership occurred when a consortium including Singapore Power purchased Alinta in 2007. The distribution partnership is now owned equally by Singapore Power and ACTEW Corporation.

ActewAGL Distribution notes that in addition to a description of the ownership structure of ActewAGL Distribution the AER seeks, via the RIN, information on relationships with other entities. The AER seeks the information to guide its assessment of whether expenditure forecasts are referable to arrangements with other persons that do not reflect arm's length terms. ActewAGL Distribution has provided the required information in pro forma 2.3.2. To aid the AER's consideration of the relationships with other entities, ActewAGL Distribution has also listed in the pro forma ownership links associated with the ActewAGL Distribution Partnership.

It should be noted that neither of the partners of ActewAGL Distribution can determine the partnership's financial and operating policies. Neither partner has control of the RNSP, although the partners acting together do have control. This applies in respect of legal rights, in respect of practical influence, and in respect of practice and patterns of behaviour.

A2.2 Corporate structure

An overview of the structure of ActewAGL Distribution, including an organisational chart, is provided in chapter 1.

A discussion of how each division contributes to the provision of direct control or negotiated distribution services and non-distribution services is also provided in chapter 1. ActewAGL Distribution's approved Cost Allocation Methodology also explains how each division contributes to the provision of services.

Current staffing and contractor numbers in each division of ActewAGL Distribution are provided in Table A2.1. Staff numbers were calculated using Aurion, ActewAGL Distribution's payroll system. Corporate Services staff numbers include: Finance and Resources, Legal and

Secretariat, Business Systems and Commercial Development and Office of the Chief Executive.

Table A2.1 Staff and contractor numbers as at 1 May 2008

	Staff	Contractors
Water Division	271	40
Electricity Networks	389	5
Gas Networks	1	0
Corporate Services	222	13

Water Division

Water Division expects an increase in staff and contractor numbers in the next regulatory period, mainly to manage the new Water Security Infrastructure program announced by the ACT in October 2007 and approved by the ICRC in its Final Decision in April 2008. Additional staff will also be required to address:

- The increased activity in burst and leaking water mains and reticulation valves and hydrants based on projected maintenance events.
- The additional maintenance demands of Stromlo and Googong Water Treatment Plants and the introduction of new assets from the Cotter Stromlo Augmentation.
- Greater maintenance demands and introduction of new assets in the future from the replacements and augmentation to the Lower Molonglo Water Quality Control Centre and Fyshwick Sewerage Treatment Plant.
- The replacement of senior engineers expected to retire over the next period;
- Carryover of ACTEW Directions from the current regulatory period; and
- Emerging planning and development issues.

Electricity Networks

It is expected that Electricity Networks has its full compliment of staff to complete the operating and capital expenditure programs as outlined in this regulatory proposal.

Gas Networks

Gas Networks does not expect an increase in staff numbers in the next regulatory period.

Corporate Services

Corporate Services does not expect an increase in staff numbers in the next regulatory period.

ActewAGL

A2.3 Key electricity network management systems

The key electricity network management systems used by ActewAGL Distribution are provided in Table A2.2. The key accounting system is Oracle Financials.

Table A2.2: Key network management systems

Network Management Systems Used by ActewAGL		
Zone Substations Database	NUOS Billing	On Call Roster and Audit Scheduler
Asset Damage	GIS Version Database	ENMAC DNR
Pole Inspection System - Field Application and Office System	GIS	EMaps
Oracle Purchasing	Drawing Viewer	FMaps
PDR Maintenance	AutoCAD	CAD Grab (CAD Link)
ENMAC Reporting Server	Drawing Management System	Streetlight Control Point Maps
Streetlights Database	Request for Service Management	Gentrack Replication Database (CIS)
Relay Test Instruction Database	Building Plan Approval Management	Gentrack (Cashiering)
RTI Settings	S&I Rules and Other Non-compliance Management	Meter Reading Software MVRS (BASIC meters only)
High Priority Poles	Management of Asset Location Requests	Incident Reporting System
Change of Service Pole Register	Management of Electrical Switchboard Approvals	Integrated Management System
WASP Reporting Database	S&I Rules, Metering Advice and Customer Shutdowns Management	Integrated Management System Versions Database
Spinaways	Customer Complaints Management Management	Electrical Test and Tag Management
Meter Asset Management	Meter and CT Number Asset Allocation	Test Equipment Calibration Register
Premise Management and RFS	Oracle Discoverer Reporting	Projects Register
Meter Reading Management	Strategiser	Projects Status - Spreadsheet
Meter Movement Register	Optimiser	WASP Project Management
Metering Contractor Job Register	Project and Work Pac Database	PSS Adept
Connection/Disconnection and Reactive Works Register	Timesheets Module	PSSU Protection Settings
Work Planners	Finanical Management Reporting	Line Design and Pole Strength Calculation
WASP Works and Asset Management	Finanical Management	Voltage Drop for Reticulation Design
MS Reporting Services	Finanical Management TM1	Trendmain
WASP Maps	Regulatory Obligations Management	Customer Contact and Works Dispatch
Reactive Works - Fill in Jobs	Training Register	SCADA Master Station
TUOS Reconcilliation	Training Records	Apply and Plant Databases
NEM B2M Management	Risk Register	Access Permits Register
NEM B2B Management	Construction Drawings	HV Network Schematics
Customer Transfer Management	WASP Materials Requisitions	HV and LV Network Geographics

A2.4 Non-regulated services

ActewAGL Distribution provides the following non-regulated services:

- Streetlighting;
- Training services;
- Contestable metering services;
- Miscellaneous services, including interstate disaster assistance, and sale of inventory to ActewAGL Retail.

