Regulatory Proposal

2015–19 Subsequent regulatory control period

Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory

2 June 2014 (resubmitted 10 July 2014)

Contents

Overview

ActewAGL Distribution owns, operates and maintains the network of poles, wires, transformers and other equipment used to distribute electricity safely and reliably to more than 177,000 homes and businesses in the ACT.

Since its formation in October 2000, ActewAGL Distribution has consistently provided the most reliable electricity distribution services and levied the cheapest electricity distribution charges in Australia. Nevertheless, it requires significant investment and ongoing funding to continue to meet customer expectations as well as its regulatory obligations. Its distribution network charges currently make up around 30 per cent [1] of a typical ACT customer's electricity bill.

ActewAGL Distribution recently developed a regulatory proposal that, when approved by the Australian Energy Regulator, will establish its revenue allowance for the period 1 July 2014 to 30 June 2019 (the 2014–19 regulatory period). As part of this process, it engaged with customers to help inform the key components of its proposal, including its safety and service standards, expenditure programs, revenue requirements and prices for this period.

Box 1 How ActewAGL Distribution's regulatory proposal is in the long term interests of consumers

ActewAGL Distribution believes its regulatory proposal is in the long-term interests of consumers because:

- the proposed revenue requirement reflects an efficient and prudent level of capital and operating expenditure, underpinned by robust long-term planning and asset management
- safety will remain ActewAGL Distribution's number one priority, and its current high service standards will be maintained, in line with what customers have said they value and are willing to pay for
- ActewAGL Distribution will continue to provide the cheapest and most reliable electricity distribution services in the country, as well as a choice of flexible tariff options
- the proposal meets all requirements set out in the National Electricity Law and the National Electricity Rules.

The sections below provide an overview of the regulatory proposal for ActewAGL Distribution's customers and their representatives, focusing on what it means for customers. They:

[1] Combined network charges (distribution, jurisdictional schemes and transmission) make up around 45 per cent of a typical ACT customer's electricity bill.

- provide brief background information on the price review process
- explain the distribution network services and charges covered by the regulatory proposal
- outline how prices, safety and service standards change under the proposal
- explain the proposed operating and capital expenditure programs and their benefits for customers
- discuss the proposed total revenue requirement, and
- describe the consumer engagement that informed the development of the proposal.

Background to the review process

Like all electricity distribution network service providers in Australia, ActewAGL Distribution is a regulated business. It must comply with the National Electricity Rules (NER) and the National Electricity Law (NEL), including the National Electricity Objective (see Box 2). It must also set its distribution charges in line with the Australian Energy Regulator's (AER's) determinations.

The AER makes these determinations roughly every five years, after an extensive review process. As part of this process, ActewAGL Distribution submits a regulatory proposal, which details its proposed expenditure programs for the coming regulatory period and the total revenue it requires to fund this expenditure.

The AER reviews this proposal to check that it complies with the NER and NEL. Essentially, it checks that ActewAGL Distribution needs to spend what it proposes to spend, that this expenditure reflects what an efficient distribution service provider would spend to deliver the same quality services, and that the proposal is in the long-term interests of customers. It then makes a determination that establishes ActewAGL Distribution's revenue allowance for the regulatory period.

The AER's current determination on ActewAGL Distribution will expire on 30 June 2014. However, due to changes to the NER, the AER's price review and determination for next regulatory period—1 July 2014 to 30 June 2019—has been deferred for a year. In the interim, ActewAGL Distribution submitted a transitional proposal for the first year of the period (2014/15). The AER released a transitional decision (including a 'placeholder' revenue allowance) for this year.

The regulatory proposal discussed in this document covers the full 2014–19 regulatory period, including any adjustments necessary due to differences between the AER's transitional decision and ActewAGL Distribution's final proposal for 2014/15.

Box 2 The National Electricity Objective

The National Electricity Objective, set out in the NEL, is to:

"promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system"

What distribution network charges are covered in this proposal?

ActewAGL Distribution's distribution network charges must recover the costs of funding its significant capital investments in building the ACT electricity distribution network and replacing or renewing ageing assets, as well as the costs of operating and maintaining the network. They include charges for the following services:[2]

- access to and use of the electricity distribution network
- the provision of metering equipment, meter reading and data forwarding, and
- miscellaneous services as required by the customer (such as disconnection and reconnection services).

A portion of the costs of ActewAGL Distribution's high voltage lines and exit and entry services (which operate parallel to and provide support services for TransGrid's transmission network), is recovered through a separate transmission network charge.[3] The costs associated with these "dual function assets" are shared between ActewAGL Distribution's ACT customers and TransGrid's NSW customers.[4] They represent around 15 per cent of ActewAGL Distribution's total costs.

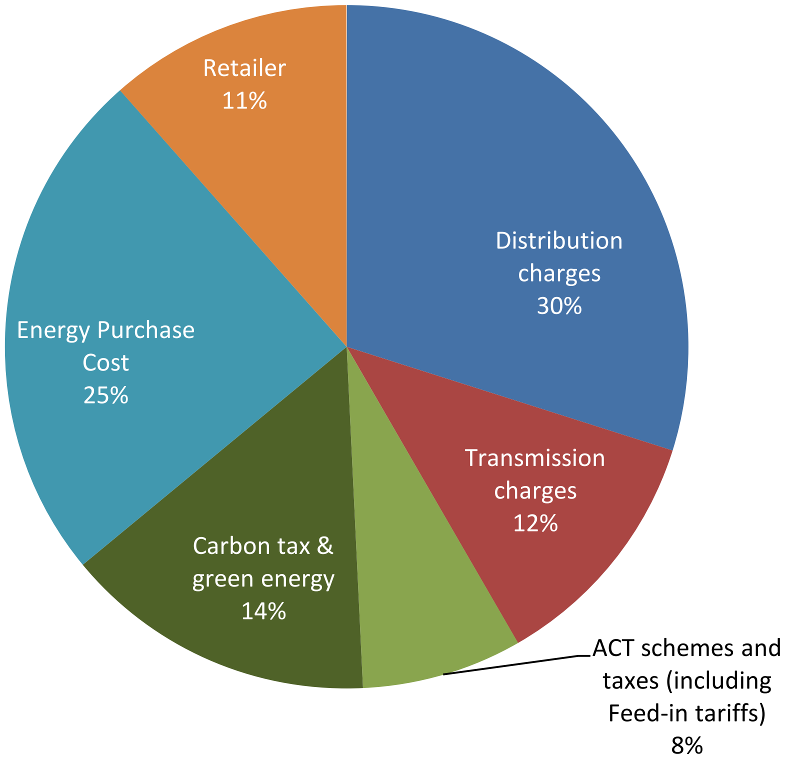
Customers may not see ActewAGL Distribution's network charges itemised on their electricity bills, as retailers incorporate these charges in their end prices and charges, along with the other costs of producing and supplying electricity. As Figure 0.1 below shows, these distribution network charges typically make up approximately 30 per cent of an ACT customer's total electricity retail bill.

[2] These services are classified by the AER as 'standard control services' and 'alternative control services'.

[3] TransGrid owns the electricity transmission network in NSW.

[4] These services are classified by the AER as transmission services.

Figure 0.1 Estimated components of an ACT electricity retail bill[5]



Prices, safety and service standards under the proposal

Under ActewAGL Distribution's regulatory proposal, the annual retail bill for a residential customer using 5,000 kWh will increase by an average of 3.1 per cent in each of the four years of the 2015-19 regulatory period. The annual bill for a commercial customer using 20 MWh will increase by 3.5 per cent on average each year.[6]

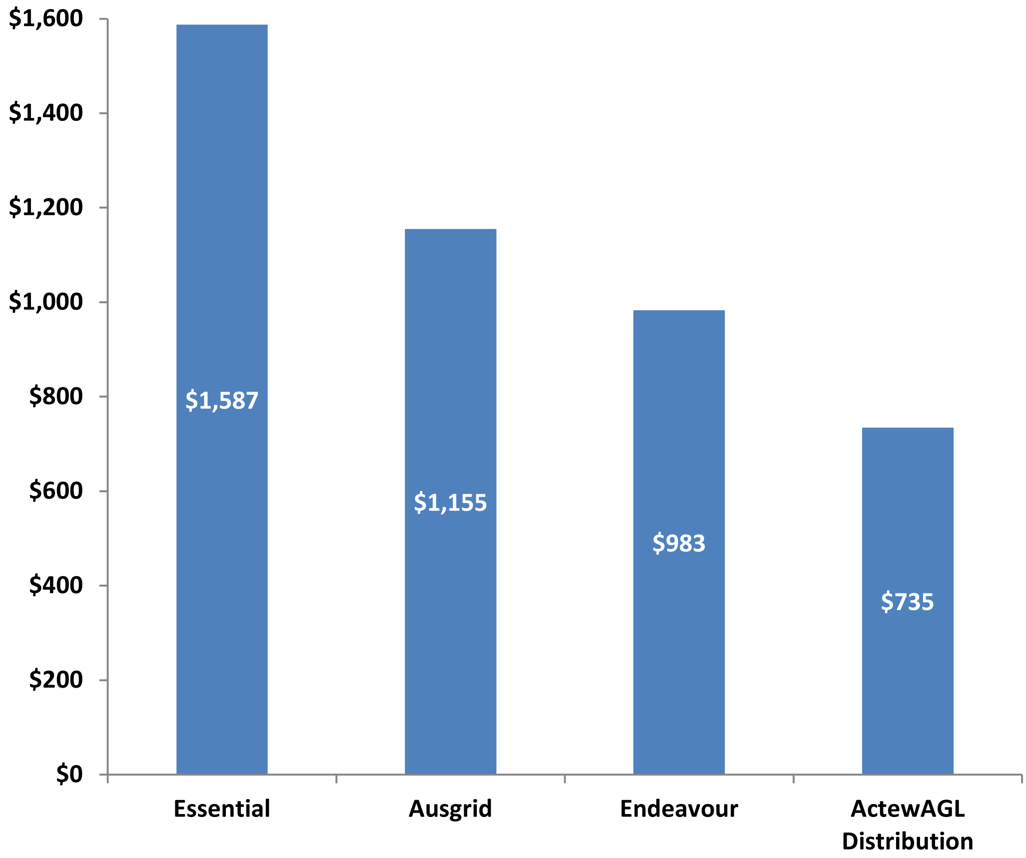
[5] The retailer component is based on the estimated regulated Transitional Franchise Tariff (TFT) for 2014/15 from the ICRC's Draft Decision of 14 February 2014, with the network component updated for this proposal and energy loss factors updated for Australian Energy Market Operator published data. The Energy Purchase Cost (EPC) is based on the EPC derived by the ACT Independent Competition and Regulatory Commission for 2014/15.

[6] These bill impacts assume the carbon tax is repealed and is no longer included in energy prices from 1 July 2014.

Even with the proposed price increase, ActewAGL Distribution will continue to provide the cheapest distribution network services in Australia. Also, it will continue to provide the most reliable distribution services in the country.

Figure 0.2 below compares the network charges to be paid by a typical ACT residential customer in 2014/15 against the estimated network charges paid by NSW customers.[7]

Figure 0.2 Comparison of Residential network charges in the ACT and NSW[8]



Importantly, ActewAGL Distribution's proposed prices and reliability standards are consistent with its ACT customers' preferred balance between cost and reliability, as identified in several major willingness-to-pay studies. For example, in 2003 a survey of all ActewAGL's customer groups found that all groups preferred to maintain the current reliability standards over

[7] There are three distribution network service providers in NSW – Essential Energy, Ausgrid and Endeavour Energy.

[8] For a typical residential customer using 7,000 kWh per year, including GST

accepting lower standards at the corresponding lower price.[9] In 2012, a further survey confirmed that residential customers' willingness to pay has remained relatively constant in real terms since 2003.[10]

Because of the focus ActewAGL Distribution has placed on maintaining current reliability levels, ensuring public safety and maximising the value to consumers from proposed expenditure programs, ActewAGL Distribution considers this proposal minimises any risks to consumers. Likely benefits to consumers from this proposal are listed in the following sections.

The proposed operating and capital expenditure programs

Like most business, ActewAGL Distribution incurs two broad types of costs in providing its services—operating expenditure and capital expenditure. In the 2014–19 regulatory period, it expects that its average annual operating expenditure will remain about the same as in the 2009–14 period, while its average annual capital expenditure will increase marginally. The proposed expenditure programs are efficient, prudent and reflect the long-term interests of customers.

Operating expenditure forecast to remain about the same

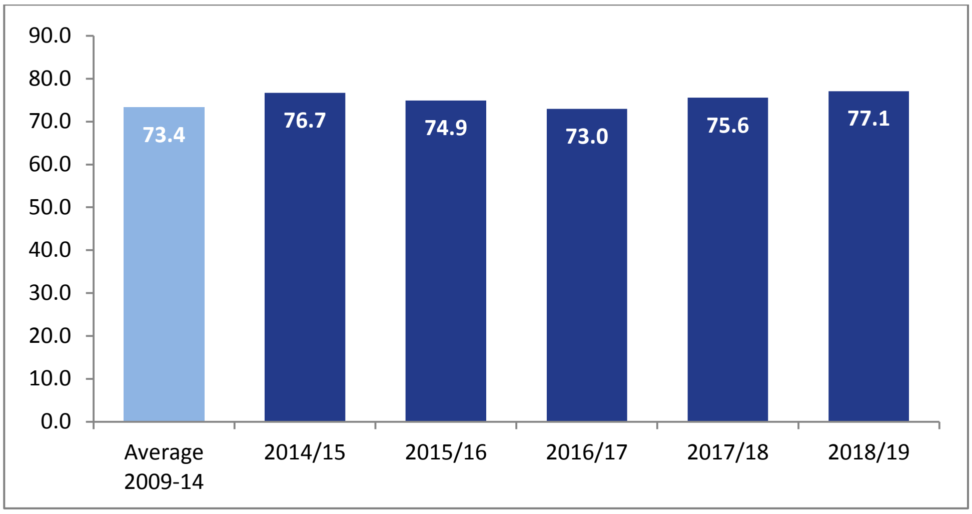
Operating expenditure includes the costs of operating and maintaining the poles, wires and other physical assets required to provide distribution network services and meet safety and service standards. It also includes the costs of related functions, such as managing demand and complying with regulatory and legal obligations.

ActewAGL Distribution expects its operating expenditure to remain relatively stable over the 2014–19 period. As Figure 0.3 shows, the forecast annual expenditure over the period is broadly in line with the annual expenditure in 2012/13 (the base year used to forecast expenditure in future years under the NER).

[9] This study, commissioned by ActewAGL, was undertaken by NERA Economic Consulting and AC Nielsen.

[10] Study undertaken by researchers at the Australian National University

Figure 0.3 ActewAGL Distribution's forecast annual operating expenditure 2014–19



The proposed operating expenditure program allows ActewAGL Distribution to continue several initiatives it began during the 2009 period to embed an effective 'safety culture' throughout its organisation, and to respond to changes in Work Health Safety legislation. The program's long-term benefits to consumers include enabling ActewAGL Distribution to:

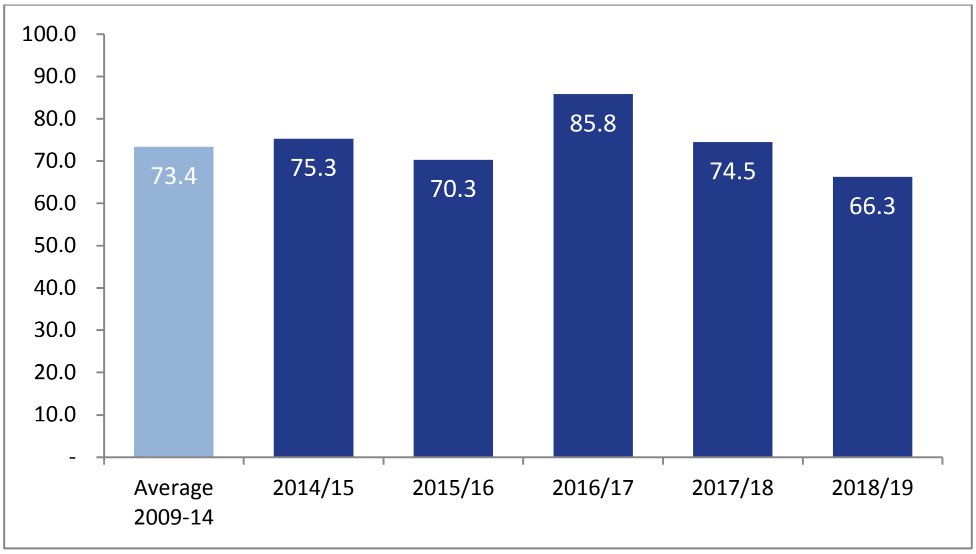
- manage, operate and maintain the safety, reliability, quality and security of the ACT's electricity distribution system
- improve the safety of its staff, contractors and the public by improving work health and safety programs, the management of work practices, and safety rules and guidelines
- improve the way it engages with its customers by making engagement activities part of its usual business practice and implementing a new consumer engagement strategy, and
- increase the accessibility and scope of information on its network and business, including information available directly from it and through additional regulatory reporting.

Capital expenditure will increase marginally

Capital expenditure includes the investments in buying, building and renewing the physical assets required to deliver the network distribution services and meet safety and service standards.

ActewAGL Distribution proposes capital expenditure of $372 million for the 2014 regulatory period. This is marginally higher than the expected total capital expenditure for the current period. Figure 0.4 below compares the forecast annual capital expenditure for this period with the average annual capital expenditure over the current 2009 period.

Figure 0.4 ActewAGL Distribution's forecast capital expenditure 2014–19



The proposed capital expenditure program maintains the continuous improvement approach ActewAGL Distribution has taken to managing its assets and delivering its capital program in recent years. This approach aims to minimise the total lifecycle cost of assets, increase the efficiency of the capital delivery process, and maximise value-for-money for consumers.

ActewAGL Distribution is confident that the proposed program is prudent and efficient and in the long-term interest of our customers. The projects it contains have been carefully evaluated, planned and prioritised to ensure they will deliver maximum benefits for minimal costs. Wherever possible, a non-network alternative to building additional infrastructure has been considered as part of the planning process.

The main focus of the program is continuing major projects and asset replacement programs begun during the 2009–14 period to ensure the ongoing safety and reliability of the network. Its long-term benefits to consumers include enabling ActewAGL Distribution to:

- continue augmenting the ACT electricity distribution network to meet urban expansion in the Molonglo region. For example, the program includes:
    - the construction of a new zone substation at Molonglo, which will meet demand from new suburbs in ACT Government's key growth area, and support the development of residential developments, commercial businesses, town centres and other facilities.
- the completion of the Southern Supply to ACT project, which will make the supply of electricity to the ACT more secure.
- increase expenditure on asset replacement programs to ensure safety standards are maintained at the current levels and improved in others, and that reliability standards are met. For example, the program will:

- replace ageing assets which have led to a growing number of underground cable faults in recent years.
- continue the replacement of aged wooden poles with fibreglass and concrete poles, which have lower whole-of-life cost than wooden poles. Fibreglass poles are also much safer and easier to replace in back yards.
- continue the meter replacement program, which will enable a greater portion of customers to move onto time-of-use tariffs to give them greater control over their consumption of and expenditure on electricity.

- improve ActewAGL Distribution's operational technology systems to help to provide ACT customers with more information about their consumption habits, and to:
  - provide customers with access to accurate and real-time outage information and allow them to report outages and damaged assets, increasing transparency;
  - ensure that outages and network faults are located and attended to more quickly, ensuring minimal interruptions to customer supply;
  - enable condition-based maintenance, which will reduce asset failures and hence outages; and
  - enable targeted power quality correction, which will reduce distribution losses, voltage drops and improve customer power quality.

The proposed total revenue requirement

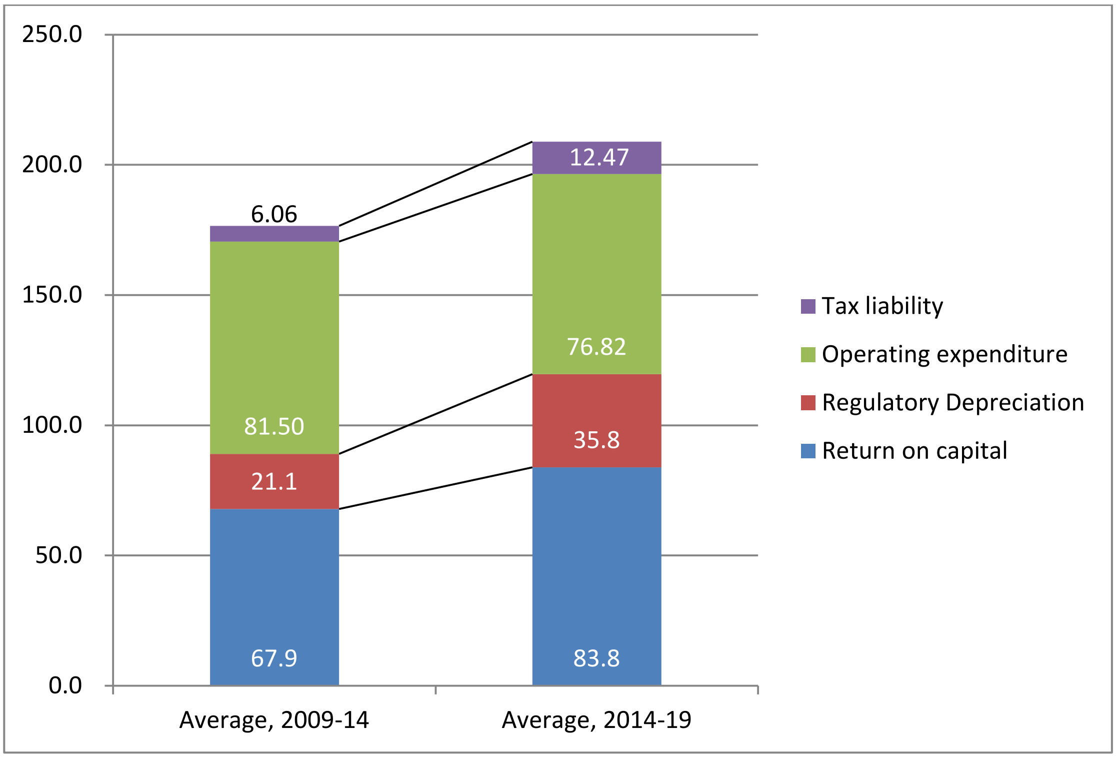
In general, to run its business effectively, ActewAGL Distribution must generate enough revenue to recover:

- its forecast operating expenditure over the regulatory period;
- its forecast capital funding costs over this period (or 'return on capital', which covers interest and other costs related to its borrowings for past capital expenditure and its forecast capital expenditure over the period);
- depreciation on its asset base (or 'return of capital', which is the amount it needs to recover over the regulatory period so that it will recover its capital expenditure over the expected life-time of each asset); and
- its tax liability on the income it will generate over the regulatory period.

To calculate this total revenue requirement, ActewAGL Distribution has estimated and summed these 'building block costs', using the AER's model. For the 2014–19 regulatory period, it calculates that its total revenue requirement for distribution and metering will be $946 million (nominal) over the five-year period, or an average of $189 million per year. This is 13.9 per cent higher than the average revenue it recovered per year in the 2009–14 period.

Figure 0.5 compares ActewAGL Distribution's proposed average annual revenue requirement for the 2014 period to its actual average annual revenue for the current 2009 period.

Figure 0.5 Comparison of ActewAGL Distribution annual revenue requirement 2009–14 and 2014–19



The main reasons for the increase in the average annual total revenue requirement are that the 'return on capital', 'depreciation' and 'corporate tax' building block costs have increased. This is due to:

- an increase in the overall value of ActewAGL Distribution's asset base, following the completion of major augmentation and ICT replacement projects in the current period; and
- ActewAGL Distribution's proposed higher allowance for the corporate income tax liability.

Under the NER, ActewAGL Distribution is entitled to a fair return on its investment in the ACT electricity distribution network. Building electricity infrastructure is expensive, and in the absence of a fair return on that investment, there is less incentive to invest.

ActewAGL Distribution has proposed a rate of return building block that is based on a weighted average cost of capital (WACC) of 8.9 per cent. ActewAGL Distribution considers that this proposal is in the long term interest of consumers because it will ensure that ActewAGL

Distribution is able to undertake necessary investments in the network in the next regulatory period and beyond. Under-investment in the network will result in higher costs and ultimately higher prices to customers in the long term.

ActewAGL Distribution's consumer engagement activities

ActewAGL Distribution believes that consumer engagement is important, and is committed to conducting ongoing engagement with its customers as part of its 'business as usual'. This engagement will help ensure that its service offerings remain aligned with consumer expectations on reliability, price and other aspects of its distribution network services, and that its expenditure proposals reflect consumers' long-term interests.

ActewAGL Distribution has developed a consumer engagement framework which sets out its existing engagement activities, and includes a plan for making sure these all become business-as-usual processes. This framework will also help consumers gain a greater understanding of ActewAGL Distribution's operations and how they are funded. ActewAGL Distribution will continually monitor and assess the effectiveness of its consumer engagement activities to make sure they are transparent and open to all consumers.

ActewAGL Distribution is listening to its customers

ActewAGL Distribution has considered and incorporated the feedback it received from consumers through its current and previous consumer engagement and communication activities in developing the asset management planning decisions on which this regulatory proposal is based. These activities include:

- studies of customers' willingness-to-pay for reliability and other service standards (2003, 2009 and 2012);
- consultation on major projects;
- engagement with major/critical customers;
- engagement on its demand management strategy;
- customer satisfaction surveys; and
- customer communication via its website and social media, and on network safety communications through advertising campaigns and media releases.

Willingness-to-pay studies

ActewAGL Distribution's major consumer engagement initiative to date has been to periodically undertake studies into customer willingness to pay (WTP) for changes in service levels. These studies used targeted focus groups and surveys to obtain meaningful information on customer preferences in relation to striking a balance between cost and levels of service. The interaction with customers that has taken place as part of this research has enabled ActewAGL Distribution to gain a deep and considered understanding of customer preferences, attitudes and views. The focus on quantification of preferences has delivered results that have direct relevance to making investment and operating decisions in customers' interests.

ActewAGL Distribution has been at the forefront of WTP research within the utilities sector over the last decade, utilising world-leading authorities in the application of choice modelling techniques to valuation of utilities service quality. Three WTP studies have been undertaken over that period.

The first study was undertaken for ActewAGL Distribution and ACTEW Corporation by NERA Economic Consulting (NERA) and ACNielsen in 2003.[11] The study measured WTP and attitudes across a range of attributes of electricity network services for small and large business organisations, government organisations, and residential (including concession card holder) consumers. The findings showed that, as far as customers were concerned, ActewAGL did not wastefully over engineer its infrastructure and that customers did not want lower service levels at corresponding lower prices.

The study found that customers were less concerned with planned (than unplanned) outages of a given duration, as long as they were given two to seven days prior notice of the outage. ActewAGL Distribution has continued to undertake a relatively high proportion of planned (rather than reactive) maintenance on the network in recognition of this finding and the difficulties associated with accessing backyard reticulation to address unplanned outages.

The research found that keeping trees clear of powerlines was a problem for 37 per cent of respondents in areas with overhead wires. This finding prompted ActewAGL Distribution to consider options for addressing this concern, including replacing existing overhead supply infrastructure with underground wires (undergrounding). Some 22 per cent of respondents with overhead wires had nominated undergrounding as a required improvement to supply.

The second study in 2009 investigated this issue directly. It was undertaken by the Australian National University (ANU) and University of Sydney and focused on estimating residential customers' WTP for undergrounding in established urban areas.[12] The study found large variation in WTP, with the highest economic benefits likely to be achieved by undergrounding in areas with higher household income and older residents where improved appearance, safety, tree trimming, or restrictions on the use of yard space are of concern. This finding prompted ActewAGL Distribution to investigate the potential for a pilot undergrounding program in the future.

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[11] For details of the residential electricity component of the study, see: Hensher, D.A., Shore, N., Train, K. (2014). *Willingness to pay for residential electricity supply quality and reliability*. Applied Energy 115, 280-292.

[12] McNair, B.J., Bennett, J., Hensher, D.A., Rose, J.M. (2011). *Households' willingness to pay for overhead-to-underground conversion of electricity distribution networks*, Energy Policy 39, 2560–2567

The most recent study in 2011/12 was an independent research project undertaken by researchers at the ANU into the preferences of Canberra households for electricity supply reliability. The study found that the average value placed on avoiding supply interruptions had not changed markedly in real terms since the 2003 study. Estimates of willingness to pay from this and the earlier 2003 study have been used to develop ActewAGL Distribution’s proposal in relation to the level of rewards and penalties to apply in the 2014–19 regulatory period under the AER’s Service Target Performance Incentive Scheme. This will ensure that incentives to invest in the network reflect customers’ preferred balance between cost and supply reliability.

Major projects consultation

ActewAGL Distribution undertakes targeted stakeholder consultation on major capital projects during the planning and construction phases. For example, in planning the East Lake Zone Substation (located within the Jerrabomberra Wetlands), it consulted closely with the Friends of the Jerrabomberra Wetlands group to ensure positive environmental outcomes. It also engaged with other interested stakeholder groups throughout the process, including the Conservation Council ACT, ACT Government representatives and Members of Parliament.

Consultation with major customers

ActewAGL Distribution has formed strong working relationships with its major customers, including developers, ACT and federal governments, large industrial and commercial businesses, educational facilities and hospitals. Its Customer Solutions Branch is responsible for major customer and major project liaison. Dedicated account managers are in regular contact with existing and prospective large customers to assist with their operations or future planning. ActewAGL Distribution works in partnership with major customers to assist them in managing issues such as demand and load constraints. Feedback from major customers is a key input into ActewAGL Distribution’s asset management planning processes and resultant expenditure programs.

Demand side engagement strategy

ActewAGL Distribution’s demand side engagement strategy aims to create a cooperative and proactive relationship with customers and proponents of non-network demand management solutions, and incorporate their views in ActewAGL Distribution’s network planning and expansion decision making processes.[13] As part of this strategy, ActewAGL Distribution encourages customers and potential non-network service providers to participate in demand management activities to address future network problems and achieve optimal economic and technical outcomes. ActewAGL Distribution has factored existing and potential demand

[13] More information on ActewAGL Distribution’s demand side engagement strategy and demand side management planning processes is set out in Chapters 3 and 6 of this regulatory proposal.

management activities and non-network solutions into its proposed capital expenditure program for the 2014–19 period.

Customer satisfaction surveys

ActewAGL undertakes customer satisfaction surveys annually. These surveys cover overall satisfaction, as well as satisfaction with products, services, performance and reliability, customer contact and communication. ActewAGL consistently performs well in these surveys.

The most recent customer satisfaction survey, undertaken in 2013, identified an overall satisfaction score of 88 per cent, and found that only 2 per cent of respondents were dissatisfied. It also provided valuable information on customer awareness of and use of ActewAGL's communication channels, including its website, social media, customer newsletter, and community sponsorship initiatives.

ActewAGL Distribution used the information on customer satisfaction to inform its planning around network services and reliability. It plans to use the information on customer awareness ActewAGL's communication channels to build on the current levels of awareness and better utilise these channels during the 2014–19 regulatory period.

Customer communication

ActewAGL Distribution's website provides useful information on topics such as energy saving tips, major capital projects, safety advice, network standards and guidelines, and network pricing. ActewAGL Distribution is actively engaged in social media, predominantly using Twitter and Facebook to communicate with its customers. This method of communicating with customers is particularly useful during crisis situations such as the heatwave Canberra experienced in January 2014, and to inform the public about planned outages or prominent maintenance activities like helicopter inspection of vegetation near power lines.

ActewAGL Distribution conducts regular public awareness campaigns on important safety topics like tree clearing around power lines, extreme weather events and public safety. It also keeps consumers informed about progress of major projects or planned maintenance activities via media releases.

1 Introduction

1.1 Purpose and scope of the regulatory proposal

This regulatory proposal for the *subsequent regulatory control period* is submitted by ActewAGL Distribution in respect of the services provided by the electricity distribution network that it owns, controls and operates in the Australian Capital Territory (ACT). It has been prepared in accordance with savings and transitional measures in Division 2 of Part ZW of Chapter 11 (transitional provisions) of the National Electricity Rules (NER or the Rules). [14]

On 29 November 2012, the Australian Energy Market Commission (AEMC) published its final determination on the *Economic Regulation of Network Service Providers* rule changes. The rule changes required the Australian Energy Regulator (AER) to develop several regulatory guidelines. This process, in combination with the objective set by the AEMC of applying the new rules as soon as possible to as many as possible network service providers, required an interruption to the established cycle of regulatory determinations. The transitional provisions set out the requirements for affected network service providers to secure a transitional regulatory determination from the AER for the transitional regulatory period from 1 July 2014 to 30 June 2015. ActewAGL submitted its transitional regulatory proposal to the AER on 31 January 2014. The AER delivered its transitional determination on 16 April 2014.

Following submission of this subsequent regulatory proposal by 2 June 2014, the AER will make a regulatory determination (the subsequent determination) covering the four year period 1 July 2015 to 30 June 2019 which includes an adjustment or *true up* of revenues allowed in the transitional determination.

1.2 ActewAGL Distribution's structure and services

The ActewAGL joint venture was formed in October 2000 combining ACTEW Corporation's network and retail electricity business with AGL's ACT and Queanbeyan network and retail gas business to become the first multi-utility in Australia operating as a public-private partnership. ActewAGL operates as two partnerships: ActewAGL Distribution and ActewAGL Retail.

Since the conclusion of business dealings between AGL and Alinta in October 2006, ownership of ActewAGL Retail has been shared equally between AGL Energy Limited and ACTEW Corporation Limited. At that time, ownership of ActewAGL Distribution became 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.

[14] All terms used in this subsequent regulatory proposal that are defined in Chapter 10 or clause 11.55.1 of the Rules are intended to take that defined meaning unless the context otherwise requires.

The ActewAGL Distribution partnership is now equally owned by Jemena Ltd and ACTEW Corporation Ltd via their respective subsidiary companies, Jemena Networks (ACT) Pty Ltd and ACTEW Distribution Ltd. As well as the electricity network in the ACT, ActewAGL Distribution owns and controls the gas distribution networks in the ACT/Queanbeyan/Palerang, and Shoalhaven regions.

In January 2014, the State Grid Corporation of China became 60 per cent owner of Singapore Power's energy assets held by SPI (Australia) Assets Pty Ltd (Jemena).

ActewAGL Distribution continues to deliver a combination of comparatively low network prices, and a high level of network reliability. According to the AEMC's most recent annual report on national electricity price trends, network charges in the ACT are the lowest in Australia. The AEMC found that the 2012/13 regulated network charge in the ACT (in cents/kWh) was around half that of New South Wales, and about 20 per cent lower than in Victoria.[15]

Service performance measures published annually by the AER indicate that the ACT has the most reliable network in the National Electricity Market (NEM), in terms of the average frequency and duration of interruptions.[16] This level of reliability is in line with the jurisdictional minimum standard for customer minutes off supply and reflects a range of factors including a relatively compact network with only two voltage levels and a relatively high proportion of undergrounding. A customer willingness to pay survey undertaken by NERA Economic Consulting and AC Nielsen for ActewAGL in 2003 supports these reliability levels, with all customer groups preferring to maintain the current standards to the alternative of accepting lower standards at the corresponding lower price. Further survey work by researchers at the Australian National University in 2012 confirmed that residential customers' willingness to pay has remained relatively constant in real terms since that time.

1.3 Structure of the regulatory proposal

The Overview preceding this introduction provides a summary of the regulatory proposal which explains the regulatory proposal in reasonably plain language to electricity consumers. It includes:[17]

- a description of how the Distribution Network Service Provider has engaged with electricity consumers and has sought to address any relevant concerns identified as a result of that engagement;
- a description of the key risks and benefits of the regulatory proposal for electricity consumers; and

[15] AEMC 2013, *Electricity price trends, Final Report*, December

[16] AER 2013, *State of the Energy Market 2013*, December, p 80. The SAIDI and SAIFI measures reported by the AER do not distinguish between planned and unplanned outages.

[17] Consistent with Rules clause 6.8.2(c1)

- a comparison of the ActewAGL Distribution's proposed total revenue requirement with its total revenue requirement for the current regulatory control period and an explanation for any material differences between the two amounts.

Following this introductory chapter:

- chapter 2 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 programs;
- chapter 3 discusses activities undertaken by ActewAGL Distribution to engage with the needs of consumers and its consumer engagement strategy going forward, recognising the growing need for consumer engagement in determining directions and priorities;
- chapter 4 summarises regulatory obligations and requirements imposed upon ActewAGL Distribution, generally with the intent of meeting the reliability, safety and security expectations of customers, but which are also a substantial driver of the costs facing ActewAGL Distribution in the construction, operation and maintenance of its electricity network;
- chapter 5 provides a summary of ActewAGL Distribution's forecasts of maximum demand and the methodology used to derive the forecasts of required capital and operating expenditures. It also provides forecasts of energy sales, along with explanations and supporting documentation, which are required under the average revenue cap control mechanism determined by the AER;
- chapter 6 sets out ActewAGL Distribution's network planning and asset management policies, plans and procedures that provide the framework for ensuring that the regulatory obligations and customer requirements, discussed in the previous chapters, are met in the most prudent and efficient way;
- chapter 7 sets out ActewAGL Distribution's forecast capital expenditure that is included in the current building block proposal for the 2014–19 regulatory control period;
- chapter 8 sets out ActewAGL Distribution's forecast operating and maintenance expenditure that is included in the current building block proposal for the 2014–19 regulatory control period;
- chapter 9 describes the derivation of the Regulatory Asset Base (RAB) used in calculating ActewAGL Distribution's return on capital and regulatory depreciation;
- chapter 10 chapter sets out ActewAGL Distribution's proposed rate of return, gamma, forecast inflation and debt and equity raising costs to apply to the next regulatory period;
- chapter 11 sets out the calculation of the corporate income tax expense included in ActewAGL Distribution's revenue building blocks;

- chapter 12 sets out the summation of ActewAGL Distribution's revenue requirements for distribution and transmission standard control services from the elements of the cost building blocks calculated in earlier chapters;
- chapter 13 provides ActewAGL Distribution's proposals relating to the control mechanism and indicative prices for distribution standard control services;
- chapter 14 outlines why ActewAGL Distribution does not require a negotiating framework or Negotiated Distribution Service Criteria (NDSC) for the 2014–19 regulatory period;
- chapter 15 sets out ActewAGL Distribution's proposals for Alternative Control Services (regulated metering and ancillary network services) including classifications, control mechanisms and indicative prices;
- chapter 16 details several specific proposals by ActewAGL Distribution in relation to the operation of regulatory incentive schemes;
- chapter 17 sets out ActewAGL Distribution's proposal for cost pass through events; and
- chapter 18 provides an overview of the regulatory requirements and the key elements of ActewAGL Distribution's proposed connection policy for 2015-19.

Following chapter 18 is a glossary of terms used in the proposal.

Detailed supporting information, as indicated in the text, is included in attachments to the proposal. The list of these attachments, which form part of the proposal, can be found at the end of this document.

2 Context for the 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 regulatory context for the determination, including the impacts of the November 2012 Rule changes and the implications of the AER's Framework and Approach (F&A) process, is also examined in the chapter. An overview of the constituent decisions and ActewAGL Distribution's proposals in relation to each is also provided in the chapter.

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 177 000 customers in the ACT. The network serves an important role in reliably suppling several of the nation's major political, administrative and strategic institutions and its largest inland city. In the National Electricity Market (NEM) ActewAGL Distribution is the smallest distributor by customer numbers, maximum demand and second smallest in terms of kilometres of line.[18] A map of the network is provided at Figure 6.1.

The ACT is supplied with electricity from the New South Wales (NSW) transmission grid through three bulk supply substations: two at 132 kV (at Canberra and Williamsdale) and one at 66 kV (at Oaks Estate). In 2006 the ACT Government introduced a new statutory network performance requirement (Network Service Criterion) requiring establishment of the second 132 kV connection to ActewAGL Distribution's distribution network. ActewAGL Distribution was required to construct two new 132 kV lines to connect the new southern supply point at Williamsdale to the existing ACT distribution network. The purpose of the southern supply point requirement was to enhance the security of electricity supply for the ACT, but the connection also results in ActewAGL Distribution's high voltage network being available for support of TransGrid's transmission network.

Accommodation of the southern supply point required the largest upgrade of ActewAGL Distribution's network for several decades and was a major component of ActewAGL Distribution's capital expenditure program for 2009–14.

The bulk supply substations and the incoming 330 kV and 132 kV transmission lines are owned and operated by TransGrid. The 132 kV sub-transmission lines from the Canberra and

[18] AER 2013, *State of the Energy Market 2013,* p 63

Williamsdale substations are owned by ActewAGL Distribution, as are the two 66 kV lines from the Queanbeyan bulk supply substation.

ActewAGL Distribution operates 13 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 and Williamsdale bulk supply substations. Ten of the 13 zone substations and the two switching stations were commissioned before 1990, while the Gold Creek Zone Substation was commissioned in 1994. Angle Crossing and East Lake zone substations were commissioned during the current (2009–14) regulatory period, in 2012 and 2013 respectively. The need to repair and maintain ageing zone substations is an important driver of ActewAGL Distribution's operating expenditure forecasts. A new zone substation will be required during the 2015-19 regulatory period to serve the extensive greenfield urban development at Molonglo, while major upgrades will be required at Civic and Belconnen zone substations.