The proportion of revenues recovered from these services as a proportion of total revenues earned by Electricity Networks is set out in Table A2.3.

Table A2.3: Proportion of revenues recovered from non-regulated services, 2006/07

Proportion of Total Revenue, 2006/07	
Standard Control	91.21%
Alternative Control	3.84%
Non-regulated	
Streetlighting	*3.93%*
Training	*0.25%*
Contestable Metering	*0.23%*
Miscellaneous	*0.54%*
Total	**100.0%**

A2.5 Customer base

As described in chapter 2 and set out in pro forma 2.3.8, ActewAGL Distribution's electricity network customers are predominantly residential. In 2006/07, 91 per cent of customers were residential, 9 per cent were low voltage non-residential customers and the remainder (22 customers) were high-voltage commercial customers.

Customer numbers have an indirect link to the demand and energy forecasts outlined in chapter 5. Residential land releases and demand growth (which both have a relationship to additional customer numbers) are, respectively, key drivers of customer initiated and augmentation capital expenditure. These relationships are further described in chapters 5 and 7.

A2.6 Environmental factors

While topographic factors are not important drivers of ActewAGL Distribution's proposed expenditure programs, other aspects of the physical environment, in particular the relatively high level of vegetation in Canberra's urban areas, are significant drivers of operating costs. These factors are described in chapters 2 and 8. The relationship between climate (and weather) and demand forecasts is described in detail in chapters 2, 5 and attachment 4. The relationships between demand and energy forecasts and cost forecasts are outlined above as well as in chapters 5 and 7.

A2.7 Network overview

Chapter 2 provides a detailed description of ActewAGL Distribution's network, and a map of the network is provided in attachment 3.

Attachment 3—Map of the Network

Provided as a separate document.

Attachment 4—SKM demand and energy forecast report

Provided as a separate document.

Attachment 5—SKM demand and energy forecast model

Provided as a separate document.

Attachment 6—Roll Forward Model (standard control)

Provided as a separate file.

Attachment 7—Tax Asset Base Roll Forward Model (standard control)

Provided as a separate file.

Attachment 8—Post Tax Revenue Model (standard control)

Provided as a separate file.

Attachment 9—Proposed negotiating framework

ActewAGL Distribution's proposed negotiating framework is provided as a separate document.

Table A9.1 provides a checklist of compliance of the proposed negotiating framework with the minimum information requirements specified in Part DA 6.7.5(c) of the transitional *Rules*.

Table A9.1: Proposed negotiating framework – compliance with transitional Rules

Clause	Requirement	Addressed in Proposed Negotiating Framework
6.7A.5(c)(1)	Requirement to negotiate in good faith.	Section 3
6.7A.5(c)(2)	DNSP must provide all commercial information that service applicant may require to engage in effective negotiation.	Section 7.1
6.7A.5(c)(3)(i)(ii)	Negotiating Framework must identify and inform service applicant as to reasonable costs incurred in providing service and must demonstrate to service applicant that charges reflect costs incurred in providing service.	Section 7.1.3
6.7A.5(c)(3)(iii)	Negotiating Framework must have appropriate arrangements for assessment and review of charges.	Section 8
6.7A.5(c)(4)	Negotiating Framework must specify a requirement for service applicant to provide all commercial information as DNSP may reasonably require to allow DNSP to engage in effective negotiation.	Section 5; Section 6
6.7A.5(c)(5)	Negotiating Framework must specify a requirement for DNSP to provide a reasonable period of time for commencing, progressing and finalising negotiations as to the price for the services.	Section 4.1, 4.2, Table 1, Section 4.5
6.7A.5(c)(5)	Negotiating Framework must specify a requirement for each party to use reasonable endeavours to adhere to specified time periods during negotiation.	Section 4.3
6.7A.5(c)(1)	Must provide that all disputes are to be dealt with in accordance with relevant provisions of the National Electricity Rules and National Electricity Law.	Section 11
6.7A.5(c)(7)	Must allow for payment by the service applicant of the DNSP's reasonable direct expenses incurred in processing application to provide the service.	Section 12
6.7A.5(c)(8)	Negotiating Framework must specify a requirement for the DNSP to determine the potential impact on other distribution network users	Section 9.1
6.7A.5(c)(7)	Negotiating Framework must specify a requirement for the DNSP to notify and consult with any affected distribution network users	Section 9.2.
6.7A.5(c)(7)	Negotiating Framework must specify a requirement for the DNSP to publish the results of negotiations on its website	Section 15

6.7A.5(d)	Negotiating Framework must not be inconsistent with any of the requirements of Rules 5.3, 5.4A and 5.5 and relevant provisions of chapter 6 and 6A	Section 2.3
6.7A.5(e)	Each DNSP and service applicant must comply with the requirements of the negotiating framework	Section 2.2

Attachment 10—Roll Forward Model (alternative control)

Provided as a separate file.

Attachment 11—Tax Asset Base Roll Forward Model (alternative control)

Provided as a separate file.

Attachment 12—Post Tax Revenue Model (alternative control)

Provided as a separate file.

Attachment 13—ICRC letter 250806 (confidential)

Provided as a separate document.

Attachment 14—ICRC letter 181006 (confidential)

Provided as a separate document.

Attachment 15—ICRC letter 280308 (confidential)

Provided as a separate document.

Attachment 16—Variance justifications

Section 2.2.4 of the RIN requires the RNSP to identify and explain significant variations between forecast and historical expenditure. The baseline for comparison is defined as the actual outcome of the third year of the current regulatory control period and the term *significant variation* as a ten per cent or greater variation between the baseline and the average forecast expenditure for the five years in the next regulatory control period. The AER has developed pro forma 2.2.4 to identify the cost items where an explanation must be provided.

This attachment provides justification for all significant variances in ActewAGL Distribution's capital and operating expenditures. Unless otherwise stated, all monetary values are in 2008/09 dollars.

Variance justifications for each applicable class of ActewAGL Distribution's capital and operating expenditures are provided below.

A16.1 Capital expenditure variance justifications

ActewAGL Distribution's relatively small distribution network and RAB value contribute to the lumpy nature of its capital expenditure requirements. A representative range of capital projects is less likely to be undertaken in any one regulatory period. ActewAGL Distribution's capital expenditure is subject to more substantive variation as large capital items require replacement at infrequent intervals. For example, ActewAGL Distribution has not installed a new zone substation since 1994, but two new zone substations and major additions to a third are required during the next regulatory period.

In addition to this local circumstance, the international resources boom has caused commodity prices to rise to historic highs. The ABS index of Non-Residential Construction Costs has increased by 25 per cent since December 2003, compared to a CPI increase of 8.3 per cent over the same period. Market price surveys conducted by SKM show that power transformer prices increased by more than 20 per cent in 2 years, aluminium cable and overhead conductor prices rose by 27 per cent, and copper cable by 46 per cent. Labour rates in the electricity industry have also outstripped growth in the CPI since 2002. Significant input price escalations are also expected to be observed in the next regulatory period, and this is a key driver of cost forecasts varying from those experienced in the current regulatory period.

Asset renewal/replacement

Table A16.1 provides ActewAGL Distribution's forecast of capital expenditure on asset renewal/replacement for the next regulatory period.

Table A16.1 Asset renewal/replacement capital expenditure 2009–14

$ ‘000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
Zone Substation	3,950	4,968	2,183	2,283	1,998	**3,076**	1,371
Distribution Substation	2,156	2,259	1,804	1,563	1,693	**1,895**	1,528
Distribution Underground	1,127	917	911	904	895	**951**	131

Zone Substation

The step increase in ActewAGL Distribution’s forecast expenditure on zone substations is due mainly to the need for replacement of 11 kV switchboards at Civic Zone Substation. The zone substation’s switch room hosts two high voltage (11 kV) switchboards each comprising 13 panels. Both switchboards have been in continuous service since 1967.

A further factor in the large variance is implementation of the zone substation fence upgrade program. This program is required to meet the National Electricity Rules capital expenditure objective to “maintain the safety and security of the distribution system through the supply of standard control services.” ActewAGL Distribution is obliged by the *Management of Electricity Network Assets Code* under the *Utilities Act 2000 (ACT)* to maintain its network in a manner that ensures the safety of persons.

Distribution Substation

The proposed expenditure on replacement/refurbishment of ground mounted substations is in line with the age profile of the substations as demonstrated by asset replacement modelling. The increasing age of these assets translates into increased volume of work due to equipment obsolescence, safety considerations or operational constraints.

Reasons (or triggers) for asset replacement fall into three main categories:

- Programmed replacement of assets known to be in a condition that results in unacceptable risks or operational constraints including possible imminent failure;
- Reactive replacement of an asset due to its failure;
- Relocation of assets.

Replacement is required to:

- Ensure compliance with regulatory obligations associated with the provision of electrical services; and
- Maintain the reliability, safety and security of the distribution system.

ActewAGL Distribution has not undertaken any significant planned equipment replacement programs in recent years. Replacements have generally been made on a reactive basis.

ActewAGL Distribution has initiated a new program of planned replacements, continuing into the next regulatory period, to address known safety, operational and age- or condition-related issues of some ground substation components.

Distribution Underground

Almost 50 per cent of ActewAGL Distribution's distribution network is an underground network. The main components of the underground network are substations, cables and pillars. The distribution substations are discussed in the section above. The reasons for the proposed increased in the expenditure related to underground main and service cables and distribution pillars are summarised in this section. More details are provided in projects justifications which form part of the Asset Management Plan, Section 8.

Generally, in the past, underground network renewal did not require attention commensurate with the high value and operational importance of these assets. However, in recent years ActewAGL Distribution has experienced a number of failures and became increasingly concerned with some underground cables, joints and terminations due either to their age or poor conditions. The modelling of future asset replacement requirements has also supported these concerns. The modelling indicated that these problems are expected to escalate in the future. Failures of the underground cables usually result in lengthy and costly repairs associated with the disruption of supply, traffic and inconvenience to businesses and consumers. Those impacts can be often mitigated if the work is done in a planned rather than reactive manner.

In addition, there is an evidence of aged communication cables (pilot cables) which are, in some locations, installed along the distribution power cables. The reliability of the communication cables is crucial to operation of electrical protection schemes.

Furthermore, some of the categories of existing distribution pillars installed in ActewAGL Distribution's network do not have capacity to accommodate additional or upgrade services. Such upgrades became a frequent requirement due to urban infill development and escalating use of larger air-conditioning units.