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 requirements set out in the ACT Government's Territory Plan. Underground lines now account for somewhat more than half the total line length in ActewAGL Distribution's network. This proportion is considerably higher than the national average.

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 were significant drivers of ActewAGL Distribution's increased operating expenditures during the 2009–14 regulatory period and the operating expenditure forecasts for 2014–19.

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 2009–14 regulatory period has been higher than forecast.

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 key characteristics of ActewAGL Distribution's electricity distribution network are summarised in chapter 6.

An important implication of ActewAGL Distribution's relatively small size is that major network augmentations, which need to be built to a minimum feasible scale, have a significant step impact on total capital expenditure. This is apparent in the capital expenditure forecasts presented in chapter 7.

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 attempt at efficiency comparisons be based on a range of measures, rather than a single measure such as costs per customer or costs per kilometre of line.

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 also to 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 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 commercial load has a significant cooling load and the recent growth of the commercial load has contributed to a rise in the summer demand.

The growth in summer maximum demand has contributed to the gradual improvement in ActewAGL Distribution's asset utilisation in recent years. ActewAGL Distribution's network management policies, network pricing and demand management initiatives have also contributed to the improvements.

System utilisation in the ACT remains difficult to improve, reflecting the impact of:

- 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 lower utilisation than their capacity.

2.1.2 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 chapter 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:

- 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.

2.1.2.1 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 the norm 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.

Screen vegetation planted by lessees[19] 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* requires ActewAGL Distribution to cover the costs of emergency

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

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 leaseholders. ActewAGL Distribution has the responsibility for managing these trees. The *Tree Protection 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 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. 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.

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 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, and more recently, fibreglass 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.

2.1.2.2 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.[20]

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 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, incurring 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.

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 and maintenance expenditures.

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

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 few commercial loads restricted to the local shopping facilities. As discussed above, this separation of commercial and residential development means that ActewAGL Distribution is not able to exploit natural diversity between domestic and commercial loads, and as a result ActewAGL Distribution's system utilisation levels are relatively low.

2.1.2.3 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 institutions such as Parliament House, Australian Signals Directorate, Department of Defence, Australian Security Intelligence Organisation, 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 set out the charging principles to be applied to cases where a customer requires 'infrastructure of a higher standard' to be installed (clause 3.3). Connection services provided to a higher standard than the least cost technically acceptable standard are now covered by the provisions of chapter 5A of the Rules and ActewAGL Distribution's Connection Policy.

The additional capacity built into the system over many years to meet supply security requirements is reflected in ActewAGL Distribution's relatively low asset utilisation rates (discussed 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 recovered in accordance with ActewAGL Distribution's Connection Policy, in certain circumstances 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.

2.2 Impact of the Rule changes

On 29 November 2012, the AEMC published its final determination on the *Economic Regulation of Network Service Providers* rule changes. This involved the publication of *amending rules* under

Schedules 1 and 3 of the *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*.

The rule changes also required the AER to develop several regulatory guidelines. This process, in combination with the objective set by the AEMC of applying the new rules as soon as possible to as many as possible network service providers, interrupted the established cycle of regulatory determinations. Transitional provisions governing the process for New South Wales and ACT Distribution Network Service Providers (DNSPs), whose five-year regulatory period was to end on 1 July 2014, were inserted in Division 2 of Part ZW in Chapter 11 of the Rules. The transitional provisions set out the requirements for a transitional regulatory determination (transitional determination) from the AER for the transitional period to be followed by a full determination (the subsequent determination) covering the four year period following the completion of the transitional period (the subsequent period).

2.2.1 Transitional (placeholder) determination

The AER released its transitional "placeholder" determination for AAD's electricity distribution network on 16 April 2014. The determination sets ActewAGL Distribution's average revenue allowance for the 2014/15 transitional regulatory period and is subject to adjustment via in the AER's determination for the subsequent regulatory period.

The AER accepted the indicative expenditure forecasts proposed by ActewAGL Distribution in its transitional regulatory proposal, but determined a lower return on capital than proposed. The AER also reduced ActewAGL Distribution's proposed allowance for corporate income tax as a result of increasing the gamma (utilisation of franking credits) parameter to 0.5 from the proposed 0.25. These two adjustments resulted in a distribution revenue adjustment for 2014/15 of the Consumer Price Index (CPI) minus 19.6 per cent.

2.2.2 Subsequent regulatory period

Clause 11.56.4(k)(1) of the NER states that if an affected DNSP proposes in its *regulatory proposal* a period of 4 *regulatory years* as the period for the subsequent regulatory control period of the affected DNSP, then the *AER* must, in its distribution determination for that subsequent regulatory control period, approve that period as (and that period will be) the *regulatory control period* for the affected DNSP that immediately follows the transitional regulatory control period.

ActewAGL Distribution proposes that the subsequent regulatory control period be for a period of four years from 1 July 2015 to 30 July 2019.

Clause 11.56.4(b) requires that DNSP must prepare and submit its *regulatory proposal* for the subsequent regulatory control period of the affected DNSP, together with all the information that is required to accompany that *regulatory proposal*, in accordance with current Chapter 6 of the Rules, and as if:

(1) the subsequent regulatory control period comprised the transitional regulatory control period (as the first *regulatory year* of the subsequent regulatory control period) and all of the *regulatory years* of the subsequent regulatory control period (as the remaining *regulatory years* of the subsequent regulatory control period); and

(2) the transitional regulatory control period were not a separate *regulatory control period*.

For the purposes of assessing past capital and operating expenditure, the transitional regulatory period is treated as the last year of the 2009–14 regulatory period.

Adjustment to the annual revenue requirement, including for smoothing of revenue, is subject to clause 11.56.4(h) of the Rules.

2.3 Framework and approach stages 1 and 2

The purpose of the framework and approach (F&A) phase of a regulatory review is to settle a number of issues prior to regulatory proposals being submitted. The F&A process is designed to facilitate early public consultation and assist network service providers to prepare regulatory proposals.

The AEMC's Regulation of Network Service Providers rule determination of 29 November 2012 made substantial changes to the F&A process requirements in clause 6.8.1 of the Rules.

Clause 6.8.1(b) of the current Rules lists the matters that must be set out in an F&A paper. The transitional Rules require the AER to publish the ACT F&A paper in two stages.

2.3.1 Stage 1 Framework and approach

The Stage 1 F&A paper released in March 2013 sets out the AER's:

- proposed approach to distribution service classification (which services are to be regulated);
- decision on control mechanisms (how prices will be determined) to apply and the AER's proposed formulae to give effect to the control mechanisms; and,
- decision on dual function assets (how transmission type assets will be treated).

2.3.1.1 Classification of services

Under 6.12.1(1) of the current Rules, the AER is required to make as part of a distribution determination "a decision on the classification of services to be provided ... during the course of the regulatory control period".

The Stage 1 F&A paper sets out the AER's proposed approach to the classification of services provided by ActewAGL Distribution. The AER intends to classify the following as standard and alternative control services in the transitional and subsequent regulatory control periods:

- Standard control services—network services and connection services; and

- Alternative control services—metering services (Types 5-7) and ancillary network services.

ActewAGL Distribution accepts the broad classification of services set out by the AER in the Stage 1 F&A paper but notes that some clarification is required on the services covered by the alternative control services classification. This is discussed in chapter 15 of this regulatory proposal.

In the Stage 1 F&A paper the AER did not classify any service provided by ActewAGL Distribution as a negotiated distribution service. [21] ActewAGL Distribution accepts this classification.

2.3.1.2 Control mechanisms

Under clauses 6.12.1(11) and 6.12.1(12) of the Rules, the AER is required to make a decision on the form of control mechanisms for standard control services and alternative control services (in accordance with the relevant F&A paper) and on the formulae that give effect to those control mechanisms.

For services the AER has classified as standard control services, the AER has determined in the Stage 1 F&A that it will apply the average revenue cap control mechanism in the transitional and subsequent regulatory control periods.

For services the AER has classified as alternative control services, the AER has determined in the Stage 1 F&A that it will apply caps on the prices of individual services in the transitional and subsequent regulatory control periods.

While the *form* of the control mechanisms must be as specified in the Stage 1 F&A paper, the *basis* for the control mechanism is to be determined in the distribution determination process.[22]

ActewAGL Distribution's proposals regarding the control mechanism for standard control services are set out in chapter 13 (Control mechanisms and indicative pricing) and chapter 15 (Alternative control services) of this regulatory proposal.

2.3.1.3 Dual function assets

Dual function assets are high voltage transmission assets forming part of a distribution network. Considering these assets as part of a distribution determination avoids the need for a separate regulatory proposal.

In Stage 1 F&A, the AER determined under clause 6.25(b) of the Rules that Part J of chapter 6A (transmission pricing) of the Rules will apply to relevant standard control services provided by ActewAGL's dual function assets in the subsequent regulatory period. The AER subsequently

[21] AER 2013, *Stage 1 Framework and Approach—ActewAGL*, March, p 9

[22] *National Electricity Rules*, clause 6.2.6(b)

determined in the Stage 2 F&A that this treatment would also apply to the transitional regulatory period.

Consequently, ActewAGL Distribution has prepared a separate revenue proposal and pricing methodology in respect of dual function assets performing transmission services. These are contained in chapter 13.

2.3.2 Stage 2 Framework and Approach

The Stage 2 F&A paper, published on 31 January 2014, sets out as required the AER's decisions on application to ActewAGL Distribution of:

- a Service Target Performance Incentive Scheme (STPIS);
- an Efficiency Benefit Sharing Scheme (EBSS);
- a Capital Expenditure Sharing Scheme (CESS);
- a demand management and embedded generation connection incentive scheme (DMEGCIS);
- a small scale incentive scheme; and
- the Expenditure Forecast Assessment Guidelines.

2.3.2.1 Service Target Performance Incentive Scheme

For the transitional period the STPIS does not apply. Current reporting obligations for the scheme will apply with no revenue at risk. For the subsequent period, a service standard factor (s-factor) will apply. ActewAGL Distribution's proposals for STPIS in the subsequent period are at chapter 16.

Jurisdictional Guaranteed Service Level (GSL) arrangements continue to apply in both transitional and subsequent periods.

2.3.2.2 Efficiency Benefit Sharing Scheme

For both the transitional and subsequent period, the AER will apply version 2 of the EBSS published as part of its Better Regulation process.

For the transitional year, however, the EBSS target will not be known until the subsequent decision. The AER says that while distributors may not know their final opex targets until the final determination (April 2015), the draft determination of November 2014 is 5 months into the transitional period and a draft opex allowance will provide a degree of guidance for distributors.

2.3.2.3 Capital Expenditure Sharing Scheme

In the transitional period, no CESS applies. For the subsequent period, version 1 as per capital expenditure incentive guideline published as part of Better Regulation.

In chapter 16, ActewAGL Distribution proposes that the CESS for the subsequent period exclude customer initiated capital expenditure.

2.3.2.4 Demand management incentive scheme

ActewAGL Distribution is currently subject to a DMIS comprising the demand management incentive allowance (DMIA).

Whether the AER will develop and implement a new DMIS depends on progress of the Standing Council on Energy and Resources (SCER) Power of Choice rule change proposal on demand management and the inclusion of relevant transitional provisions.

2.3.2.5 Expenditure Forecast Assessment Guideline

The AER has said that it will apply all of the assessment tools set out in the expenditure assessment guideline including information requirements.

2.3.2.6 Other matters

Calculation of depreciation

The AER is to use forecast depreciation for 2014–19 for updating the RAB in 2019.

Alternative control services

The AER said in the Stage 2 F&A paper that it would outline "in its determinations" how price caps are to be set for these services that is, whether it will "use building block or another method".

ActewAGL Distribution proposes to adopt a building block approach to metering services and a cost build-up approach to ancillary and other alternative control services. The proposals are provided in chapter 15 of this regulatory proposal.

In the Stage 2 F&A the AER says that the prices for quoted services will be derived from relevant input costs for each year, and the AER will set a price for each by substituting the calculated cost of each quoted service into the formula in Stage 1 F&A. ActewAGL Distribution notes that this appears to be inconsistent with the position set out in the Stage 1 F&A paper, whereby the basis of the control mechanism would be determined in the distribution determination process, consistent with clause 6.6.2(b) of the Rules. ActewAGL Distribution's proposed formula for calculating quoted services prices is provided in chapter 15 of this regulatory proposal.

In the Stage 2 F&A the AER included public lighting as an alternative control service for ActewAGL Distribution. However, ActewAGL Distribution does not supply such a service and public lighting in the ACT is predominantly owned and controlled by the ACT Government and the National Capital Authority. In addition, the quoted services listed in the ACT Stage 2 F&A are those applying to the New South Wales DNSPs, not ActewAGL Distribution.

2.4 Constituent decisions

Clause 6.12.1 of the Rules contains the constituent decisions the AER must make in a distribution determination. ActewAGL Distribution's proposals in relation to each of the constituent decisions are set out in this regulatory proposal. References to the relevant parts of the regulatory proposal are provided in Table 2.1.

ActewAGL Distribution believes that the determination for the 2014–19 regulatory period that best supports consumers' long term interests requires a correct and unbiased approach to making each constituent decision. Under the building block method as set out in the Rules, each constituent decision is designed to fund a given activity and/or motivate a specific desired behaviour, as set out in Table 2.1. Each constituent decision will influence management decision-making over the 2014–19 regulatory period and will have consequences for the level of service that ActewAGL Distribution's customers have expressed a willingness to pay for.

Table 2.1 Constituent decisions—ActewAGL Distribution proposals

	Constituent decision	*ActewAGL Distribution proposal*
(1)	a decision on the classification of the services to be provided by the *Distribution Network Service Provider* during the course of the *regulatory control period*	ActewAGL Distribution proposes to adopt the classification of services as determined by the AER in the Stage 1 F&A paper. ActewAGL Distribution seeks clarification of the services covered by the alternative control services classification (see chapter 15). The classification of services decision influences ActewAGL's ability to set dynamically efficient and cost reflective prices for distribution services.
(2)	a decision on the *Distribution Network Service Provider's* current *building block proposal* in which the *AER* either approves or refuses to approve: (i) the *annual revenue requirement* for the *Distribution Network Service Provider*, as set out in the *building block proposal*, for each *regulatory year* of the *regulatory control period*; and (ii) the commencement and length of the regulatory control period as proposed in the building block proposal	ActewAGL Distribution's building block proposal for each year of the subsequent regulatory period is provided in chapter 12. ActewAGL Distribution proposes that the subsequent regulatory period will commence on 1 July 2015 and end on 30 June 2019, a period of 4 years. The annual revenue requirement influences management's network investment priorities and ability to meet its financing obligations

	Constituent decision	*ActewAGL Distribution proposal*
(3)	a decision in which the *AER* either: (i) acting in accordance with clause 6.5.7(c), accepts the total of the forecast capital expenditure for the *regulatory control period* that is included in the current *building block proposal*; or (ii) acting in accordance with clause 6.5.7(d), does not accept the total of the forecast capital expenditure for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the Distribution Network Service Provider's required capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors	ActewAGL Distribution's capital expenditure proposal is provided in chapter 7. Capital expenditure allowances reflect a cost build-up of specified capital projects and programs, and a decision to not provide adequate funding influences Management's decision to undertake the program or project, particularly in light of the capex incentive mechanism.
(4)	a decision in which the *AER* either: (i) acting in accordance with clause 6.5.6(c), accepts the total of the forecast operating expenditure for the *regulatory control period* that is included in the current *building block proposal*; or (ii) acting in accordance with clause 6.5.6(d), does not accept the total of the forecast operating expenditure for the *regulatory control period* that is included in the current *building block proposal*, in which case the *AER* must set out its reasons for that decision and an estimate of the total of the *Distribution Network Service Provider's* required operating expenditure for the *regulatory control period* that the *AER* is satisfied reasonably reflects the *operating expenditure criteria*, taking into account the *operating expenditure factors*	ActewAGL Distribution's operating expenditure proposal is provided in chapter 8.

	Constituent decision	ActewAGL Distribution proposal
(4A)	a decision in which the *AER* determines: (i) whether each of the *proposed contingent projects* (if any) described in the current *regulatory proposal* are *contingent projects* for the purposes of the distribution determination in which case the decision must clearly identify each of those *contingent projects*; (ii) the capital expenditure that it is satisfied reasonably reflects the *capital expenditure criteria*, taking into account the *capital expenditure factors*, in the context of each *contingent project* as described in the current *regulatory proposal*; (iii) the *trigger events* in relation to each *contingent project* (in which case the decision must clearly specify those *trigger events*); and (iv) if the *AER* determines that such a *proposed contingent project* is not a *contingent project* for the purposes of the distribution determination, its reasons for that conclusion, having regard to the requirements of clause 6.6A.1(b)	ActewAGL Distribution does not propose any contingent projects for the subsequent regulatory period.
(5)	a decision on the allowed rate of return for each regulatory year of the regulatory control period in accordance with clause 6.5.2	ActewAGL Distribution's rate of return proposal is provided in chapter 10 and supporting material is provided in attachments E1-14. An appropriate rate of return provides an assurance to our investors that they will be able to earn an appropriate risk adjusted rate of return which encourages ongoing investment, promoting allocative efficiency in the long term interest of consumers
(5A)	a decision on whether the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) and, if that is the case, the formula that is to be applied in accordance with clause 6.5.2(l)	ActewAGL Distribution's proposal for the return on debt is provided in chapter 10.
(5B)	a decision on the value of imputation credits as referred to in clause 6.5.3	ActewAGL Distribution's proposal on the value of imputation credits is provided in chapter 10.
(6)	a decision on the regulatory asset base as at the commencement of the *regulatory control period* in accordance with clause 6.5.1 and schedule 6.2	ActewAGL Distribution's proposed regulatory asset base at the commencement of the subsequent regulatory period is provided in chapter 9.

	Constituent decision	*ActewAGL Distribution proposal*
(7)	a decision on the estimated cost of corporate income tax to the *Distribution Network Service Provider* for each *regulatory year* of the *regulatory control period* in accordance with clause 6.5.3	ActewAGL Distribution's proposed cost of corporate income tax is provided in chapter 11. Sufficient compensation for tax liabilities provides an assurance to investors that they will be able to recover corporate income tax costs, which encourages ongoing investments to be made in the long term interest of consumers.
(8)	a decision on whether or not to approve the depreciation schedules submitted by the *Distribution Network Service Provider* and, if the *AER* decides against approving them, a decision determining depreciation schedules in accordance with clause 6.5.5(b)	ActewAGL Distribution's depreciation proposal is provided in chapter 9. The depreciation schedules are provided in Attachments B2 (for distribution services) and B5 (for transmission services).
(9)	a decision on how any applicable *efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme* is to apply to the *Distribution Network Service Provider*	ActewAGL Distribution's proposals for the incentives schemes are provided in chapter 16.
(10)	a decision in which the *AER* decides other appropriate amounts, values or inputs	ActewAGL Distribution's proposed energy forecasts of energy sales, along with explanations and supporting documentation, which are required under the average revenue cap control mechanism determined by the AER, are provided in chapter 5.
(11)	a decision on the form of the control mechanisms (including the X factor) for *standard control services* (to be in accordance with the relevant *framework and approach paper*) and on the formulae that give effect to those control mechanisms	ActewAGL Distribution proposes to adopt the form of the control mechanisms and the formulae determined by the AER in the Stage 1 F&A paper (see chapter 13).
(12)	a decision on the form of the control mechanisms for *alternative control services* (to be in accordance with the relevant *framework and approach paper*) and on the formulae that give effect to those control mechanisms	ActewAGL Distribution proposes to adopt the form of the control mechanism and the formulae determined by the AER in the Stage 1 F&A paper. The proposed basis for the control mechanism for alternative control services is set out in chapter 15.
(13)	a decision on how compliance with a relevant control mechanism is to be demonstrated	ActewAGL Distribution's proposals on demonstrating compliance with the control mechanisms are provided in chapter 13 (standard control services) and chapter 15 (alternative control services).
(14)	a decision on the additional *pass through events* that are to apply for the *regulatory control period* in accordance with clause 6.5.10	ActewAGL Distribution's proposal for additional pass through events is provided in chapter 17.

	Constituent decision	ActewAGL Distribution proposal
(15)	a decision on the *negotiating framework* that is to apply to the *Distribution Network Service Provider* for the regulatory control period (which may be the *negotiating framework* as proposed by the *Distribution Network Service Provider*, some variant of it, or a framework substituted by the AER)	ActewAGL Distribution's position on the negotiating framework is provided in chapter 14. Given that the AER has not classified any ActewAGL Distribution services as negotiated distribution services, no negotiating framework is submitted.
(16)	a decision in which the AER decides the *Negotiated Distribution Service Criteria* for the *Distribution Network Service Provider*	ActewAGL Distribution's position on the NDSC is provided in chapter 14. Given that the AER has not classified any ActewAGL Distribution services as negotiated distribution services, no *Negotiated Distribution Service Criteria* are submitted.
(17)	a decision on the procedures for assigning *retail customers* to *tariff classes*, or reassigning *retail customers* from one *tariff class* to another (including any applicable restrictions)	ActewAGL Distribution's proposal is set out in chapter 13.
(17A)	a decision on the approval of the proposed pricing methodology for transmission standard control services (if rule 6.26 applies)	ActewAGL Distribution's transmission pricing methodology is set out in Attachment D15.
(18)	a decision on whether depreciation for establishing the regulatory asset base as at the commencement of the following *regulatory control period* is to be based on actual or forecast capital expenditure	ActewAGL Distribution's depreciation proposal is provided in chapter 9. The proposal is to adopt forecast depreciation.
(19)	a decision on how the *Distribution Network Service Provider* is to report to the AER on its recovery of *designated pricing proposal charges* for each *regulatory year* of the *regulatory control period* and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges	ActewAGL Distribution's proposals for reporting on recovery of designated pricing proposal amounts and subsequent adjustments for under or over recovery are provided in chapter 13.
(20)	a decision on how the *Distribution Network Service Provider* is to report to the *AER* on its recovery of *jurisdictional scheme amounts* for each *regulatory year* of the *regulatory control period* and on the adjustments to be made to subsequent *pricing proposals* to account for over or under recovery of those amounts. A decision under this subparagraph (20) must be made in relation to each *jurisdictional scheme* under which the *Distribution Network Service Provider* has *jurisdictional scheme* obligations at the time the decision is made	ActewAGL Distribution's proposals for reporting on recovery of jurisdictional scheme amounts and subsequent adjustments for under or over recovery are provided in chapter 13.
(21)	a decision on the *connection policy* that is to apply to the *Distribution Network Service Provider* for the *regulatory control period* (which may be the *connection policy* as proposed by the *Distribution Network Service Provider*, some variant of it, or a policy substituted by the *AER*	ActewAGL Distribution's proposed connection policy is provided at Attachment D13. An overview is provided in chapter 18.

Clause 11.56.4 of the Rules sets out transitional provisions that apply to the making of the distribution determination for the subsequent regulatory control period for ActewAGL Distribution. Under clause 11.56.4(j):

> *The determination by the AER of the amount of the notional annual revenue requirement for the transitional regulatory control period under paragraph (c), and of the adjustment amount under paragraph (i), are each taken to be constituent decisions for the purposes of clause 6.12.1 of current Chapter 6.*

ActewAGL Distribution's proposals for the notional revenue requirement for the transitional regulatory period and the adjustment amount are provided in chapter 12 (revenue requirement).

3 Consumer engagement

This chapter discusses activities undertaken by ActewAGL Distribution to engage with the needs of consumers and its consumer engagement strategy going forward.

ActewAGL Distribution has a long-standing commitment to its consumers and has consulted with consumers through a range of mediums in the past. It recognises that broader consumer engagement is a growing priority in the energy sector and has formalised its consumer engagement through the development of a consumer engagement strategy, to be rolled out over the 2014–19 regulatory period, which sets out a clear path for engagement with consumers in the future.

ActewAGL Distribution's existing communication with consumers is extensive, using traditional written correspondence, information brochures and face to face meetings; through to information campaigns, mainstream media, social media and online information.

Over the 2014–19 regulatory period, ActewAGL Distribution intends to build on its commitment to providing excellent customer service and existing communications to focus on ways to better understand its consumers' views and develop proactive initiatives to engage with consumers into the future. Effective engagement will enable ActewAGL Distribution to work with consumers to ensure it can respond to the changing operating environment and needs and expectations of the communities served.

ActewAGL Distribution's consumer engagement activities for the 2014–19 regulatory period will provide a number of long term benefits to consumers. These include:

- through implementation of the consumer engagement strategy, consumers will benefit from having their views, expectation and preferences better understood by ActewAGL Distribution.
- improved alignment of ActewAGL Distribution's service provision with long term consumer interests.
- improved opportunities for consumers to be informed, ask questions and provide feedback about ActewAGL Distribution's policies, products and services.
- improved understanding of the drivers of electricity distribution charges and the value of products and services provided by ActewAGL Distribution.

3.1 Requirements of the Rules and the AER

3.1.1 Requirement of the Rules

The National Electricity Objective requires electricity transmission and distribution network service providers (NSPs) to operate networks in the long term interests of consumers. As part of the changes to the Rules that were finalised in December 2012 clause 6.8.2(c1)(2) requires, as part of an accompanying overview paper:

> *a description of how the Distribution Network Service Provider has engaged with electricity consumers and has sought to address any relevant concerns identified as a result of that engagement.*[23]

ActewAGL Distribution has provided this within the overview paper provided with this regulatory proposal, and also sets out its consumer engagement activities within this chapter.

3.1.2 AER consumer engagement guideline

As part of its better regulation reform program, the AER developed a consumer engagement guideline for NSPs. The guideline was released in November 2013 and sets out a framework for NSPs to improve consumer engagement. The guideline aims to support the intentions of rule makers and governments that brought about the changes to the Rules relating to consumer engagement and give guidance on the AER's expectations of consumer engagement. The guideline is not binding, however the AER has stated its expectation that service providers adopt its guideline[24] and its intention to have regard to how service providers have engaged with consumers and accounted for the long term interests of those consumers when reviewing regulatory proposals.[25]

The guideline is not prescriptive, but it is expected that NSPs will develop their approach to consumer engagement in a way that addresses the best practice principles and four key components of the guidelines, being priorities, delivery, results and evaluation and review.

The four best practice principles set out by the AER are:

- clear, accurate and timely communication
- accessible and inclusive
- transparent
- measurable

ActewAGL Distribution supports these overarching principles and has committed to underpinning its consumer engagement activities with these principles as it moves into a new era of consumer engagement. This is detailed in section 3.3 of this chapter.

[23] *National Electricity Rules*, clause 6.8.2(c1)(2)

[24] AER 2013, *Consumer engagement guideline for network service providers,* November, p 5

[25] AER 2013, *Consumer engagement guideline for network service providers,* November, p 4

3.2 Current consumer focus

ActewAGL Distribution's current and past consumer engagement and communication activities include:

- willingness to pay studies;
- major projects consultation;
- major/critical customer engagement;
- demand side engagement strategy;
- customer satisfaction surveys;
- time of use and demand pricing; and
- other customer communications including:
  - the ActewAGL Distribution website;
  - social media; and
  - network safety communications including advertising campaigns and media releases.

3.2.1 Willingness to pay studies

ActewAGL Distribution's major consumer engagement initiative to date has been to periodically undertake studies into customer willingness to pay (WTP) for changes in service levels. These studies used targeted focus groups and surveys to obtain meaningful information on customer preferences in relation to striking a balance between cost and levels of service. The interaction with customers that has taken place as part of this research has enabled ActewAGL Distribution to gain a deep and considered understanding of customer preferences, attitudes and views. The focus on quantification of preferences has delivered results that have direct relevance to making investment and operating decisions in customers' interests.

ActewAGL Distribution has been at the forefront of WTP research within the utilities sector over the last decade, utilising world-leading authorities in the application of choice modelling techniques to valuation of utilities service quality. Three WTP studies have been undertaken over that period—in 2003, 2009 and 2011-12.

The first study was undertaken for ActewAGL Distribution and ACTEW Corporation by NERA Economic Consulting (NERA) and ACNielsen in 2003.[26] The study measured the WTP and attitudes of both residential and non-residential customers across a range of attributes of water, gas and electricity network services in the ACT, with the focus of the electricity component of the

[26] For details of the residential electricity component of the study, see: Hensher, D.A., Shore, N., Train, K. (2014). *Willingness to pay for residential electricity supply quality and reliability*. Applied Energy 115, 280-292

study on the quality and reliability of supply. The research was prompted by an enquiry from the Independent Competition and Regulatory Commission about whether customers prefer lower service standards at lower prices and if, as a result, service standards are excessive.

More than 480 customers participated in the electricity component of the 12-month project, which included focus groups, face-to-face questioning, and computer-aided telephone interviews. Separate focus groups were held for small and large business organisations, government organisations, and residential (including concession card holder) consumers. NERA used a stated preference choice modelling survey to reveal customer preferences, simulating a market environment by providing customers with choices between various scenarios described in terms of service quality and price. Two leading authorities in the application of this technique were part of the research—Professor Ken Train and Professor David Hensher. The findings showed that, as far as customers were concerned, ActewAGL did not wastefully over-engineer (or 'gold plate') its infrastructure and that customers did not want lower service levels at corresponding lower prices.

The study found that customers were less concerned with planned (than unplanned) outages of a given duration, as long as they were given sufficient notice of that outage (two to seven days prior notice). ActewAGL Distribution has continued to undertake a relatively high proportion of planned (rather than reactive) maintenance on the network in recognition of this finding and the difficulties associated with accessing backyard reticulation to address unplanned outages.

The research found that 37 per cent of respondents in areas with overhead wires indicated that keeping trees clear of powerlines was a problem for them. This finding prompted ActewAGL Distribution to consider options for addressing this concern, including replacing existing overhead supply infrastructure with underground wires (undergrounding). Some 22 per cent of respondents with overhead wires had nominated undergrounding as a required improvement to supply.

The second study in 2009 investigated this issue directly. It was undertaken by the Australian National University (ANU) and University of Sydney and focused on estimating residential customers' WTP for undergrounding in established urban areas.[27] The study was overseen by two of Australia's leading exponents of the choice modelling valuation technique—Professor Jeff Bennett and Professor David Hensher. A survey of 1755 residential customers, including 11 in-depth, face-to-face interviews, found large variation in WTP, with the highest economic benefits likely to be achieved by undergrounding in areas with higher household income and older residents where improved appearance, safety, tree trimming, or restrictions on the use of yard space are of concern. Subsequent analysis by ActewAGL Distribution indicated that there may be economic merit in undergrounding at least some suburbs in Canberra.

[27] McNair, B.J., Bennett, J., Hensher, D.A., Rose, J.M. (2011). *Households' willingness to pay for overhead-to-underground conversion of electricity distribution networks*, Energy Policy 39, 2560–2567.

The most recent study in 2011/12 was an independent research project undertaken by researchers at the ANU (with peer review by Professor Riccardo Scarpa) into the preferences of Canberra households for water, gas and electricity network services, including electricity supply reliability. Some 414 residential customers participated in the electricity component of the study—six in-depth, face-to-face interviews, and 408 in an online choice modelling survey. The findings were generally consistent with those of the 2003 study, with the vast majority of customers expressing the view that ActewAGL Distribution networks are well maintained and that ActewAGL Distribution is responsive in the event of a supply problem. The average value placed on avoiding supply interruptions had not changed markedly in real terms since the 2003 study. The study confirmed that residential customers dislike all types of supply interruptions, but that the nature of the interruption matters. WTP to avoid additional interruptions increases with interruption duration and WTP to avoid unplanned interruptions is around twice the level of WTP to avoid planned interruptions.

The results of this study and the non-residential component of the earlier 2003 study have been used to develop ActewAGL Distribution's proposal in relation to the Service Target Performance Incentive Scheme so that incentives align with ACT customers' preferred balance between reliability and cost.

3.2.2 Major projects consultation

ActewAGL Distribution has undertaken targeted stakeholder consultation during the planning and construction phases of major capital projects to ensure effected stakeholders are informed and any issues can be addressed.

One example is the construction of the East Lake Zone Substation, a new 132/11 kV zone substation built to increase the capacity of the distribution network supplying the South Canberra region and meet growing demand in areas such as Fyshwick, the Canberra Airport precinct and South Canberra. The site is situated within the Jerrabomberra Wetlands.

The East Lake Zone Substation development will be undertaken in two stages. Stage 1 was completed in early 2014 and involved the construction of a new zone substation and undergrounding of high voltage transmission lines to Bruce and City East.

Throughout the planning phase of this project, ActewAGL Distribution consulted closely with the Friends of the Jerrabomberra Wetlands group to ensure positive environmental outcomes. Interested stakeholder groups were also engaged throughout the process, including the Conservation Council ACT, local government representatives and MPs.

During construction of major transmission and substation projects ActewAGL Distribution undertakes detailed environmental impact investigations to comply with the *Environment Protection and Biodiversity Conservation Act 1999* and to consider and minimise the impact of these projects on the environment. During these investigations ActewAGL Distribution has consulted affected property owners and conducted public forums to engage other stakeholders to address their issues. Specialist consultants have been engaged during these processes to facilitate this engagement including the onsite investigations to identify the impact and make recommendations.

3.2.3 Consultation with major customers

ActewAGL Distribution's major customers include developers, local and federal government, large industrial and commercial businesses, educational facilities and hospitals. ActewAGL Distribution has formed strong working relationships with these major customers.

These relationships are maintained by the Customer Connections Branch whose function is to manage key customer interfaces relating to all major, minor and routine connections, and to oversee the delivery of optimal supply and demand side solutions. Activities covered include technical assistance, account and tariff queries, outage management and notification, system planning and demand management. This business unit has dedicated account managers who are in regular contact with ActewAGL Distribution's existing and prospective large customers to assist their operations or future planning.

For major proposals such as a new ACT urban development like Molonglo or the Canberra Airport Expansion, joint working groups are established with monthly meetings between the key parties. Consultation with major ACT stakeholders, such as the Land Development Agency, also occurs to facilitate future development opportunities.

ActewAGL Distribution also meets regularly with industry groups to share knowledge and discuss issues of mutual and concern, such as quarterly meetings with the Master Builders' Association and its members.

ActewAGL Distribution works in partnership with major customers to assist them in managing issues such as demand and load constraints. A key step in this process is being able to identify each customer's needs. A good example of this is the work undertaken with one of ActewAGL Distribution's major customers, the ANU. ActewAGL Distribution and the ANU have regular meetings to discuss issues of importance such as possible demand management schemes.

3.2.4 ActewAGL Distribution's demand side engagement strategy

ActewAGL Distribution's demand side engagement strategy aims to create a cooperative and proactive relationship with customers and proponents of non-network demand management solutions, and involve them in ActewAGL Distribution's network planning and expansion. ActewAGL Distribution will then encourage customers and potential non-network service providers to participate in demand management activities with the objective that future network problems can be met by a full range of solutions to achieve optimal economic and technical outcomes.

ActewAGL Distribution's demand side engagement strategy objectives are:

- to embrace demand side management (DSM) and provide opportunities to our customers and non-network service proponents to participate in resolving network and customer supply limitations;

- develop and apply a transparent DSM process for network planning and development;
- identify DSM options for individual and broad based demand management situations;
- provide proponents of non-network solutions with simple and effective mechanisms for obtaining information on network development proposals; and
- develop demand management tools and industry alliances to readily facilitate non-network options.

ActewAGL Distribution's DSM planning process includes a public consultation phase. Initial public consultation will take place as part of the evaluation phase and is aimed at gathering additional information to determine the level of incentives which should be offered to the participants to make DSM schemes attractive. ActewAGL Distribution and proponents will co-operatively conduct technical studies to determine the suitability and effectiveness of the solutions. The financial benefits for all parties will be calculated at this stage to determine financial viability. Further public consultation may be carried out as part of the assessment phase, and ongoing consultation with potential DSM providers will take place throughout the process.

ActewAGL Distribution maintains comprehensive information on DSM on its website and provides opportunities for prospective users and interested parties to contact ActewAGL Distribution for further information through a dedicated email address or register interest through an online contact form.

Further information on ActewAGL Distribution's DSM planning process is provided in chapter 6 of this proposal.

3.2.5 Customer satisfaction surveys

ActewAGL undertakes a customer satisfaction survey annually. These surveys cover the ActewAGL brands and include both ActewAGL Distribution and ActewAGL Retail. The surveys provide valuable information on overall levels of customer satisfaction and level of awareness of and engagement in ActewAGL's communication channels such as the website, social media and customer newsletter.

These surveys cover such areas as overall satisfaction, products and services, performance and reliability, customer contact and communication. ActewAGL consistently performs well in its customer satisfaction surveys. The most recent study undertaken in 2013 achieved an overall satisfaction score of 88 per cent, with only 2 per cent of respondents being dissatisfied.

3.2.6 Time of use and demand pricing

Since 1 October 2010 all customers connecting to the network are put on a time of use (TOU) network tariff, unless they choose an alternative. This enables customers to reduce their network charges if consumption is shifted from peak to shoulder or off-peak times.

The application of maximum demand and capacity charges in several commercial tariff options has further strengthened price signals to customers, provided incentives to use the network more efficiently and resulted in a significant customer response. The maximum demand charges signal to customers the relatively high cost of providing capacity to meet demand and provide incentives to customers to improve both their load factor (that is, spread their load more evenly) and power factor (which allows the existing network to deliver more energy).

Over the long–term, the shifting of households' and businesses' electricity load to off peak times has the potential to reduce the impact of consumption on the available capacity of the electricity network and defer capital expenditure.

3.2.7 Other customer communications

3.2.7.1 Website

ActewAGL Distribution's website provides useful information on topics such as energy saving tips, major capital projects, safety advice, network standards and guidelines, and network pricing. A major increase in the functionality of this website is planned over the coming year.

3.2.7.2 Social media

ActewAGL Distribution is actively engaged in social media, predominantly using Twitter and Facebook for two-way communication with its customers. These channels are particularly useful during crisis situations such as the heatwave Canberra experienced in January 2014, as well as for major projects of public interest like the helicopter inspections of urban powerlines in February 2014. Day-to-day interaction also occurs on topics ranging from power outages, overgrown vegetation near powerlines and meter faults. Some examples of ActewAGL Distribution's use of social media to inform consumers are below.

Online outages tool

An automatic electricity outage notification tool went live in December 2013. Real time tweets are sent about outages, and are linked to ActewAGL Distribution's website outage notifications page. There has been a spike in Twitter followers since the tool went live, with positive feedback from customers who appreciate being proactively notified about electricity outages affecting their suburb.

Helicopter patrols

Facebook and Twitter were actively used during ActewAGL Distribution's helicopter vegetation patrols during February 2014. The schedule of public announcement messages informed customers about the purpose of the low flying helicopter patrols and updated them about the helicopter's flight path. ActewAGL Distribution received a large number of questions about the patrols via social media and liaised with contacts at Networks to provide responses.

January 2014 heat wave

A large number of tweets and Facebook posts were generated and responded to regarding planned electricity outages during extreme heat conditions in January 2014. Daily social media updates were sent when necessary to inform customers of cancelled planned outages.

3.2.7.3 Network safety communications including advertising campaigns and media releases

A large number of ActewAGL Distribution's normal electrical distribution functions are conducted with periodic or annual public awareness campaigns on key areas such as tree clearing around power lines, extreme weather events and public safety, as well as media releases on progress of major projects.

3.3 Consumer engagement for the 2014–19 determination process

ActewAGL Distribution has undertaken initial consultation with stakeholders during the determination process and will continue to engage throughout the determination process. Initial consultation has included meetings with the following key stakeholders on key elements of this proposal such as the connection policy:

- ACT Independent Competition and Regulatory Commission
- ACT Government Environment and Sustainable Development Directorate
- Master Builders' Association
- Housing Industry Association
- Property Council of Australia
- Land Development Agency

Engagement with consumers more broadly will involve a public information session following submission of this proposal, as well as an update of ActewAGL Distribution's website to include additional information on consultation opportunities, the transitional arrangements, the connection policy and manual as well as fact sheets containing a range of useful information for consumers.

3.4 Consumer engagement 2014–19

3.4.1 Consumer engagement strategy—stage 1

While ActewAGL Distribution's existing communication with consumers is extensive, ActewAGL Distribution is formalising a consumer engagement strategy that will set out a clear path for engagement with consumers in the future.

Stage 1 of the consumer engagement strategy has been prepared and will be rolled out over the coming regulatory period. Through implementation of this strategy, ActewAGL Distribution seeks to achieve a greater understanding of the views, expectation and preferences of its consumers. For the consumer engagement strategy, ActewAGL Distribution has defined consumers as *people and organisations that use its services in relation to its electricity and gas networks.* ActewAGL Distribution consumers can be grouped into the following categories:

- **Residents—**the families and households that access energy provided through the distribution networks;
- **Large and or critical customers—**those customers that access large amounts of energy, have more than standard infrastructure or those, such as hospitals, having specialist service delivery needs;
- **Commercial business owners**—businesses of all sizes (including home based businesses) that access energy through the network, or provide goods and services associated in relation the network; and
- **Land and property developers**—through the creation of new network infrastructure to service their developments.

The strategy also provides a basis for expanding the focus of ActewAGL Distribution's engagement program beyond consumers to other key stakeholder areas including partners, regulators, shareholders and those with a particular special interest such as emergency services or regional local councils. It establishes a framework for the delivery of stage 1 and longer term consumer engagement plans.

3.4.1.1 Consumer engagement objectives

The objectives of ActewAGL Distribution's consumer engagement strategy—stage 1 are to:

- foster a strong alignment between consumer interests and ActewAGL Distribution's products and service offerings;
- embed best practice consumer engagement in ActewAGL Distribution so that it becomes part of the way ActewAGL Distribution does business; and
- ensure ActewAGL Distribution meets its regulatory obligations relating to consumer engagement.

Through achieving these objectives, the following consumer outcomes will be realised:

- consumers will recognise they have an opportunity to ask questions and provide feedback and they will be listened to;
- consumers will be better informed and empowered to participate in conversations about our policies, products and services; and
- ActewAGL Distribution's products and services will be even more relevant and valued by its consumers.

Success will be demonstrated by the embedding of practices within ActewAGL Distribution's business systems and processes that foster and facilitate ongoing engagement with our stakeholders and the strengthening of a consumer-focussed culture.

3.4.1.2 Consumer engagement benefits

Working towards the above objectives and strengthening a culture of engagement will provide benefits to both ActewAGL Distribution and its consumers.

For ActewAGL Distribution stronger engagement with consumers will:

- deliver more informed decision-making to better balance the need for ActewAGL Distribution's operations to be technically feasible and financially viable while also being acceptable to the community and the local environment;
- ensure the delivery of services is matched to the needs and expectations of consumers;
- result in efficiencies in service delivery by reducing delays and re-work through better, earlier, liaison with those directly impacted by works and a greater understanding of their needs and expectations; and
- capture early and direct input from consumers to better inform long-term planning and associated reporting to regulators and other authorities.

For consumers better engagement will:

- result in more comprehensive, relevant and timely information on the work of ActewAGL Distribution and its potential impacts;
- mean increased and more regular opportunities to provide input in relation to issues that they are most interested in; and
- lead to a better understanding of what decisions impact on energy bills and therefore more transparency around decision-making and the impacts of regulatory activities and processes.

3.4.1.3 Engagement principles

ActewAGL Distribution's consumer engagement will be guided by the overarching principles listed in Table 3.1, which are in line with those recommended by AER.

Table 3.1 ActewAGL Distribution overarching principles for consumer engagement

Principle	What this means for our consumers
Clear, accurate and timely information	Information will be provided that is useful, relevant and easy to understand so that consumers can make informed choices and contribute effectively to the conversation.
Accessible and inclusive	Consumers will be engaged broadly across relevant communities and through a variety of interactions, so that they have the opportunity to participate in discussions, express opinions and understand the outcomes of conversations.
Transparent	Engagement with consumers will be open and honest, with regular and meaningful reporting, to enable an understanding of how consumer views and comments were taken into consideration.
Measurable	Each consumer engagement activity will establish clear and measurable criteria against which the success of the engagement can be measured. This will allow for continued improvement across the entire engagement program and ensure ActewAGL Distribution is accountable against the objectives of each engagement activity.
Long-term	Engagement with consumers will be on-going and regular, recognising that consumers will be at differing levels of understanding and involvement in our organisation over time.

3.4.1.4 ActewAGL Distribution's consumer engagement strategy roadmap

Stage 1 of the consumer engagement strategy is focussed on:

- investing in better understanding consumers, what their needs, perceptions and expectations are, and how they would best like to be communicated with and engaged in ActewAGL Distribution's work;
- building recognition within ActewAGL Distribution of the importance of engagement with consumers; and
- reconsidering business practices to encourage engagement across ActewAGL Distribution's work.

Figure 3.1 shows ActewAGL Distribution's planned consumer engagement pathway to 2019.

Figure 3.1 Consumer engagement roadmap 2014—2019

3.4.1.5 Stage 1 consumer engagement activities

Stage 1 consumer engagement activities will follow three clear steps (as shown in Figure 3.2)—to further understand ActewAGL Distribution's consumers, to continue the conversation with consumers and to start the work of reviewing business processes and establishing clear stage 2 priorities for the future. The work of stage 1 will be informed by the consumer engagement activities already completed or underway as detailed in section 3.3.

These activities will be aided by ActewAGL Distribution's planned investment in an engagement and information portal as detailed in section 7.12.3.3 of this proposal.

Figure 3.2 Steps in consumer engagement activities

ActewAGL Distribution will **better understand its customers** through consumer analysis out of which it will develop consumer stakeholder performance indicators against which to measure progress

ActewAGL Distribution will **continue the conversation** by creating improved consumer engagement pathways, including the creation of a Consumer Reference Group

ActewAGL Distribution will work on **processes and plan for Stage 2** through a review of business processes and developing a culture of consumer centricity

3.4.1.6 Consumer engagement resourcing

To implement ActewAGL Distribution's consumer engagement strategy resources will be required, particularly with respect to project management of the strategy and implementation engagement activities detailed in the strategy. ActewAGL Distribution proposes for one full-time resource to be allocated to the consumer engagement work along with funds for relevant consultancies. This additional resourcing is required to ensure ActewAGL Distribution's consumer engagement is driven by dedicated and appropriately skilled staff, with assistance from expert consultants as required. This additional resourcing has been included in ActewAGL Distribution's operating expenditure forecast and in the step change for regulatory compliance and strategy as detailed in Attachment B10.

This Strategy does not require additional expenditure for any anticipated amendments to business process that may be identified as part of the business process review undertaken during stage 1. Amendments to business processes, development of new systems and allocation of appropriate staff resources will be considered at part of stage 2.

4 Regulatory obligations and requirements

This chapter summarises regulatory obligations and requirements required to be adhered to by ActewAGL Distribution which are also a substantial driver of the costs facing ActewAGL Distribution in the construction, operation and maintenance of its electricity network.

4.1 Key points

- 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 ACT's Independent Competition and Regulatory Commission and other relevant regulators.
- There are a number of new or changing regulatory requirements that have had an impact in the 2009–14 regulatory period. These include a significant increase in regulatory reporting, the National Network Planning and Expansion Framework, the National Energy Customer Framework and the *Work Health Safety Act 2011*.
- There are also a number of new or changing regulatory requirements that are likely to emerge in the 2014–19 regulatory period. These include a proposed national STPIS, the Demand Management and Embedded Generation Connection Incentive Scheme, the AEMC review of national frameworks for network reliability and the ACT Government's Light Rail Project.

Table 4.2 provides a more detailed overview of the new and changing obligations to face ActewAGL Distribution. This is followed by a description of the changing regulatory obligations in the sections that follow.

4.2 Consumer benefits

The regulatory obligations and requirements imposed upon ActewAGL Distribution have generally been developed with the intent of meeting the reliability, safety and security expectations of consumers. They seek to:

- ensure compliance with technical requirements involved in owning, managing and operating electricity network assets;
- ensure compliance with obligations imposed on ActewAGL Distribution as a natural monopoly provider;
- improve consumer engagement;
- improve the safety of ActewAGL Distribution staff and contractors and the public through compliance with the procedures and processes required to operate, maintain and build network assets;

- ensure compliance with responsibilities as an operator in the ACT environment, including preparation for emergencies, as well as natural and built environment issues; and
- ensure compliance with obligations relating to the role of ActewAGL distribution as a distribution network service provider in the National Electricity Market.

4.3 Requirements of the NEL and the Rules

Compliance with applicable legislative and regulatory obligations and requirements associated with the provision of standard control services is one of the four objectives for capital and operating expenditure set out in the Rules.[28] The building block proposal prepared by ActewAGL Distribution under the 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 associated with the provision of standard control services.

Section 4.5 of this chapter describes the broad range of legislative and 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 2014–19 regulatory period, described in chapters 6, 7 and 8. The chapter also includes new or changing obligations in section 4.6.

This chapter and associated RIN 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 *Competition and Consumer 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.

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[28] *National Electricity Rules,* clauses 6.5.6(a)(2) and 6.5.7(a)(2)

ActewAGL Distribution's electricity network operations in the ACT are subject to a significant number of legislative and regulatory obligations. The number of obligations increased significantly during the 2009–14 regulatory period, in part due to the introduction of the National Energy Customer Framework (NECF) in 2012. This is discussed further in section 4.7.4 below. To facilitate compliance with an ever increasing number of legislative and regulatory obligations ActewAGL Distribution upgraded its legal compliance framework during the 2009–14 regulatory period. Implementation of the legal compliance database (CMO) has improved end to end capability, ensuring the capture and implementation of new and amended obligations relevant to ActewAGL's operations, and monitoring of compliance against these obligations. The implementation of NECF included training and support activity for both CMO and for NECF compliance in general. This included training right across the business on how to use CMO, and also includes fact sheets, intranet content and other services (for example, legal advice) to optimise compliance with the NECF.

4.4 Categories of regulatory 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.

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 creates 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 Work Health & Safety Act 2011(ACT)*, the *Electricity Safety Act 1971 (ACT)*, the *Building Act 2004 (ACT)*, the *Construction (Occupations) 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 act 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)*, the *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 Australian Energy Market Operator (AEMO), *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 on 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.

4.5 Key obligations

4.5.1 Industry obligations

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.

4.5.1.1 Utilities Act 2000

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* is also the Act under which numerous technical codes are enforced. For example, the *Electricity Network Boundary Code 2000* and the *Emergency Planning Code 2011*.

The *Utilities Act* also requires ActewAGL Distribution pay an Energy Industry Levy (EIL). The EIL covers national and local regulatory costs, including a contribution to support the AEMC. ActewAGL Distribution is also required to pay a Utilities Network Facilities Tax (UNFT).

These costs are determined annually, and can change from year to year, as determined either by the levy administrator or the ACT government. Following acceptance of ActewAGL Distribution's request that the AER determine that the Energy Industry Levy and the Utilities Network Facilities Tax are jurisdictional schemes, forecasts of these costs are not included in the distribution revenue requirement. Instead forecast amounts are included in the annual network pricing proposal, and prices are adjusted to account for any under or over recovery in payment amounts associated with the schemes.

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; and
- on application, vary the capacity of the connection between the premises and the network.

This obligation leads to significant customer initiated capital expenditure which is often difficult to forecast. This is discussed in more detail in section 7.9.

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 asset management Plan, and drive significant capital and operating costs. Additional costs are incurred where there are delays in issuing notices, 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.

Although these regulations have not yet been applied, 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.

4.5.1.2 Territory-owned Corporations Act 1990

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.

4.5.1.3 Utility 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 historical and forecast operating costs. Approaches and measures to minimise network losses are highlighted in chapter 6 of this regulatory proposal, describing network planning and management.

4.5.1.4 National Energy Customer Framework

The National Energy Customer Framework (NECF) commenced in the ACT on 1 July 2012, introducing a new set of national laws, rules, and regulations governing the sale and distribution of energy to retail consumers. The NECF involves the transfer of current state and territory responsibilities to a new national regulatory regime to apply to the sale and supply of energy to retail customers, including new connections to distribution networks. The NECF framework primarily deals with:

- the retailer-customer relationship and associated rights, obligations and energy specific consumer protection measures;
- distributor interactions with customers and retailers, and associated rights, obligations and consumer protection measures;
- national retailer authorisations (previously jurisdictionally licensed); and
- compliance monitoring, enforcement and performance reporting.

The NECF comprises a number of key instruments including:

- National Energy Retail Law (NERL);
- National Energy Retail Regulations;
- National Energy Retail Rules;
- Amendments and additions to the Rules made under the *National Electricity Law*; and
- Amendments and additions to the Rules made under the *National Gas Law*.

The Retail Law and Rules set out key protections and obligations for energy customers and the retail and distribution businesses they buy their energy from. The AER monitors and enforces compliance with the Law and the Rules. Implementation of the framework has impacted on many parts of the business, including:

- distributor connection contracts;
- connection procedures;
- disconnection guidelines;
- complaints and dispute resolution procedures;
- access for customers to information; and
- reporting requirements.

There has been significant regulatory burden and costs associated with the introduction of NECF since 1 July 2012 to meet the increased reporting and audit requirements and to oversee process changes and improvements.

4.5.1.5 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 guaranteed service levels to which rebates can apply. These guaranteed service levels 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.

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.

4.5.1.6 Ring-fencing guidelines

Under clause 6.17.1 of the *Rules*, ActewAGL Distribution must comply with the Distribution ring-fencing guidelines prepared in accordance with clause 6.17.2.

ActewAGL Distribution is currently subject to ACT ring-fencing guidelines, the *Ring Fencing Guidelines for Gas and Electricity Network Service Operators 2002,* established under the then *National Electricity Code*. These guidelines require:

- legal separation of the network business from other related 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*.

In 2012, the AER undertook a review of jurisdictional electricity distribution ring-fencing arrangements, including the adequacy of current ring fencing arrangements and whether a nationally consistent set of Distribution Ring-Fencing Guidelines would be more appropriate.

The AER's preferred position is to develop national ring-fencing guidelines to apply to electricity distributors in the NEM.[29] The AER's preliminary view is that the guideline should allow for a wide range of obligations to be imposed, however the AER has not provided details.

In June 2013 the AER advised stakeholders that the process of developing the guidelines would be deferred.[30] ActewAGL submitted that the AER should only adopt new ring fencing guidelines where it is clear that they will result in better outcomes than the current jurisdictional arrangements. At the time of submitting this regulatory proposal, the likely additional costs for ActewAGL Distribution are unclear. ActewAGL Distribution has therefore proceeded on the basis that new or changed ring-fencing obligations would qualify as a regulatory change event and the additional costs would be recovered under the cost pass through provisions in the Rules, subject to materiality requirements.

4.5.2 Technical Obligations

4.5.2.1 Utilities Act 2000

The *Utilities Act 2000* (ACT) also includes obligations to comply with technical and safety regulations, administered through ACTPLA and the ACT 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.

[29] AER 2012, *Electricity distribution ring-fencing guidelines, Position paper*, September, p 11

[30] AER 2013, Electricity distribution ring-fencing guideline—deferral of consultation, Letter to stakeholders, 11 June

4.5.2.2 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. This code prescribes minimum standards for the quality and reliability of electricity distributed through electricity networks.

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*, which are set out in Table 4.1. In accordance with clauses 6.5.6 and 6.5.7 of the NER, the expenditure proposal for 2014-15 to 2018-19 set out in chapters 7 and 8 is the amount required to meet these minimum reliability standards.

Table 4.1 Minimum reliability targets under the Supply Standards Code

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

4.5.2.3 Management of Electricity Network Assets Code

The *Management of Electricity Network Assets Code* requires electricity distributors to design, construct, operate and maintain their electricity networks with reasonable care to avoid injury to any person or property.

The 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, the *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.

4.5.2.4 Electricity Service and Installation Rules Code

The *Electricity Service and Installation Rules Code* requires electricity distributors to develop service and installation rules that set out the requirements and associated obligations and procedures for the safe, reliable and efficient connection of electrical installations to an electricity network

The 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 *Service and Installation Rules*, which are available on the ActewAGL website.

4.5.2.5 Machinery Act 1949 and associated regulations

The *Machinery Act 1949* (ACT) gives rise to various regulations, some of which 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.

4.5.2.6 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.

4.5.3 Safety Obligations

There are a significant number of national and territory specific safety acts, regulations, codes, guidelines and standards relevant to ActewAGL Distribution. ActewAGL Distribution has not listed all of these obligations in this regulatory proposal however many newly updated health and safety obligations are predominantly contained in the Work Health and Safety harmonised laws that commenced in January 2012. The new *Work Health and Safety Act (2011)* and *Work Health, Safety Regulation (2011)* and accompanying codes which continue to be approved and released by the ACT government have resulted in ongoing reviews and updates to processes related to the design, construction and ongoing maintenance of the electricity network.

Compliance with health and safety obligations has made and will continue to make 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 practices emerge.

ActewAGL is committed to providing all of its employees with a workplace that is safe, does not impact on the environments in which it operates or affect the health or wellbeing of workers or the public. ActewAGL's Environment, Health, Safety and Quality (EHSQ) Division was created during the 2009–14 regulatory period to guide the organisation's cultural shift toward a proactive safety culture. Safety has been identified in the ActewAGL Strategic Outlook 2012-2022 as the number one priority for the organisation during the 2009–14 regulatory period and the next period. The Director of EHSQ Division, appointed in June 2011, reports to the CEO, and has a team of 11 staff who manage environment, sustainability, health, safety and quality programs across the organisation.

ActewAGL managers are required to display ongoing commitment and leadership to move toward a proactive safety culture by the end of 2015. This will be achieved by focusing on delivering measurable outcomes against a number of EHSQ projects to address identified changes in ACT and NSW health, safety and environmental legislation and to improve internal EHSQ procedures, particularly as they relate to employee participation, leadership, communication, competency, compliance and reporting.

Legislative change has been a key driver of expenditure on safety across the organisation during the 2009–14 regulatory period. Specifically, the introduction of the *Work Health and Safety Act (2011)* and *Work Health and Safety Regulation (2011)* which replaced the *Occupational Health and Safety Act (1989)* required ActewAGL Distribution to rewrite all of its safety policies and procedures. The new Act and Regulation requires these to be written in consultation with staff and then be accompanied by training. This has been a resource intensive and costly process that is anticipated to continue. The EHSQ division will continue to rewrite safety policies and procedures throughout the next regulatory period to ensure compliance with the new Act, Regulation and anticipated safety Codes of Practice. Currently, there are 13 draft codes of practice listed on the ACT WorkSafe website.

There is a continuing focus of the board and executive to strive for a proactive safety culture where hazards are identified early, safety is the responsibility of all and there is continual improvement in safety outcomes. This includes improvements in safety training including incident investigation training and improvements to ActewAGL's safety leadership development program and vehicle incident prevention training.

The Always Safe Integrated Management System has been designed to address these obligations, and puts in place training, procedures and processes to ensure compliance with all health, safety and environment obligations. This system works in conjunction with the recently implemented CMO (legal compliance) data base.

Many safety-related acts, codes and guidelines require ActewAGL Distribution to keep a record of each incident or near miss (dangerous incident) and notify dangerous or serious incidents to the safety regulator within specified timeframes. In addition, the *Electricity Safety Act* and the *Management of Electricity Network Assets Code* place an obligation upon distributors to report serious electricity accidents to the Construction Occupations Registrar under the *Construction Occupations (Licensing) Act 2004* and Chief Executive of ESDD, 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.

The reporting of incidents and near-misses was a key focus during the 2009–14 regulatory period. In 2012, ActewAGL Distribution implemented Guardian—a web based reporting system, which captures incidents, actions, hazards, risks and injury management information across all divisions. Guardian replaces at least five other computer databases and spreadsheets and is designed to be easier to use, enhance the current business processes and system functionality, and have greater reporting functionality.

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.

4.5.3.1 Work Health and Safety Harmonisation

The introduction on 1 January 2012 of Work Health and Safety (WHS) harmonisation legislation under the *Work Health and Safety Act and Regulation (ACT)* and related codes initiated a complete re-write of ActewAGL Distribution's safety policies and procedures. Whilst the objective of the legislation was to make WHS requirements easier to access and understand, it also required the modification of training materials, a review of risk assessments, safe work method statements and an assessment of the impact of the legislation on all contracted projects and in-house work practices. This was necessary to ensure compliance with the new legislation.

In response to this legislative change, ActewAGL Distribution changed its training approach from classroom WHS training to a risk based competency evaluation both prior to and at the work site, as this focuses the attention on the practical needs and obligations of workers.

ActewAGL Distribution also has obligations within the *Work Health and Safety Act 2011* (ACT) and the *Utility Networks (Public Safety) Regulation 2001* to ensure the public is aware of the hazards associated with the network. To meet these obligations, ActewAGL undertakes an integrated public safety awareness campaign with seasonal messages, advice and answers to frequently asked questions. The ActewAGL public safety 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. The public safety topics cover:

- bushfire safety;
- vegetation management;
- building near utility assets;
- safety during the storm season;
- reporting damaged infrastructure;
- Christmas light safety;
- overloading power points and power boards;
- reporting tingles and shocks;
- winter safety; and
- copper theft.

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 current, as well as ensuring that contractors are appropriately qualified. This is also part of the Always Safe Integrated Management System.

4.5.3.2 Work Health and Safety Act 2011

The *Work Health Safety Act 2011 (ACT)* was introduced during the 2009–14 regulatory period and replaces the previous *Occupational Health and Safety Act 1989 (ACT)*. In addition to having to re-write safety policies and procedures to comply with the legislation, it now clearly defines contractors and their sub-contractors as workers.[31]. This has necessitated additional contract management costs, the review of contractor workplace safety strategies and safety training

[31] As defined at Section 7, *Work Health and Safety Act 2011* (ACT)

before allowing contractors on site. All construction[32] jobs over $250,000 undertaken by ActewAGL Distribution now require their own Work Health and Safety Plan.

Another key element of the WHS Act 2011 includes more obligations for businesses that design plant, substances or structures.[33] In particular, safety in design has become a more stringent obligation than under the previous Occupational Health and Safety Act. Each person with control or influence over the design of plant, substances or structures now has some level of responsibility for identifying and assessing safety throughout the plant, substance or structure's lifecycle (including conception, redevelopment and disposal).[34]

The objective of safe design is to minimise potential and actual work health and safety hazards by involving decision makers and considering the life cycle of the designed plant, substance or structure. For designers, this means applying systematic risk management techniques to make informed choices regarding the design, materials and methods of manufacture or construction to enhance safety of those who will use, handle, store, construct, assemble, dismantle, dispose of or be affected by the operation of the plant, substance or structure.

This represents a significant additional impost on ActewAGL Distribution's asset management planning processes. The cost of meeting safety in design requirements have been included in ActewAGL Distribution's operating expenditure forecasts for the 2014–19 regulatory period.

4.5.3.3 Safety Codes of Practice

In 2013, SafeWork Australia members endorsed twenty three codes of practice as part of the national harmonisation of Work Health and Safety laws. A further six are awaiting endorsement. These codes of practice are having wide reaching impacts on ActewAGL Distribution's operations. For example, the *Managing the Work Environment and Facilities* code of practice applies to all workplaces (temporary, remote and mobile) and provides guidance on how to provide a physical work environment that is without risks to health and safety. In particular, it covers:

- the physical work environment, such as workspace, lighting and ventilation;
- facilities for workers, including toilets, drinking water, washing and dining areas, change rooms, personal storage and shelter;
- remote and isolated work; and
- emergency plans.

This one code alone is impacting on every site across the organisation and imposes new access and egress requirements under various emergencies.

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[32] As defined within *Work Health and Safety Regulation 2011* (ACT)

[33] Section 22, *Work Health and Safety Act 2011* (ACT)

[34] WorkSafe ACT, http://www.worksafety.act.gov.au/page/view/1249#What is Safe Design?

There are currently 13 codes listed on the WorkSafe ACT website that are likely to be introduced during the 2014–19 regulatory period. The impact on operating costs is discussed further in Chapter 8.

4.5.3.4 Electricity Safety Act 1971

The *Electricity 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.

4.5.3.5 Dangerous Substances Act 2004

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, and 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 historical and forecast costs. Discovery of asbestos, however, is highly unpredictable and regularly disrupts capital works. There are no accurate historical records on the use of and disposal 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. The costs associated with asbestos discoveries during customer connection work at residential and commercial development locations have increased significantly in recent years. This is because the regulations that apply to contaminated land were changed in November 2009 and now require the regulated disposal of asbestos, testing for fibrous asbestos, air monitoring and increased use of protective clothing. Each asbestos find requires a notification to ACT Environment Protection Authority and ACT WorkSafe via a Dangerous Substances Occurrence report, an independent assessor, a licensed asbestos removalist to develop an Asbestos Removal Control Plan and consultation with affected neighbours, the disposal to specific waste facilities and an independent assessor to issue a clearance certificate.

The unanticipated costs associated with asbestos discoveries during the current period have been as high as $20,000 per incident. ActewAGL anticipates that the incidences of unexpected asbestos discoveries will continue to increase over the 2014–19 regulatory period as the undergrounding of electrical assets continues in new development areas.

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 mechanisms 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, as well as educating and training employees. They must also record and document compliance with the system by persons with responsibilities under it.

Under the Always Safe Integrated Management System, ActewAGL Distribution has developed a set of general principles to be included in Work Method Statements (WMS). These are statements that set out the work activities in logical sequences and identify hazards and describe control measures. Each of these 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 maintain a register of non-residential asbestos sites under section 327 of the *Dangerous Substances (General) Regulation*. This database was completed during the 2009–14 regulatory period. In 2009 ActewAGL commissioned Robson Environmental to undertake asbestos surveys on all ActewAGL Distribution buildings and zone substations. All sites are reassessed by Robson on an annual basis. The most recent inspections, carried out on the 14 chamber substations, was carried out at a cost of $10,050 and the 9 zone substations at a cost of $720 each. In addition, ActewAGL Distribution is required to ensure all personnel working on meter boards have undergone asbestos awareness training and if a house is of a certain age, it is treated as if it contains asbestos.

The introduction of mandatory asbestos surveys in 2008 has increased the administrative burden to ActewAGL. All contractors must be provided with a copy of the asbestos report for each building or zone substation before work can commence on the site. ActewAGL Distribution must also assess any plans for building work on asbestos related sites. To comply with safety requirements in dealing with asbestos, all field, 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.

The ACT *Dangerous Substances Act* requires the following steps be taken where unexpected finds of asbestos occur during excavation work.

1. Work stops if anyone suspects asbestos.
2. Area cordoned off and anything suspected of containing asbestos is covered.
3. An asbestos consulting firm is called in to assess the situation and confirm the presence of asbestos
4. Once confirmed asbestos, WorkSafe and EPA are notified in writing. An asbestos removalist firm is engaged to come in and develop a control and removal plan.
5. The asbestos removalist organises the removal.

6. Tip clearance forms must be completed and approved before the tip will accept asbestos.
7. The tip provides approval and asbestos is removed.
8. The asbestos consulting firm returns to the site to confirm all asbestos has been removed and provides clearance for work to continue.

Occurrences of unexpected asbestos finds during excavation are becoming more frequent and are expensive both in terms of rectifying the asbestos situation and delaying works.

Currently, the regulations do not require the compulsory removal of in situ bonded asbestos from buildings and zone substations unless building work is being undertaken. Rather, it can be left in place, assessed on an annual basis and maintained. ActewAGL Distribution anticipates that the mandatory removal of bonded asbestos will be introduced in the ACT in the future. The removal of all known asbestos from buildings and zone substations would result in a significant cost impact for ActewAGL Distribution. Should this be introduced during the 2009–14 regulatory period, ActewAGL Distribution proposes this be treated as a regulatory obligation pass through event.

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 confirm the considerable responsibility on ActewAGL Distribution to ensure the security of any such dangerous or potentially polluting substances used on or in maintaining the network.

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).

ActewAGL Distribution is also undertaking an upgrade of air insulated equipment at zone substations, which involves replacing existing gas circuit breakers. Gas circuit breakers contain sulphur hexafluoride (SF6)—a very potent greenhouse gas. Existing circuit breakers containing 50kg of compressed SF6 are being replaced with new ones which contain only 2kg of SF6 gas, representing a significant environmental benefit.

4.5.3.6 Scaffolding and Lifts Act 1912

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.

WorkSafe ACT[35] indicates that the *Scaffolding and Lifts Act 1912* was expected to be repealed in 2012, as most of the provisions in that legislation are now provided in the new *Work Health and Safety Act 2011* (ACT), however this has yet to occur.

Safe Work Australia has developed a draft code of practice for Cranes and Scaffolding Works. These are currently in the process of receiving approval by the Ministerial Council and are likely to be approved for application in the ACT during the 2015-19 regulatory period. This will require ActewAGL Distribution to review and update processes, training and equipment.

4.5.3.7 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 changes in the Act or relevant standards make them necessary. The *Code* also requires annual reporting on compliance with the plan.

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 *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, the *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.

[35] WorkSafe ACT, http://www.worksafe.act.gov.au/page/view/2798#Codes%20of%20Practice

4.5.3.8 Fire proofing of substations

While ActewAGL Distribution built its zone substations in accordance with the Building Code of Australia at the time they were built, the Code has been updated over the years. In particular, the Building Code of Australia in its current form provides for a level of fireproofing for substations (type 8) that is greater than what is currently present in most of ActewAGL's substations. ActewAGL has included costs in the proposed capital expenditure program for updating its zone substations to accord with the current Building Code standard for fire proofing. ActewAGL Distribution will minimise costs by removing asbestos (above ground) from the sites simultaneous to the fireproofing activities.

4.5.3.9 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.

4.5.3.10 Bushfire mitigation

Bushfires pose a significant risk to life and property within local communities serviced by ActewAGL Distribution as well as to its employees, contractors and infrastructure. Within ActewAGL Distribution's area of operation, the potential for a damaging bushfire occurs every year as a result of weather and bushfire fuel conditions. On average, large uncontrollable bushfires with the potential to cause serious damage to ActewAGL assets and the community are expected within its area of operation every 7 years.[36]

There is an increasing awareness in the community, reflected in ActewAGL Distribution, of the vulnerability of the ACT to bushfire since the 2003 fires devastated parts of Canberra. Moreover, the 2009 Victorian bushfires and the subsequent civil case against SP AusNet as well as a class action launched against Endeavour Energy following the Blue Mountains bushfires in 2013 have highlighted the significant litigious risk facing ActewAGL Distribution of a bushfire event in the ACT and surrounding area.

ActewAGL Distribution has general powers under the *Utilities Act* (subject to other environmental, heritage and tree protection legislation outlined below) to manage assets and vegetation to ensure the safety and security of the electricity system.

Increased costs have also been associated with reducing the fire-risk of network assets and maintaining assets, and managing the distribution of electricity or load shedding on the network on fire prone days.

[36] ACT Government 2009, *Strategic Bushfire Management Plan for the ACT*, October, p v

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. Furthermore, the *Emergencies (Bushfire Abatement Zone) Declaration 2006*: Notifiable Instrument (NI 2006-226) declares essentially all land outside the built up urban areas of the ACT as a 'bushfire abatement zone.'

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 Plan complies with the *Utilities Act* and 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.

4.5.3.11 Environment Protection Act 1997

This Act confers powers and rights to help protect the environment from pollution and its effects. It provides the regulatory framework to help reduce and eliminate the discharge of pollutants into the air, land and water.

The Act establishes the Environment Protection Authority (EPA) as the statutory decision maker for environmental regulation and policy. The EPA administers legislation covering air and water quality, waste, contaminated land, noise control, pesticides and hazardous chemicals. Environmental Authorisations are required under the Act to import soil and other materials. ActewAGL Distribution must also be aware of the *Contaminated Land Management Act 1997 (NSW)* which also imposes requirements, for example on remediation of contaminated land.

4.5.3.12 Code of Practice

A code of practice was signed between ActewAGL Distribution and ACT Parks, Conservation and Lands (PCL) in 2003 and revised in 2009. The code sets out practical guidelines and standards to facilitate operation between PCL and ActewAGL on controlled land.

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, the management of access tracks and easements by ActewAGL Distribution, and obligations relating to weed management and vehicle washdown, and the use of herbicides and pesticides.

4.5.3.13 ACT Strategic Bushfire Management Plan 2009 (Version 2)

The ACT Strategic Bushfire Management Plan (SBMP) was prepared by the ACT Emergency Services Agency to meet the requirements of section 80 of the *Emergencies Act* and addresses all bushfire management elements as required by S74 of the Act. An over-arching principle of bushfire management in the ACT is that of shared responsibility between the ACT Government and the community for mitigating bushfire risk.

The goal of the SBMP is for the ACT Government and the community to work together to suppress bushfires and reduce their consequences on human life, property and the environment. The SBMP considers a range of assets which may be at risk from the effects of bushfire, including the built environmental (ecological, hydrological and physical), agricultural and cultural assets and determines appropriate and effective strategies and actions to minimise the risk to these.

ActewAGL Distribution anticipates that it will update its Bushfire Management Plan during the 2014–19 regulatory period to ensure consistency with the ACT Government’s SBMP.

4.5.3.14 Regional Fire Management Plans

Several Regional Fire Management Plans have been developed in order to ensure that the objectives, goals and actions of the SBMP are met. The regional plans detail the category and timing of actions required to meet the various standards of the various fire management zones. Fire Management Plans exist for the nine regions of Gudgenby, Tennent, Tidbinbilla, Tuggeranong, Cotter Dam, Canberra, Bungendore, Umburra and Hall.

4.5.3.15 ACT Building Act 2004 and Building Regulations 2008

The Building Code of Australia (BCA) is adopted in the ACT through the ACT *Building Act 2004*. The BCA contains provisions which can be used for construction design and works to resist bushfire attack in order to reduce the risk to human life and minimise the risk of property loss. The BCA provisions apply to land that has been declared to be a Bushfire Prone Area.

A Bushfire Prone Area for the ACT was declared through the *Building Regulations 2008*. All parts of the ACT outside the defined urban area have been designated as Bushfire Prone Areas. In Bushfire Prone Areas new development works for Class 1, 2 and 3 buildings and alterations are required to meet the provisions of the BCA and the Australian Standard AS 3959—Construction of buildings in Bushfire Prone Areas.

In addition, the Land and Planning Authority has the authority to request bushfire risk assessments be undertaken in areas not declared bushfire prone if particular features or circumstances of a site create a potentially higher bushfire risk. Depending on the nature of the proposed development and the type of bushfire risk assessment required under the Building Act, the assessments may be reviewed and determined by the Land and Planning Authority and or the Emergency Services Authority.

4.5.3.16 Planning

A dual planning regime, not dissimilar to other jurisdictions, is in place in the ACT. The *National Capital Plan* establishes the Australian Government's planning guidelines in ensuring that 'Canberra and the Territory are planned and developed in accordance with their national significance', as set out in section 9 of the *Australian Capital Territory (Planning and Land management) Act 1988*.

The ACT Government is responsible for the normal day-to-day planning and development matters. Development in the ACT is controlled through the *Planning and Development Act 2007* and *Planning and Building Regulation 2008* and the *Territory Plan 2008*. With respect to the assessment of the potential environmental constraints of a site and the required planning approvals, the *Planning and Development Act 2007* and Territory Plan establish specific criteria, which if met by a proposal, trigger the requirement for an Environmental Impact Statement (EIS) to be completed before the application can be assessed for planning approval.

The *Australian Capital Territory (Planning and Land management) Act 1988* makes it clear that the National Capital Plan prevails over the Territory Plan, but the two plans are intended to be complementary.

4.5.3.17 Tree Protection Act 2005

The *Tree Protection Act* was introduced in 2005, and provides for the establishment of an ACT Tree Register across leased and unleased urban land that will identify and protect trees of exceptional value.

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.

Anyone may identify and nominate a suitable tree to the register[37] which is then assessed against formal criteria. The tree register was established during the 2009–14 regulatory period.

Exceptional trees may be included on the tree register if they are considered to be of high heritage, landscape or scientific value. The Conservator of Flora and Fauna makes the final decision in the light of advice from the Tree Advisory Panel.

It is an offence under Part 3 of the *Tree Protection Act 2005* to undertake a tree damaging activity or groundwork activity on a Protected Tree without approval. Contravening the Act can lead to an on-the-spot fine of up to $1,000 for an individual or $5,000 for a company. More serious offences can lead to penalties of up to $200,000 and a criminal record.

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.

ActewAGL Distribution's obligations under the *Tree Protection Act 2005* are captured in the ActewAGL Distribution Vegetation Management Strategy and Plan, and the Code of Practice with ACT Parks, Conservation and Lands, as appropriate.

4.5.3.18 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[38], which included a new statutory network performance obligation (Network Service Criterion) requiring establishment of an additional 132 kV connection to ActewAGL Distribution's network. This obligation applies to TransGrid

[37] http://www.tams.act.gov.au/__data/assets/pdf_file/0009/388062/Nomination_For_Tree_Registration_Jan_2013.pdf

[38] *Electricity Transmission Regulation 2006* (ACT)

directly, but also gives rise to significant obligations for ActewAGL Distribution. The purpose of this requirement is to enhance the security of electricity supply for the ACT. In response, ActewAGL Distribution constructed two new 132 kV lines to connect the new southern supply point to the existing ACT distribution network. This work was completed in March 2012.

Stage two of the second supply point project involves upgrading existing 132 kV single circuit lines to match the capacity of the newly constructed lines from southern supply point. Expenditure for this project is included in ActewAGL Distribution's capital expenditure forecasts for the 2014–19 regulatory period. Further details of this project are outlined below under *New or changing requirements* and in chapter 7.

The second supply point has 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 second supply point project complies with both of these industry codes.

During the 2009–14 regulatory period, ActewAGL Distribution has undertaken a major upgrade of security at all of its zone substations. The upgrade includes the installation of Government endorsed anti-penetration fencing and electronic surveillance equipment to detect unauthorised access. Swipe entry access control has also been installed.

ActewAGL Distribution is also in the process of replacing locks on all pad mount substations to improve security, with total expenditure on replacing locks of $4.2m.

4.5.3.19 Nature Conservation Act 1980

The *Nature Conservation Act* controls the management of trees on land leased for rural purposes.

The Territory and Municipal Services Directorate is responsible for managing and maintaining trees on public land. This includes trees on suburban streets, in parks, at local shopping centres, on major road nature strips and medians and parks and in open spaces in the ACT. The key objectives of urban tree management are to enhance the landscape setting for the city, to maintain a safe and sustainable urban forest and to conserve the natural environment.

ActewAGL Distribution's obligations under the *Nature Conservation Act* are captured in the ActewAGL Distribution *Vegetation Management Strategy and Plan*, and the Code of Practice with the (then) ACT Parks, Conservation and Lands, as appropriate.

There are fines of up to $100,000 and imprisonment of up to 5 years for individuals and corporations that breach the *Nature Conservation Act 1980.*

4.5.3.20 Utilities (Emergency Planning Code) Determination 2011

The purpose of this code is to ensure a utility has in place appropriate procedures, structures and arrangements for preventing, anticipating and responding to emergency events and potential emergency events. Utilities must develop, maintain and implement emergency management procedures, develop annual review emergency plans, report to the chief executive on compliance with this Code and with emergency plans; and develop co-operative arrangements with other utilities or agencies.

In regards to emergency preparedness for the utility network, the Code requires ActewAGL to develop and adopt emergency management procedures for emergency preparedness, response and recovery including:

- identification of potential emergency events;
- prompt detection of emergency events; and
- responding to emergency events with actions that include:
    - notifying customers most likely to be affected by an emergency event or any impending threat;
    - minimising the impact of the event on persons and property; and
    - maintaining or resuming the provision of the relevant utility services.

These emergency procedures must remain up to date and ActewAGL must undertake annual audits of the plans. The code specifies various content aspects of the emergency plans such as its objectives, the preparation and approval procedures, the distribution of the plan and requirements for compliance.

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 the Chief Executive of an emergency event, and send a written report on any such event to the Chief Executive within five business days of the event. Major storms have triggered this requirement in the past.

4.5.3.21 ACT Emergencies Act 2004—subordinate legislation

A range of subordinate legislation has been created under the (parent) Emergencies Act 2004. Of relevance to ActewAGL are the following pieces of sub-ordinate legislation:

- Emergencies (Emergency Plan) 2012 (No 1). This document forms the ACT Emergency Plan which outlines the principles of emergency management in the Territory, describes how the components of emergency management work together, identifies roles and responsibilities in relation to hazard and emergency management, and co-ordinates activities within, and outside, the Territory

- *Emergencies (Bushfire Abatement Zone) Declaration 2006*: Notifiable Instrument NI 2006-2026. The instrument declares essentially all land outside the built up urban areas of the ACT as a bushfire abatement zone
- Emergencies (ESA Incident Notification Procedure) Commissioner's Guidelines 2011. Notifiable Instrument NI2011-607

4.5.3.22 Heritage Act 2004

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.

4.5.3.23 Native Title Act 1993

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. This Act does not directly drive any costs for ActewAGL Distribution in the 2014–19 regulatory period, however it represents an unpredictable and potentially uncontrollable future cost risk for ActewAGL Distribution.

4.5.3.24 Environment Protection and Biodiversity Conservation Act 1999

ActewAGL is obliged to comply with the *Environment Protection and Biodiversity Conservation Act 1999*. The Act is the Australian Government's central piece of environmental legislation. It provides a legal framework to protect and manage nationally and internationally important flora, fauna, ecological communities and heritage places that are defined as matters of national environmental significance.

4.5.4 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 obligations in the NEL and NER.

The 2009–14 regulatory period saw the introduction of several new and amended market obligations. These include the introduction of the National Energy Customer Framework (NECF) in the ACT on 1 July 2012, the new National Planning and Expansion Framework on 1 January 2013, and changes to the National Electricity Rules in November 2012. In addition, there are a number of market reviews currently taking place, the final outcomes of which could result in further rule changes, or new or amended market obligations.

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 material costs associated with the new arrangements be treated as regulatory change pass through events.

4.5.4.1 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, associated regulations under the National Electricity Regulations and directions given under the NEL or NER, such as by AEMO, 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.

There has been a marked increase in the level of information required to be submitted to the AER in the 2009–14 regulatory period. This includes information for:

- Economic benchmarking Regulatory Information Notice;
- Category analysis Regulatory Information Notice;
- Performance reporting; and
- Reset Regulatory Information Notice.

This is discussed further in section 4.7 below.

Since the introduction of the annual regulatory reporting by the Australian Energy Regulator in the 2009-10 financial year, the volume of data that is required to be provided in annual RINs has increased significantly. In addition to the annual reports, ActewAGL Distribution is served with Regulatory Information Notices relating to economic benchmarking, category analysis and reset reports. The details of the data often means that considerable manual and semi-manual processing needs to be employed since the existing operational and financial systems were often not designed to store the details required. This factor, as well as the large volume of data requested, has significantly increased the cost of economic compliance.