Therefore, the proposed increase in expenditure over the next regulatory period is related to:

- replacement of cables (main and service), joints and terminations in high risk locations;
- replacement of pillars to increase the capacity to accommodate additional load; and
- replacement of deteriorated communication (pilot) cables.

Customer initiated

Table A16.2 provides ActewAGL Distribution's forecast of customer-initiated capital expenditure for the next regulatory period.

Table A16.2 Customer initiated capital expenditure 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
New Urban Development	6,311	6,804	6,258	4,746	3,818	**5,587**	2,916
Community and Associated Development	2,186	5,254	5,490	623	516	**2,814**	14
Customer Initiated Replacement	157	157	156	155	154	**156**	4
Services	2,035	1,928	1,812	1,952	1,832	**1,912**	1,645

New Urban Development

The main reason for the step increase in this category is a significant increase in ACT Government residential land development programs and a policy change to allow limited private sector greenfield residential land developments. Anticipated housing demand for the next three years is 2,185 to 2,385 dwellings per year, declining to 1,500 per year from 2011 to 2014.

Community and Associated Development

This is a new category of capital expenditure. Projects in this category were previously included under Special customer request and Commercial development. The key driver of expenditure is the continuing drought in the ACT which has resulted in the emergence of several major water security initiatives. Supply upgrades will be required to cater for these projects.

Customer Initiated Replacement

This is a new category of capital expenditure and this expenditure was previously included under the Special customer request category.

Services

Expenditure on new services is closely related to expenditure on new urban development. The justification for the step increase in expenditure in this category therefore mirrors that provided above for *New urban development*.

Augmentation

Table A16.3 provides ActewAGL Distribution's forecast of augmentation capital expenditure for the next regulatory period by infrastructure type.

Table A16.3 Augmentation capital expenditure 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
Sub-transmission	14,187	0	3,917	4,394	0	**4,500**	254
Distribution System	2,610	2,785	2,642	3,616	2,701	**2,871**	836
Zone Substations	13,097	11,857	7,350	7,361	0	**7,933**	0

Sub-transmission

Increased expenditure in this category is due to the two stages of the construction of feeders from the new Southern Bulk Supply Point and their connection to the ActewAGL Distribution network.

Distribution System

Major network augmentation feeder projects are needed to strengthen the network. The distribution augmentation feeder projects are required to rectify the HV network capacity shortage, and to achieve inter-zone substation load transfer so that the anticipated zone substation overload can be rectified.

Zone Substation

The main reason for the step increase is the growth cycle of new urban development. Augmentation capital expenditure has been low for more than a decade, with the last significant augmentation investment being the Gold Creek Zone Substation built in 1994. The forecast increase is due to construction of two new zone substations at Molonglo and Eastlake, and installation of a third transformer at Civic Zone Substation. This expenditure is required to meet forecast demand growth in Canberra.

Reliability and quality improvements

Table A16.4 provides ActewAGL Distribution's forecast capital expenditure on reliability and quality improvement for the next regulatory period.

Table A16.4 Reliability and quality improvement capital expenditure 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
Distribution System	104	261	311	257	254	**237**	127
Zone Substations	128	131	89	0	0	**70**	7

Distribution System

The reliability and quality improvement capital expenditure includes expenditure relating to:

- Mundaring Feeder Voltage regulator for Majura load; and
- Rural area voltage improvement.

The reliability and quality improvement program will improve the long term performance of the network and assist ActewAGL Distribution in complying with regulatory obligations.

Zone Substations

The reliability and quality improvement capital expenditure includes expenditure on under-frequency relays. The under-frequency relays are needed to comply with NEMMCO's security requirement for automatic load shedding. The program has been established after NEMMCO's review of automatic load shedding requirements in 2006.

Network IT Systems and communications

Table A16.5 provides ActewAGL Distribution's forecast capital expenditure on network systems and communications in the next regulatory period.

Table A 16.5 Network systems and communications capital expenditure 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
Network IT	4,260	4,137	3,531	3,547	5,056	**4,106**	810

The step increase in expenditure is due to necessary new investments and replacements in the Network IT Systems as follows:

- Replacement of protection intertrip and SCADA communications pilot cables at an estimated cost of $1.9 million over 2009-14 due to decline in their electrical characteristics as some cable pairs no longer meet defined criteria for protection circuit operation. This has caused unplanned outages. Some pilot cables have been *in situ* for 40 years;
- IT system replacements undertaken according to normal practice at 7 to 10 years intervals. The cost of IT system replacement will be $7.2 million during the 2009/10-2013/14 regulatory period;
- Zone substation Remote Test Unit (RTU) replacement due to failure of some units. The oldest RTUs have been in service for over 20 years and, as a consequence, replacement parts are no longer available through the manufacturer; and
- Three network automation programs that will reduce the duration of unplanned customer outages:
    - Enhancement of HV switchgear to allow remote operation;
    - Upgrade of key distribution substations to remote operability; and

- Enhancement of the fault passage indicator monitoring to improve fault location through the installation of Fault Passage Indicators (FPI) linked to the SCADA system.

Capital Contributions

Table A16.6 provides ActewAGL Distribution's forecast of customer contributions for the next regulatory period.

Table A16.6 Customer contributions 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
Customer Contributions	4,652	7,017	6,528	3,299	2,887	**4,877**	3,113

Customer Contributions are payable on relatively constant proportions of each category of customer initiated works. The increase in this category is therefore consistent with the expect rise in costs for customer-initiated capital expenditure explained in section 16.6.2 above.