Reporting on compliance requirements has also increased through the introduction of NECF which includes specific requirements for reporting of breaches and noncompliance and, to some extent, duplicates jurisdictional requirements. By and large, this new regulatory burden has been introduced in addition to the existing jurisdictional reporting which has not been reduced or phased out in spite of transfer of some regulatory functions to the Commonwealth.

4.5.4.2 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 AEMO 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 require ActewAGL Distribution to maintain 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 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 AEMO with forecast load and planning information.

Chapter 5 also requires the application of the Regulatory Investment Test for Distribution (RIT-D) before a DNSP makes an investment decision to address an identified network need, where this investment would be greater than $5 million. This is discussed in more detail in the following section.

Chapter 5 also includes requirements for connecting embedded generators that are registered market participants (generators with a capacity greater than 5MW). In April 2014 the AEMC released its final determination on amendments to these provisions. The amendments impose new obligations on ActewAGL Distribution in relation to provision of technical information and other connection related information, connection processes and dispute resolution. The final rules come into effect on 1 October 2014.

Chapter 5A contains obligations regarding different types of connection offers (basic, standard and negotiated), where customers have met minimum information and technical standards. It sets out a detailed connection process, including a timeline for processing application connections and information requirements for both ActewAGL Distribution and the connection applicant. Chapter 5A also contains connection charge principles. Proposed amendments to Chapter 5A, currently being assessed by the AEMC, would increase the level of prescription in the Chapter 5A negotiation process. These amendments include requiring DNSPs to provide specific information, such as technical and design and planning information, to embedded generator applicants at different stages of the connection process and within specified timeframes. A number of other amendments to the negotiated connection process in Chapter 5A are also proposed.[39] The proposed changes would involve additional compliance costs for ActewAGL Distribution.

Chapter 6 of the NER contains obligations that govern the preparation of this regulatory proposal. Most notable and relevant of these Chapter 6 obligations is the requirement to provide direct control services or negotiated distribution services on terms and conditions as determined through Chapters 4, 5, 6 and 7 of the NER. Several new obligations have been introduced as a result of the AEMC November 2012 rule changes and are highlighted later in this chapter..

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

4.5.4.3 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

[39] AEMC 2014, *Connecting embedded generators under chapter 5A, Information paper*, May, p 1

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.

4.5.4.4 Electricity Distribution Network Planning and Expansion Framework

Changes to the National Electricity Rules establishing the national *framework for electricity distribution network planning and expansion* commenced on 1 January 2013. The framework comprises:

- a new requirement for distribution businesses to undertake annual planning reviews;
- a new requirement for DNSPs to publish annual planning reports (DAPR);
- demand-side engagement obligations;
- joint network planning requirements;
- a new regulatory investment test for distribution (RIT-D); and
- dispute resolution provisions.

The RIT-D is discussed in more detail below. Other components of the framework such as the requirement to undertake annual planning reviews, produce a DAPR, an increased level of demand side engagement, and joint network planning are expected to increase the cost of capital works projects.

4.5.4.5 Regulatory investment test for distribution (RIT-D)

Clause 5.17 of the NER requires a distributor to conduct a regulatory investment test for distribution (RIT-D) before it makes an investment decision to address an identified network need unless an exception under the NER applies. Clause 5.17.2(d) of the NER requires the AER to develop and publish the RIT-D and application guidelines. These were published on 23 August 2013.

The RIT-D arose out of the Australian Energy Market Commission's (AEMC's) national distribution planning arrangements review,[40] and replaces the previous Regulatory Test for distribution investments. It is an economic cost benefit test for RIT-D proponents to use for assessing and ranking different electricity investment options, where the most expensive potential credible option is in excess of $5 million. Clause 5.17.1(b) provides that the purpose of the RIT-D is to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (the preferred option). It must be capable of being applied in a consistent, transparent and predictable manner.

A RIT-D project is defined in clause 5.10.2 of the NER as a project, the purpose of which is to address a need identified by a DNSP; or a joint planning project that is not a RIT-T project. Clauses 5.17.3(a)(1) and (5) provide that the RIT-D does not apply to projects relating to the refurbishment or replacement of existing assets if the project is not intended to augment a network or a project that is required to assess an urgent and unforseen network issue that would otherwise put at risk the reliability of the distribution network or a significant part of that network.

The three stage RIT-D procedure, established by clause 5.17.4 of the NER includes the preparation of a non-network options report, a Draft Project Assessment Report (DPAR) and a Final Project Assessment Report (FPAR). It also specifies that stakeholder consultation on the RIT-D project should occur.

4.5.4.6 The Electricity Metering Code

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. In addition, a December 2005 decision by the ICRC required 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 obligation are addressed in chapter 15 of this regulatory proposal.

ActewAGL Distribution's ongoing meter replacement program for type 5-7 meters is discussed in chapter 7.

4.5.4.7 Renewable energy feed-in tariff

The *Electricity Feed-in (Renewable Energy Premium) Act 2008* commenced on 1 March 2009, and has the following objectives:

- to promote the generation of electricity from renewable energy sources;
- to reduce the ACT's contribution to human-induced climate change;

[40] AEMC 2009, *Final Report: Review of National Framework for Electricity Distribution Network Planning and Expansion*, 23 September

- to diversify the ACT energy supply; and
- to reduce the ACT's vulnerability to long-term price volatility in relation to fossil fuels.

The Act established the parameters of the ACT Electricity Feed-in Tariff Scheme, which is aimed at supporting residential and small commercial renewable generators (solar or wind) with a generating capacity of up to 30 kilowatts (Stage 1).

Section 6 of the Act 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). The *Utilities (Electricity Feed-in Code) Determination 2012* sets out obligations upon ActewAGL in regard to practices and standards for the operation of the scheme for feed-in from renewable energy generators to the electricity network established under the Electricity Feed-in Act.

The premium rate is determined by the responsible minister each year under section 10 of the *Electricity Feed-in (Renewable Energy Premium) Act*. This determination is a disallowable instrument. 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 11 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).

In 2010, the Act was amended to:

- expand the scale of installations that qualify for Scheme coverage and benefit under the Act to generators of between 30kW and 200kW size;
- set capacity caps for Scheme components;
- clarify who is an eligible entity under the scheme; and
- remove clauses that relate to the creation of the Scheme which are now superfluous.

Following determination by the AER that the Large Scale Feed-in Tariff Scheme, Energy Industry Levy and Utilities Network Facilities Tax are jurisdictional schemes, the payments made are not considered under the distribution determination provisions.[41] Instead prices are adjusted through annual pricing proposals to account for any under or over recovery in payment amounts associated with the schemes. Indirect costs incurred by ActewAGL Distribution are recovered through the operating expenditure allowance.

4.5.4.8 NEM Metrology Procedure (Parts A & B)

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

4.5.4.9 B2B Procedure

The B2B Procedure is developed by the Information Exchange Committee, an Industry representative committee chaired by AEMO, and includes a number of components governing information exchange between retailers, distributors and AEMO to facilitate full retail contestability. The main components that affect ActewAGL Distribution's performance and delivery 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.

4.5.4.10 Electricity Customer Transfer Code

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

4.5.4.11 Market Settlement and Transfer Solution

Market Settlement and Transfer Solution (MSATS) is the National system that all participants who operate in the national market must monitor, download and update daily in relation to customer transfers, standing data, energy settlement, and metering data.

[41] AER 2014, *Determination: ActewAGL Distribution's request for schemes to be determined as jurisdictional schemes*, January. AER reference: 53600

4.6 New or changing requirements

There are a number of new or changing regulatory requirements that have had an impact in the 2009–14 regulatory period, or will emerge in the 2014–19 regulatory period. Table 4.2 provides an overview of new and changing obligations. Details of the changing regulatory obligations are outlined in the sections that follow.

Table 4.2 Overview of new regulatory obligations and costs

New obligation	*Comments*
Industry Obligations	
Regulatory Reporting	There has been a significant increase in the level of regulatory reporting requirements facing ActewAGL Distribution since 2009, particularly relating to AER RINs and the introduction of NECF on 1 July 2012.Further information is available in Attachment B10.
Proposed National STPIS	Development of systems and processes to implement National STPIS discussed in detail in Chapter 16 of this regulatory proposal. Ongoing opex included in OSR project budget.
National Network Planning and Expansion Framework	Components of the framework such as the requirement to undertake annual planning reviews, an increased level of demand side engagement, and joint network planning are expected to increase the cost of capital works projects.
National Energy Customer Framework	Significant cost associated with ongoing monitoring, reporting, compliance and process improvement over the 2014–19 regulatory period. Further information is available in Attachment B10.
CMO Database	The introduction of NECF has necessitated the enhancement of ActewAGL Distribution’s compliance monitoring framework. CMO was implemented in the current period, but there will be ongoing expenditure in the 2014–19 period. Further information is available in Attachment B10.
Safety Obligations	
WHS Act 2011	Ongoing development of safety policies and procedures to ensure compliance with the WHS Act 2011. Costs associated with additional training and ‘safety design’ provisions have been built into operational budgets. Further information is available in the Attachment B10.
Fair Work Act (2009) Anti-bullying amendment	Following the introduction of the Fair Work Act (2009) anti-bullying amendments on 1 January employers are now faced with increased risks following bullying allegations. Further information is available in Attachment B10.
Bushfire Management Plan	Due to a changed operating environment following recent bushfires and a review of the ACT Government’s Strategic Bushfire Management Plan 2009, ActewAGL Distribution will be required to update relevant policies and procedures, including a review of the ActewAGL Bushfire Mitigation Strategy and Management Plan. This is discussed further in the change in Attachment B10.
Vegetation clearance zones	ActewAGL Distribution expects that additional expenditure to comply with changes to the vegetation clearance zones will be recovered as a cost pass through.

New obligation	Comments
Market Obligations	
RIT-D	The requirement to undertake a RIT-D on all projects in excess of $5 m applied from 1 January 2014. A component of the National Planning and Expansion Framework
ICRC Review of regulatory frameworks	Driven by NECF, this review of the regulatory framework in the ACT, including the Utilities Code, is expected to occur during the 2015-19 regulatory period.
DMEGCIS	Power of Choice review recommended changes to DMEGCIS scheme. This is to be finalised in 2014.
NEM compliant metering	Following ActewAGL's classification as a dual function asset business, ActewAGL is required to comply with Chapter 3 of the National Electricity Rules that requires installation of NEM compliant metering at each point of connection between a transmission network and a distribution network.
Technical Obligations	
PAS 55 and ISO 55000	ActewAGL Distribution has developed its asset management strategy and systems with consideration of the requirements of PAS 55. As the new International Standard for asset management ISO 55000 series is released, ActewAGL Distribution strategy and systems will be adapted to comply with any additional or amended requirements. Further information is available in Attachment B10.
ARPANSA Standard on Electric and Magnetic Fields	ActewAGL Distribution proposes that additional expenditure to comply with the new Standard be treated as a regulatory change pass through event.
Voltage Standard AS 61000.3.100	Depending on the approach taken to comply with the new standard, this could represent a significant cost impact. ActewAGL Distribution proposes that additional expenditure in the 2015-20 regulatory period to comply with the new standard be treated as a regulatory change pass through event.
Capex	
Utilities Exemption 2006 (Southern Supply Project)	Stage 2 of the Southern Supply Project is scheduled to take place during 2015-19, and has been included in capital expenditure forecasts for the period. Further information is available in chapter 7.
Potential Obligations	
Consumer engagement	The AER Consumer Engagement Guidelines sets out how the AER expects NSPs to engage with consumers. Whilst not binding, the AER expects this to be a permanent, organisational change. In October 2013 SCER submitted to the AEMC proposed changes to the distribution pricing principles arising from the AEMC's Power of Choice review. The proposals, which have been consolidated with IPART's pricing rule change proposals, include new requirements for DNSP's to engage with retailers and consumers on network pricing and to prepare and submit for AER approval a Pricing Structures Statement. Further information is available in Attachment B10.

New obligation	Comments
Private poles	Discussions are taking place regarding the potential for ActewAGL to take on responsibility for the ongoing inspection and maintenance of all private rural power poles that are built to ActewAGL standards and materials and have an ActewAGL private pole asset identification number. Should this take place, the likely cost impact is uncertain at this time, as it is not known exactly how many rural poles are involved, and what condition the poles are in. ActewAGL Distribution proposes that any additional expenditure incurred during the 2015-19 regulatory period be treated as a regulatory pass through event.
AEMC Reliability Review	The AEMC's report for the distribution work stream of the AEMC Review of national frameworks for network reliability will be beneficial for consumer engagement but is costly and will represent a significant regulatory burden.
AER Ring-fencing review	Move to a national framework anticipated to occur during the next regulatory period. ActewAGL Distribution proposes that additional expenditure in the 2014–19 regulatory period to comply with the introduction of new ring-fencing requirements be treated as a regulatory change pass through event.
Distribution network pricing Rules	ActewAGL Distribution proposes to provide forecast additional expenditure required to meet new obligations arising from amendments to the pricing Rules (scheduled to be finalised in November 2014) once the final Rule is made and costs are known.
ACT Government Renewable Energy Target	ACT Government Action Plan 2 has set a renewable energy target of 90 per cent by 2020. This will see a significant increase in embedded generation on ActewAGL Distribution's network. ActewAGL Distribution proposes that additional expenditure in the 2014–19 regulatory period to comply with the introduction of mandatory target be treated as a regulatory change pass through event.
ACT Government Light Rail Project	The ACT Government is seeking to implement light rail from the City to Gungahlin. It is anticipated that this project would involve significant additional electricity infrastructure and relocation of existing ActewAGL Distribution infrastructure. ActewAGL Distribution proposes that expenditure in the 2015-20 regulatory period associated with the Capital Metro light rail project would be treated as a pass through event.
Climate Change Resilience	ActewAGL has included costs for the development of these methodologies, as discussed in the Section 1 of Attachment B10. If there are any material cost impacts on ActewAGL's costs as a result of this work during the 2014–19 regulatory period, ActewAGL will make a claim to the AER for recovery of the cost via cost pass through.
AEMC metering contestability framework	In October 2013 SCER submitted to the AEMC Rule change proposals to support the increased competition in metering and related services. The AEMC commenced consultation on the proposed amendments in April 2014 and a final decision is expected in April 2015. ActewAGL Distribution expects that additional expenditure to comply with changes to the metering Rules will be recovered as a pass through event.
AEMC Framework for open access and common communication standards	There is significant uncertainty over costs that may be associated with the introduction of this framework. ActewAGL Distribution therefore considers that any regulatory change in relation to metering contestability be considered as a pass through event.

The following section discusses in more detail the new obligations listed in the table above.

4.7 *Detail of new regulatory obligations and costs*

4.7.1 Regulatory Reporting

One of the key factors driving operating expenditure in the next regulatory period is regulatory reporting and compliance. Since the commencement of the 2009–14 regulatory period, there has been a significant increase in the level of regulatory reporting requirements facing ActewAGL Distribution. Annual reporting RINs have been expanded. The AER has introduced an additional RIN's for benchmarking, category analysis and reset reports. The introduction of NECF has also increased reporting requirements imposed on ActewAGL Distribution and significantly increased its monitoring, compliance and complaints handling activities.

4.7.2 Proposed National Service Target Performance Incentive Scheme

The STPIS seeks to ensure that ActewAGL Distribution does not have an incentive to make cost efficiencies that would result in deterioration of service quality for customers. The AER Stage 2 Framework and Approach paper confirmed that the STPIS will apply to ActewAGL Distribution with revenue at risk from 1 July 2015. ActewAGL Distribution's description of how it proposes the STPIS will apply is set out in Chapter 16.

The scheme requires ActewAGL Distribution to collect and report daily call centre statistics and daily reliability data disaggregated by feeder types defined for the purpose of the scheme. The introduction of STPIS with revenue at risk is expected to drive additional costs relating to implementing processes within the business to incorporate STPIS as a consideration in decisions relating to network planning and operations.

4.7.3 National Network Planning and Expansion Framework

Changes to the National Electricity Rules establishing the national *framework for electricity distribution network planning and expansion* commenced on 1 January 2013. The framework comprises:

- a new requirement for distribution businesses to undertake annual planning reviews;
- a new requirement for DNSPs to publish annual planning reports;
- demand-side engagement obligations;
- joint network planning requirements;
- a new regulatory investment test for distribution (RIT-D); and
- dispute resolution provisions.

The RIT-D is discussed in more detail below. Other components of the framework such as the requirement to undertake annual planning reviews, an increased level of demand side engagement, and joint network planning are expected to increase the cost of capital works projects.

4.7.4 National Energy Customer Framework (NECF)

The National Energy Customer Framework (NECF) commenced on 1 July 2012, introducing a new set of national laws, rules, and regulations governing the retail sale and distribution of energy to consumers. The NECF involves the transfer of current state and territory responsibilities to a new national regulatory regime governing the sale and supply of energy to retail customers, including new connections to distribution networks.

The NECF framework primarily deals with the following matters:

- the retailer-customer relationship and associated rights, obligations and energy specific consumer protection measures;
- distributor interactions with customers and retailers, and associated rights, obligations and consumer protection measures;
- national retailer authorisations (previously jurisdictionally licensed); and
- compliance monitoring, enforcement and performance reporting.

There has been a significant compliance burden associated with the introduction of NECF since 1 July 2012. ActewAGL Distribution has had to employ additional staff members to meet the increased reporting and audit requirements and to oversee process improvement. It is anticipated that there will be an ongoing resource requirement of at least one full-time staff member to meet NECF requirements.

The requirements to meet NECF obligations are discussed further in Attachment B10.

4.7.5 CMO Database

The introduction of NECF has necessitated the enhancement of ActewAGL Distribution's compliance monitoring framework, CMO. CMO was implemented in the current period, but there will be ongoing expenditure in the 2014–19 period.

Further information is available in Attachment B10.

4.7.6 Work Health Safety Act 2011

Compliance with safety legislation will continue to be a key driver of operating expenditure during the 2014–19 regulatory period as ActewAGL Distribution continues it move to a proactive safety culture that is firmly embedded in the organisation.

The introduction of the Work Health Safety Act in 2011 required a complete re-write of ActewAGL Distribution's safety policy and procedures. Because of the requirement under the Act to undertake staff consultation and training on all procedures, this process is resource intensive and time consuming. ActewAGL Distribution anticipates this process will continue throughout the 2014–19 regulatory period. The introduction of thirteen new safety codes during this period is also expected to require the development of new policies and procedures.

Quality improvements will be made in the areas of contractor management, the creation of an e-learning environment to facilitate the health and safety induction of workers and contractors alike, and fatigue management. In addition, all safety documents will be standardised and made more accessible for staff.

Further discussion on the impact of the introduction of the Work Health Safety Act 2011 can be found in Attachment B10.

4.7.7 *Fair Work Act 2009*—Anti-bullying amendment

The *Fair Work Act 2009* anti-bullying amendments came into effect on 1 January 2014, and have the potential to significantly alter the workplace practices of employers. There is no longer a requirement for the worker to first raise the bullying issue internally in the workplace. Employers are now faced with the risk of having to deal publicly with bullying allegations that the worker has not sought to resolve at the workplace level, including, for example, under a dispute resolution clause of an enterprise agreement.

The amendments also create a new workplace right. Accordingly, any application, or threat to make an application, by a worker may trigger the general protections provisions of the Act. This increases the exposure of employers to adverse action claims. In addition, the power of the Commission to make orders upon finding that bullying occurred may result in an increase of successful workers compensation claims for psychological injury. The making of orders under the anti-bullying provisions will make it increasingly difficult for employers to defend such claims resulting from bullying.

4.7.8 Bushfire Management Plan

Due to a number of recent bushfires and subsequent class actions against DNSPs, a greater focus on bushfire risk and bushfire mitigation has become a priority for DNSPs around Australia. This operating environment has placed additional pressure on ActewAGL Distribution to revise its bushfire risk assessments and review its current bushfire mitigation strategies. Bushfire mitigation standards for ActewAGL Distribution include the ACT SBMP and Technical Standards under the ACT *Utilities Act 2000*. ActewAGL Distribution will be working closely with ACT Government's Technical Standards group to address the current inadequacies surrounding bushfire mitigation industry standards.

The Strategic Bushfire Management Plan 2009, prepared by ACT Emergency Services Agency is currently under review and is expected to result in future changes in planning and operations for ActewAGL Distribution. ActewAGL Distribution will be required to update relevant policies and procedures, including a review of the ActewAGL Bushfire Mitigation Strategy and Management Plan to ensure it aligns with the environmental requirements and the ACT's Strategic Bushfire Management Plan. This is discussed further in the change in Attachment B10.

4.7.9 Vegetation clearance zones

The ACT *Utility Networks (Public Safety) Regulation 2001* specifies prescriptive distances of clearance from aerial lines (overhead power lines). The distances were specified in 2000 when the utility legislative framework began. Since then, there have been at least two major fires in the ACT that have affected ActewAGL assets and altered society's expectations around public safety and reliability of supply. ActewAGL Distribution considers that legislated clearance distances no longer align with community awareness around public safety and bushfire risk.

ActewAGL's Environment Health Safety and Quality section (EHSQ) recently mapped the vegetation in the ACT to determine where the proximity of vegetation to ActewAGL assets places both ActewAGL Distribution assets and vegetation at risk. Areas found to be of most concern and of risk to public safety include some remote rural locations and the Bushfire Abatement Zone.

ActewAGL notes that the Victorian Bushfire Royal Commission (recommendation 30) highlighted the gap between the legislatively prescribed clearance distances in Victoria and the risk that exists near those points of delineation, as follows:[42]

> *The State amend the regulatory framework for electricity safety to require that distribution businesses adopt, as part of their management plans, measures to reduce the risks posed by hazard trees—that is, <u>trees that are outside the clearance zone but that could come into contact with an electric power line</u> having regard to foreseeable local conditions.*

ActewAGL Distribution has approached the ACT Technical Regulator to seek amendment to the Regulation. The ACT Technical Regulator has verbally indicated that it is supportive of the proposed changes however there has been no response to a request for amendment to the legislation.

ActewAGL Distribution is also seeking a determination to legislate responsibility to the land owner or occupier for the ongoing health and maintenance of all trees outside the clearance zones that may fall onto any electricity infrastructure, to align with the Victorian Bushfire Royal Commission recommendation 30. A material increase in costs arising from a change to the vegetation clearance zones will be treated as a potential pass through event.

4.7.10 Regulatory Investment Test—Distribution (RIT-D)

The RIT-D came into effect on 1 January 2013. Although only a small number of ActewAGL Distribution projects in the 2014–19 regulatory period are likely to require application of the RIT-D, costs have been incurred through considerable effort undertaken during the current period to develop RIT-D reports and a stakeholder consultation framework.

[42] Victorian Bushfires Royal Commission 2009, Final Report Recommendations, p 2

4.7.11 ICRC review of regulatory frameworks

Due to NECF, the ICRC is likely to review the regulatory framework in the ACT during the 2015-2019 regulatory period. The Environment and Sustainable Development Directorate (ESDD) of the ACT Government has commenced part of this review and is currently conducting a review of Part 5 of the Utilities Act 2000 with the aim of creating the stand-alone *Utilities (Technical Regulation) Act 2014*.

Part 5 of the *Utilities Act* deals with technical regulation. It vests the Minister for Environment and Sustainable Development with the power to determine technical codes and also sets out functions such as monitoring and enforcing compliance with technical codes.

The stated purposes of the amendment are to:

- clarify statutory objectives and the scope of technical regulation;
- update regulatory powers for more practical enforcement of technical regulation;
- set out clear requirements for technical performance and compliance; and
- create a comprehensive regulatory framework for the full range of electricity, gas, water and sewerage services, covering the utilisation of sustainable energy and water and generation of power energy.

There may be costs incurred during the 2015-2019 regulatory period associated with responding to the review and potential regulatory change.

4.7.12 Demand Management and Embedded Generation Connection Incentive Scheme

The AEMC's final Power of Choice review report in November 2012 made recommendations for supporting market conditions that facilitate efficient demand side participation (DSP) including reforms to the DMEGCIS. The majority of these recommendations require changes to the NER. The AER intends to consult on the development of a new scheme based on the AEMC's draft specifications.[43] The consultation will take into account the forthcoming draft rule proposals which are to be determined by the AEMC following consideration by the SCER.

The new scheme is to be finalised in 2014. The cost impact of the scheme is unknown at this stage. Accordingly, ActewAGL Distribution has proposed a cost pass through event which is detail in chapter 17.

4.7.13 NEM Compliant Metering

Following ActewAGL Distribution's classification as a dual function asset business, ActewAGL Distribution is required to comply with Chapter 3 of the NER, which requires installation of NEM

[43] AER 2014, *Stage 2 Framework and approach—ActewAGL*, January, p 31

compliant metering at each point of connection between a transmission network and a distribution network. Further information is provided in Chapter 7 of the submission.

4.7.14 PAS 55 and ISO 55000

ActewAGL Distribution has developed its asset management strategy and systems with consideration of the requirements of PAS 55, which is a Publicly Available Specification published by the British Standards Institution (BSI), and distributed and supported worldwide through the Institute of Asset Management. PAS 55 has generally been regarded as a de-facto world-wide specification for any organisation seeking to demonstrate a high level of professionalism in whole life cycle management of their physical assets.

As the new International Standard for asset management ISO 55000 series is released, ActewAGL Distribution strategy and systems will be adapted to comply with any additional or amended requirements.

The adoption of this standard is discussed further in section 6.7.

4.7.15 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.

Publication of the Standard as guidance on the management of the EMF issue for Australia continues to be anticipated. The title of the new draft Standard is now *Limits and Precautionary Measures for Reducing Exposure to EMF—0 to 3 kHz.* There remains uncertainty as to when this Standard will be introduced, and what it will mean for distribution businesses. 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 regulatory change event pass through.

4.7.16 Voltage Standard AS 61000.3.100

The Australian Standards committee recently developed and published a new standard AS 61000.3.100 “Limits—Steady State voltage limits in public electricity systems”. Embodied in this standard are important new concepts for establishing limits for steady state voltage for both low voltage and medium voltage customer supplies.

The new standard will bring Australia into line with the 230 (nominal) voltage standard for which most electrical equipment is now designed, manufactured and rated. It defines a preferred voltage range for the average supply voltage, which will assist in the connection of low voltage embedded generation, and improve compatibility and harmonization with global equipment standards, leading to improved efficiency and life expectancy of electrical equipment

The development of this standard has been largely driven by the uptake of embedded generation, especially photovoltaic generation that can lead to reverse power flows in many parts of the LV network that were never planned or designed for. In many locations, the resulting voltage rises have stressed networks and exposed many electricity customers to voltage levels higher than normal. For Australian networks that are historically designed for a 240V system, the added voltage rise effects need careful management by electricity distribution companies.

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 regulatory change event pass through.

4.7.17 Utilities Exemption 2006 (No1) made under the Utilities Act 2000 (Southern Supply Project)—Stage 2

The *Electricity Transmission Regulation 2006* required ActewAGL to construct two 132 kV lines from the ACT's southern bulk supply point to provide the ACT with a second point of supply, Stage 1 of the Southern Supply to ACT project.

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—Stage 2

$ million (2012/13)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Forecast costs for Southern Supply project—Stage 2	6,350	3,300	0	0	0	**9,650**

4.7.18 Consumer engagement

Various new and anticipated consumer engagement obligations will contribute to increased operating expenditure over the 2014–19 regulatory period. In particular, the AER's consumer engagement guideline sets out how the AER expects service providers to engage with their consumers.[44] Although not binding, the AER has stated that the DNSPs' consumer engagement "will be a factor in how we assess expenditure proposals". The AER also expects consultation to be ongoing, not only at the time of the determination..

The Australian Energy Market Commission's (AEMC's) October 2012 final decision on the *Distribution network planning and expansion framework* includes new requirements DNSPs to

[44] AER 2013, *Explanatory Statement Consumer engagement guideline*, November

develop a demand side engagement strategy and to communicate and consult with stakeholders (through the RIT-D process and publication of a Distribution Annual Planning Report).

Furthermore, as noted previously, SCER submitted a rule change proposal on distribution pricing principles which, along with the proposal submitted by IPART, includes new requirements for engagement of DNSPs with retailers and consumers on network pricing. The AEMC is currently assessing the proposals, with a final decision expected at the end of 2014.

In consultation forums on the draft consumer engagement guidelines, the issue of cost recovery has been raised and the AER stated that they "will scrutinise any additional costs service providers include in their expenditure proposal relating to consumer engagement in the same manner that [they] would review any costs a service provider seeks to recover."[45] The AER says that it expects comprehensive ongoing consultation, not only in relation to the 5 year regulatory proposals but also outside reset periods.[46] This will require significant resources and involve additional ongoing costs for NSPs.

The quality of a service provider's consumer engagement will be a factor in how the AER assess expenditure proposals. There is a need to engage with the AER's Consumer Challenge Panel as they will also have a role in advising the AER on the effectiveness of service providers' engagement activities with their consumers and how this engagement has informed, and been reflected in, the development of their expenditure proposals.

ActewAGL Distribution has forecast an amount for increased consumer engagement activities in the 2014-2019 period. This is discussed further in Attachment B10.

4.7.19 Private Poles

The 2010 Utilities Technical Regulation report, *ACT Rural Private Poles,* recommended that the Act Government obtain ActewAGL's agreement to take on responsibility for the ongoing inspection and maintenance of all private rural power poles that are built to ActewAGL standards and materials and have an ActewAGL private pole asset identification number.

It is ActewAGL Distribution's view that any such arrangement must be underpinned by appropriate legislation, and has requested the ACT Government to draft a proposal and legal instrument facilitating the transfer of responsibility and ownership of the private overhead poles to ActewAGL.

The likely cost impact of this proposal is uncertain at this time, as it is not known exactly how many rural poles are involved, and what condition the poles are in. ActewAGL Distribution

[45] AER 2013, *Explanatory Statement Consumer Engagement Guideline for Network Service Providers*, November, p 23

[46] AER 2013, *Explanatory Statement Consumer Engagement Guideline for Network Service Providers*, November, p 27

proposes that any additional expenditure incurred during the 2015-19 regulatory period be treated as a regulatory pass through event.

4.7.20 AEMC Review of national frameworks for network reliability

On 27 September 2013, the AEMC published its final report for the distribution work stream of the AEMC Review of national frameworks for network reliability. The approach will be beneficial for consumer engagement but is costly and will represent a significant regulatory burden.

The proposed framework includes the following:

- A 12-month process for setting output-based reliability targets to commence 35 months prior to each regulatory control period, involving:
  - Identification of alternative reliability scenarios informed by customer consultation (by NSPs and AER or other body appointed by jurisdictional minister);
  - Update of VCR estimates (by AER);
  - Estimation of costs of alternative reliability scenarios (by NSPs);
  - Economic assessment of alternative reliability scenarios (by AER or other body appointed by jurisdictional minister); and
  - Decision on reliability targets (by jurisdictional minister or, if delegated, AER or some other body);
- Targets will form the basis of AER regulatory expenditure forecasts and STPIS targets; and
- Audits of internal process for meeting targets.

In December 2013, SCER agreed to two interim measures proposed by the AEMC by requesting the AEMC develop common definitions for distribution reliability measures and agreeing to the AER assuming responsibility for establishing values of customer reliability for use in the setting of reliability requirements for the next round of regulatory determinations commencing in mid-2019. Individual jurisdictions will report to COAG on their position on adopting the national framework following the first SCER meeting in 2014.[47]

4.7.21 AER Ring-fencing review

On 4 September 2012, the AER released a Position Paper setting out its view on whether or not national Distribution Ring-Fencing Guidelines should be developed. The AER's preferred position is to develop national ring-fencing guidelines to apply to electricity distributors in the NEM. The AER has commenced developing a framework for electricity distribution ring-fencing, providing

[47] SCER 2013, Meeting Communiqué, 13 December, p 2

greater detail around the arrangements and obligations that may apply. However further consultation on the development of electricity distribution ring-fencing guidelines has been deferred.

The likely cost impact of the framework is uncertain at this time. ActewAGL Distribution proposes that any additional expenditure incurred during the 2015-19 regulatory period be treated as a regulatory pass through event.

4.7.22 Distribution network pricing Rules

On 18 September 2013, SCER submitted a rule change request to improve the arrangements within the National Electricity Rules by which distribution network prices are set and structured. This rule change request is in response to recommendations made to SCER in the Power of Choice review.

The AEMC has consolidated the rule change request with the Annual Network Pricing Arrangements rule change that was initiated by the AEMC on 6 June 2013 as requested by the Independent Pricing and Regulatory Tribunal which sought to amend the timing of the annual pricing process for earlier notification of network prices and introduce greater certainty and consultation into the annual network pricing process.

The proposed amendment, currently being considered by the AEMC, would involve significant new obligations on DNSPs to consult and engage with consumers when developing and amending network tariffs. The proposals would also require the implementation of new models for identifying relevant costs and allocating them to tariff components. ActewAGL Distribution proposes to provide forecast additional expenditure required to meet new obligations arising from amendments to the pricing Rules (scheduled to be finalised in November 2014) in its revised regulatory proposal.

4.7.23 ACT Government Renewable Energy Target

The ACT Government passed the *Climate Change and Greenhouse Gas Reduction (Renewable Energy Targets) Determination 2013 (No 1)* in October 2013 which sets a target of 90 per cent use of renewable energy (electricity) by 2020. This will see a significant increase in embedded generation on ActewAGL Distribution’s network. The impact of power taken from renewable energy sources on supply quality in ActewAGL’s distribution network is still to be determined.

ActewAGL Distribution proposes that expenditure undertaken in the 2015-20 regulatory period to comply with the introduction of mandatory target be treated as a regulatory change pass through event.

4.7.24 ACT Government Light Rail project

In order to achieve a more efficient transport network for Canberra over the next 20 years, the ACT Government is seeking to implement a light rail transit (LRT) system from the City to Gungahlin, along Northbourne Avenue and Flemington Road. The system will be electrically operated and the increased energy demand will impact upon existing electrical infrastructure during the next regulatory period if the project goes ahead.

ActewAGL has commenced an initial assessment[48] of the energy demand, additional infrastructure and the associated cost impact of the light rail project if it proceeds during the next regulatory period.

There is still significant uncertainty regarding the system delivery timeline. Costs of the project will be recovered as a pass through should they be incurred during the 2014–19 regulatory period.

4.7.25 Climate change resilience

Existing climate vulnerabilities highlight the need for businesses, including utilities, to be able to respond to climatic variability that may affect their operations. It is expected that climate change will significantly impact on performance of networks over time and it is necessary to ensure impacts are accounted for in investment decisions by planning for extreme events, understanding benefits adaptation and costs of inaction.

The ENA commissioned a report on energy network infrastructure and climate change challenge in 2009 as it has stated that managing the impacts of climate change on assets to ensure continuity and reliability of service to customers is one of the biggest challenges facing infrastructure owners and operators today. This was followed up by a report by the Climate Institute in 2012 which highlights a number of concerns facing the energy sector.

The ENA is developing a guidance manual on how to use climate science in assessing impacts on energy networks infrastructure including the physical impacts, the interdependency with other networks and demand forecasting. This may be introduced during the regulatory period and become industry standard. Understanding how and when to adapt to potential increased risks from climate change is crucial. ActewAGL will develop appropriate methodologies which will determine if/when, and how, assets and services will be impacted by ongoing change, and will ensure that these methodologies are consistent with the industry wide approach to climate risk and resilience which is currently being developed by the ENA. ActewAGL has included costs for the development of these methodologies in its operating expenditure forecasts, as discussed in the Attachment B10. If there are any material cost impacts on ActewAGL’s costs as a result of this work during the 2014–19 regulatory period, ActewAGL will seek to recover these via a cost pass through.

4.7.26 AEMC Contestability Framework for Advanced Metering

Australian governments, through the SCER have agreed to introduce contestability for coordinating and providing metering and data services to consumers. Key elements of the

[48] AECOM and ActewAGL Distribution 2013, *ACT light rail electrical demand and infrastructure assessment*, October

contestability framework for advanced metering that has been proposed by the AEMC are as follows:

- retailers are obliged to arrange for a NEM compliant meter at a consumer's premises;
- provision of metering services (new role of 'metering coordinator') separated from retail energy contracts and Distribution use of System charges to enable metering service provider to recover their costs over a longer period;
- consumers would be able to contract with any accredited coordinator of metering services if they so wish;
- where consumers change retailers, they would not be required to change meters;
- a transparent exit fee would exist where a consumer upgrades its meter owned by a distribution network to cover sunk costs; and
- network businesses would be able to fund smart meters and additional functionality as part of a network DSP program (regulated by the AER).

In October 2013 SCER submitted a set of rule change proposals to the AEMC. The rule change request seeks to amend Chapter 7 of the Rules, and make other consequential changes as required, so that:

- no party has the exclusive right to provide a particular type of meter, unless a jurisdiction prescribes otherwise;
- responsibility for coordinating metering services is separated from the roles of the Financially Responsible Market Participant or the Local Network Service Provider, by creating a new Metering Coordinator role; and
- customers may engage a Metering Coordinator directly.

The rule change request also seeks to codify a smart meter minimum functionality specification through the NER. This would provide the option for Metering Coordinators to identify to market participants which of these capabilities are available at a particular connection point, allow for standardised procedures that take advantage of these capabilities, and if adopted by jurisdictional policy, may be referred to as a requirement for meters in defined situations such as new connections and replacements.[49]

There is currently significant uncertainty over the final form of the new framework and the associated costs. ActewAGL Distribution has therefore proceeded on the basis that any rule changes or new regulatory requirements or service standards in relation to metering may be considered as a pass through event. Proposed pass through events are discussed further in chapter 17 of this regulatory proposal.

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[49] SCER 2013, *Introducing a new framework in the National Electricity Rules that provides for increased competition in metering and related services, Rule change request*, October, p 2

4.7.27 AEMC Framework for open access and common communication standards

The AEMC released its final report on a framework for open access and common communication standards in April 2014. The review, undertaken at the request of SCER, considered whether communication standards should be adopted to support the ability of parties to communicate with each other to access smart meter functionality. The AEMC also considered whether the provision of such access and any associated charges should be subject to regulation.

The final report recommends:

- A shared market protocol be adopted, which would define the format of communications between authorised service providers and the parties that manage access to a smart meter's functionality;
- The market for energy services enabled by smart meters should be able to develop without the need for further regulation of access to smart meter functionality or the charges for such access; and
- The AEMC should conduct a competition review of the energy services market in three years' time.

The AEMC identifies further advice that is required in order to implement the recommendations. The implementation will also depend on outcomes from related projects, including the review of SCER's metering competition rule change proposal. The new framework is scheduled to be in place in mid-2015. The likely cost impacts for ActewAGL Distribution will become apparent when the details of the framework are developed.

5 Demand and energy forecasts

The need to meet or manage expected demand for standard control services is one of the *expenditure objectives* that the AER must consider when assessing ActewAGL Distribution's regulatory proposal and making its constituent decisions in relation to forecast capital expenditure and forecast operating expenditure under clauses 6.12.1(3) and 6.12.1(4) of the Rules.[50]

The Rules require the AER to accept the operating and capital expenditure forecasts for the regulatory period if it is satisfied that they reasonably reflect the operating and capital expenditure criteria, which include, among other things, "a realistic expectation of the demand forecast and cost inputs required to achieve the [operating/capital expenditure] objectives."[51]

Regulatory templates 5.3 and 5.4 of the Reset RIN and Section 8 of Schedule 1 to the Reset RIN set out the information the AER has deemed necessary to assess ActewAGL Distribution's forecast of maximum demand and fulfil its obligations under the Rules. ActewAGL Distribution provides the required forecasts, explanations and supporting documentation in this chapter, regulatory templates 5.3 and 5.4 of the Reset RIN and Attachment C1 to this regulatory proposal. An explanation of how the demand forecast is used to derive capital expenditure forecasts is provided in chapter 7.

This chapter also provides forecasts of energy sales, along with explanations and supporting documentation, which are required under the average revenue cap control mechanism that the AER determined in its Stage 1 Framework and Approach paper would apply to ActewAGL Distribution standard control services in the coming regulatory control period.[52]

5.1 Demand forecasts

This section provides a summary of ActewAGL Distribution's forecasts of maximum demand and the methodology used to derive the forecasts. A detailed description of the methodology used by ActewAGL Distribution to develop its demand forecasts is set out in Attachment C1.

5.1.1 Independent verification of forecasts

The forecasts presented in this section have been independently verified by Jacobs SKM—a consulting firm with extensive expertise and experience in developing and undertaking verification of demand forecasts. The report by Jacobs SKM, which is provided at Attachment C2,

[50] *National Electricity Rules,* clauses 6.5.6(a)(1) and 6.5.7(a)(1).

[51] *National Electricity Rules,* clauses 6.5.6(c)(3) and 6.5.7(c)(3).

[52] AER 2013, *Stage 1 Framework and Approach Paper—ActewAGL*, March, p 28.

shows that Jacobs SKM has examined the reasonableness of the method, processes and assumptions used to determine the forecasts. It states:

> *As an overall observation, Jacobs SKM find the report presents a credible set of zone substation forecasts, supported by an appropriate level of reconciliation with the overall system demand forecast, and the overall ActewAGL energy forecast.*

Much of the report is dedicated to identifying potential improvements to an earlier version of the forecast. In relation to these recommended improvements, the report states:

> *Subsequent to the load forecasting debriefing workshop held at ActewAGL's offices on 29 November 2013, ActewAGL have incorporated a number of the above recommendations into their 2013 Peak Demand Forecast document (version 1.1, dated 23 Dec. 2013)*

Jacobs SKM subsequently noted that the ActewAGL demand forecast contained in the 2013 Distribution Annual Planning Report was a "current state forecast", whereby the forecast was based on the existing state of the network in December 2013 and did not reflect new zone substations and permanent load transfers that would take place after December 2013. ActewAGL Distribution and Jacobs SKM subsequently prepared an enhanced demand forecast which reflected the establishment of zone substations at East Lake (December 2013) and Molonglo (mid-2018), as well as a number of planned permanent load transfers between zone substations. This enhanced forecast is summarised in section 5.1.3 and provided in full in Attachment C1.