Non-system Assets

Table A16.7 provides ActewAGL Distribution's forecast of non-system asset capital expenditure for the next regulatory period.

Table A16.7 Non-system assets capital expenditure 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
Other non-system assets	514	514	514	514	514	**514**	412
Share of corporate assets	7,436	1,461	1,570	1,392	1,470	**2,666**	801

Other non-system assets

Expenditure on non-system assets has ranged from $0.4 million to $0.6 million over the last ten years and was $0.412 million in the base year, the lowest expenditure of the current regulatory period. The forecast makes provision for ongoing expenditures of a similar magnitude and will allow for the acquisition of equipment that complies with the Occupational Health and Safety standards.

Share of corporate assets

The forecast incorporates capital expenditure for existing properties and the relocation of ActewAGL Distribution Corporate Headquarters to 6 Mort Street, Canberra City. Due to the relocation there will be a considerable increase in capital expenditure in both Facilities Management and Business Systems and Commercial Development areas in 2009/10 but, thereafter, overall operating expenditure will decrease. The sale of the current ActewAGL

House will lead to a reduction in the total value of corporate assets, resulting in a net decrease in the RAB.

Alternative Control Services

Table A16.8 provides ActewAGL Distribution's forecast of capital expenditure on alternative control services for the next regulatory period.

Table A16.8 Alternative Control Services capital expenditure 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
New Meter Installations	2,083	2,022	2,006	2,155	2,016	**2,056**	1,783
Meters Replacements	3,766	1,153	1,176	1,197	1,216	**1,702**	211

New meter installations

Expenditure on new meters has a close correlation to expenditure on new urban development. The factors referred to in section 16.6.2 above are therefore relevant to justification of the variation from the base year.

Meter replacements

The 2007/08 ActewAGL Distribution Meter Asset Management Plan (MAMP) was found to be in accordance with the National Electricity Rules and subsequently approved by NEMMCO. The MAMP details a significant expansion by ActewAGL Distribution of both its meter testing and replacement programs. It includes the costs associated with the Domestic Meter Replacement Program involving the replacement of 3,600 meters annually. Expenditure on this program is forecast to be approximately $1.2 million per annum since its effective start in 2007/08.

The forecast increase in meter replacement capital expenditure in 2009/10 results from a project to trial the benefits of multi-utility metering technology. In its April 2008 Final Decision on prices for water and wastewater service supplied by ACTEW Corporation in the ACT, the ICRC allowed expenditure of $2.8 million ($2006/07) in 2008/09 for the water component of a multi-utility smart metering trial. The ICRC assumed the allocation of costs for the trial on the basis of 40 per cent for electricity, 40 per cent for water, and 20 per cent for gas.

ActewAGL Distribution has included the recovery of $2.8 million in expenditures for the electricity portion of the multi-utility smart metering trial. The ICRC allowance for ACTEW Corporation comprised $2.4 million ($2006/07) in capital expenditure and $0.4 million ($2006/07) in operating expenditure. Consistent with this treatment, ActewAGL Distribution included $2.4 million ($2006/07) in meter replacement capital expenditure and $0.4 million ($2006/07) in operating expenditure for the electricity portion of the project.

A16.2 Operating expenditure variance justifications

Network operations expenditures

Table A16.9 provides ActewAGL Distribution's forecast of operating expenditure on network operations for the next regulatory period.

Table A16.9 Network operations expenditures 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
Network Control	3,756	3,889	3,999	4,116	4,224	**3,997**	3,466
IT Planning and Operations	811	883	901	919	935	**890**	770
Network Systems Operations	2,965	3,053	3,127	3,197	3,263	**3,121**	2,673
Quality, Environmental and Safety Systems	1,273	1,305	1,331	1,357	1,381	**1,329**	975
Executive & Financial Management	1,763	1,836	1,901	1,960	2,016	**1,895**	1,291
Other Network Operating Costs	2,857	2,955	3,038	3,844	3,939	**3,327**	2,645

Network control

Payroll related costs account for 85 per cent of expenditure in this category and the driver for the increased network control expenditure is wage increases in line with market movements. Further details can be found in chapter 8.

IT Planning and Operations

Payroll related costs account for 55 per cent of expenditure in this category and the driver for the increased IT planning and operations operating expenditure is wage increases in line with market movements.

Forecast expenditure also allows for the development of systems and processes required to implement the National Service Target Performance Incentive Scheme (STPIS).

Network Systems Operations

Payroll related costs account for 65 per cent of expenditure in this category and the driver for the increased network systems operating expenditure is wage increases in line with market movements. Further details about wage escalation can be found in chapter 8.

The forecasts also allow for additional costs associated with new obligations under the *Planning and Development Act 2007* (ACT) in respect of:

- The limited timeframe within which to consider development applications;
- The expected increase in the number of applications to be considered as a result of consultation with ActewAGL Distribution being mandated in the Act;
- The development of an on-line application process and automated database of assets to assist the consideration of applications within the allotted timeframe; and
- The costs which may be incurred if advice provided by ActewAGL Distribution is inaccurate, incomplete or late and leads to the need to relocate assets or address difficult access issues.

ActewAGL Distribution estimates that the revised approval process under the *Planning and Development Act* will require additional staff at an annual cost of $107,000 in 2008/09. ActewAGL Distribution will also incur upfront costs for the establishment of the on-line application process and asset database in the order of $25 000 with ongoing database management costs of $15 000 per annum. It should be noted that the costs associated with the database are to be shared between ActewAGL Distribution's water and electricity networks businesses, and hence are significantly less than stand-alone costs. Each business will carry the respective risks and associated costs that may arise from providing, inaccurate, incomplete or late advice.

Quality, Environmental and Safety Systems

Payroll related costs account for 55 per cent of expenditure in this category and the driver for the increased quality, environmental and safety systems operating expenditure is wage increases in line with market movements.

The forecasts also include provision for the increased level of safety and environmental training necessary to comply with Occupational Health, Safety and Environment obligations. Further details can be found in chapter 4.

Executive and Financial Management

The driver for the increased executive and financial management operating expenditure is wage increases in line with market movements. Payroll related costs account for 95 per cent of this expenditure category and are anticipated to increase beyond the 10 per cent baseline variation in the next regulatory period (see Table 8.4). The forecasts include allowance for annual increases in executive remuneration.

Other Network Operating Costs

Payroll related costs account for 85 per cent of expenditure in this category and the driver for the increased other network operating costs is wage increases in line with market movements.

The forecasts also include provision for expenditure in 2012/13 and 2013/14 for the next regulatory price review process. Such costs have previously been treated as capital expenditure.

Network Maintenance Expenditures

Table A16.10 provides ActewAGL Distribution's forecast of operating expenditure on network maintenance for the next regulatory period.

Table A16.10 Network maintenance expenditures 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
Zone Substation Planned	1,977	2,074	2,074	2,216	2,062	**2,081**	1,490
Zone Substation Reactive	165	170	174	178	182	**174**	155
Sub-transmission Planned	556	459	348	241	243	**369**	148
Sub-transmission Reactive	23	23	24	24	25	**24**	4
Underground Dist Planned	344	353	361	368	375	**360**	31
Overhead Dist Planned	8,106	8,022	7,903	8,018	7,455	**7,901**	6,154
Overhead Dist Reactive	2,120	2,174	2,221	2,265	2,307	**2,218**	1,986
Dist Substation Planned	2,047	2,092	2,131	2,168	2,061	**2,100**	640
Dist Substation Reactive	217	222	226	230	234	**226**	177

Zone Substations Planned

Forecasts have been calculated using the *zero base* bottom-up approach. Payroll related costs account for 57 per cent of expenditure in this category and is an important driver for the increased zone substation planned maintenance costs.

In addition to ongoing maintenance, zone substation planned maintenance will increase throughout the next regulatory period due to:

- Painting - it is intended to repaint major elements of the buildings, outdoor timber and metal structures of three zone substations each year. Painting was last done about 6 years ago and has been done on a when needed basis;
- Remedial actions such as labelling or sealing - assessment reports will identify areas of concern;
- Pumping out and inspection of oil interceptor tanks by a sullage contractor – ActewAGL Distribution will commence the first round of inspections in its leak inspection cycle.
- Expanded generator test run, thermo vision program, and earth stick testing.

Zone Substations Reactive

Payroll related costs account for 95 per cent of expenditure in this category and the driver for the increased zone substation reactive operating expenditure is wage increases in line with market movements.

Sub-transmission Planned

Forecasts have been calculated using the *zero base* bottom-up approach. Regrowth in some fire affected pine forest areas has been significant since 2003. Forecasts provide funds to remove the regrowth pines inside easements while they are still able to be handled from the ground.

Fence, earthing and gate maintenance is also required as is ongoing access track maintenance. Sub-transmission towers have now reached an age of 30 years necessitating inspection and planned maintenance. Until recently only sub-transmission poles have received inspection or planned maintenance. Current inspections show elements including conductor clamps, insulators, spiral vibration and dog bone dampers need repair or replacement. Mid-span spacers will require helicopter access or access by chair at some point to tighten or replace. Additional cyclic maintenance costs have been included to facilitate this work. Bird diverters and anti-bird nesting devices will be trialled to prevent nesting close to conductors.

Sub-transmission Reactive

Payroll related costs account for 80 per cent of expenditure in this category and the driver for the increased sub-transmission reactive operating expenditure is wage increases in line with market movements.

Underground Distribution Planned

Forecasts have been calculated using the *zero base* bottom-up approach.

In July 2007, the ACT Technical Regulator undertook an audit of various ground-mounted distribution assets (substations and distribution pillars). Having given consideration to the outcomes of this audit, ActewAGL Distribution has acknowledged that the former reactive approach is no longer acceptable due to asset ageing and deterioration. ActewAGL Distribution has sought to develop a condition monitoring approach based around a 5-yearly inspection and maintenance cycle which will enable it to more effectively discharge its obligations under the *Management of Electricity Network Assets Code*.

This will result in a step increase in planned maintenance costs in 2008/09 and 2009/10.

Overhead Distribution Planned

Forecasts have been calculated using the *zero base* bottom-up approach. Payroll related costs account for 44 per cent of expenditure in this category.

Forecasts for overhead planned maintenance have increased throughout the next regulatory period due to costs associated with:

- Replacement of rusted black king bolts—the older pole top construction utilised black steel (non-galvanised) kingbolts. Over 4 900 bolts in need of replacement have been identified to date. Other structural components secured by these black bolts may also require maintenance or replacement;
- Increased maintenance to realign and readjust air break switches and HV links for correct operation;
- The replacement of hand ties with preformed distribution ties and spiral vibration dampers to prevent broken ties and dislodgement of conductors on rural poles in bushfire prone areas;
- Inspection, testing and maintenance of substation earths. This maintenance has not been undertaken before as previous random testing had not shown a necessity to undertake a more rigid earth testing regime. Due to the prolonged drought it appears that earthing resistivity has increased as recent random testing (substation upgrades, transformer failures etc) of earthing systems has indicated. An increase in surveillance is a prudent method of monitoring the situation.
- Low voltage cast iron *pot head* connections are failing and will require replacement with XLPE cable.