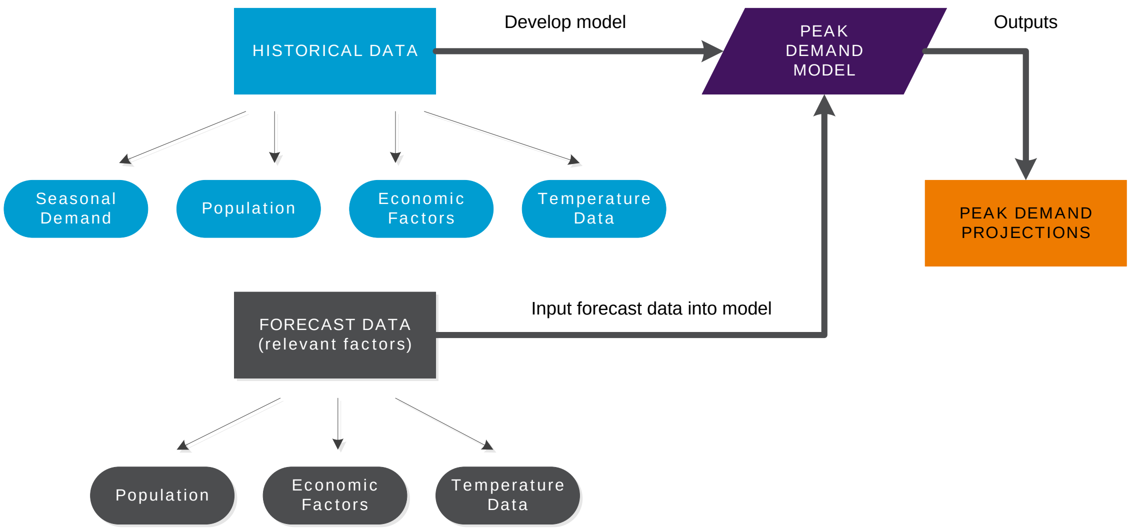
5.1.2 Methodology

ActewAGL Distribution is continually reviewing and refining its demand forecasting methodology to ensure it is using the most up to date analytical models and techniques. The load demand forecasting is critical because it is one of the main drivers for capital expenditure. Within the planning drivers, the network load demand forecasting is possibly the most complex because of its probabilistic and unpredictable nature. It is unpredictable due to its dependence on a number of factors such as customer choices, ambient temperatures, weather patterns, and in particular, load growth patterns.

Ten-year forecasts of maximum summer and winter load demands at all zone substations are developed. Load growth varies from year to year and is not uniform across the whole network. It is not unusual to find parts of the network that grow at three or four times the average network growth rate, while other parts of the network experience negative growth.

ActewAGL Distribution's zone substation forecasts use multiple-linear regression to model the historical trend of demand growth, and to forecast future peak demand (see Figure 5.1). Two separate forecast scenarios are produced, for summer and winter peak demands. This is because peak demands usually occur in summer and winter, where there are severe weather conditions. Also, summer and winter are observed to have different drivers/patterns of demand.

Figure 5.1 Overview of demand forecast model



The best-practice modelling/forecasting principles that ActewAGL Distribution adopts are described in Table 5.1.

Table 5.1 Modelling and forecasting principles

Principle	*Description*
Data	Obtain reliable and unbiased data from reputable sources, conduct data checks to remove/repair erroneous data and manage data effectively.
Model calibration	Use appropriate statistical estimation methods.
Parsimony	Use only as many parameters as necessary to fit the model, to minimise unnecessary complexity and allow model to be easily replicable.
Fit to theory	Choose models which are supported by relevant theory.
Fit to evidence	Show that the model adequately accounts for history used in calibration (conduct back-testing).
Logical model	Explanatory variables in the model should have theoretical basis, and have theoretically correct signs.
Model validation	Analyse the statistical significance of variables, goodness of fit, diagnostic checking of residuals etc.
Model documentation	Detailed and thorough documentation of modelling process to ensure transparency and repeatability.
Version source control	Track changes made to models

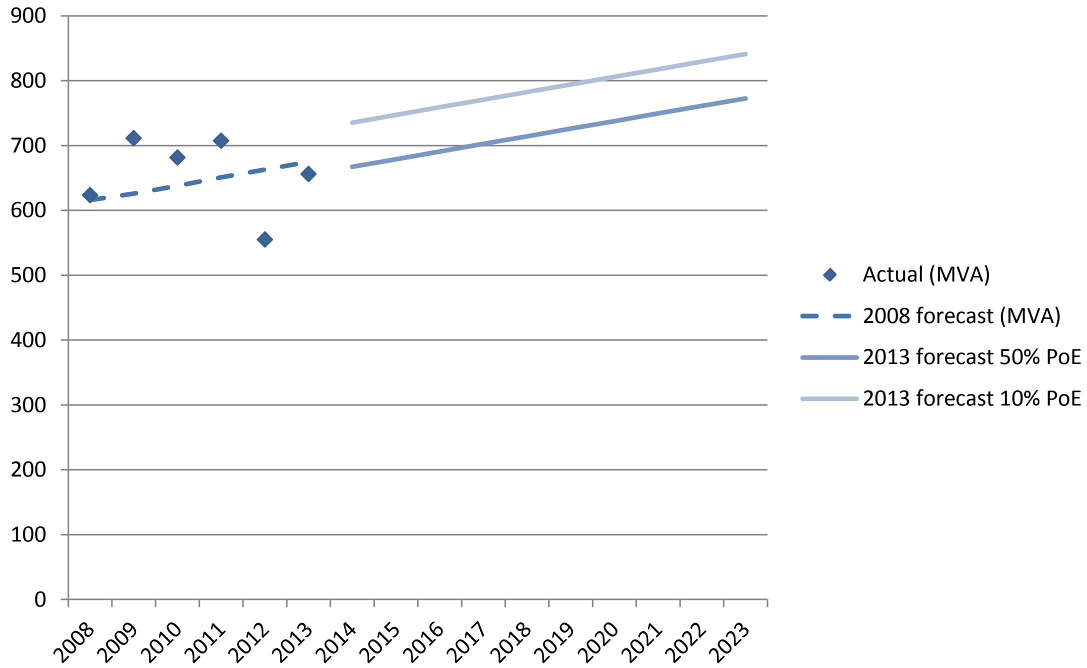
Key features of ActewAGL Distribution's substation demand forecast are as follows.

- the system wide maximum demand (historical and forecast) is reconciled against the energy delivered p.a., to monitor the trend in the average annual load factor;
- the zone substation forecast is reconciled against the BSP demand forecast to enable demand coincidence factors to be established, and ensure consistency between the forecasts;
- the model uses several different temperature variables, and only those variables with a high correlation factor are used;
- 10 per cent probability of exceedence (PoE) and 50 per cent PoE forecasts are produced;
- wherever possible, known temporary or abnormal load transfers are removed from historical data;
- known or highly probable spot load increases are incorporated into the early years of the forecast, however only a portion of the spot load increases are included, to the extent that the extra loads are in excess of normal historical growth; and
- the final zone substation maximum demand forecast is constructed to reflect known or "most probable" future augmentations to the network (for example, new zone substations, permanent load transfers).

5.1.3 Forecasts

ActewAGL Distribution's weather-corrected forecasts of system summer maximum demand are presented in Figure 5.2 along with actual demand observed in 2008-2013 and the weather-corrected demand that was forecast for that period in 2008. Summer system maximum demand has been quite volatile over the period 2008 to 2013. Initially, actual recorded maximum demands were tracking above the forecast from 2008 to 2011, however in the summer of 2012 unseasonally mild conditions saw the 2012 system maximum demand drop to 555 MVA, some 21 per cent below the 2011 level. By the summer of 2013 the system maximum demand had risen to 656 MVA (up 18 per cent), within 3 per cent of the forecast determined at the commencement of the regulatory period. System maximum demand growth is forecast to continue at around 12 MVA per annum in the forthcoming regulatory period.

Figure 5.2 System summer maximum demand



The estimated electrical loading of the known and probable customer-initiated projects is analysed at a zone substation level, and where the spot loads are substantially above historical load growth, the zone substation forecasts are adjusted accordingly. Analysis of the probability weighted maximum (customer estimated) and minimum (ActewAGL estimated) estimates of additional electrical loadings by zone substation are shown in Table 5.2.

Table 5.2 Additional electrical loadings by substation

Zone substation	*Max. forecast increase (customer estimate)*	*Min. forecast increase (ActewAGL estimate)*	*% of total (min.) forecast increase*
Belconnen	3,984	3,560	28%
Telopea Park	4,905	3,058	24%
Woden	3,488	2,256	18%
Gold Creek	3,056	1,972	15%
City East	1,867	1,300	10%
Latham	611	341	3%
Fyshwyck	275	237	2%
Civic	140	126	1%

Table 5.3 presents summer and winter ratings, while Table 5.4 and Table 5.5 present 10 per cent and 50 per cent PoE maximum demand forecasts, respectively, for a selection of ActewAGL Distribution's zone substations of interest, over the period 2014 to 2023. Forecasts for all

substations are available at Attachment C1. These forecasts take account of planned load transfers between zone substations during the forecast period, including those associated with the commissioning of the East Lake Zone Substation in December 2013 and the Molonglo Zone Substation by mid-2018.

Table 5.3 Forecasts for selected zone substations

Zone Substation		*Belconnen*		*East Lake*		*Gold Creek*		*Molonglo*	
Season (summer/winter)		S	W	S	W	S	W	S	W
Rating	Continuous	55	55	50	50	57	57	25/50	25/50
	Emergency	63	76	0	0	76	76	0	0
Post upgrade	Continuous	87	87	100	100				
	Emergency								

Table 5.4 Selected zone substations 50 per cent PoE load forecast, MVA

Zone	*Belconnen*		*East Lake*		*Gold Creek*		*Molonglo*	
Season	*S*	*W*	*S*	*W*	*S*	*W*	*S*	*W*
2014	55.8	53.1	8.3	16.5	49.2	55.6	0.00	0.00
2015	60.3	57.6	16.6	16.7	50.1	56.5	0.00	0.00
2016	60.3	57.6	16.8	34.1	53.2	59.6	0.00	0.00
2017	60.3	57.6	34.2	46.1	56.2	62.7	0.00	0.00
2018	60.3	57.6	46.2	46.6	59.3	65.8	0.00	10.4
2019	60.3	57.6	46.7	47.1	62.4	68.9	10.4	10.93
2020	60.3	57.6	47.1	47.5	65.5	72.0	10.93	11.48
2021	60.3	57.6	47.6	48.0	68.6	75.2	11.48	12.02
2022	60.3	57.6	48.1	48.5	71.6	78.3	12.02	12.66
2023	60.3	57.6	48.6	49.0	74.7	81.4	12.62	13.29

Table 5.5 Selected zone substations 10 per cent PoE load forecast, MVA

Zone	*Belconnen*		*East Lake*		*Gold Creek*		*Molonglo*	
Season	*S*	*W*	*S*	*W*	*S*	*W*	*S*	*W*
2014	60.0	53.5	8.3	16.5	52.2	55.7	0.00	0.00
2015	64.5	58.0	16.6	16.7	53.1	56.7	0.00	0.00
2016	64.5	58.0	16.8	34.1	56.2	59.8	0.00	0.00
2017	64.5	58.0	34.2	46.1	59.3	62.9	0.00	0.00
2018	64.5	58.0	46.2	46.6	62.4	66.0	0.00	11.2
2019	64.5	58.0	46.7	47.1	65.5	69.1	11.2	11.76
2020	64.5	58.0	47.1	47.5	68.5	72.2	11.76	12.34
2021	64.5	58.0	47.6	48.0	71.6	75.3	12.34	12.96
2022	64.5	58.0	48.1	48.5	74.7	78.4	12.96	13.61
2023	64.5	58.0	48.6	49.0	77.8	81.5	13.61	14.29

5.2 *Energy sales forecast*

5.2.1 Background

ActewAGL Distribution engaged consultants Jacobs SKM to identify key factors influencing electricity consumption in the ACT and to prepare an independent energy sales forecast for the ACT electricity network for the 2014-2019 regulatory control period. Jacobs SKM has considerable expertise and experience in developing network energy forecasts and advising on energy forecasting methods. This section provides a summary of the forecast and the approach used to derive it. Further detail on the method, processes and assumptions used to determine the forecasts is provided in Jacobs SKM's report at Attachment C3.

As discussed in ActewAGL Distribution's Transitional Regulatory Proposal, there is considerable inherent uncertainty associated with forecasting energy use over a five year horizon, notwithstanding the utilisation of expert external advice to develop the best possible forecast. This uncertainty is greater now than it has been in the past.[53] Decreases in annual energy sales in the NEM had not been observed prior to 2010. Energy forecasts now need to contemplate not only the potential magnitude of growth in sales, but also the possibility that sales will continue to decline.

5.2.2 Methodology

Consumption was analysed in four separate categories:

- Residential general purpose (GP);
- Residential off-peak (OP);
- Non-residential low-voltage (LV); and
- Non-residential high voltage (HV).

For each category, the method employed by Jacobs SKM involved the following stages. First, historical energy consumption over 2000-2013 was weather normalised. This normalisation involved regressing the number of heating and cooling degree days each month against monthly consumption. This analysis showed that residential GP consumption growth began to fall in 2008, becoming negative from 2010, with energy efficiency and photovoltaic generation playing a central role. LV and HV consumption has been approximately constant since 2008. Residential OP has been in steady decline since 2002.

Second, a range of models utilising historical values of potential explanatory variables were tested and the preferred models identified. These models used annual weather normalised consumption as the dependent variable, with or without adjustment for historical energy efficiency savings, on either a total, average per person or average per customer basis. Following

[53] See for example the analysis and conclusions in AEMC 2013, *Consideration of differences in actual compared to forecast demand in network regulation*, Advice to SCER, April, pp 51-53.

application of model selection criteria focusing on model fit (as measured by R^2 and the Akaike Information Criterion), the preferred models are:

- for residential GP, a model using employment per person to predict zero efficiency consumption per person, with efficiency savings applied *ex post*;
- for residential OP, a fixed rate per year using the rate from 2008 to 2013;
- for non-residential LV, a model using State Final Demand and interest rates to predict zero efficiency consumption, with efficiency savings applied *ex post*; and
- for non-residential HV, a model using State Final Demand to predict zero efficiency consumption, with efficiency savings applied *ex post*.

Finally, projections of the selected explanatory variables were used to prepare a forecast for the period 2013-2019. ActewAGL Distribution commissioned BIS Shrapnel to provide the projections for macroeconomic and demographic variables. Energy savings were projected by Jacobs SKM based on AEMO projections for the effect of Commonwealth schemes and the expected additional impact of the Energy Efficiency (Cost of Living) Improvement Act 2012 implemented in the ACT.

5.2.3 Forecasts

Figure 5.3 illustrates ActewAGL Distribution's energy sales forecast and fitted values from the forecasting models, disaggregated by customer type, along with weather normalised actual sales. It shows that decreases in energy sales observed in recent years are forecast to continue until 2015-16. These decreases are driven by expectations of a weakening ACT economy and labour market resulting from Commonwealth government cost cutting and by ongoing energy efficiency savings.[54] Energy sales are expected to increase with growth in the ACT economy and labour market from 2016-17.

[54] The forecasts of economic and demographic variables underlying the energy sales forecast were made prior to the Federal Budget 2014-15. The impacts of Commonwealth Government cost cutting are potentially more severe than those assumed in ActewAGL Distribution's forecast.

Figure 5.3 Actual, fitted and forecast energy sales

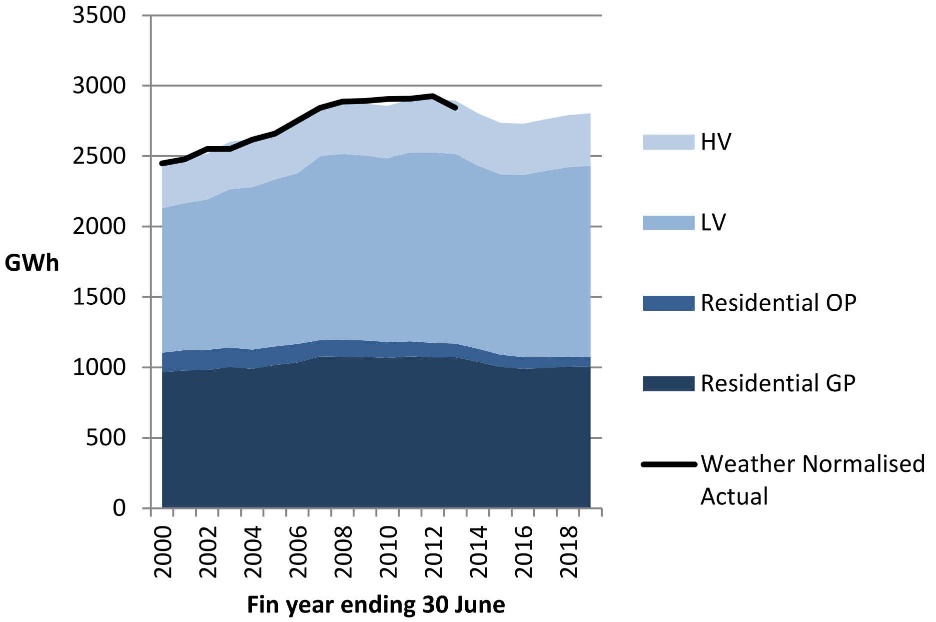


Table 5.6 provides the energy sales forecast in numerical form, disaggregated by customer type.

Table 5.6 Forecast energy sales, GWh

Financial year ending 30 June	*2015*	*2016*	*2017*	*2018*	*2019*
Residential general purpose	1,002	990	996	1,005	1,005
Residential off-peak	87	83	78	73	68
Non-residential low voltage	1,281	1,293	1,322	1,344	1,359
Non-residential high voltage	366	364	366	370	372
Total	**2,737**	**2,730**	**2,761**	**2,791**	**2,804**

5.3 Consistency of energy sales and demand forecasts

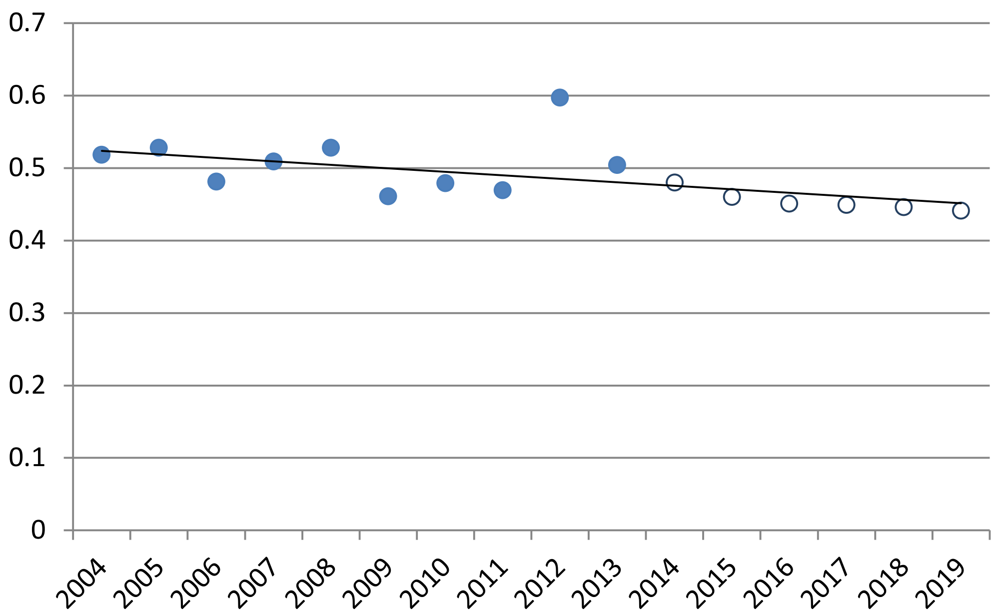
Consistency between the energy sales and summer peak demand forecasts has been assessed by comparing historical and forecast system annual average load factors. The system annual average load factor is approximately a scalar multiple of the ratio of energy sales and maximum demand:

$$\text{System Annual Average Load Factor} = \frac{\text{Energy delivered during year}}{\text{System Maximum Demand} \times \text{Number of days in year}}$$

Figure 5.4 shows actual system annual average load factor for 2004 to 2013 and forecasts for the forthcoming regulatory period based on the system summer maximum demand and energy sales forecasts discussed above. The extremely mild summer conditions in 2012 are evident, with the 21 per cent drop in maximum demand during a year of average energy consumption resulting in the annual average load factor departing significantly from the long term trend line. Aside from this outlier observation, there is a consistent trend across the historical and forecast load factors, which indicates that the forecasts have been grounded upon similar assumptions about growth patterns and energy consumption trends, even though the two forecasts were independently produced.

Figure 5.4 System annual average load factor—actual and forecast

(Wh/VAh)



6 Network Planning and Asset 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.

6.1 Asset management in ActewAGL Distribution

Effective implementation of asset management requires a disciplined approach which enables an organisation to maximise value and deliver its strategic objectives through managing its assets over their whole lifecycle. ActewAGL Distribution's asset management philosophy is captured in its *asset management policy*. This is a key component of the broader asset management system (AMS) and is discussed in more detail in section 6.6.1below.

ActewAGL is committed to operating and maintaining an AMS that conforms with the British Standards Institute Publicly Available Specification PAS 55 -1:2008 *Specification for the optimised management of physical assets* which supports effective asset management outcomes and ensures continuous improvement in asset management processes.

The overall aim of the AMS is to continue and build upon a well planned and executed infrastructure replacement program based on a PAS55 compliant methodology and Reliability Centred Maintenance that controls costs while meeting customer and community expected reliability goals.

ActewAGL Distribution uses Riva decision support asset management software to perform a range of functions, including the projection of capital and operational expenditure forecasts.

It integrates with the WASP asset information system, and generates an activity and expenditure forecast (in real terms), which is as current as the operational inventory, associated inspections and work orders. It also generates Asset Specific Plans for each asset type and forecasts service level, risk, cost and other performance measures.

6.2 Meeting AER expenditure forecast assessment guidelines

ActewAGL has reviewed and analysed the informational requirements of the recently released expenditure forecast assessment guidelines, and to the extent that historical and existing information and data permits, has structured this proposal to meet those guidelines.

The information required can loosely be categorised into requirements for data, and requirements related to methodology, that is, explanations of how forecasts and related factors have been determined. The following sections summarise the requirements into these two categories.

6.2.1 AER expenditure assessment guideline requirements for data

ActewAGL Distribution has determined the following data requirements of the AER expenditure assessment guideline:

- ability to split capex and opex into expenditure categories and sub categories based on the key drivers, asset types, activity type, routine and non-routine (opex);
- forecast and historical volumes and unit costs for key expenditure categories (capex and opex);
- forecast and historical volumes of opex activities: maintenance intervals; changes in numbers and types of asset serviced; condition of assets including age, failure rates and modes, compliance, risk management and condition monitoring;
- total quantum of assets added and disposed by asset category;
- average value of assets added in each category by year;
- age distribution of assets by key asset category;
- historical number of assets replaced in past years by key asset category;
- expected mean and standard deviation of asset lives by key asset category;
- expected costs associated with replacing asset in each category;
- demand forecasts including global and spatial peak demand at different PoE in MW and MVA;
- data underlying augmentation expenditure including capacity and voltage constraints, load movement, security, efficiency, compliance and land and easements;
- historical and forecast information by network segment for demand, utilisation and augmentation cost;
- historical and forecast unit costs by category of augmentation;
- forecast volumes and costs for customer connections and customer driven works;
- forecast volumes and costs for non-network expenditure;
- input data: Costs and quantities of overhead lines, underground cables, transformers and other capital, opex, depreciation and return on investment;
- output data: customer numbers, energy delivered, peak demand, system capacity by line length, reliability, revenue;

- line length, terrain factors customer, energy and peak demand intensity;
- emergency response data;
- vegetation management data including historical and forecast split by activity, volume of activities, fire starts, legal obligations, audit outcomes; and
- overhead expenditure by major cost category and details of size/complexity of business, number of employees, legal obligations.

6.2.2 AER expenditure assessment guideline requirements for methodology

ActewAGL Distribution has determined the following methodology related requirements of the AER expenditure assessment guideline:

- methods of calculating, and calculations of any allowances for real cost escalation;
- methodology used to develop expenditure forecasts (capex and opex);
- economic analysis demonstrating efficiency and prudency of forecast expenditure;
- reasons for costs differing from historical expenditure and/or costs from other DNSPs;
- identification and explanation of potential work and efficiency trade-offs between capex and opex;
- planning and strategy documents for key opex categories;
- identification and explanation of key decisions in asset management plans that impact forecast expenditure;
- identification of, and demonstration that material changes (step changes) in expenditure compared with historical expenditure levels are prudent and efficient;
- governance plans and explanation of whether these have been followed;
- planning and strategy documents for expenditure categories (including AMPs);
- benchmarking data and explanations of why material differences between benchmark costs are prudent and efficient;
- explanation of the demand forecasting methodology and models including selection of inputs and assumptions made; and
- explanation of overhead workload activities (historical and forecast), details of cost allocation policies and practices, and capitalisation policies and practices.

6.3 Network Description

6.3.1 ActewAGL Distribution operating environment

ActewAGL provides electricity and gas services over a supply area of 2,358 square kilometres to 177,256 electricity and 129,413 gas customers, as of 30 June 2013, within the ACT.

ActewAGL is licensed under the *Utilities Act 2000* (ACT) to provide electricity distribution services and electricity connection services. ActewAGL is registered as a Distribution Network Service Provider by AEMO and since August 2012 as a Transmission Network Service Provider.

The National Electricity Law (NEL) and National Electricity Rules (NER) are enacted in the ACT by the *Electricity—(National Scheme) Act 1997* (ACT).

The AER is responsible for economic regulation of the ACT electricity distribution and transmission networks. ActewAGL Distribution's current electricity network prices are set in accordance with the AER's final decision for the period 1 July 2009 to 30 June 2014.

Technical regulation is overseen by the Environment and Sustainable Development Directorate (ESDD) within the Australian Capital Territory Planning and Land Authority (ACTPLA).

ActewAGL is responsible for the operation, maintenance, planning and augmentation of the transmission and distribution system within the ACT. There are a small number of rural cross border high voltage lines feeding rural customers within NSW. Because of the presence of the Brindabella Ranges the developed electricity network is mainly confined to the Canberra urban and surrounding rural areas on the north east side of the ACT.

6.3.2 Key network statistics

ActewAGL Distribution's electricity network takes supply at three TransGrid connection points:

- Canberra 330/132 kV bulk supply substation;
- Williamsdale 330/132 kV bulk supply substation; and
- Queanbeyan 132/66 kV bulk supply substation.

These bulk supply stations are TransGrid owned network assets. ActewAGL network assets include the 132 kV transmission lines, 66 kV sub-transmission lines, 132/22/11 kV and 66/11 kV zone substations, 22 and 11 kV distribution feeders, associated substations, low voltage (230/400 V) circuits, and services to customers.

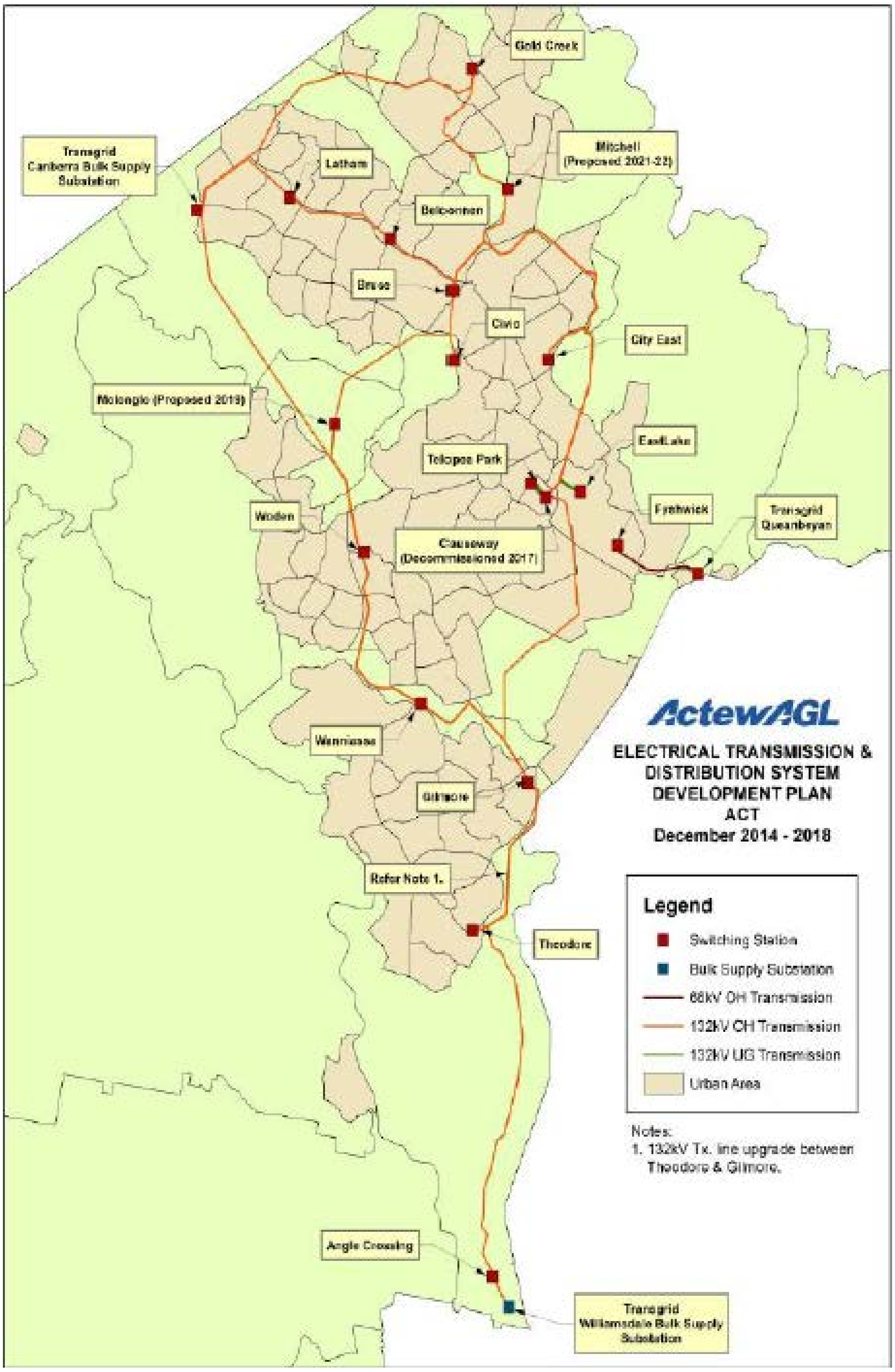
A brief summary of ActewAGL's electricity network, and key operating statistics are shown in Table 6.1.

Table 6.1 Electricity network—statistics (as at 30 June 2013)

Measure/statistic	*Value*
Supply area (km^2)	2,358
No. customer connections at 30 June 2013	177,256
Coincident System Maximum Demand (MVA)	586
Total energy delivered (GWh)	2,904
Number of injection points (BSP's)	3
Transmission network length—circuit km	
• 132 kV overhead	189
• 132 kV underground	3
• 66 kV overhead (sub-transmission)	7.2
• 66 kV underground (sub-transmission)	0
Distribution network length—circuit km	
• 22 kV overhead	34
• 22 kV underground	2.5
• 11 kV overhead	980
• 11 kV underground	1,434
• LV overhead	1,184
• LV underground	1,255
Number of zone substations:	
• 132/11 kV (including East Lake, commissioned Dec 2013)	12
• 132/22 kV	0
• 66/11 kV	1
Total installed zone transformer capacity (MVA nameplate)	1,478
No. of switching stations (132 kV)	2
No. of distribution substations	
• 22/0.415 kV	0
• 11/0.415 kV	3,434
Total installed distribution transformer capacity (MVA nameplate)	2,052
Percentage of network undergrounded (all voltages)	55%
Weighted average network age (years)	26
System SAIDI (actual planned and unplanned)	
• Total	71.3
System SAIFI (actual planned and unplanned):	
• Total	0.78
System CAIDI (actual—unplanned only):	
• Total	91.4

The geographic layout of ActewAGL Distribution's network is detailed in Figure 6.1.

Figure 6.1 ActewAGL electricity transmission and distribution network



Source: ActewAGL, 20 December 2013, *Distribution Annual Planning Report 2013,* version: initial release p 9.

6.3.3 Dual function assets

ActewAGL is registered as a Distribution Network Service Provider by AEMO, and since August 2012 as a Transmission Network Service Provider.

NER Rule 6.24.2 provides that any part of a network owned, operated or controlled by a Distribution Network Service Provider which operates between 66 kV and 220 kV, and which operates in parallel with and provides support to the higher voltage transmission network is deemed to be a dual function asset.

Part of ActewAGL's network meets the requirements of part (a) of the NER definition for transmission assets. As these network assets are owned, operated and controlled by a Distribution Network Service provider they are regarded as dual-function assets for the purposes of Chapters 6 and 6A of the Rules.

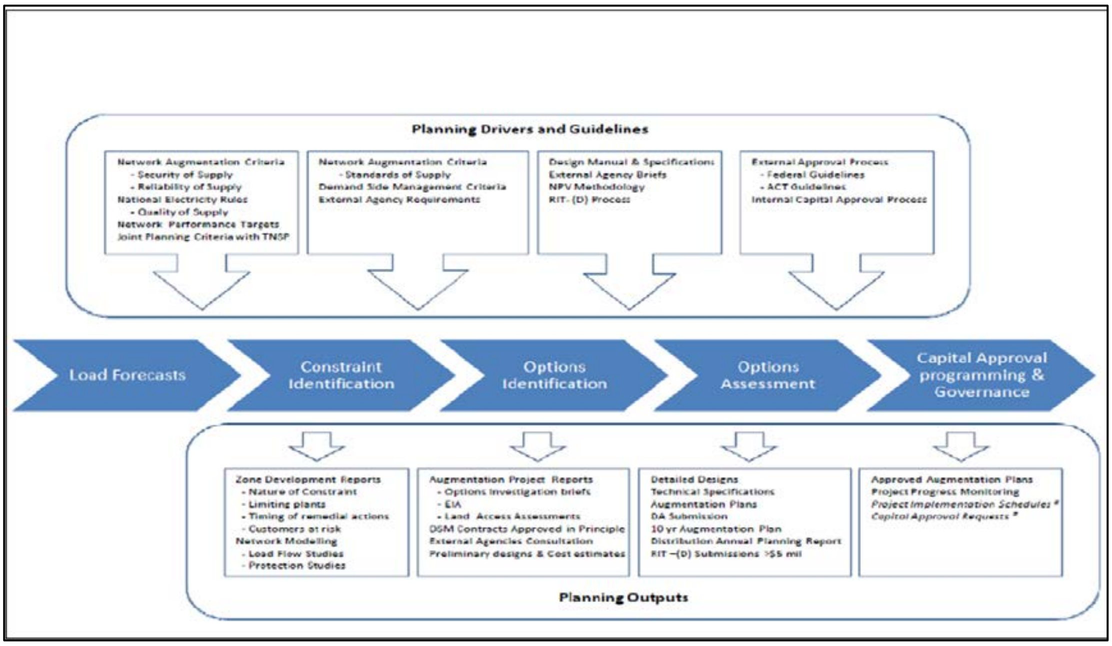
6.4 Security of supply and planning standards

6.4.1 Network planning framework and processes

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.

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 6.2.

Figure 6.2 Framework for distribution network planning and expansion



ActewAGL Distribution utilises an integrated network planning and performance management process. The Asset Management and Network Services Divisions are a primary part of ActewAGL Distribution with responsibility for the management and operations of the distribution system.

The *ActewAGL Distribution Strategy* supports the Corporate Business Plan and is part of ActewAGL Distribution's annual planning cycle. This 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.

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.

6.4.2 Security of supply and planning criteria

ActewAGL regularly reviews its planning philosophy to ensure network performance is maintained at an appropriate level as demanded by customers and regulators.

ActewAGL applies a redundancy based deterministic planning approach to make decisions for network development and expansion. This approach takes into account the combination of demand forecasts, asset ratings and estimated asset failure rates to identify the severity of the constraints and the timing of the solutions.

The applicable design planning criteria and supply security standard are set out in ActewAGL Distribution's *Distribution Network Augmentation Criteria*, and are summarised in Table 6.2 and Table 6.3 below.

Table 6.2 Network supply security

Standard network element	*Security standard*
Transmission Lines	N-1
Zone Substations	N-1
Distribution Subs—Commercial	N
Distribution Subs—Urban Residential	N
Distribution Subs—Rural Residential	N

N security standard specifies that the load concerned will be supplied from a system which has no inbuilt automatic redundancy although limited alternative supply will normally be available after manual switching is undertaken.

N-1 security specifies that the maximum demand of the load concerned will be secured, with no loss of supply, for any single credible contingency event at the transmission and zone substation level (e.g. loss of a single transformer, loss of a single circuit).

At the distribution feeder level, N-1 security may (and usually does) involve a loss of supply, which is restored after manual switching.

HV feeder performance is monitored and evaluated as part of ActewAGL's network management and planning process and to ensure that the network reliability targets set out in the technical regulator's Electricity Distribution (Supply Standards) Code 2013 are met. Poorly performing feeders undergo detailed analysis to develop solutions to address performance issues.

At the distribution (HV) feeder level, different levels of security of supply are applied, depending upon the magnitude of the load to be secured, the relative importance of the load, and the economic justification for providing a higher level of security. This is reflected in Table 6.3 below.

During the 2009–14 regulatory period, ActewAGL conducted a review of its 11 kV feeder reliability guidelines with a view to reducing the extent of inbuilt redundancy on the distribution system, thereby reducing / deferring augmentation expenditure without sacrificing overall reliability of supply to the customer.

The outcome of the review was to recommend that:

- the firm rating for feeders with 2 or more ties be raised from 67 per cent to 75 per cent of thermal rating, and

- augmentation projects justified on the basis of maintaining contingency reserves be compared to other reliability improvement options on the basis of cost and risk.

The practical outcome of this policy change is that 11 kV distribution feeders are now loaded to higher levels under normal system conditions, prior to augmentation / load relief taking place, and that other more cost effective solutions are researched and implemented wherever possible.

Table 6.3 HV distribution feeder security standard

Feeder configuration	*Firm rating (percentage of thermal capacity)*
Two or more feeder ties	75%
One feeder tie	50%
Feeders operating in parallel	{(n-1)/n}% *
Partial feeder tie	100% or less †
No feeder tie	100%

* *n* represents the number of feeders operating in parallel.
† A partial feeder tie refers to a tie with limited back feeding capacity. The firm capacity of a feeder with a partial feeder tie may be set below 100 per cent of its thermal capacity.

6.4.3 Key network planning documents

In addition to the Asset Management Policy and the Asset Management Strategy, ActewAGL Distribution' augmentation and asset management capital works programs are based on the following key long-term planning documents:

- Distribution Network Augmentation Criteria;
- Distribution Network Planning and Expansion Framework;
- the 2013 Distribution Annual Planning Report (DAPR);
- Network Augmentation Capital Works Plan;
- Customer Initiated Capital Works Plan;
- ActewAGL ICT Strategy 2014-2019;
- ActewAGL Distribution ICT Operational Environment Strategy;
- the Metering Asset Management Plan; and
- Electrical Data Manual, Document Number: EN 4.04 P10.

These planning documents are attached to this submission.

6.5 Augmentation planning process

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 6.4.

Table 6.4 Network security criteria for key asset classes

Asset type	*Network security criterion*
Transmission and 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 feeder	High voltage feeder capacity must be augmented or demand management solution provided if the forecast feeder maximum demand based on 10% PoE is to exceed the firm ratings [as given in Table 2

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

The 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;

- Designing zone substation configuration to enable the additional transformer providing N-1 security to be spread over a number of substations
- 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 *Distribution Network Augmentation Criteria*. This document can be found at Attachment D5.

6.5.1 Application of emergency ratings to substation equipment and transmission lines

ActewAGL Distribution has applied short-time emergency ratings to its transmission line and zone substation equipment for a number of years, and such emergency ratings are comparable with contemporary electricity industry practice in Australia. The timing of major augmentation projects are deferred significantly by the use of this emergency ratings, resulting in higher levels of asset utilisation and lower capital costs, with marginal changes in the levels of risk.

The methodology used by ActewAGL Distribution to calculate emergency ratings is provided in ActewAGL Distribution's *Electrical Data Manual Document No. EN 4.04 P10*. This manual was first published in 2007, and is updated every 2 years with the intention of matching the changing nature of substation daily and annual cycles with the maximum applicable short time emergency ratings that can be applied to substation equipment.

Implications of applying short time emergency ratings to zone substations and transmission lines are as follows:

Zone Substations:

- 2 hour emergency transformer ratings are used to determine N-1 emergency substation capacity, unless there is some other item of substation equipment which has a lower rating than the transformer;
- 2 hour emergency ratings are calculated using an assumed winter ambient temperature of 15°C, and a summer ambient temperature of 35°C;
- on average, across the ActewAGL system, the application of 2hr emergency ratings results in a 10.05 per cent increase in summer ratings, and a 21.3 per cent increase in winter ratings.