Overhead Distribution Reactive

Payroll related costs account for 82 per cent of expenditure in this category and the driver for the increased overhead distribution reactive operating expenditure is wage increases in line with market movements. Further details about wage escalation can be found in chapter 8.

Distribution Substation Planned

Forecasts have been calculated using the *zero base* bottom-up approach.

As with underground distribution planned operating expenditure, ActewAGL Distribution has responded to the Technical Regulator's audit report by implementing a condition monitoring approach based around a 5-yearly inspection and maintenance cycle to better enable ActewAGL Distribution to discharge its obligations under the *Management of Electricity Network Assets Code*. This will result in a step increase in planned maintenance costs in 2008/09 and a continuing higher level of annual costs throughout the next regulatory period.

Distribution Substation Reactive

Payroll related costs account for 82 per cent of expenditure in this category and the driver for the increased distribution substation reactive operating expenditure is wage increases in line with market movements. Further details about wage escalation can be found in chapter 8.

Other Expenditures

Table A16.11 provides ActewAGL Distribution's forecast of other operating expenditures for the next regulatory period.

Table A16.11 Other operating expenditures 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
Corporate Management Fee	10,774	10,978	11,531	11,751	11,988	**11,405**	9,962
Apprentice Training Program	5,010	5,158	5,284	5,405	5,520	**5,275**	3,910
Costs of Services in Connection with Regulated Miscellaneous Charges	1,251	1,287	1,318	1,347	1,375	**1,316**	1,176

Corporate Management Fee

In 2009/10, ActewAGL will relocate its Corporate Headquarters. Operating expenditures from 2009/10 will increase as the current corporate headquarters is owned by ActewAGL but the new building will be leased. Beyond this, the change in the corporate management fee is mainly due to wage increases in line with the market, and as described further in chapter 8.

Apprentice Training Program

All expenditure in this category is payroll related and forecast to increase in real terms above the 10 per cent variation threshold.

The forecasts provide for the increased number of apprentices, trainees and cadets being trained since the 2006/07 base year and the increased costs from their progression up the pay scales.

Costs of Services in Connection with Regulated Miscellaneous Charges

The driver for the increased network control expenditure is wage increases in line with market movements. Payroll related costs account for 65 per cent of this expenditure category and are anticipated to increase beyond the 10 per cent baseline variation in the next regulatory period (see Table 8.4).

The Utilities Network Facilities Tax

Table A16.12 provides ActewAGL Distribution's forecast of its liability under the ACT's Utilities Network Facilities Tax (UNFT).

Table A16.12 UNFT liability 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
UNFT expenditures	3,975	4,073	4,170	4,269	4,375	**4,172**	2,536

The ACT Government introduced the UNFT in 2006 during the current 2004-09 regulatory period. ActewAGL Distribution sought and was granted a cost pass-through for the cost of the tax under the tax change event provision of ICRC's 2004 Final Decision.[166]

For the 2009/10-2013/14 regulatory period, ActewAGL Distribution has included in its operating expenditure forecasts an estimate of the UNFT payable to the ACT Government. The inclusion of this tax results in a step increase of $4 million in operating expenditure in 2009/10.

Vegetation control maintenance

Table A16.13 provides ActewAGL Distribution's forecast of its vegetation control maintenance.

Table A16.13 Vegetation control maintenance expenditure 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
Vegetation control maintenance expenditure	2,987	2,923	2,678	2,708	2,737	**2,807**	2,000

Forecasts have been calculated using the *zero base* bottom-up approach. Payroll related costs account for 33 per cent of expenditure in this category.

Since the 2003 Canberra Bushfires, dedicated access tracks to distribution lines in the National Parks and rural areas have suffered significantly from erosion and in many places have become unusable. They require major repair in some areas to permit vegetation inspection and clearing. These tracks are also used for line patrols, inspections and pole replacement. An increase in maintenance expenditure is required to restore the tracks to a usable condition. The fires also killed many substantial trees immediately outside the line easements. The distribution lines are in danger from these trees which could fall across them. Dead trees cannot be accessed for removal by climbing and can only be trimmed from an Elevated Work Platform (EWP) or the more expensive option of being felled (where approval has been granted) after the line has been isolated and temporarily removed. They must also be carted away owing to fuel hazard from dead timber.

At present, tree related problems are the major single cause of customer outages. Increased effort in vegetation control is expected to decrease the incidence of tree related outages.

[166] The 2004 decision was amended by ICRC 2007, *Final Decision Electricity Distribution Services: Proposed Amendment to the 2004 Pricing Direction* to include a specific provision for ACT taxes.

Without access to trim or clear these trees there is a very significant risk of the trees collapsing across the HV network necessitating their removal in emergency conditions.

Due to this background ActewAGL Distribution is stepping up the vegetation maintenance expenditure at the end of the current regulatory period (2007/08 and 2008/09), which is the main reason why the cost in the next regulatory period will be higher. As the vegetation maintenance starts to have an impact ActewAGL Distribution expects the costs to decrease.

Alternative Control Services

Alternative Control Services other expenditures

Table A16.14 provides ActewAGL Distribution's forecast of its alternative control services operating expenditure.

Table A16.14 Alternative Control Services Other expenditures 2009–14

$ '000 (2008/09)	2009/10	2010/11	2011/12	2012/13	2013/14	Average	2006/07 Baseline
Other Expenditures	433	0	0	0	0	**87**	0

Other expenditures is a new category of operating expenditure for alternative control services.

The addition of 'other expenditure' in 2009/10 results from a project to trial the benefits multi-utility metering technology. ActewAGL Distribution proposes that, consistent with the ICRC's Final Decision for ACTEW Corporation, the AER allow the recovery $2.8 million in expenditures for the electricity portion of the multi-utility smart metering trial. The ICRC allowance for ACTEW Corporation comprised $2.4 million ($2006/07) in capital expenditure and $0.4 million ($2006/07) in operating expenditure. Consistent with this treatment, ActewAGL Distribution proposes that the AER approve $0.4 million ($2006/07) in operating expenditure for the electricity portion of the project.

Attachment 17—Unit rates (confidential)

Provided as a separate document.

Attachment 18—SKM cost escalation report

Provided as a separate document.

Attachment 19—PwC audit report

Provided as a separate document.

Attachment 20—SAHA self-insurance report (confidential)

Provided as a separate document.

Attachment 21—Policies, strategies, plans (certain documents marked as confidential)

Provided in a separate folder.

Attachment 22—AER letter 170308 (confidential)

Provided as a separate document.

Attachment 23—Confidential information

Provided as a separate document.

Attachment 24—Statutory declaration

Provided as a separate document.

Attachment 25—Certification statements

Provided as a separate document.

Attachment 26—Abbreviations

ABN	Australian Business Number
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
ACTPLA	Australian Capital Territory Planning and Land Authority
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AGL	Australian Gas Light Company
AMP	Asset Management Plan
ARPANSA	Australian Radiation Protection and Nuclear Safety Agency
ASIO	Australian Security Intelligence Organisation
ATO	Australian Tax Office
AWOTE	Average Weekly Ordinary Time Earning
B2B	Business to Business
bp	Basis Point
BRW	Burns and Roe Worley Pty Ltd
CAIDI	Customer Average Interruption Duration Index
capex	capital expenditure
CBA	Cost Benefit Analysis
CBD	Central Business District
CCA	Creosote and Tanalith
CDD	Cooling Degree Day
CEG	Competition Economists Group
CEO	Chief Executive Officer
CGS	Commonwealth Government Security
COAG	Council of Australian Governments
CPI	Consumer Price Index
CT	Current Transformer
Cwth	Commonwealth
DNSP	Distribution Network Service Provider
DOFA	Department of Finance and Administration
DRC	Depreciated Replacement Cost
DRP	Debt Risk Premium
DUOS	Distribution Use of System

EBA	Enterprise Bargaining Agreement
EBSS	Efficiency Benefit Sharing Scheme
EHV	Extra High Voltage
EMF	Electric and Magnetic Field
ENA	Energy Networks Association
esaa	Energy Supply Association of Australia
ESAA	Electricity Supply Association of Australia
ESC	Essential Services Commission of Victoria
EST	Eastern Standard Time
ETC	Estimated Tax Cost
ETI	Estimated Taxable Income
FPSC	Fixed Price Service Charge
GIS	Geographic Information System
GSL	Guaranteed Service Level
GWh	Gigawatt Hour
HDD	Heating Degree Days
HSE	Health, Safety and Environment
HV	High-Voltage
ICRC	Independent Competition and Regulatory Commission
IGP	International Good Practice
ILUA	Indigenous Land Use Agreement
IT	Information Technology
km	Kilometre
kV	Kilovolt
kVA	Kilovolt ampere
kWh	Killowatt hour
LV	Low-Voltage
m	Million
MAMP	Metering Asset Management Plan
MAR	Maximum Average Revenue
MCE	Ministerial Council on Energy
MD	Maximum Demand
MMA	McLennan Magasanik Associates
MRP	Market Risk Premium
MVA	Megavolt ampere
MW	Megawatt
NCA	National Capital Authority

NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
NERA	NERA Economic Consulting
NPV	Net Present Value
NSP	Network Service Provider
NSW	New South Wales
NTER	National Tax Equivalent Tax Regime
NUOS	Network Use of System
OHS	Occupational Health and Safety
opex	operating expenditure
pa	per annum
PCBs	polychlorinated biphenyls
PoE	Probability of Exceedance
PTRM	Post-Tax Revenue Model
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RC	Replacement Cost
RFM	Roll Forward Model
RIN	Regulatory Information Notice
RNSP	Regulated Network Service Provider
RTU	Remote Terminal Unit
SAHA	SAHA International
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCO	Standing Committee of Officials
SFD	State Final Demand
SKM	Sinclair Knight Merz
STPIS	Service Target Performance Incentive Scheme
TAB	Tax Asset Base
TAMS	Department of Territory and Municipal Services
TMR	Trunk Mobile Radio
TNSP	Transmission Network Service Provider
TOU	Time-Of-Use
TUOS	Transmission Use of System

UMA	Utilities Management Agreement
UNFT	Utilities Network Facilities Tax
WACC	Weighted Average Cost of Capital
WTP	Willingness to Pay

Attachment 27—RIN pro formas

Provided as a separate file.