Transmission Lines:

- emergency line ratings are used to determine N-1 contingency constraints on the transmission system.
- transmission line ratings (continuous and emergency) are based on an assumed summer maximum ambient temperature of 35°C, and a winter minimum ambient temperature of 15°C;
- transmission line ratings (continuous and emergency) are based on an assumed wind speed of 1.0m/s, and continuous ratings allow for a conductor temperature of 75°C, while the emergency ratings allow for a conductor temperature of 120°C;
- on average, across the ActewAGL system, the application of emergency ratings to transmission lines increases the summer ratings by 51.7 per cent, and the winter ratings by 30.5 per cent.

6.5.2 Developing the augmentation plan

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 Chapter 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 6.3 below 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 Asset Management Plan (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.

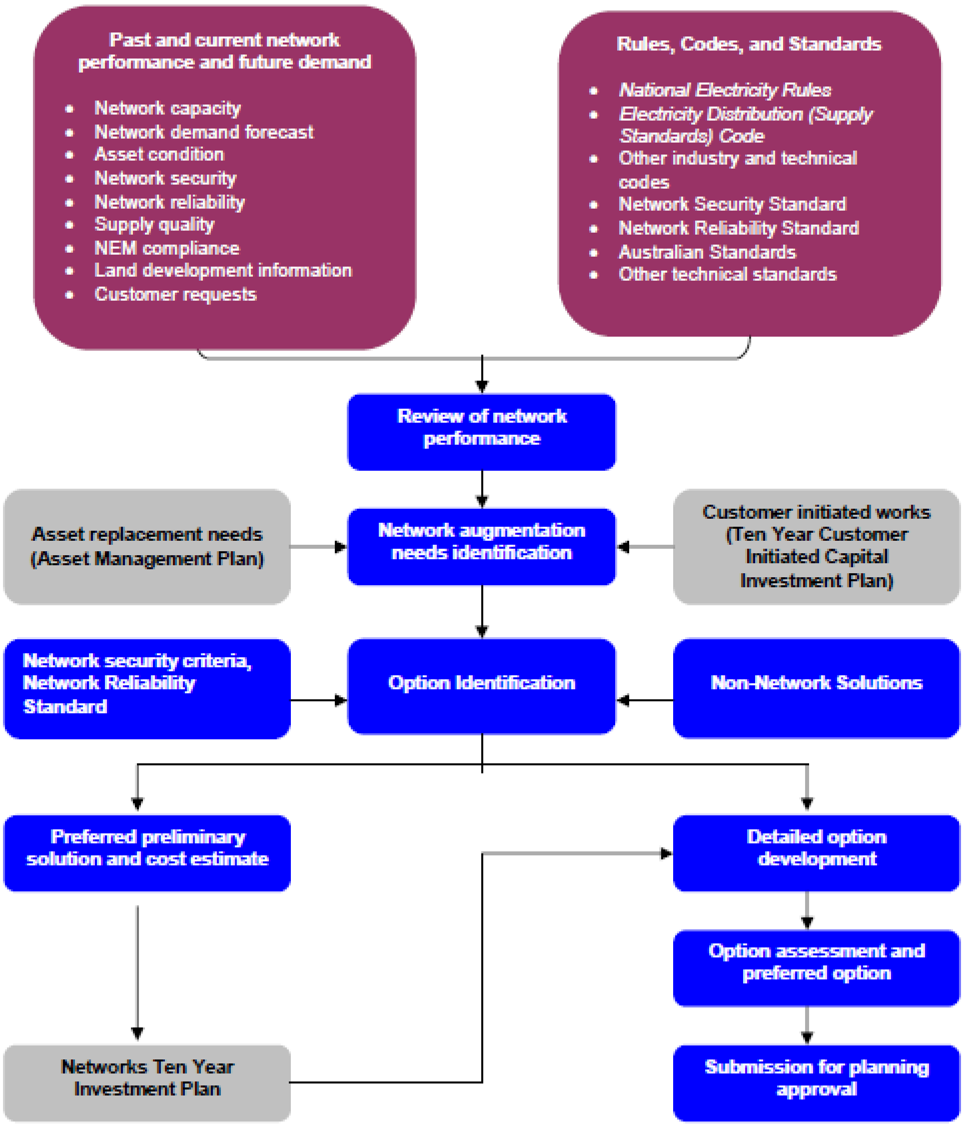
This is a two-stage process comprising:

> Stage 1—the basic options are considered and the “most likely option” included in the Investment Plan; and
>
> 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 a consideration of possible non-network solutions.

In addition, all large distribution projects are subject to the Regulatory Investment Test for Distribution (RIT-D) 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 RIT-D process. ActewAGL Distribution’s approach to non-network and demand management initiatives are discussed in section 6.12 of this proposal.

Figure 6.3 Network augmentation process

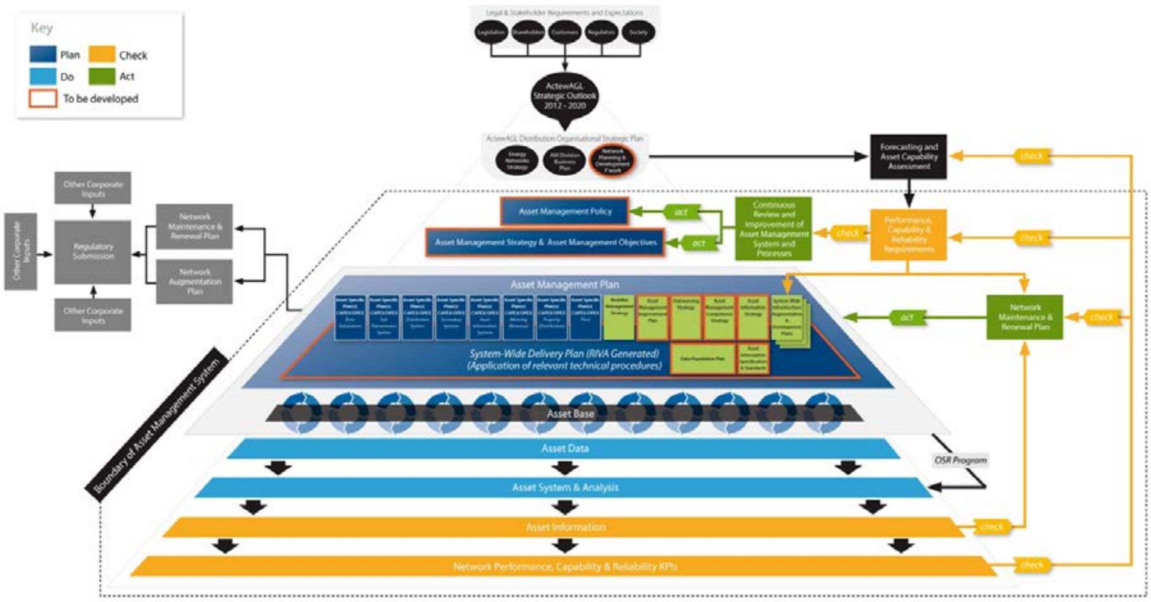


6.6 ActewAGL Distribution's Asset Management Framework

At the highest level of ActewAGL Distribution's asset management framework is the corporate *Asset Management Policy* which defines broad, high-level requirements to have plans in place to manage network assets. Under this sits the *Asset Management Strategy* which identifies the activities to be undertaken, via implementation of the *Asset Management Plan.* ActewAGL Distribution's asset management plan is composed of approximately 50 *Asset Specific Plans* (ASP). These ASPs are very detailed in their description of the assets to which they relate, planned activities and asset cost information.

Figure 6.4 shows the structure of the ActewAGL Distribution asset management system.

Figure 6.4 Asset management framework



6.6.1 Asset Management Policy

Effective asset management requires a disciplined approach which enables an organisation to maximise value and deliver its strategic objectives through managing its assets over their whole lifecycle. ActewAGL is committed to operating and maintaining an AMS that conforms with the British Standards Institute Publicly Available Specification *PAS 55-1:2008 Specification for the optimised management of physical assets* which supports effective asset management outcomes and ensures continuous improvement in asset management processes.

It is ActewAGL Distribution's Asset Management Policy that:

- all assets shall be managed in full compliance with any relevant statutory and mandatory legal and safety requirements;
- the management of asset related risk and Asset Management related risk shall be undertaken in accordance with the Corporate Risk Management Policy;
- assets, systems and networks shall be managed in a sustainable manner including due consideration of long-term financial, societal and environmental impacts;
- the asset management approach shall be appropriate to the scale and relative importance of the assets and asset systems to achieving the overall organisational objectives; and

- ActewAGL Distribution shall proactively seek continually improvement of its Asset Management capabilities and activities to assure value for money for customers and stakeholders.

ActewAGL Distribution's Asset Management Policy can be found at Attachment D1 to this submission.

6.6.2 Asset Management Strategy

In order to deliver these policy statements, ActewAGL applies an asset management approach that incorporates the following principles:

- the appropriate balance between stakeholder expectations regarding system reliability, risk and cost will be determined;
- all asset management interventions will be justified by robust engineering analysis underpinned by appropriate asset information;
- future projects will be prioritised based on the lifecycle costs and impact on customers in accordance with Board directives;
- modern equivalent technology will be adopted but only where that technology has already been proven in a similar business environment;
- the preventative maintenance program will be improved through implementation of a risk-based approach to determining maintenance requirements that deliver required levels of reliability;
- the utilisation of internal and contracted labour resources will be improved;
- the asset management capabilities of the organisation will be developed to an appropriate level to deliver efficient outcomes for customers and stakeholders; and
- asset management activities will take into account the output and recommendations from consumer engagement initiatives to emphasise the partnership between ActewAGL Distribution and its customers.

The overall aim of the Asset Management Strategy is to continue and build upon a well planned and executed infrastructure replacement program based on a PAS55 compliant methodology and Reliability Centred Maintenance that controls costs while meeting customer and community expected reliability goals. The specific and integrated asset management objectives are:

- establish the criticality of assets, based on a systematic analysis process considering cost, risk and performance across the entire asset base;
- capital investment programs will be considered and prioritised on an asset criticality basis including appropriate whole-of-life cost modelling (cost/benefit analysis);
- develop decision support tools to support the above analysis;

- optimised maintenance interventions for all assets will be established on a fully quantified cost/risk basis/criticality;
- optimised maintenance interventions for medium and low-criticality assets will be established on a defined and appropriate cost/risk basis;
- manage, rectify and record faults based on the failure mode analysis undertaken as part of the maintenance optimisation processes;
- recommendations from the 2012 review of ActewAGL Distribution's asset management plan will be fully implemented; and
- establish appropriate asset management maturity capability requirements for ActewAGL Distribution across the asset management system.

6.7 Asset information systems

During the 2009–14 regulatory period, ActewAGL Distribution commenced the Operational Systems Replacement Program (OSRP)—an operational technology reform program aimed at replacing critical asset management systems that were key to ensuring the continued delivery of a safe and reliable electricity supply in the ACT. The OSRP is discussed in detail in chapter 7 of this proposal.

Once complete, ActewAGL Distribution will have established a single, integrated operational platform to support the operations and management of the distribution network. The key principles that will be realised include implementation of:

- a geospatially-centric operational platform capable of tracking geographically distributed assets, customers and service deliverables. A geospatial operational environment also enables location intelligence and network connectivity to be accurately maintained, providing end-to-end visibility of the distribution network;
- commercially available off-the-shelf products which; minimise development and/or customisation costs, provide flexibility for future system upgrades, improve system maintenance and support efficiencies; and
- an operational technology environment where duplication of functionality and data will be minimised. Operational planning and management systems will have a 'single source of truth'. This best practice principle will drive continuous operational efficiency improvements through enhancing the accessibility of asset information and maintaining network data integrity.

ActewAGL Distribution has developed its asset management strategy and systems with consideration of the requirements of PAS 55, which is a Publicly Available Specification published by the British Standards Institution (BSI), and distributed and supported worldwide through the Institute of Asset Management. PAS 55 has generally been regarded as a de-facto world-wide specification for any organisation seeking to demonstrate a high level of professionalism in whole life cycle management of their physical assets.

PAS 55 will be discontinued in 2015 following the publication of the new International Standard for asset management ISO 55000 series in 2014. As discussed in chapter 4, ActewAGL Distribution’s asset management strategy and systems will be adapted to comply with any additional or amended requirements.

6.7.1 PAS 55

BSI PAS 55:2008 comprises:

- definition of terms in asset management;
- requirements specification for good practice; and
- guidance for the implementation of such good practice.

PAS 55 provides objectivity across 28 aspects of good asset management, from lifecycle strategy to everyday maintenance (cost/risk/performance). It enables the integration of all aspects of the asset lifecycle: from the first recognition of a need to design, acquisition, construction, commissioning, utilisation or operation, maintenance, renewal, modification and/or ultimate disposal.

PAS 55 also provides a common language for cross-functional discussion and provides the framework for understanding how individual parts fit together, and how the many mutual interdependencies can be handled and optimized.

The standard is split into two parts:

1. Specification for the optimised management of physical infrastructure assets; and
2. Guidelines for the application of PAS 55-1.

PAS 55 is structured around the Plan—Do—Check—Act cycle of continual improvement, and introduces the need for a number of essential ‘enablers and controls’ to ensure alignment, integration and sustainability of efficient and effective asset management activities as shown in Figure 6.5.

Figure 6.5 PAS 55 management system structure

PAS 55 is provided as a framework, rather than as a strict or rigid implementation of asset management strategies and systems. Historically, electricity distribution utilities in Australia have prepared and maintained extensive asset management plan documentation covering all aspects of asset management, from policy, to overall asset strategy, to maintenance plans, replacement/refurbishment strategies, and capital and operational forecasts. Such documentation was typically reviewed on an annual or regular basis.

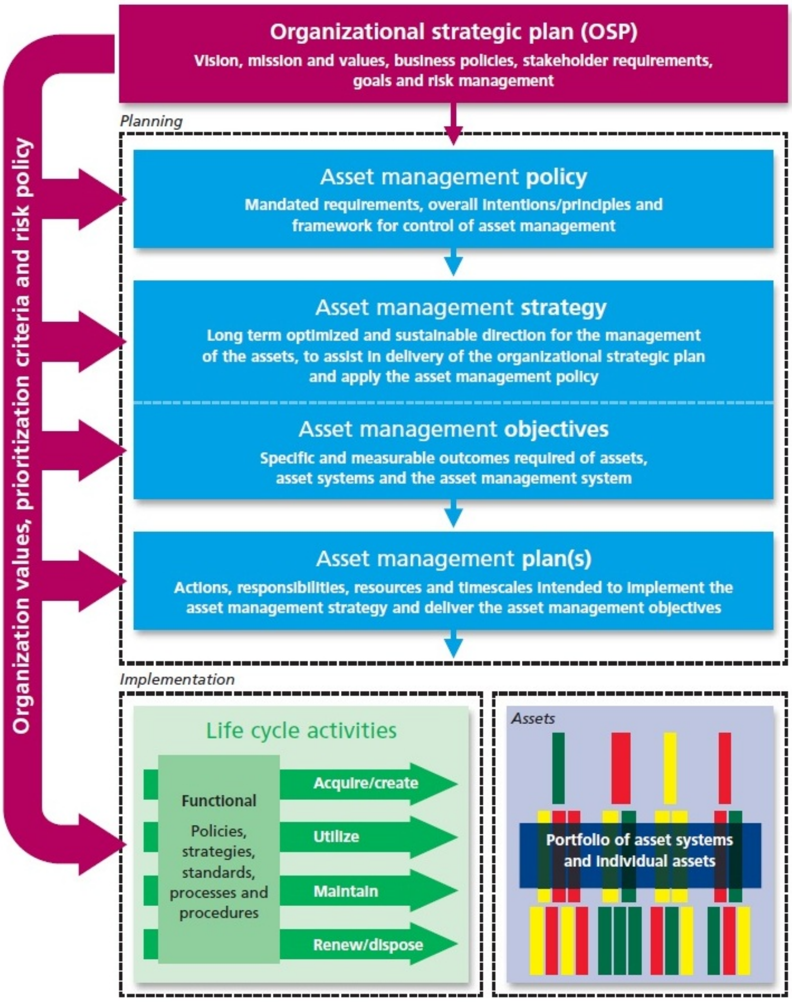
Recent industry practice has adopted a different approach which organises the asset management documentation into a hierarchy of policy, strategy and specific asset class plans.

6.8 Asset management implementation

ActewAGL Distribution's asset management framework embodies the PAS 55 management systems structure. The organisational strategic plan is the starting point for development of the asset management policy, strategy, objectives and plans. These, in turn, direct the optimal combination of life cycle activities to be applied across the diverse portfolio of asset systems and assets (in accordance with their criticalities, condition, performance and chosen risk profile of the organisation).

The "line of sight" between organisational strategic direction and the day-to-day activities of managing assets is an important component of the asset management system. This aligns the "top down" aspirations of the organisation with the "bottom up" realities and opportunities of the assets. Figure 6.6 shows the planning and implementation elements of the asset management system that drive this alignment.

Figure 6.6 Planning and implementation elements



The implementation of the PAS 55 approach in the asset management framework ensures "line of sight" between the different components shown in Figure 6.4 earlier in this chapter. The asset data and asset system and analysis components of this framework are undertaken using Riva software.

6.8.1 Riva Decision Support

ActewAGL Distribution uses Riva's asset optimisation software, Riva Decision Support (Riva) software to perform a range of functions, including the projection of capital and operational expenditure forecasts.

Riva provides enterprise wide transparency for long-range forecasts of ActewAGL Distribution’s asset investment needs. It integrates with the asset inventory systems, and generates an activity and expenditure forecast (in real terms), which is as current as the operational inventory, associated inspections and work orders. It also generates ASPs for each asset type and forecasts service level, risk, cost and other performance measures.

The ASPs are plans for each network, non-infrastructure and non-network asset type, and are integrated over the life of the asset, and with other assets to produce the optimum whole-of-life/whole-of-system strategy for each asset.

In compliance with the PAS 55 asset management standard, the suite of documents that are shown in Figure 6.7 below deliver the asset management objectives across the following life cycle activities:

- creation, acquisition or enhancement of assets;
- utilisation of assets;
- maintenance of assets; and
- decommissioning and/or disposal of assets.

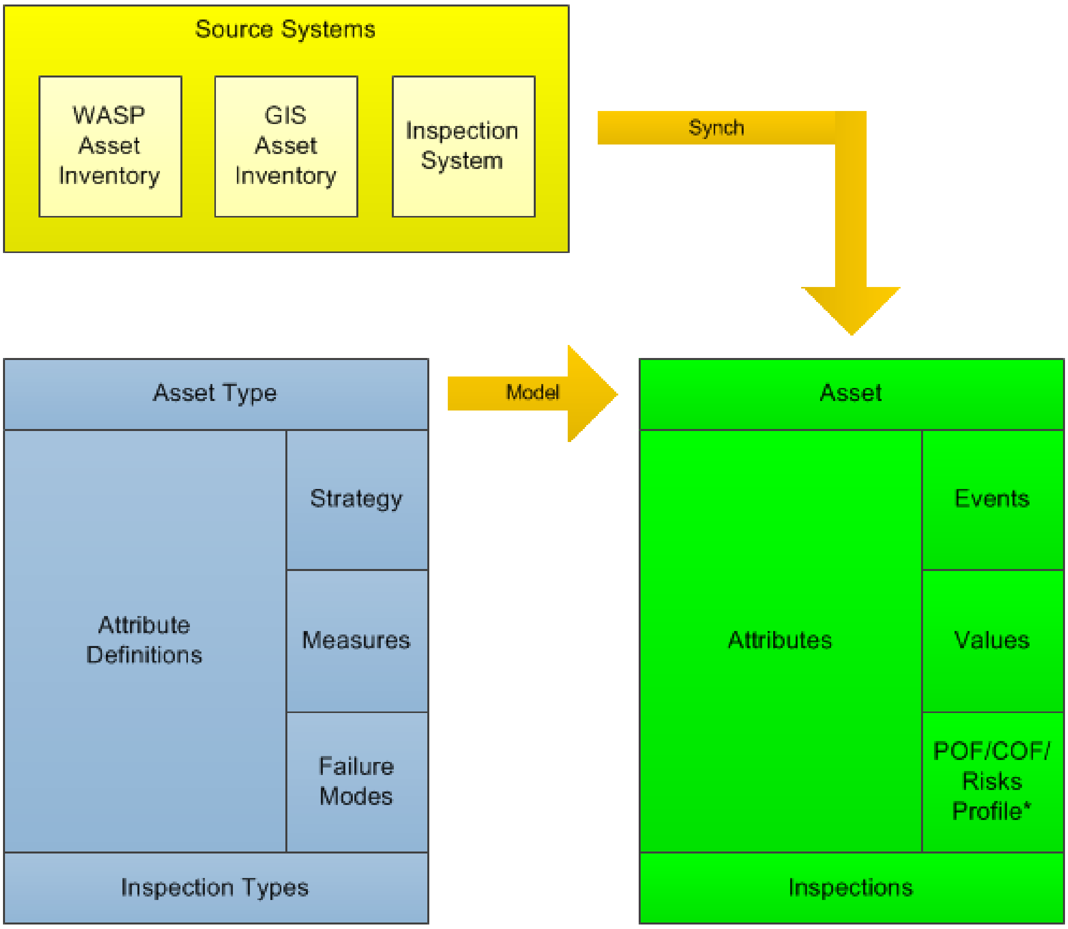
The processes and procedures for the implementation of the asset management plan are consistent with the asset management policy, asset management strategy and asset management objectives. They ensure that costs, risks and asset system performance are controlled across asset life cycle phases.

6.8.2 Asset data

Riva has an asset type classification that includes asset attribute definitions and a management strategy that indicates the life cycle maintenance and refurbishment activities. It also includes definitions for performance measures and the failure modes.

Information is extracted from WASP or GIS to generate the distinct assets. Each asset contains all of the attributes defined for it, such as age, in-service, material, diameter, voltage etc. It also contains a set of events and activities that have been generated for that asset based on ActewAGL Distribution’s *asset management strategy*, predicted values of future measures, and probability, consequence and risk profiles. Figure 6.7 demonstrates how Riva generates an ASP for each asset from various source materials.

Figure 6.7 Riva Decision Support asset model



All electricity assets are entered into Riva as a single inventory source. The inputs are entered at the specific asset level, thereby allowing consolidated reporting at the category and group levels. A range of input data factors are captured for each asset. These include:

- asset condition;
- forecast useful asset life;
- probability of failure;
- consequence of failure;
- replacement cost of the asset; and
- event (triggered by asset management strategy by asset type) and activity (work inserted manually) costs.

Other non-specific inputs are used, including maintenance data from the WASP asset management system. Riva then runs a series of algorithms to determine the optimal management of the assets and prioritises work schedule activity based on a risk assessment. These algorithms include:

1. Cost/benefit on when to replace the asset;
2. Optimal replacement schedule;
3. Cost/benefit on when to maintain the asset;
4. Optimal maintenance schedule; and
5. Priorities based on risk assessment.

Riva then uses the algorithms and optimal work schedule to project the associated operational and capital expenditure forecasts. A zero-based approach is used for the generation of the capital expenditure forecasts for asset renewal/replacement, metering, network augmentation and customer initiated capital expenditure. ActewAGL Distribution's forecasting approach for each capital expenditure category is contained in chapter 7 of this submission.

The operational expenditure forecast is a mixture of zero-based approach and base year, dependent upon the nature of the expenditure category. Network maintenance is the result of the inputs and parameters of each asset combined with algorithms that prioritise the maintenance schedule. Being fully zero-based, maintenance costs can be difficult to predict. In such cases, additional system algorithms help smooth and remove any volatility by bringing forward and deferring maintenance needs as appropriate, with the objective to minimise the cost over time. ActewAGL Distribution's forecasting approach for each operating expenditure category is contained in chapter 8 of this submission.

6.8.3 Riva implementation progress

ActewAGL Distribution has made good progress in incorporating Riva software into its asset management systems during the 2009–14 regulatory period and has used some Riva generated asset renewal and maintenance (planned/unplanned/condition) expenditure in developing its capital and operating expenditure programs for the 2014-9 regulatory period. Where some Riva generated forecasts are still subject to internal and external review, ActewAGL Distribution has forecast its expenditure using existing asset management systems.

When Riva is fully implemented, it will be used to generate bottom-up estimates for capital and operational expenditure across the following:

- network augmentation;
- customer initiated augmentation;
- asset renewal;
- poles;
- meters; and

- network maintenance (planned/unplanned/condition monitoring).

In respect of the expenditure forecasts presented by ActewAGL Distribution for the 2014–19 regulatory period:

- for network and customer augmentation forecasts, ActewAGL Distribution has relied upon business cases, investment tests and other supporting documentation for the generation of forecasts and scheduling of capital expenditure based on identified network constraint and customer requirements. This approach is discussed in chapter 7 of this submission;
- so that Riva may generate a 10-year capex-opex summary report, the forecast expenditures for capital augmentation are entered into Riva separately. Riva is an asset-orientated system, and will not generate expenditure forecasts for any new assets until the augmentation has become a committed project and the related assets have been created within the asset management system;
- the review of metering data in Riva is yet to be completed, and therefore the expenditure forecasts for all alternative control services for metering (contained in chapter 15 of this submission) have been based on the level of activities detailed in ActewAGL Distribution's Metering Asset Management Plan;
- the capital expenditure forecasts for asset renewal have been based on the projections generated for each asset class based on the relevant nominated refurbishment and replacement asset lives. These Riva generated estimates have been checked against previous legacy systems to identify and address any step changes that may have been introduced. The majority of primary network assets such as zone substation assets, poles, overhead line and switchgear, pole and ground substations and transmission assets have been loaded and configured in Riva, with ongoing reviews for accuracy and completeness;
- the network maintenance forecasts for planned/unplanned/condition monitoring activities have been based on the nominated level of activity for each asset type detailed in the Asset Specific plans. The scheduling of the expenditure has been based on the nominated asset lives for each asset category in Riva;
- Riva does not include expenditure forecasts for fleet, operational systems replacement program, maintenance strategy, planning and reporting, or vegetation management. These forecasts are generated external to Riva;
- the expenditure projections generated by Riva have a base year of 2012/13, and are direct costs only. A sample of the unit rates stored in Riva for both asset renewal and maintenance activities have been independently reviewed and assessed as being reasonable (assuming a base year of 2012/13). In developing the capital and operating expenditure forecasts for the 2014–19 regulatory period, the Riva generated estimates have been escalated to 2013/14 dollars and corporate overheads have been added;

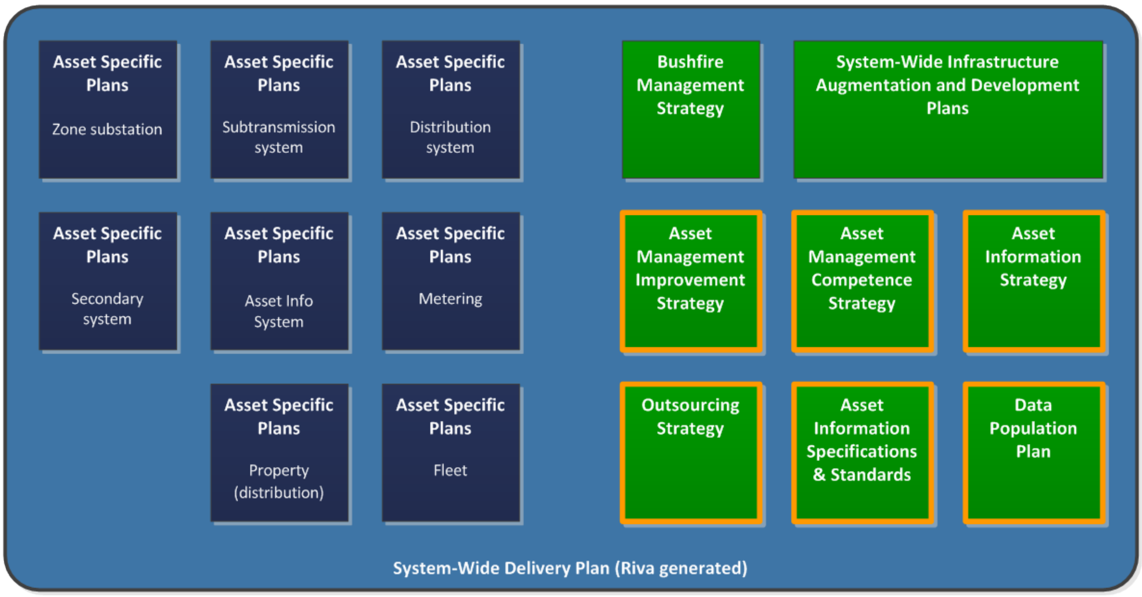
- the asset lives adopted in Riva for the generation of the network maintenance forecast have been independently reviewed and found to be reasonable and suitable for use; and
- it should be recognised that forecasts generated by Riva are based on current data extracted from the WASP asset management system and the customer initiated and network augmentation projects. As a result the forecasts are subject to constant change as assets are added and disposed. Riva does not retain historical values for expenditure projections or changes in project timelines. Such historical data has been captured separately for identifying and analysing variations, trends and any step changes.

6.9 Asset Management Plan

As discussed earlier in this chapter, ActewAGL Distribution's Asset Management Policy is informed by corporate level policy objectives, and states that ActewAGL Distribution is committed to the effective implementation of asset management with a disciplined approach to maximise value and deliver its strategic objectives through managing assets over their whole lifecycle. This approach conforms to the requirements of *PAS 55-1:2008* which supports effective asset management outcomes and ensures continuous improvement in asset management processes.

With the incorporation of Riva Decision Support software into ActewAGL Distribution's asset management framework, ActewAGL Distribution no longer relies upon a conventional asset management plan. Rather, the current asset management plan is a collection of ASPs and other Riva generated documentation, supporting network augmentation plans and management strategies. This is shown in Figure 6.8 below.

Figure 6.8 ActewAGL Asset Management Plan



Note: The documents shown with an orange border ☐ are yet to be developed.

6.9.1 Asset Specific Plans

Currently there are approximately 50 ASPs that can be generated by Riva in respect of ActewAGL Distribution's assets. These are very detailed documents and include:

- Detailed description of the asset and its functions;
- Quantitative information on asset population;
- Deterioration drivers and failure modes, and asset criticality;
- Risk assessment and risk-based priority for expenditure;
- Service level and reliability standards;
- Current and future health and risk reporting;
- Event and activity unit costs (capital and operating expenditure) for planned maintenance, unplanned maintenance, condition monitoring and replacement/refurbishment;
- Details of asset quantities and forward projections of capital and operating expenditure requirements to 2032;
- Asset age profiles, percentage of life consumed and a "health index" profile over time; and
- Disposal strategies.

As the ASPs are produced by Riva upon request, they use current asset data, and include current asset numbers, age profiles and health assessments. ActewAGL has developed a template for the ASPs to ensure consistent plan attributes across all of the network and non-network asset categories.

6.10 Asset age and replacement/refurbishment modelling

A key element of the management of the diverse range of assets on an electricity distribution system is to have a comprehensive asset database with effective condition monitoring capability, and the functionality to accurately model forecast replacement and refurbishment costs.

With the implementation of Riva DS software, ActewAGL Distribution now has such a database, and the analytical capability to manage and model forward forecasts of replacement/ refurbishment capital expenditure, and future trends in operating expenditure.

In its 2009–14 regulatory proposal (section 6.7) ActewAGL provided an overview of the asset age profiling and its capex/opex trade-off modelling

The key features and findings at that time were:

- ActewAGL and SKM jointly developed a pole replacement / refurbishment model (the Pole Model);
- ActewAGL and SKM jointly developed a network asset replacement / refurbishment model (the Network Model);
- the weighted average system age in 2007/8 was 24.88 years;
- age profile forecasting indicated that the weighted average system age would increase to 26.8 years by 2012/13 and 27.5 years by 2013/14; and
- the pole replacement/refurbishment model developed by ActewAGL/SKM at the time indicated the necessity for an annual expenditure of between $9.9 million and $10.4 million in order to maintain the pole population in a safe and serviceable condition. Actual expenditure has been within this range. ActewAGL Distribution's ongoing pole replacement program is discussed in section x of this submission.

ActewAGL and SKM jointly developed an "energy at risk" model specifically designed to evaluate the optimum timing for replacement of ageing and potentially unreliable assets. This model was subsequently applied to assessing the costs and benefits of replacing the ageing 11 kV switchboard at Civic Zone Substation, which was completed in the 2009–14 regulatory period, and is a case study covered in Attachment B17.1.

6.10.1 Trend in system average age

As part of the Network Model, ActewAGL/SKM undertook in 2008 extensive age profiling of ActewAGL Distribution's network assets on an individual asset category basis. With the introduction of Riva, ActewAGL Distribution now has a comprehensive "live" database of assets, asset quantities, and asset ages which provide the latest vision of the trends in asset class and overall system age.

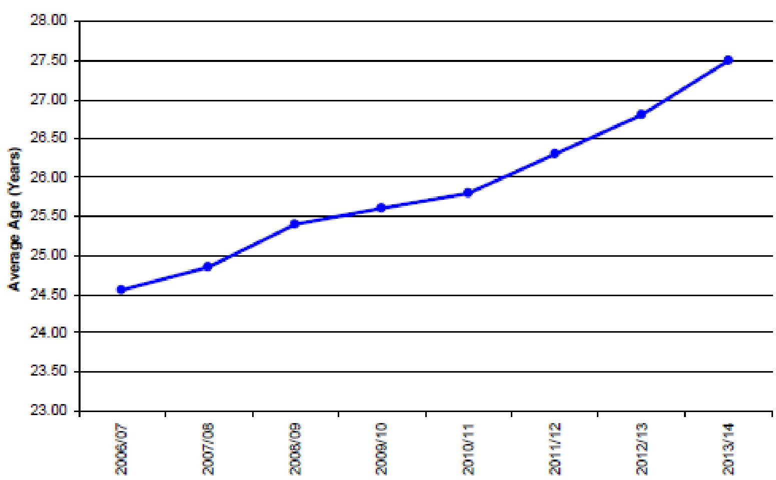
Table 6.5 below compares the results of the age profile modelling undertaken in 2008 with the current age profile information available from Riva, on an asset class by asset class basis.

Table 6.5 ActewAGL distribution average asset age by category

Asset category	*Weighted average age 2007/08*	*Weighted average age 2012/13*	*Average expected life*
Sub-transmission overhead lines	28.88	32.9	50
Sub-transmission underground	5.00	11.7	50
Zone substations	26.11	21.8	47
Distribution substation	23.92	24.0	41
Distribution underground	22.57	25.1	50
Distribution poles	31.00	39.9 (wood) 17.9 (concrete) 13.7 (steel) 3.1 (fibreglass)	45 (wood) 80 (concrete) 60 (steel) 70 (fibreglass)
Distribution overhead lines	22.48	31.0	50
Distribution other	22.29	N/A	31
Total weighted average system age	**24.88**	**26.3**	-
Total weighted average system life	-		**46**

In 2008 ActewAGL and SKM forecast that the weighted average age of the network would increase from 24.88 years in 2007/08 to approximately 26.8 years in 2012/13, as shown in Figure 6.9 below.

Figure 6.9 Forecast weighted average age of network



This was based on the assumption that the requested level of replacement/refurbishment capital expenditure in the ActewAGL regulatory proposal would be approved, and expended. It should 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.

The latest figures available from Riva indicate that the weighted average network age in 2012/13 was 26.3 years, indicating a slightly slower rate of ageing than previously indicated. This may be distorted by the fact that the latest Riva data includes a wider range of assets, including short life assets.

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 2014–19 regulatory period, and will need to analyse asset condition and performance information from Riva in order to target specific poor performing and high risk assets for replacement/refurbishment.

6.11 Capex/opex trade-off

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.

In addition to Riva, ActewAGL also uses a number of sophisticated modelling tools to analyse capital and operating expenditure trends for various asset categories to ensure that total forecast costs (capital and operating) are minimised. This involves consideration of the likely future trend in maintenance costs as the system assets age, and condition deteriorates, together with the risks and costs associated with a certain percentage of in-service asset failures.

This analysis of total asset costs (capex and opex) underpins the whole concept of the Riva software used by ActewAGL Distribution to schedule replacement and refurbishment works and its associated expenditure, and is often given the rather simplistic term of ‘capex/opex trade-off.’

Over the past 5 years ActewAGL has further developed it’s suite of capex/opex trade-off tools, and applied these in making key investment decisions during the 2009–14 regulatory period and in respect of the 2014–19 regulatory period. An example of the interaction between forecast operating and capital expenditure programs is ActewAGL Distribution’s underground cable replacement program that is being implemented during the 2014–19 regulatory period to address an increase in underground cable faults during the 2009–14 regulatory period (discussed in section 7.8.5).

To summarise, approximately 15 per cent of ActewAGL Distribution’s underground cables have exceeded their average service life and an additional 11 per cent will exceeded their average service life over the next 10 years. Expenditure on reactive maintenance has been increasing over the 2009–14 regulatory period as aged cables fail at an increasing rate.

As a result of ActewAGL Distribution's decision to invest in the replacement of underground cables over the 2014–19 regulatory period, it is anticipated that there will be a decline in reactive maintenance operating expenditure as well as an increase in condition monitoring or planned maintenance in respect of underground cables in the future.

Similarly, there are important operating expenditure considerations associated with ActewAGL Distribution's decision to replace wood poles with concrete and fibreglass poles. ActewAGL Distribution's ongoing pole replacement program is discussed in more detail in section 7.8.4. Specifically, steel and fibreglass poles require few inspections, do not take in moisture, and are not susceptible to termite attack of timber rot. Fibreglass poles have a longer expected average service life than timber and steel poles, reducing the whole of life replacement cost.

Jacobs SKM has reviewed ActewAGL Distribution's wood pole replacement and underground cable replacement programs and associated operating cost savings. In both cases, Jacobs SKM found ActewAGL Distribution's capital replacement investment decisions to be prudent. This analysis is contained in Attachment B.17.1.

Since the 2009–14 regulatory proposal, ActewAGL has implemented and populated its Riva system which offers far more powerful recording, analytical, and forecasting tools than it has had at its disposal in the past. However, Riva will not replace these capex/opex optimisation modelling tools, and ActewAGL continues to develop and enhance the application of such tools for optimisation purposes.

6.12 Non-network options and demand management initiatives

During the 2009–14 regulatory period, ActewAGL Distribution developed a Demand Side Engagement Strategy. This is available on ActewAGL Distribution's website and at Attachment D18.

In summary, the strategy aims to create a cooperative and proactive relationship with customers and proponents of non-network solutions and involve them with ActewAGL Distribution's network planning and expansion. ActewAGL Distribution aims to encourage customers and potential non-network service providers to participate in ActewAGL Distribution demand management activities with the objective that future network problems can be met by a full range of solutions to achieve optimal economical and technical outcomes.

To facilitate the achievement of these objectives, ActewAGL Distribution is currently in the process of finalising a demand management plan and establishing a demand management team, whose role it will be to implement the plan. Investigations are continuing into the feasibility of various non-network alternatives to efficiently manage network demand and address identified network constraints, taking into account:

- expected load growth, and the relative cost of augmenting the distribution network;
- de-rating of network assets which occurs during high temperature events;
- current and expected level of reactive load on the network; and

- customer profiles, including domestic, commercial and industrial.

ActewAGL Distribution will continue to increase its focus on demand side management activities during the 2014–19 regulatory period in accordance with the demand side management engagement strategy, the demand management plan and relevant provisions of the NER. Specifically it will focus on:

- developing and implementing non-network solutions to efficiently defer supply side (network) capital expenditure;
- developing and implementing targeted projects to efficiently manage specific peak demand constraints;
- developing and implementing broad-based projects including trials to test potential long-term network wide DSM solutions;
- applying and optimizing customer incentive including Time of Use tariff strategies; and
- developing and implementing pricing reforms via a tariff realignment initiative.

Some of the non-network options and demand management initiatives (including tariff reforms) that ActewAGL Distribution plans to undertake during the 2014–19 regulatory period are discussed in more detail below.

6.12.1 Non-network planning approach

ActewAGL Distribution conducts an annual planning review in which it forecasts rates of peak demand and energy growth for the ActewAGL Distribution network for a ten year period. Using these forecasts an analysis of the ActewAGL network system capacity is conducted to identify specific areas that will become constrained over the forecast period. A preliminary investigation is conducted of these constrained network areas to determine economically and technically feasible solutions.

The options that may be available to solve a network constraint are:

- a network solution (supply side option); or
- a non-network solution (demand side option); or
- a combination of both.

A network option may involve solutions such as increasing the supply capability into an area by constructing a new high voltage feeder, augmenting an existing high voltage feeder, constructing a new 132/11 kV zone substation or similar capital projects. In contrast, a non-network option may involve reducing demand overall or at critical times in the particular geographic zone via DSM initiatives such as demand response programs, peak shaving generation, embedded generation, or energy storage connected at customers' premises.

ActewAGL Distribution also runs innovation broad based programs some of which are supported by funding through the DMEGCIS.

6.12.2 Demand management and embedded generation connection incentive scheme

The Stage 2 Framework and Approach paper sets out the AER's proposed approach to the application of the DMEGCIS. The AER proposed to continue applying part A, the Demand Management Innovation Allowance (DMIA), of the existing Demand Management Incentive Scheme (DMIS) to ActewAGL Distribution.[55]

The AER also noted its intention to develop and implement a new DMEGCIS for the subsequent regulatory control period, depending on the progress of the rule change process.[56] To facilitate the introduction of any new DMEGCIS, ActewAGL Distribution has proposed a DMEGCIS pass through event, discussed in the cost pass through chapter of this proposal.

ActewAGL Distribution supports the AER's proposal, as specified in the Stage 2 Framework and Approach, to apply the DMEGCIS in the same manner as in the previous regulatory period as an interim measure.

Continuation of the DMEGCIS contributes towards the continued implementation of broad based and innovative demand management projects.

6.12.3 Demand Management initiatives

ActewAGL Distribution will devote internal resources and use DMEGCIS funding to support potential initiatives including; Smart Network Integrated Urban Planning, Targeted Appliance Switching, the Canberra Urban Solar Project and Panasonic Battery Storage Trial. These are discussed in turn below.

6.12.3.1 Smart Network Integrated Urban Planning

ActewAGL Distribution will be investigating innovative methods for assessing, analysing and utilising distribution network information to:

- enhance the benefits to consumers through forward integrated planning with local government planning rules, including holistically for new residential precincts; and
- enact smarter network 'real-time' decisions to alleviate or defer the need for network augmentation.

This is an emerging knowledge base within ActewAGL Distribution which will mature during the 2015-19 regulatory control period. ActewAGL Distribution has commenced the implementation of Advanced Distribution Management Systems (ADMS). These systems will be used to provide real time information allowing for automated network switching decisions and realisation of 'self-healing' network principles.

[55] AER 2014, *Stage 2 Framework and approach—ActewAGL*, p 44

[56] AER 2014, *Stage 2 Framework and approach—ActewAGL*, p 44

During the 2015-19 regulatory period, ActewAGL Distribution proposes to enhance its DSM knowledge base and experience by engaging with local government urban planning entities and to help drive sustainable change in DSM for future urban planning initiatives. The intent is to influence changes to the intensity, amount and/or time of energy usage. This initiative can be broadly described as Smart Networks within an Urban Planning context. Smart networks incorporate computer-based electronics into utility networks to enhance information and price signals to customers. This proactive and long term approach complements the DSM objective of effectively managing load growth on ActewAGL's distribution network.

Any form of built development has important implications for levels of demand on ActewAGL network. The involvement of ActewAGL Distribution in an early stage of the development process is required to assist designers, architects and users with the optimisation of energy efficiency in new town planning precincts and potentially in the revision of building construction codes.

ActewAGL Distribution proposes to fund this new initiative out of the Demand Management Allowance (DMIA) for the 2014–19 regulatory period.

6.12.3.2 Targeted Appliance Switching

The emergence of viable smart home technologies together with possible smart meter rollouts provides a platform on which to develop demand side management strategies that aim to modify consumer's use of energy. Targeted appliance switching has the potential to adjust consumer behaviour patterns and switch on/off energy consuming appliances, such as air conditioners, when they are not needed or when they could be utilised to benefit from on-site power generation or off-peak electricity. Installation of non-disruptive technologies into existing domestic environments will be targeted.

This type of demand side management does not necessarily reduce total power consumption, but it does offer the potential to smooth daily demand, reduce peak requirements and hence reduce necessary peak capability. Typical appliances considered are pool pumps, air conditioners, dishwashers, washing machines and tumble dryers. The potential to expand this program to other appliances will be investigated, with the broad selection criteria being:

- their operation does not need to be at the point of use (they can be controlled remotely); and
- they use a considerable amount of energy and thus the impact of time-shifting achieved would be significant, especially when aggregated to multiple households.

ActewAGL Distribution proposes to fund this new initiative out of the DMIA for the 2014–19 regulatory period.

6.12.3.3 Canberra Urban Solar Project

The Canberra Urban Solar Project (CUSP) is a research project headed up by the Environment and Sustainable Development Directorate (ESDD) and includes involvement from several parties including the ANU, CIT, Zhinfra and ActewAGL Distribution. The CUSP will trial micro solar-storage systems in real world applications to help better inform business, government and the Australian community on the technical, economic, social, skills and knowledge challenges impacting the future deployment of solar-storage technologies in the residential sector. By helping define and assess the barriers to solar-storage technologies, it can enhance the prospects for this technology to be deployed in a cost-effective way and with the greatest public benefit.

The project also has a number of benefits for Canberra, including but not limited to:

- it will contribute to the ACT's 90 per cent renewable energy target;
- it will enable greater understanding of the achievable and effective levels of solar penetration (over current assumed technical limits) to further enhance the vision of Canberra as Australia's Solar Capital; and
- it will support the development of future policies and regulation for low and zero-emissions buildings providing national leadership on a sustainable built environment.

ActewAGL Distribution has a strong interest in facilitating greater demand side participation across the ACT Distribution Network including the effective management of what is a trend to higher penetration of renewables. ActewAGL Distribution is currently implementing a new Advanced Distribution Management System (ADMS) that will provide enhanced capacity to communicate with customers appliances and meters across the network to trigger various forms of demand response.

ActewAGL Distribution considers Advanced PV-integrated storage systems, in conjunction with its ADMS, as a demand side management option has the potential to address a number of emerging issues including:

- peak demand growth associated with suburban expansion and urban in-fill; and
- potential overvoltage issues associated with high penetration PV clusters on the network.

ActewAGL Distribution's need for further information also extends to the development of safe working methods for PV-storage installation and operational guidelines which will be a key outcome from the CUSP project. There is also a strong interest in customer research outcomes that can be used by ActewAGL Distribution to inform new business models and marketing strategies.

Implementation will be conducted over five years (2014/15 to 2018/19) with the first year focusing on project establishment and the final year on knowledge diffusion.

Project outputs will be a series of major thematic research reports for an industry/government audience. Data will be shared through an online portal under open-access licence terms for use by other researchers, businesses and policy-makers, both nationally and internationally. A major focus will be transmission of information to householders interested in PV and PV/battery systems.

ActewAGL Distribution proposes to fund this new initiative out of the DMIA for the 2014–19 regulatory period.

6.12.3.4 Battery Storage Trial

The introduction of battery storage technology in residential premises may contribute towards reducing both peak and base loads in the electricity network especially if ActewAGL Distribution has control over when the battery is charged and discharged via a control switch. This would be similar to the Energex PeakSmart scheme, in which a signal is sent remotely by Energex that tells a customer's air-conditioner to cap its energy consumption on occasions when the network reaches peak demand.

ActewAGL Distribution is currently investigating the potential to introduce standalone energy storage batteries and possible integration with residential PV. In particular ActewAGL Distribution is investigating how it could leverage these options could benefit from network demand planning and the investigation, analysis and evaluation of:

- The impact, and potential benefits of connecting solar generation and battery storage products to ActewAGL Distribution's electricity network;
- The potential of residential micro storage systems to contribute to demand reduction and peak load shifting on ActewAGL Distribution's network; and
- Issues and potential solutions with regard to electricity network load shedding implications from energy storage.

ActewAGL Distribution proposes to fund this new initiative out of the DMIA for the 2015-19 regulatory period.

6.12.4 Tariff Incentive Structures

ActewAGL Distribution's approach to demand-side management for some time has been to focus 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.

Providing incentives and opportunities for demand management is a key component of ActewAGL Distribution's pricing strategy. ActewAGL Distribution's pricing strategy has in recent years accommodated the development of some innovative tariffs and yielded significant customer responses. For example, in line with the strategies of setting cost reflective prices and providing opportunities and incentives for demand management, ActewAGL Distribution has gradually introduced several time-of-use charging options for both commercial and residential customers. More than 50 per cent of the total load in the ACT is now subject to time-of-use or controlled load (off-peak) charges. For the non-residential sector, nearly 80 per cent of the load is on time-of-use or controlled load tariffs.

In October 2010, time-of-use tariffs became the default tariff for all new residential and commercial premises, with the option to select an alternative tariff.

The application of maximum demand and capacity charges in several commercial tariff options has further strengthened price signals to customers, provided incentives to use the network more efficiently and resulted in significant customer response. The maximum demand charges signal to customers the relatively high cost of providing capacity to meet demand and provide incentives to customers to improve both their load factor (that is, spread their load more evenly) and power factor (which allows the existing network to deliver more energy). Between 1999/00 and 2012/13, customers on the Low Voltage demand network tariff improved their load factor and therefore their utilisation of the network by 11.4 per cent, increasing the average energy consumed relative to the average of their monthly maximum demand from 40.1 per cent to 44.7 per cent. Over the same period, high voltage customers increased their load factor, and therefore their utilisation of the network, from 54.2 per cent to 59.3 per cent, an improvement of 9.4 per cent.

In preparation for the 2014–19 regulatory review ActewAGL Distribution commenced a review of network tariffs. The broad aims of ActewAGL Distribution’s tariff re-alignment initiative are to ensure that the tariff structure continues to provide cost reflective price signals to consumers, and to respond to the risks and opportunities created by recent and emerging developments including:

- changing patterns of energy consumption and use;
- new technologies for energy supply and use; and
- increasing public and regulatory focus on the need for cost reflective tariffs.

The tariff re-alignment initiative is discussed in more detail in Chapter 13.

7 Capital expenditure

7.1 Key points

ActewAGL Distribution’s capital expenditure plan for the 2014–19 regulatory period continues key capital expenditure reform programs that were initiated during the current period to ensure the ongoing reliability of the network and alignment with the ACT Government’s planning and system security requirements.

ActewAGL Distribution’s capital expenditure for the 2014–19 regulatory period is forecast to be marginally higher than expenditure in the 2009–14 regulatory period. This is largely driven by the continuation of zone substation augmentation to meet demand for electricity in new urban areas and meet reliability standards, as well as an increased focus on asset renewal and replacement to address an increase in reactive maintenance in the 2009–14 regulatory period.

7.2 Consumer benefits

ActewAGL Distribution intends that the proposed capital expenditure program for the 2014–19 regulatory period will deliver that following benefits to customers:

- asset replacement programs will ensure that reliability standards are met and safety levels will be maintained at their current levels in most areas and improved in others;
- ActewAGL Distribution will deliver value for money to customers by continuing to improve the way it manages its assets and delivers capital works projects;
- a new zone substation will be constructed at Molonglo to meet demand from new suburbs in ACT Government’s key growth area which will support the development of residential developments, commercial businesses, town centres and other facilities;
- the supply of electricity to the ACT will be made more secure by the completion of the Southern Supply to ACT project;
- the ongoing meter replacement program will allow more customers to move onto time of use tariffs, and have more control over their electricity consumption;
- changes to ActewAGL Distribution’s operational technology systems will also help to provide consumers with more information about their consumption habits, as well as:
    - provide customers with access to accurate and real-time outage information as well as allow customers to report outages and damaged assets, increasing transparency;
    - ensure that outages and network faults are located and attended to more quickly, ensuring minimal interruptions to customer supply;

- allow for condition based maintenance which will reduce asset failures and hence outages; and
- allow for targeted power quality correction which will reduce distribution losses, voltage drops and improve customer power quality.

7.3 Regulatory requirements

The AER's requirements in respect of ActewAGL Distribution's capital expenditure forecasts, methodology and assumptions are set out in the NER (Chapter 6 and schedule 6), the AER's *Expenditure Forecast Assessment Guideline* and the Regulatory Information Notice (RIN).

7.3.1 Requirements of the NEL and the Rules

The *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).

Clause 6.5.7(a) of the Rules states that a building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the DNSP considers is required to achieve each of the *capital expenditure objectives*.

The *capital expenditure objectives* are as follows:

- 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*;
- to the extent that there is no applicable regulatory obligation or requirement in relation to:
  - the quality, reliability or security of supply of *standard control services*; or
  - the reliability or security of the *distribution system* through the supply of *standard control services*,
- to the relevant extent:
  - maintain the quality, reliability and security of supply of *standard control services*; and
  - maintain the reliability and security of the *distribution system* through the supply of *standard control services*; and
- maintain the safety of the *distribution system* through the supply of *standard control services*.

Clause 6.5.7(c) of the 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 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 6.5.7 and S6.1.1 of the Rules and Schedule 1 of the RIN set 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.

7.3.2 Expenditure Forecast Assessment Guideline

The Rules require the AER to develop and publish Expenditure Forecast Assessment Guidelines.[57] The AER's *Expenditure Forecast Assessment Guideline* was published in November 2013 and describes the process and techniques that the AER might adopt in setting expenditure allowances for network businesses, and associated data requirements. It also sets out the AER's principles for guiding its reliance on assessment techniques and a business's forecasting approach.

7.3.3 Regulatory Information Notice

On 7 March 2014, the AER issued ActewAGL Distribution with a Regulatory Information Notice (RIN) under Division 4 of Part 3 of the National Electricity (ACT) Law. The RIN requires ActewAGL to provide, prepare and maintain the information in the manner and form specified in the notice. The AER requires the information to publish network service provider performance reports (annual benchmarking reports) and to assess benchmark operating expenditure and benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider relevant to building block determinations.[58]

The RIN specifies the information that the AER requires, in addition to the requirements set out in clause S6.1.1 of the Rules, to allow it to assess the forecast capital expenditure. Schedule 1 of the RIN sets out additional information requirements for ActewAGL Distribution to address, and specifies in detail the types of supporting documentation that ActewAGL Distribution is required to provide in support of its regulatory proposal.

[57] *National Electricity Rules*, clause 6.2.8(a)(1)

[58] AER letter to ActewAGL Distribution, 7 March 2014

In accordance with Schedule 1 clause 1.5(e), ActewAGL Distribution has compiled a table that references each response to a paragraph in Schedule 1 of the RIN, and where it is provided in or as part of the regulatory proposal. This table can be found at Attachment A1 to this submission. Where a Schedule 1 RIN requirement has not been addressed in this submission or in the attached RIN templates, the required information is provided in Attachment A2.

In accordance with clause S6.1.1 of the Rules and clause 5.2 of Schedule 1 of the RIN, the following sections describe the methodology used in developing ActewAGL Distribution's capital expenditure forecasts and some of the key underlying assumptions that have been made. Further details on drivers for each capital expenditure category are contained in asset specific plans and individual project justification reports.

7.3.4 Capital expenditure objectives and factors

The principal drivers of ActewAGL Distribution's capital expenditure program, referred to in the 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 *Rules* stipulates that the DNSP must include the total forecast capital expenditure that is required to achieve the *capital expenditure objectives*. Furthermore, paragraph 5.1 of Schedule 1 of the RIN requires ActewAGL Distribution to provide justification for ActewAGL's total forecast capex including, amongst others:

- why the total forecast capex is required for ActewAGL Distribution to achieve each of the objectives in clause 6.5.7(a) of the NER;[59]
- how ActewAGL's total forecast capex reasonably reflects each of the criteria in clause 6.5.7(c) of the NER;[60]
- how ActewAGL's total forecast capex accounts for the factors in clause 6.5.7(e) of the NER;[61]
- an explanation of how ActewAGL Distribution's plans, policies, procedures and regulatory obligations, consultants reports, economic analysis and assumptions have been incorporated;[62] and

[59] RIN Schedule 1, clause 5.1(a)

[60] RIN Schedule 1, clause 5.1(b)

[61] RIN Schedule 1, clause 5.1(c)

[62] RIN Schedule 1, clause 5.1(d)

- an explanation of how each response provided to paragraph 5.1 is reflected in any increase or decrease in expenditures or volumes, particularly between the *current and forthcoming regulatory control periods*.

Chapter 7 of this regulatory proposal outlines ActewAGL Distribution's approach to planning future capital expenditure in order to meet its service standard and regulatory obligations in a prudent and strategic manner. In accordance with Schedule 1 RIN requirement 5.1, it explains how key plans, policies and procedures have been incorporated into capital expenditure forecasts. Proposed expenditures are based on a realistic expectation of the demand forecast as described in chapter 6 and efficient costs as described throughout this chapter.

7.3.5 AER Constituent Decisions

Under clause 6.12.1(3) of the Rules, a distribution determination is predicated on a decision in which the AER either:

(i) acting in accordance with clause 6.5.7(c), accepts the total of the forecast capital expenditure for the regulatory control period that is included in the current building block proposal; or

(ii) acting in accordance with clause 6.5.7(d), does not accept the total of the forecast capital expenditure for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the Distribution Network Service Provider's required capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors;

Under clause 6.12.1(4A) of the Rules, a distribution determination is predicated on a decision in which the AER determines:

(i) whether each of the *proposed contingent projects* (if any) described in the current *regulatory proposal* are *contingent projects* for the purposes of the distribution determination in which case the decision must clearly identify each of those *contingent projects*;

(ii) the capital expenditure that it is satisfied reasonably reflects the *capital expenditure criteria*, taking into account the *capital expenditure factors*, in the context of each *contingent project* as described in the current *regulatory proposal*;

(iii) the *trigger events* in relation to each *contingent project* (in which case the decision must clearly specify those *trigger events*); and

(iv) if the *AER* determines that such a *proposed contingent project* is not a *contingent project* for the purposes of the distribution determination, its reasons for that conclusion, having regard to the requirements of clause 6.6A.1(b)

This chapter sets out ActewAGL Distribution's forecast capital expenditure for the for the 2014–19 regulatory control period that is included in the current building block proposal.

ActewAGL Distribution has not included any contingent projects in its forecast capital expenditure for the 2014–19 regulatory control period.

Historical and forecast expenditures presented in this chapter do not include margins referable to arrangements that reflect non arms-length terms, or expenditure that should have been treated as operating expenditure in accordance with ActewAGL Distribution's capitalisation policy.

7.4 Capital expenditure program

In this section/chapter, ActewAGL Distribution explains why the total forecast capital expenditure is required for ActewAGL to achieve the objectives in clause 6.5.7(a) and other criteria set out below.

When forecasting capital expenditure for the 2014–19 regulatory period, ActewAGL Distribution considered the *capital expenditure factors* set out in clause 6.5.7(e). ActewAGL Distribution's expenditure forecasts reflect the efficient cost of service provision and this is demonstrated through:

- the execution of long term plans, strategies and procedures (see chapter 7) to ensure the optimal project solution is chosen, thereby ensuring that expenditure is prudent;
- option analyses, including assessment of non-network alternatives and demand side management, where appropriate (following the process outlined in chapter 7 and described in attached project justifications);
- an approach to asset management during the 2014–19 regulatory period of increasing network utilisation and extracting maximum value from assets;
- the application of corporate policies in respect of contract management and procurement that ensure contract arrangements reflect arm's length terms, and all goods and services provided to ActewAGL Distribution meet specified performance requirements and minimise the total acquisition cost;
- the use of cross industry, independently verified standard estimates/escalators of input cost growth for major capital inputs as described below;
- an asset management framework and system that is closely aligned with PASS 55, as discussed in chapter 6 of this proposal;
- analysis of the actual and expected capital expenditure for each asset category in the current and past regulatory periods;
- consideration of the relative prices of different capital and operating inputs;

- wherever possible, non-network alternatives to network augmentation capital works have been assessed as part of routine network planning processes; 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 optimisation may be possible.

According to clause 6.5.7(c) of the 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 expenditure reasonably reflects efficient costs, the costs are prudent and are based on a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives. ActewAGL Distribution believes that its proposed capital expenditure program meets all three of these requirements.

ActewAGL Distribution has also had regard to the provisions in the AER's *Expenditure Forecast Assessment Guidelines* in this respect. Some specific examples are:

- ActewAGL Distribution's internal governance, asset management and planning processes ensure the production of expenditure forecasts that are prudent and efficient;
- ActewAGL Distribution is following a process of continual improvement in the governance and process framework of its capital delivery;
- the implementation of Riva DS software during the 2014–19 regulatory period demonstrates ActewAGL Distribution's commitment to developing expenditure forecasts that are as accurate as possible and based on total life cycle costing;
- the implementation of the Advanced Distribution Management System (ADMS) during the 2014–19 regulatory period will provide for improved asset management and works delivery;
- ActewAGL Distribution's capital expenditure forecasts are supported by economic justification (including cost benefit analysis) and supporting information that demonstrates forecasts are prudent and efficient and are consistent with minimising the long run cost of achieving the expenditure objectives;
- unit costs on which capex forecasts are based have been independently verified and found to be reasonable;
- the forecasts of load growth relied upon to derive the capex forecasts and the forecasting methodology used to derive these forecasts are consistent with principles of best practice demand forecasting as set out in the expenditure and forecasting assessment guidelines.

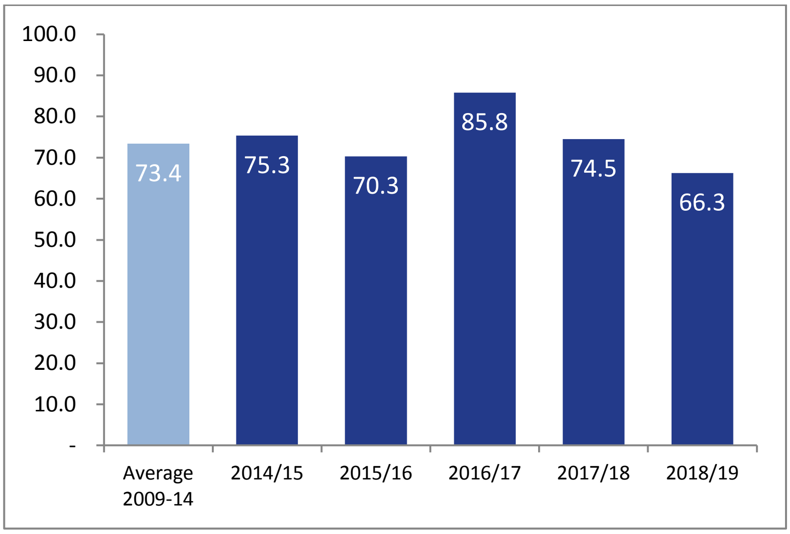
The main drivers of ActewAGL Distribution's capital expenditure forecasts for the 2014–19 regulatory period are:

- an increased focus on asset renewal and replacement to address ActewAGL Distribution's ageing asset base;
- the requirement for zone substation augmentation due to continued urban expansion and completion of Stage 2 of the Southern Supply to the ACT project;[63] and
- completion and extension of various operational technology (OT) and information technology (IT) projects that were commenced in the 2009–14 regulatory period, to refresh or replace critical technologies and systems that were at capacity, no longer supported, or end of useful life.

Capital expenditure for the 2014–19 regulatory period is presented in Figure 7.1 below.

Figure 7.1 Forecast capital expenditure 2014–19

($ million 2013/14)



7.5 Overview of historical capital expenditure

In April 2009, the AER released its Final Decision on prices for electricity distribution services in the ACT for the period 2009/10 to 2013/14. This included the capital expenditure allowance shown in Table 7.1 below.

The capital expenditure forecasts submitted to the AER for the current period were based on ActewAGL Distribution's Network *Ten Year Augmentation Plan* in 2008, and as such were the best estimates at that time of the efficient and prudent capital expenditure requirements for each year of the current period.

[63] This project was initiated by the ACT Government's *Electricity Transmission Regulation 2006.*

Table 7.1 Actual capital expenditure versus AER regulated allowance 2009–14

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
AER allowance	71.4	65.2	63.8	56.7	54.2	**311.4**
ActewAGL Distribution actual/forecast*	71.0	75.0	69.6	67.3	83.8	**366.8**
Variance	**(0.4)**	**9.8**	**5.8**	**10.6**	**29.6**	**55.4**

ActewAGL Distribution’s actual capital expenditure by category for the 2009–14 regulatory period is shown in Table 7.2 below.

Table 7.2 Historical capital expenditure by category 2009-2014

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Asset renewal/replacement	19.3	20.5	19.0	15.2	18.5	92.4
Customer initiated	26.5	33.0	30.5	24.6	21.2	135.6
Augmentation	13.1	14.8	22.4	23.8	20.5	94.6
Reliability and Quality Improvements	0.5	0.6	0.1	0.0	0.0	1.3
Network OT Systems	1.5	1.0	2.9	7.5	22.2	35.2
Less Capital Contributions	-7.3	-11.8	-9.6	-14.7	-12.1	-55.5
Non-system assets	11.8	11.7	2.0	6.7	4.5	36.8
Corporate Services Business Support	5.6	5.2	2.4	4.1	8.9	26.3
Total Capital Expenditure	**71.0**	**75.0**	**69.6**	**67.3**	**83.8**	**366.8**

ActewAGL Distribution’s actual capital expenditure for the current period will exceed the regulated allowance determined by the AER in 2009 by approximately $55.4 million ($2013/14).

Key drivers of the higher than forecast capital expenditure over the current period include:

- higher than forecast customer initiated capital works due to strong growth in commercial and industrial developments and new urban development midway through the regulatory period, and the difficulty associated with forecasting this type of expenditure in the outer years. Much of the customer initiated expenditure incurred by ActewAGL Distribution during a regulatory control period is unforseen and beyond the organisation’s control. This is discussed in more detail in section 7.9.1 below;
- the decision to acquire land and construct a warehouse office space at Greenway to accommodate ActewAGL Distribution’s Logistics Branch in 2010/11, as an alternative to re-leasing the Fyshwick logistics site. The existing lease arrangement at Fyshwick was

due to expire in March 2010 and rental charges for the property were to increase significantly. Relocating Logistics staff from Fyshwick to Greenway has resulted in improved working conditions for Logistics staff and increased productivity of field crews due to reduced travel time. This expenditure was unforseen at the time of the 2009–14 determination;

- implementation of a major Systems Replacement Program (SRP) aimed at replacing and refreshing key operational (OSRP) and core (CSRP) systems that had become increasingly ineffective in supporting core business functions, or because they were either nearing capacity, end of useful life or vendor support arrangements. This expenditure has also been necessary for ActewAGL Distribution to comply with service standards, reduce risk and meet emerging consumer level data and regulatory reporting requirements. The OSRP and CSRP projects are discussed further in sections 7.12.1 and 7.13.1.1 below; and
- higher than anticipated asset augmentation costs associated with the construction of the new East Lake Zone Substation, augmentation of the Civic Zone Substation, and the construction of Stage 1 of the Southern Supply to ACT project[64] as required by the *Electricity Transmission Regulation 2006*. Drivers of this higher than anticipated expenditure are discussed in section 7.10.1 of this chapter.

It is important to note that the regulated capital expenditure allowance was exceeded due to projects that were undertaken, or additional costs incurred during the 2009–14 regulatory period that were unforseen at the time of the 2009 determination. Importantly, this also occurred during a period of organisational reform in which asset management, capital governance and program delivery processes were improved to minimise the total life cycle costs of assets, thereby maximising value for consumers.

ActewAGL Distribution has not received a return on the additional expenditure incurred during 2009–14 regulatory period.

7.6 Overview of capital expenditure forecasts

ActewAGL Distribution's capital expenditure plan for the 2014–19 regulatory period continues key capital expenditure reform programs that were initiated during the current period to ensure the ongoing reliability of the network and alignment with the ACT Government's planning and system security requirements.

The majority of forecast augmentation capital expenditure is attributed to construction of the Molonglo Zone Substation, the timing of which is largely driven by ACT Government planning

[64] This involved the construction of two 132 kV lines from the ACT's southern bulk supply point to provide the ACT with a second point of supply.

requirements and land release program,[65] and stage two of the second supply to ACT project, a requirement of the ACT Government's *Electricity Transmission Regulation 2006.*

The current pole replacement program, approved by the AER in 2008 will continue to dominate ActewAGL Distribution's asset replacement program, and expenditure on asset replacement will increase in the next regulatory period as ActewAGL Distribution increases its focus on underground cable replacement to address an increasing amount of underground cable faults.

Expenditure on Network IT will focus on the completion and extension of various operational technology (OT) and information technology (IT) projects that were commenced in the 2009–14 regulatory period, to refresh or replace critical technologies and systems that were at capacity or end of useful life.

A summary of forecast capital expenditure by category for the 2014–19 regulatory period is provided in Table 7.3 below. This table provides consolidated expenditure forecasts in respect of ActewAGL Distribution's standard control (transmission and distribution) services.

Key transmission capital expenditure projects are identified separately in section 7.14 below.

Table 7.3 Forecast standard control capital expenditure for 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Asset renewal/replacement	26.4	28.0	27.9	27.4	25.6	135.3
Customer initiated	22.4	21.7	19.4	20.6	23.8	107.9
Augmentation	9.4	16.9	35.2	26.3	16.5	104.3
Reliability and Quality Improvements	1.6	1.5	2.8	2.0	0.2	8.2
Network OT Systems	9.7	1.5	1.0	0.7	1.5	14.5
Less Capital Contributions	-8.3	-8.4	-7.6	-7.7	-9.2	-41.2
Non-system assets	10.9	7.1	5.7	3.1	5.7	32.5
Corporate Services Business Support	3.1	2.0	1.5	2.2	1.9	10.7
Net Capital Expenditure[66]	**75.3**	**70.3**	**85.8**	**74.5**	**66.3**	**372.2**

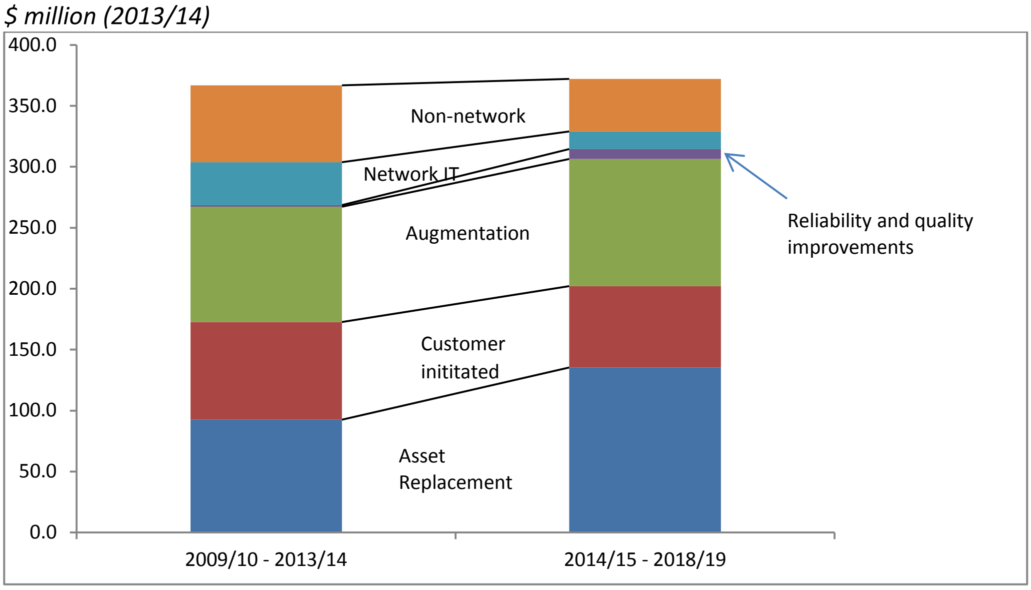
Despite important organisational reforms in asset management, capital governance and program delivery processes undertaken during the 2009–14 regulatory period, ActewAGL Distribution has forecast that it will spend almost 50 per cent more on asset replacement in the 2014–19

[65] In the ACT, dwelling construction must be commenced within one year and completed within three years of land sale.

[66] Excludes equity raising costs

regulatory period. Reliability and quality improvements capital expenditure will also increase significantly but these increases will be offset by decreases in other capital expenditure categories, including customer initiated, network ICT, and non-network capex. These movements are reflected in Figure 7.2 below.

Figure 7.2 Components of 2009–14 and 2014–19 capital expenditure



Key increases in capital expenditure by category are discussed briefly below.

7.6.1 Replacement capex

Asset renewal and replacement expenditure in the 2014–19 regulatory period is expected to be almost 50 per cent higher than in the 2009–14 period.

The biggest replacement and renewal expenditure item in this category is the ongoing pole replacement program that was included in the expenditure approved by the AER in the current determination and will continue beyond the 2014–19 regulatory period. Planned replacement of underground cables will commence in 2014/15 as assets reach the end of their useful life, or where replacement becomes an economic alternative to reactive maintenance and replacement. In particular, the program will address an increase in underground cable faults incurred during the current period.

These replacement and renewal projects are necessary to ensure that ActewAGL Distribution continues to meet safety obligations under the 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*.

ActewAGL Distribution's pole replacement and underground cable replacement programs have been independently verified by SKM and found to be efficient and prudent. These programs are discussed in more detail in section 7.8.5 and 7.8.4 below.

7.6.2 Reliability and quality improvements

ActewAGL Distribution's reliability and quality improvement capital expenditure during the 2009–14 regulatory period was relatively low, but this was offset by an increase in reliability focused operating and maintenance expenditure particularly in respect of vegetation management.

For the 2014–19 regulatory period planned augmentation expenditure will contribute to security of supply and the maintenance of current reliability levels. The majority of forecast expenditure in the 2014–19 regulatory period is attributed to the installation of optical ground wires (OPGW) on the 132 kV transmission network. This infrastructure will replace existing capacity constrained communication networks with a single network and will provide a number of important benefits. Improved speed, security, reliability and functionality will enable ActewAGL Distribution to comply with fault clearing times specified in the National Electricity Rules (NER) for network performance standards.

7.7 Forecasts, methodology and assumptions 2014–19

The following sections explain ActewAGL Distribution's approach to capital expenditure forecasting and how this relates to the capital expenditure objectives and factors set out in the Rules and the AER's guidelines. Section 0 below provides a description of ActewAGL Distribution's forecasting methodology and approach to cost escalation. The sections that follow provide the forecasts for each of ActewAGL Distribution's capital expenditure categories and a discussion of the particular assumptions and methodologies adopted for each category.

7.7.1 AER capex categories

ActewAGL Distribution notes the high level capex categories specified by the AER in the guideline,[67] but has presented capital expenditure forecasts in this proposal in categories that are consistent with its own internal reporting and forecasting processes. ActewAGL Distribution believes that presenting information in this way will result in a submission that is more informative and reflective of ActewAGL Distribution's key asset management objectives.

Figure 7.3 below reconciles the AER's high level capex categories with ActewAGL Distribution's own capex categories. Historical and forecast information presented in the RIN templates have been provided in accordance with the AER's high level categories.

[67] AER, 2013, *Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution*, November

Figure 7.3 AER and ActewAGL Distribution capex categories

AER high level categories	*ActewAGL Distribution categories*
Replacement capex	Asset Renewal and Replacement
Augmentation capex	Augmentation capex
	Reliability and Quality Improvements
Connection and customer driven works capex	Customer Initiated capex
Non-network capex	Non-network capex
	Network OT

7.7.2 Method and Input cost escalation

Clause 6.8.1A and 11.56.4(o) of the Rules require ActewAGL Distribution to inform the *AER* of the methodology it proposes to use to prepare the forecasts of operating expenditure and capital expenditure that form part of its *regulatory proposal* at least 19 months before the expiry of a distribution determination that applies to the *Distribution Network Service Provider*.[68]

ActewAGL Distribution's operating and capital expenditure forecasting methodology was submitted to the AER on 30 November 2013. The methodology was prepared in accordance with the AER's guidelines.[69] An updated version of this document can be found at Attachment B19 to this proposal.

7.7.3 ActewAGL Distribution's Expenditure Forecasting Methodology

ActewAGL Distribution uses a combination of zero-based and base year approaches when forecasting capital expenditure. The zero-based method assumes a *bottom-up* construction of capital expenditure associated with projects. The actual unit rates used by ActewAGL Distribution in constructing project costs are detailed in individual project justifications, and asset management plans. Expenditure forecasts are then escalated throughout the regulatory period in line with independently verified material and labour cost escalators.

Both the key unit rates and the cost escalation factors that have been applied by ActewAGL Distribution in building up capital expenditure forecasts for the 2014–19 regulatory period have been developed with the assistance of independent consultants and have been verified by external experts.

ActewAGL Distribution's key asset management processes, forecasting models and demand assumptions have been reviewed internally, and independently verified to ensure that the

[68] *National Electricity Rules*, clause 6.8.1A(b)(1) requires a DNSP to submit its forecasting methodology at least 24 months before the expiry of a distribution determination. Clause 11.56.4(o) of the *Savings and Transitional Measures* takes this timeframe back to at least 19 months before the expiry of the distribution determination.

[69] AER 2013, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November

capital expenditure forecasts contained in this proposal are free of error and reasonably reflect efficient costs.

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 has not included contingencies in its forecasts.

7.7.4 Riva modelling

In 2012, ActewAGL Distribution implemented RivaDS—a real time, web based software tool. RivaDS provides a platform that supports long range asset management planning and decision making by bringing together asset data from various sources within ActewAGL Distribution including spatial, work management and financial systems.

The implementation of RivaDS during the 2014–19 regulatory period is discussed in detail in Chapter 6 of this proposal. In summary, Riva provides ActewAGL Distribution with a systematic approach to maintaining, upgrading and operating physical assets in a cost effective way. The installation of RivaDS means that ActewAGL Distribution can now manage its assets more efficiently than it has in the past. Specifically, it can simultaneously maximise the lifespan of assets, manage risk and meet service reliability standards within predetermined budget constraints. This delivers real benefits to consumers.

RIVA produces individually optimised treatment plans and associated life cycle expenditure forecasts for each asset class. These form the basis of capital expenditure forecasts contained in this chapter.

7.7.5 Unit rates

ActewAGL Distribution engaged Sinclair Knight Mertz (SKM, now Jacobs SKM) to undertake a comparative review of unit rates for a selection of activities that are included in ActewAGL Distribution’s expenditure programs.

For each unit rate, SKM calculated the variance between an SKM reference estimate and ActewAGL Distribution’s estimate. In several cases, SKM adjusted its reference estimates to more closely align with ActewAGL Distribution’s work descriptions where these were provided.

Overall, SKM found that the ActewAGL activity unit rate estimates for the selected activities are reasonable and efficient. SKM’s report can be found at Attachment B11 to this proposal.

7.7.6 Input cost escalation

ActewAGL Distribution also engaged SKM to undertake an independent and systematic review of the material and labour cost escalators applied to various asset classes in forecasting capital expenditure for the 2014–19 regulatory period.

SKM has undertaken a significant level of research and analysis into input cost escalation in the energy sector over the past decade, and has developed a modelling process that captures the likely impact of input cost drivers on future electricity infrastructure pricing.

As a first step in developing cost escalators for each asset class, ActewAGL Distribution calculated percentage breakdowns of each asset class into material cost and labour costs based on its recent history with asset construction and management. This data was reviewed by SKM and assessed against SKM's database of unit rates and a number of bottom-up asset assessments it had previously undertaken. SKM found ActewAGL Distribution's labour and material breakdowns to be reasonable, and this data was used to determine the effect that each escalator has on the overall installed price of an asset.

Applying the escalation factors differs in complexity between cost categories. For labour costs, the process is relatively simple, with costs escalated by the appropriate labour index (general, utility or professional) each financial year. The process is more complicated when forecasting capital expenditure, particularly the acquisition and replacement of assets. To escalate forecasts, the asset base must be further broken down into its material categories, for example aluminium, copper, steel, crude oil.

Real cost escalation indices for the following material and labour cost drivers were calculated for ActewAGL Distribution by Competition Economists Group (CEG) for the 2014–19 regulatory period:

- aluminium;
- copper;
- steel;
- crude oil;
- labour, including utilities industry, professional services and general labour; and
- construction—both engineering and non-residential.

In addition, economic consultants Independent Economics were engaged to develop annual labour cost escalators specific to the ACT for the 2014–19 regulatory period.

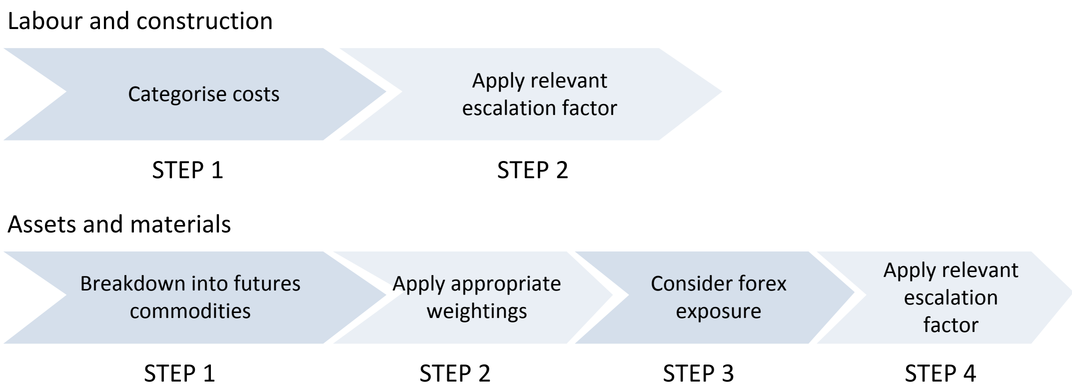
Taking these individual material and labour cost escalators, SKM calculated escalation factors specific to various asset classes by applying a suitable percentage contribution, or weighting by which each of the underlying cost drivers were considered to influence the total price of each completed item, or asset.

In determining the appropriate weighting of cost drivers for network assets, SKM drew on a wide range of information including its knowledge of commercial rise and fall clauses contained within confidential network procurement contracts signed by SKM during market price surveys, information passed on during its interviews with equipment suppliers and manufacturers; as well as industry knowledge held within its large internal pool of professional estimators, Engineering

Procurement and Construction Management (EPCM) project managers, economists, engineers and operational personnel.

The final step in developing escalation factors for each asset class is to take into account foreign exchange movements (primarily the United States dollar (USD) to Australian dollar (AUD) relationship) to convert the price of international commodities that are typically quoted in USD. This process is depicted in Figure 7.4.

Figure 7.4 Price escalation process



In total, SKM calculated real annual material and labour cost escalation indices for 15 of ActewAGL Distribution’s standard asset classes. These indices are provided in Table 7.4 below.

Table 7.4 Real annual material and labour cost escalation indices for capital expenditure

ActewAGL Asset Type	*Real cost escalation factor **					
	Jun-14	*Jun-15*	*Jun-16*	*Jun-17*	*Jun-18*	*Jun-19*
Transmission overhead	1.012	1.008	1.021	1.016	1.014	1.011
Transmission underground (copper)	1.017	1.003	1.013	1.014	1.013	1.012
Distribution overhead lines	1.023	1.006	1.017	1.020	1.019	1.019
Distribution underground lines (aluminium)	1.024	1.006	1.017	1.020	1.020	1.019
Zone substation switchgear	1.015	1.003	1.011	1.010	1.009	1.008
Zone substation civil engineering	1.007	1.005	1.009	1.008	1.007	1.005
Distribution substations	1.016	1.003	1.013	1.011	1.010	1.009
Meters	1.020	1.003	1.012	1.014	1.013	1.013
Other non-system assets (corporate)	1.000	1.000	1.000	1.000	1.000	1.000
IT and communication systems (Networks)	1.005	1.004	1.007	1.010	1.010	1.010
Motor vehicles	1.000	1.000	1.000	1.000	1.000	1.000
Other non-system assets (Networks)	1.000	1.000	1.000	1.000	1.000	1.000
Zone substation transformer	1.018	1.004	1.018	1.010	1.007	1.005
Relays (protection and control)	1.021	1.004	1.013	1.017	1.017	1.016
Zone substation electronics/other	1.015	1.001	1.007	1.007	1.006	1.006

* Annual average year-to-June real cost escalation factor For complete asset Proportionally weighted for material and labour

The independent report provided by SKM in support of the escalation factors used by ActewAGL Distribution in its capital expenditure forecasting is provided as Attachment B11 to this proposal. The reports prepared by CEG and Independent Economics and used by SKM to prepare ActewAGL Distribution's escalations factors are provided as attachments B12 and B13 respectively.

7.8 Asset renewal and replacement—methodology and forecasts

Asset replacement and renewal programs are necessary to manage 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 the ongoing wooden pole replacement program and the proposed underground cable replacement program.

Replacement capital expenditure is usually driven by condition, that is, where deterioration of the equipment results in an unacceptably high maintenance cost, risk of failure or other impact. Other drivers of asset replacement may include limited functionality or compatibility with the network, assets no longer meeting current requirements, unavailability of spares or other support.

The asset replacement category covers expenditure on the existing network assets that is capitalised as part of the capital expenditure budget. Asset replacement decisions typically impact forecast operating expenditure. This trade-off or optimisation of capital expenditure and operating expenditure is discussed in chapter 6 of this regulatory proposal.

7.8.1 Overview of current period asset renewal and replacement capex

An overview of the total electricity asset replacement and renewal capital expenditure in the 2009–14 regulatory period is set out in Table 7.5.

Table 7.5 Historical replacement and renewal capital expenditure programs 2009–14

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Zone Substations	2.7	3.1	2.0	1.6	2.2	11.7
Transmission	0.0	0.0	0.0	0.0	0.4	0.4
Distribution System	16.5	17.4	16.9	13.5	15.9	80.3
Secondary Systems	0.0	0.0	0.0	0.0	0.0	0.0
Property	0.0	0.0	0.0	0.0	0.0	0.0
Total renewal and replacement	**19.3**	**20.5**	**19.0**	**15.2**	**18.5**	**92.4**
AER allowance	21.5	23.4	20.9	20.9	21.6	108.4
Variance	**(2.3)**	**(2.9)**	**(2.0)**	**(5.8)**	**(3.1)**	**(16.0)**

Expenditure on asset renewal and replacement during the current period was approximately 15 per cent lower than the allowance set by the AER in 2009. This is largely due to ActewAGL Distribution replacing fewer poles than planned because of access issues and an increase in its pole reinforcement program. In addition, replacement of the Civic zone substation switchboard was re-classified as an augmentation project after the AER's final decision in 2009 in line with changes to the scope of the project.

7.8.2 Methodology for estimating asset replacement and renewal costs

Asset renewal investment is driven primarily by the need to address an ageing asset base and comply with relevant safety, reliability obligations. The objective of asset replacement capital expenditure is to manage risks and requirements relating to:

- managing 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:

- historical trends;
- escalation of material and contractor costs
- 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 Work Health Safety and Environmental requirements; and
- assessment of operating expenditure/capital expenditure trade-offs.

As noted in chapter 7 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, such as online condition monitoring of assets.

The adoption of an asset management system that is consistent with PAS 55 combined with the use of RivaDS software means that once an asset replacement need has been identified, ActewAGL Distribution is able to generate the most cost effective asset replacement solution and schedule.

7.8.3 Overview of forecast asset renewal and replacement capital expenditure

ActewAGL Distribution's forecast asset replacement and renewal capital expenditures for the 2014–19 regulatory period are set out in Table 7.6 below. Total asset renewal and replacement expenditure in the 2015-19 period is expected to be almost 50 per cent higher than in the current period (Table 7.5).

Table 7.6 Forecast replacement and renewal capital expenditure programs 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Zone Substations	2.1	1.3	2.2	1.8	1.8	9.2
Transmission	0.6	0.6	0.6	0.6	0.6	2.8
Distribution System	20.9	22.9	21.9	21.9	21.7	109.4
Secondary Systems	1.2	1.6	1.6	1.5	1.5	7.4
Property	1.7	1.6	1.6	1.6	0.0	6.5
Total Renewal and Replacement	**26.4**	**28.0**	**27.9**	**27.4**	**25.6**	**135.3**

The majority of this capital expenditure is attributed to several major replacement and renewal programs. These are summarised in Table 7.7 below.

Table 7.7 Major replacement and renewal programs

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Pole replacement, pole substation replacement and pole reinforcement	10.6	10.5	9.6	9.7	9.6	50.0
Underground cables planned replacement	1.5	2.4	2.4	2.4	2.4	11.3
Overhead lines and pole hardware	1.9	2.5	2.5	2.0	1.5	10.5
Meter replacement types 5-7	1.3	1.3	1.3	1.3	1.3	6.6
Share of asset replacement and renewal expenditure						**58.0%**

The pole replacement, pole substation replacement and pole reinforcement programs continue to dominate the asset renewal and replacement capital expenditure forecast. These programs were approved by the AER in 2009 and will continue beyond the 2009–14 regulatory period. Other key asset replacement programs to be commenced in the next regulatory period include underground cable replacement and overhead lines and pole hardware. These programs are discussed in more detail below.

7.8.4 Pole replacement, pole substation and reinforcement programs

Poles are a key element in ActewAGL Distribution's network, supporting electrical current carrying equipment above ground level and are predominantly used in ActewAGL Distribution's HV and LV networks. It is a critical component in the performance, reliability and safety of an overhead network. Poles generally contribute around 20-30 per cent to the total capital cost of an overhead line on a per kilometre basis.

ActewAGL Distribution's pole replacement, pole substation and reinforcement program accounts for almost 40 per cent of the asset renewal and replacement budget, and is the largest single component of ActewAGL Distribution's forecast capital expenditure. The current program was approved by the AER in 2008 and will continue beyond the end of the next regulatory period.

The replacement of wooden poles with concrete and fibreglass poles over the next regulatory period will ensure continued reliability and safety of the network and will contribute to a reduction in future maintenance expenditure. The operating expenditure considerations of this replacement program are presented in section 7.8.4.1 below.

With the aged nature of the wood pole assets, ActewAGL Distribution has developed and implemented strategies to extend the life of wood poles, determined economic strategies for when to replace pole top assemblies (verses replacing whole of pole structures), and has investigated, sourced and implemented an innovative pole replacement methodology which is unique in Australia. The latter was the result of an unusual low voltage network dominated by back of block overhead reticulation which prevents heavy vehicle access for pole replacement.

The replacement poles now used by ActewAGL Distribution have a demonstrably lower whole of life asset cost, and are safer in the rear of block reticulation situations.

ActewAGL Distribution has had its pole replacement program reviewed by Jacobs SKM. Jacobs SKM found ActewAGL Distribution to be both efficient and prudent in its management of wood pole replacements to date.

7.8.4.1 Background to pole replacement

As well as investigating options for pole life extension, in the late 1980s ActewAGL commenced a series of major reviews of the type of poles being used for pole replacements. Whilst the average life for a timber pole is 45 years, ActewAGL Distribution wanted to ensure that the replacement pole was the optimal asset for the network, and provided a greater asset life. Other key considerations in the selection of pole type were:

- the capital cost of the replacement pole;
- reduced ongoing operating expenditure requirements;
- constructability; and
- safety.

Each of these key considerations is discussed in more detail below.

Capital expenditure considerations

In the 1980s steel distribution poles could be installed safer and more economically than timber poles. Accordingly steel poles became the standard asset for pole replacements in back of block situations. However, with the significant increases in commodity prices which were experienced in the early 21st century, the cost of steel poles increased significantly.

ActewAGL Distribution continued reviewing appropriate replacement poles and commenced investigating the use of fibreglass poles which, whilst manufactured in Canada, were a more competitive alternative to steel poles. Fibreglass poles have been used by ActewAGL Distribution for back of block pole replacements since 2008.

Since ActewAGL Distribution commenced purchasing and installing fibreglass poles in the ACT, a fibreglass pole manufacturing plant has been established in NSW and is now a source of fibre glass poles for ActewAGL Distribution. This has realised further cost savings, eliminating off-shore transportation costs and import duties.

Opex considerations

Timber poles require inspection at and below ground level every 4.5 years. This involves excavating the soil from around the pole base, inspecting the integrity of the timber for rot, termite activity and the effects of moisture on the poles.

Whilst steel poles also require below ground inspections every 4.5 years, they are not susceptible to termite attack or timber rot. Additionally the steel poles have an outer galvanised coating providing protection against corrosion.

Average service life is a consideration in determining whole of life replacement cost for poles. Timber poles have the shortest average service life as evidenced in Table 7.8 below. Fibreglass poles have a longer average service life than both timber and steel poles.

Table 7.8 Average asset service life of poles

Pole type	*Average service life*
Timber	45 years
Timer (reinforced)	55 years
Steel	Approximately 50 years*
Fibreglass	At least 60 years*
Concrete	At least 80 Years*

*It is too early to be precise

In the late 1980s, ActewAGL Distribution started to move away from wood pole to steel replacement poles for back of block reticulation and concrete pole replacements where heavy vehicle access is available. In 2008, ActewAGL moved fully to the use of fibreglass poles in lieu of steel poles for back of block distribution.

Fibreglass and concrete poles do not require below surface pole inspections as neither are susceptible to rot, termite infestation nor rust. As such the annual operating expenditure requirement for below ground inspections was eliminated, realising operating expenditure savings that compound annually, as the timber pole population is progressively replaced with fibreglass and concrete poles.

Based on the financial assumptions included in Table 7.9, ActewAGL Distribution has calculated that over the extended asset life of 55 years achievable by reinforcing a timber pole at the end of its service life, the whole of life economic cost for timber poles is $28,049 compared with $14,992 for concrete poles.

Table 7.9 Whole of life cost for timber and concrete poles

	Timber poles	*Concrete poles*
Asset life	Reinforce at 45 years; replace at 55 years.	80 years
Installation cost	$10,500	$12,660
Inspection cost	$348	$150
Inspection frequency	4.5 years	4.5 years
Assumed annual inflation rate	3%	3%
Whole of asset life at 45 years	$25,127	$14,505
Whole of asset life at 55 years (not including the cost of pole replacement	$28,049	$14,992

Constructability

ActewAGL Distribution's low voltage network is dominated by back of block overhead reticulation. Heavy vehicle access is not available to transport in and construct new timber poles. Replacement poles must be carried to the back of the block and installed manually. The steel poles selected by ActewAGL were multi part assemblies, allowing the base to be installed separately. The remainder of the pole was then assembled by sections.

All of the fibreglass poles used are similarly supplied in sections allowing the base to be installed prior to assembly of the top section. Pole top assemblies are fitted once the pole has been fully assembled. The old, condemned pole is cut into manageable sections and removed from the back of the block.

There is no difference in constructability issues between wood poles and concrete poles where there is heavy vehicle access.

Safety

The safety afforded by the fibreglass poles is a significant consideration, especially for poles at the rear of blocks. They are considerably lighter than timber and steel poles. In addition, fibreglass poles are electrical insulators. As such, when compared with steel and concrete poles, they eliminate the potential for step and touch voltage rises at the pole base in the event of a fault.

7.8.4.2 ActewAGL Distribution's ageing pole asset base

In 2013, 63 per cent of ActewAGL Distribution's pole population was wood; however, this percentage is slowly reducing over time as they are gradually replaced by concrete or fibreglass poles. Between 2008 and 2013, the population of wooden poles declined by 5,500, from 39,000 to 33,480. During the 2014–19 regulatory period, ActewAGL Distribution plans to replace approximately 800 wooden poles per annum with concrete or fibreglass poles.

Despite this, ActewAGL Distribution's network continues to feature an aged population of timber poles as evidenced in Table 7.10 below.

Table 7.10 Average pole age

Pole Type	*Average age of poles*	*Number of poles*
Concrete	16	10,266
Creosote	40	6,097
Fibreglass	3	2,030
Natural round timber	57	17,612
Steel	15	5,919
Stobie	65	359
Tanalith	27	7,191

7.8.4.3 Wooden pole extension strategies

As well as continuing the wooden pole replacement program during 2014–19 regulatory period, ActewAGL Distribution will continue its extensive pole nailing (reinforcement) regime, to extend the life of condemned timber poles. Approximately 38 per cent of all timber poles in service are now reinforced and this ratio is forecast to increase slightly during the next regulatory period. ActewAGL Distribution plans to reinforce approximately 700 wooden poles per annum over the course of the 2014–19 regulatory period.

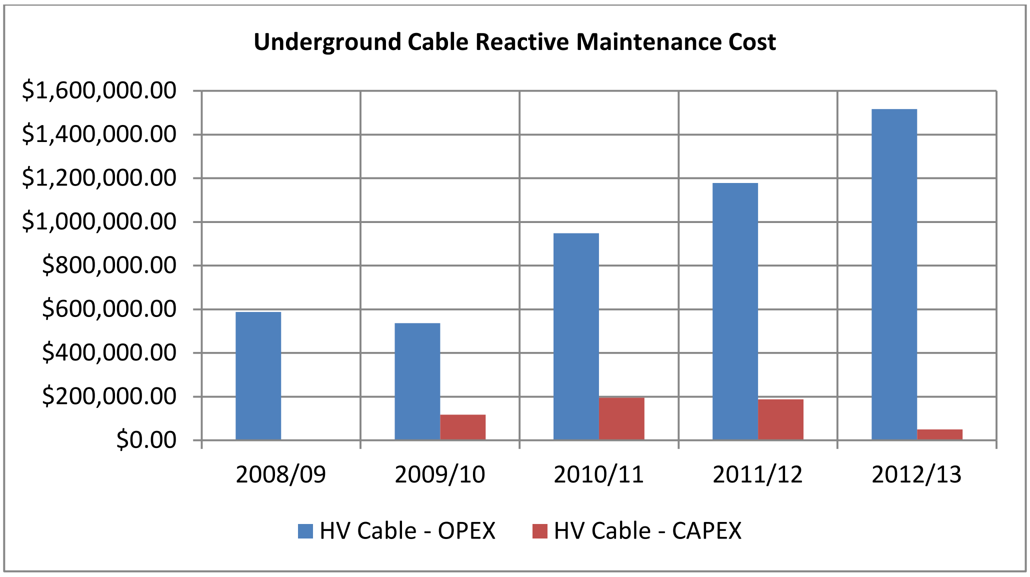
Another strategy aimed at extending the serviceable life of poles is ActewAGL Distribution's cross arm replacement program. This 'pole-top upgrade' program involves identifying deteriorated cross arms (during routine inspection) on poles that are in otherwise good condition. Jacobs SKM have reviewed this strategy and found it to be prudent and efficient.

7.8.5 Underground cable replacement

ActewAGL Distribution has an aged and growing underground distribution network. There is approximately 1,475km of high voltage underground cables in the ActewAGL Distribution network. Approximately 15 per cent of the underground cables have exceeded their average service life and an additional 11 per cent will exceed their average service life in the next 10 years. These aged cables are failing at an increasing rate.

Up until now, ActewAGL Distribution has adopted the strategy of running the underground cables to failure, and any replacement decisions have been driven by repeated root cause failure. Reactive maintenance expenditure (repairs and replacements) have been increasing throughout the 2009–14 regulatory period, as demonstrated by Figure 7.5.

Figure 7.5 Historical underground cable reactive maintenance cost



To address this trend ActewAGL Distribution has developed an asset management strategy that involves condition monitoring of high voltage underground cables and prioritisation of the high voltage underground cable replacement with suspected problems.

Three critical HV feeders will be condition monitored between 2014/15 and 2015/16 and this schedule will increase to 5 critical HV feeders from 2016/17 and onwards.

As part of ActewAGL Distribution's underground cable asset replacement program, it is estimated that 700 metres of cable section will be identified for replacement in 2014/15 from the condition monitoring, and 4.5km of cable section will be identified for replacement from 2015/16 and onwards. It is expected that this program will reduce the risk of asset failure and associated reactive maintenance expenditure levels in future regulatory periods.

ActewAGL Distribution's underground cable replacement program has been reviewed by SKM Jacobs and found to be efficient and prudent.

7.8.6 Overhead lines and pole hardware

AAD's distribution network comprises overhead high voltage (HV), low voltage (LV) and service lines, poles and pole top hardware. Pole top hardware consists of cross-arms, insulators, insulator ties, support brackets, armour rods, vibration dampers, switchgear, cable terminations, and surge diverters. Other line components include pole stays, conductor spacers and aircraft warning markers.

ActewAGL Distribution plans to spend $10.5 million over the 2014–19 regulatory period on major overhead lines and pole hardware replacement and renewal program. Components of the this program include:

7.8.6.1 Rural pole top upgrade (planned maintenance)

The rural pole top upgrade program was initiated in 2009 to accelerate the replacement of deteriorating cross-arms and to install vibration dampers, armour rods, preformed distribution ties on all rural high voltage overhead lines. The objective of this program is to reduce the risk of bushfires resulting from pole top failure as recommended in the report by the Royal Commission into the 2009 Victorian bushfires.

7.8.6.2 Pole top hardware renewal/cross-arm replacement (planned maintenance)

Some poles require the renewal of pole top hardware during the service life of the pole. The pole top hardware renewal is identified from the pole inspections and high resolution aerial pole top photograph. Pole top hardware renewal on suitable poles is a cost effective way to extend the service life of the complete pole.

7.8.6.3 Cast iron LV pothead replacement

Cast Iron LV potheads (old type of pole top cable termination) are typically located in Canberra's older suburbs. In recent years there have been some incidents of pothead failure (about 2 per cent per year). There are currently only about 500 left on ActewAGL Distribution's network and these have been prioritised for replacement based on an assessment for their failure risk and consequence. The highest priority has been given to those in public areas, near schools, childcare facilities, high pedestrian activity area. ActewAGL Distribution plans to replace 50 potheads per annum over the next ten years.

7.9 Customer initiated capital expenditure—methodology and forecasts

Customer initiated capital works is dominated by land releases for development by residential, commercial and industrial customers and special purpose developments. It also provides for large spot loads that are known and considered, definite, likely or potential loads depending on the timing of their development.

In essence, Customer Initiated capital works are non-discretionary. ActewAGL Distribution is obliged to ensure that adequate budget exists to meet all customer requests in a timely and cost effective manner.

7.9.1 Overview of customer initiated expenditure in the 2009–14 regulatory period.

An overview of the actual and estimated total customer initiated capital expenditure during the 2009–14 regulatory period is set out in Table 7.11 below.

Table 7.11 Customer initiated capital expenditure program 2009–14

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Commercial and Industrial Developments	5.9	8.8	8.1	9.6	4.6	37.0
Community and Associated Developments	5.3	3.6	2.4	0.5	0.5	12.2
New Urban Development	6.4	8.8	10.0	5.2	5.8	36.2
Relocations	3.0	3.3	2.2	2.2	2.6	13.4
Replacement	0.1	0.2	0.3	0.1	0.3	1.0
Rural Developments	0.2	0.6	0.1	0.0	0.1	1.0
Services	3.5	3.7	4.3	3.9	4.1	19.4
Special Customer Requests	0.5	0.5	0.6	0.4	1.0	3.1
Urban Infill	1.6	3.4	2.5	2.7	2.2	12.3
Total Capital Expenditure	**26.5**	**33.0**	**30.5**	**24.6**	**21.2**	**135.6**
AER Allowance	23.3	26.6	23.4	18.0	15.6	106.7
Variance	3.2	6.4	7.1	6.6	5.6	28.9

Total customer initiated capital expenditure for the 2009–14 regulatory period was $136 million, or around 35 per cent of total capital expenditure for the period. This expenditure exceeded the AER's decision in the current determination by around $29 million (or 27 per cent) and was driven by stronger than anticipated growth in commercial and industrial development, as well as urban development associated with ACT Government land releases. The relatively high level of community and associated development expenditure early in the period was attributed to the construction of a mobile substation at Angle Crossing, which had been unforseen at the time of the AER's 2009 Determination.

The variance between forecast and actual expenditure also reflects the difficulty associated with forecasting customer initiated expenditure particularly in the out years of the regulatory period. Much of the customer initiated expenditure incurred by ActewAGL Distribution during a regulatory control period is unforseen and beyond the organisation's control.

7.9.2 Methodology for estimating customer initiated costs

Customer initiated capital expenditure relates to new housing and similar developments, where the customer (being the developer) contributes to the cost of a network to service the area. As such, where the nature and timing of the project is reasonably well known, expenditure is typically forecast using a zero based approach. For some customer initiated expenditure categories, particularly in the outer years of the regulatory period, forecasts are based on historical expenditure levels.

In developing forecast customer initiated capital expenditure, ActewAGL Distribution 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 BIS Shrapnel economic forecasting data; and
- historical expenditure in the various customer initiated work categories, adjusted to reflect the anticipated broader short-term economic environment.

7.9.3 Impact of known and probable projects

ActewAGL Distribution maintains a current and up to date database of known and probable new customer initiated projects, with estimates of the electrical loading for each project. Generally speaking, ActewAGL Distribution only becomes aware of customer initiated projects of this sort within about an 18—24 month timeframe before supply is required (sometimes shorter). Consequently the 2014–19 customer initiated capital expenditure forecast is a hybrid of "known and probable" projects combined with trend analysis.

The estimated electrical loading of the known and probable customer initiated projects is analysed on a zone substation by zone substation basis, and where the spot loads are substantially above historical load growth, the zone substation forecasts are adjusted accordingly. Analysis of the probability weighted maximum (customer estimated) and minimum (ActewAGL estimated) estimates of additional electrical loadings by zone substation are shown in the Table 7.12 below:

Table 7.12 Estimate of additional electrical loading by zone substation

Zone substation	*Max. forecast increase (customer estimate)*	*Min. forecast increase (ActewAGL estimate)*	*% of total (min) forecast increase*
Belconnen	3,984.00	3,560.00	28
Telopea Park	4,905.13	3,057.80	24
Woden	3,487.56	2,256.00	18
Gold Creek	3,056.00	1,972.30	15
City East	1,867.20	1,299.50	10
Latham	611.00	340.50	3
Fyshwick	274.50	236.70	2
Civic	139.50	126.00	1

This gives a general indication of the high growth areas, with Telopea Park, Belconnen, Woden and Gold Creek zones figuring prominently.

7.9.4 Land releases in the ACT

Land released for development within the ACT is controlled by the ACT Government, which prepares and releases a four year indicative land release program. This program sets out the ACT Government's intended program for residential, commercial, industrial and community land releases. The programs are indicative and subject to change as market conditions change or as government priorities are adjusted.

The objective of the land release programs include:

- promoting the economic and social development of the Territory, including contributing to the vision set out in the Canberra Plan of a city representing the best in Australian creativity, community living and sustainable development;
- meeting the on-going strong demand for residential land in the Territory, particularly generated by increased levels of migration into the ACT;
- establishing an appropriate inventory of serviced land;
- maintaining flexibility of land releases to ensure they reflect market conditions and do not contribute to rapid land price changes;
- providing a mix of land and housing options;
- facilitating the provision of affordable housing;
- addressing the locational objectives set out in key Government documents such as the Territory Plan and the Spatial Plan;
- achieving satisfactory returns to the Territory from the sale of unleased Territory land; and

- assisting the operation of a competitive private sector land development market.

Once blocks of land are purchased, dwelling construction must commence within one year of purchase, and be completed within three years.[70] As a result, ActewAGL Distribution's customer initiated expenditure is largely driven by the timing and extent of land sales in new areas of Canberra and can be difficult to forecast, particularly in the out years of the five year regulatory period.

7.9.5 Forecasting customer initiated capital expenditure

The methodology for forecasting each category is described in ActewAGL Distribution's *Customer Initiated capital works plan.* This can be found at Attachment D3 to this submission.

To summarise, expenditure forecasts for developer related categories—commercial and industrial, new services, new urban development and urban infill development—are based on BIS Shrapnel's Building and Construction Industry indicators in its Building in Australia series (33rd edition—2013 to 2028) as ActewAGL Distribution's historical trends for these categories correlate closely with activity in the construction industry. The expenditure profile for most of these categories is predicted to trend downwards over the 2014–19 regulatory period primarily due to public sector budget cuts resulting in weaker population growth and underlying demand for construction in the ACT.

The remaining customer initiated capital expenditure categories—community and associated development, relocations, customer initiated replacements, rural development and special customer requests—tend not to follow any particular market indicator. Consequently, ActewAGL Distribution forecasts a provisional amount for each category based on expenditure in previous years.

7.9.6 Overview of customer initiated expenditure in the 2014–19 regulatory period

Customer initiated capital expenditure (residential and commercial) is expected to be lower in the 2014–19 regulatory period, but will remain relatively stable, averaging around $22.3 million per year.

About 32 per cent of the total customer initiated program will be recovered as capital contributions in accordance with *ActewAGL Distribution's Connection Policy* and the ACT *Capital Contributions Code*. Capital contributions are discussed further in section 7.15 of this regulatory proposal.

Table 7.13 below sets out the customer initiated capital expenditure forecasts for the 2014–19 regulatory period.

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[70] *Building Act 2004*, s.36(1)(a)

Table 7.13 Forecast customer initiated capital expenditure programs (excluding capital contributions)

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Commercial and Industrial Developments	4.6	6.0	5.2	6.2	8.7	30.8
Community and Associated Developments	0.6	0.6	0.6	0.6	0.6	2.9
New Urban Development	8.8	7.6	5.9	6.6	6.5	35.4
Relocations	2.8	2.8	2.8	2.2	2.9	13.5
Replacement	0.3	0.3	0.3	0.3	0.3	1.3
Rural Developments	0.6	0.6	0.6	0.7	0.7	3.2
Services	3.3	2.6	2.7	2.7	2.7	14.0
Special Customer Requests	0.6	0.6	0.6	0.7	0.7	3.2
Urban Infill	0.9	0.6	0.7	0.6	0.8	3.6
Total Capital Expenditure	**22.4**	**21.7**	**19.4**	**20.6**	**23.8**	**107.9**

7.9.7 Customer initiated capital expenditure and the CESS

In its Framework and approach stage 2 paper, the AER proposed to apply the CESS as set out in its capital expenditure incentive guideline[71] in respect of ActewAGL Distribution's capital expenditure in the subsequent regulatory period.

ActewAGL Distribution proposes that customer initiated capital expenditure be excluded from the calculation of CESS penalties in respect of the 2014–19 regulatory period at the commencement of 2019-24 regulatory period, because it is difficult to forecast and often beyond the control of ActewAGL Distribution. This proposal is discussed in more detail in section 16.3.1 of this submission.

7.10 Network augmentation expenditure—methodology and forecasts

Augmentation expenditure can be demand or non-demand driven. Demand driven augmentation is usually undertaken to meet growing demand in new and existing suburbs, address voltage issues caused by growing demand, or to meet planning criteria where growing demand results in one or more planning criteria no longer being met.

Non-demand driven augmentation would be undertaken to address reliability concerns (not capacity additions to maintain N-1), resolve fault level issues not directly linked to demand

[71] AER 2013, Better Regulation, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November

driven works, address environmental, safety and compliance issues or to enhance functionality of network assets (for example, improved SCADA, additional switching flexibility).

7.10.1 Overview of augmentation capital expenditure in the 2009–14 regulatory period

An overview of total network augmentation capital expenditure during the 2009–14 regulatory period is set out in Table 7.14 below. Key augmentation projects undertaken during the 2009–14 regulatory period include:

- the establishment of a new **East Lake Zone Substation** 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 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 increased capacity at the Substation by 50MVA to meet demand requirement in City and City West, and postpone the need of augmentation of City East Zone Substation.
- construction of 132 kV lines from the **Southern Supply to ACT** (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. Stage 2 of this project will be undertaken during the 2014–19 regulatory period.

This expenditure followed a sustained period of very low investment in zone substation augmentation (the last major project was the Gold Creek substation in 1994) and was necessary to meet network constraints and consumption trends, as load approached maximum capacity at Civic and Fyshwick zone substations.

Table 7.14 Historical augmentation capital expenditure 2009–14

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Zone Substations	1.2	3.7	12.9	22.0	15.9	55.6
Transmission	8.6	6.5	5.0	1.0	0.4	21.5
Distribution System	3.4	4.6	4.4	0.9	4.3	17.5
Secondary Systems	0.0	0.0	0.0	0.0	0.0	0.0
Total Augmentation capital expenditure	**13.1**	**14.8**	**22.4**	**23.8**	**20.5**	**94.6**
AER Allowance	17.7	15.9	21.4	16.3	13.6	84.9
Variance	**(4.6)**	**(1.1)**	**0.9**	**7.6**	**6.9**	**9.7**

ActewAGL Distribution's augmentation expenditure in the 2009–14 regulatory period was approximately 11 per cent higher than the allowance set by the AER in 2009. Key drivers of this additional expenditure include:

- scheduling delays and environmental costs associated with moving the East Lake Zone Substation site;
- changes to the scope of the Second Supply to ACT project and contract variations to accommodate inclement weather, TransGrid approval delays and environmental remediation; and
- higher than anticipated costs at the Civic Zone Substation project driven by complexities associated with integrating the new transformer into a brown field site and subsequent delays at the Civic Zone Substation.

In addition to project specific cost overruns there was a general increase in the price of construction materials driven by high levels of augmentation activity in the electricity distribution sector between 2009–14.

7.10.2 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
- the scope for non-network alternatives to be employed.

Key drivers of augmentation expenditure in the 2014–19 regulatory period, and the projects that ActewAGL Distribution intends to undertake to address them are set out below.

7.10.3 Overview of forecast augmentation expenditure for the 2014–19 regulatory period

ActewAGL Distribution's forecast *augmentation* capital expenditure for the 2014–19 regulatory control period is set out in Table 7.15.

Table 7.15 Forecast augmentation capital expenditure programs 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Zone substations	0.4	11.3	19.7	14.1	8.7	54.2
Transmission	0.6	0.6	8.1	4.3	0.0	13.6
Distribution system	7.3	3.9	6.3	6.9	6.8	31.3
Secondary systems	1.0	1.1	1.0	1.1	1.0	5.2
Total augmentation capital expenditure	**9.4**	**16.9**	**35.2**	**26.3**	**16.5**	**104.3**

ActewAGL Distribution's augmentation plan for the 2014–19 regulatory period reflects the continuation of important augmentation expenditure that was commenced in the 2009–14 regulatory period that followed a sustained period of very low investment. It will ensure that ActewAGL Distribution is able to comply with reliability standards and efficiently meet anticipated customer demand in new urban areas.

Network augmentation expenditure is expected to increase from a total of $94.6 million in the 2009–14 regulatory period to just over $104 million in the 2014–19 regulatory period.

Major augmentation projects expected to be undertaken during the 2014–19 regulatory period include:

- a new zone substation[72] in the Molonglo district for the provision of power to new suburbs in Molonglo and North Weston. The new zone substation will be able to take over some load in Weston Creek currently supplied by the Woden Zone Substation, thereby deferring the need for capacity augmentation at the Woden Zone Substation;
- installation of a 3rd 132/11 kV transformer at the Belconnen Zone Substation to meet current and future estimated load requirements, and to manage ongoing reliability in the Belconnen region by ensuring that n-1 redundancy is maintained at the station; and
- upgrade of the 132 kV transmission line between Gilmore and Theodore Zone Substation, known as Southern Supply to ACT—Stage 2. This is a network security project aimed at upgrading existing lines to meet a capacity rating required by the *Electricity Transmission Regulation 2006* and will increase security of supply to the ACT.

[72] Construction of the Molonglo zone substation was originally planned for the 2009–14 period but was deferred due to deferred urban development in the areas to be serviced by this zone substation.

Table 7.16 Largest augmentation projects 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Molonglo Zone Substation and associated feeders	-	4.6	11.6	7.0	1.4	24.6
Belconnen Zone Substation	-	-	2.9	3.7	6.1	12.7
Southern Supply to ACT—Stage 2	-	-	6.4	3.3	-	9.7
Capital expenditure—major projects	**-**	**4.6**	**20.9**	**14.0**	**7.5**	**47.0**

7.10.4 Zone substation constraints and proposed developments

ActewAGL Distribution has twelve 132/11 kV zone substations (incl. East Lake), one mobile 132/22 kV zone substation, one 66/11 kV zone substation, and two 132 kV switching stations. Due to the dual function categorisation of assets all 132/11 kV zone substations are classified as transmission assets, except Fyshwick, Telopea Park and Angle Crossing which are classified as distribution assets.

Stage 1 of the East Lake Zone Substation project completed in late 2013, relieved an existing overloading situation at Fyshwick Zone Substation and will provide additional supply capacity to meet increasing electrical demand in the South Canberra region.

The ten year zone substation 10 per cent PoE load forecast (refer Table 4 above), combined with analysis of system limitations on the 11 kV distribution system indicates that some zone substation augmentation will be required within the 2014-2019 regulatory period.

Cost effective solutions have been identified to address the existing and emerging constraints at zone substations, and on the related distribution feeder systems. These include a combination of equipment upgrades, load transfers between zone substations, and potential demand management solutions.

7.10.4.1 New Molonglo Zone Substation

The Molonglo Valley to the west of Canberra is being promoted by the ACT Planning and Land Authority (ACTPLA) as the centre of residential and retail development over the next 20 years. The main area of development includes the suburbs of Wright and Coombs. The ultimate development of the Molonglo area is estimated to have a population of 55,000 over the next 20 years, with electrical demand expected to reach 15MVA by about 2020.

ActewAGL Distribution’s zone substation forecast suggests that there is adequate capacity to supply additional Molonglo load from the adjacent zone substations at Woden (nearing capacity) and Civic. However the nature of the terrain, the existence of other developments and infrastructure, and other construction restrictions suggests that it will be extremely difficult to construct additional overhead or underground feeders into the Molonglo area from adjacent zone substations.

Construction of the Molonglo Zone Substation will be staged in a way that will supply capacity to the area as it is expands. At present, Molonglo Zone Substation is scheduled for commissioning in mid-2018, and is expected to have an initial loading of approximately 11 MVA.

7.10.4.2 Belconnen Zone Substation zone upgrade

Belconnen Zone Substation was built in 1976 and has been serving the Belconnen District for 36 years. The substation was designed as a two 132 kV/11 kV power transformer substation with two 11 kV switchboards. The continuous firm rating of this substation is 55 MVA in both summer and winter.

The 2 hour emergency firm rating has recently been increased to 74 MVA in summer and 76 MVA in winter, by upgrading the 11 kV transformer cables. The continual residential and commercial load growth over the past 36 years resulted in the demand on Belconnen Zone Substation exceeding the summer 2 hour emergency firm rating in both 2009 and 2011.

Although the latest demand forecast for Belconnen zone appears fairly flat, significant potential and sizeable block load increases in the next few years could result in capacity constraints recurring towards the end of the next regulatory period.

It is proposed to return Belconnen to N-1 security by installing a third transformer, associated building works, 132 kV and 11 kV switchgear, and associated control and protection systems, for completion by 2018/19.

7.10.5 Other zone substation projects

In addition to the major augmentation work at zone substations there are several other upgrade projects scheduled for the 2014–19 period. These include:

7.10.5.1 Zone substation earthing upgrade

The earth grids at ActewAGL Distribution’s zone stations were installed when the stations were first developed and hence range in age up to 46 years. As the earth grids are buried beneath the station surfaces, and most likely beneath at least some equipment foundations, their widespread exposure for physical inspection is not practical nor could it be easily achieved. As such the condition of the earth grids, particularly those of the greatest age, is largely unknown.

In light of their unknown condition and the increase in network fault levels over time, the effectiveness of the earth grids and hence the level of safety provided at each station is uncertain. It is proposed to undertake a staged program of inspection, electrical testing and refurbishment/upgrading the station earth grids as necessary. For each station the program would be comprised of two stages:

- Stage 1 would incorporate the sample inspections, electrical testing and overall condition assessment of the earth grids.
- Stage 2 would cover the refurbishment and upgrading as necessary of the earth grids as determined by the Stage 1 outputs.

The proposed program would be conducted over the period 2014 to 2018 with works being undertaken nominally at a rate of three stations per year.

7.10.6 Provisional power transformer

ActewAGL has a fleet of twenty-five 132/11 kV zone substation power transformers of nominal ratings up to 57 MVA within the distribution network. The zone substation transformers are one of, if not the most critical asset class within the network, with their reliability directly related to that of customer supplies from the respective zone substations.

Unlike most other asset classes the lead time for procurement of transformers is long, typically of the order of 6 to nine months. In the absence of a suitable spare, the loss of a transformer can result in disruption to customer supplies for an extended period of time until a replacement can be sourced.

The transformers within the ActewAGL network range in age from five to 46 years. Condition assessment based on regular analysis of oil samples has shown that for other than the two most recently installed units, typical aging characteristics are evident across the balance of the population. Given that the loading regime for the transformers has mostly been within their nominal ratings the observed deterioration is generally in line with the age of the respective units.

ActewAGL has had an independent audit done of its fleet of zone transformers and identified four transformers with an estimated remaining life of less than five years.

Options are currently being considered as to the best and most effective location to place the provisional transformer.

7.10.7 HV Distribution Feeder augmentation and inter-zone tie capacity

There is also a number of large HV feeder projects scheduled to be undertaken over the 2014–19 regulatory period. Some of these projects will be required to cater for local area load growth, while others are designed to strengthen inter-zone ties and to rebalance and optimise zone substation loading into the future. These include but are not limited to:

- Remote area power supply (RAPS) for Gudgenby and Corin Dam—bushfire mitigation purposes.
- Ijong feeder augmentation—replacement of ageing and redundant 11 kV cable.
- Australian Data Centre HV supply, Mitchell
- East Lake substation feeders, Stage 2 & 3
- Upgrading of the HV feeder system supplying ANU, and the establishment of a second 11 kV bulk supply point
- Augmentation to Tuggeranong Town Centre

- Extending and uprating the existing Black Mountain and Hilder 11 kV feeders to provide additional feeder capacity into the Molonglo area
- New 11 kV feeders are required from Gold Creek Zone Substation to supply residential and commercial load in the Mitchell area
- A new 11 kV feeder into the Belconnen zone supply area from Latham Zone Substation

7.10.8 Transmission augmentation capital expenditure

Major augmentation projects being undertaken in respect of on ActewAGL Distribution's transmission network include the completion of the Southern supply to ACT project and the installation of transmission connection point metering.

7.10.8.1 Southern supply to ACT—Stage 2 (132 kV line upgrade)

In 2006, the ACT Government introduced the Electricity Transmission Regulation 2006, the objective of which was to increase security of electricity supply in the ACT by introducing a second point of supply.

Stage 1 of the Southern supply to ACT project required ActewAGL Distribution to upgrade the 132 kV transmission line between Gilmore and Theodore zone substations such that should supply be lost from the Canberra 330/132 kV bulk supply substation in West Belconnen, the ACT could be supplied from the Williamsdale 330/132 kV bulk supply substation in the south of Canberra. This involved the construction of a 15.3km double circuit single structure 132 kV line from Williamsdale to Theodore.

Stage 2 of this project involves upgrading the 132 kV transmission line interface between the completed stage 1 works and the existing ActewAGL Distribution Gilmore to Theodore (G2T) transmission line. At the completion of stage 2, there will be equivalent transmission line capacity from the 330/132 kV Williamsdale Bulk Supply Substation to both the 132 kV Theodore Zone Substation and 132 kV Gilmore Zone Substation.

Completion of stage two of the Southern supply to ACT project will ensure there is full line capacity to pick up the entire electricity network supply to the ACT in case of any failure at the West Belconnen point of supply, thereby meeting the requirements of the Electricity Transmission Regulation 2006. This will also support supply to Cooma through TransGrid's transmission network.

7.10.8.2 TNSP Metering Installation

As discussed in section 4.7.13, Chapter 3 of the NER requires ActewAGL Distribution as a registered Transmission Network Service Provider (TNSP) to install NEM compliant metering at each point of connection between a transmission network and a distribution network.

ActewAGL Distribution plans to spend almost $1 million installing TNSP metering in the first two years of the 2014–19 regulatory period. This expenditure will be attributed to the completion of site works, the installation of energy meters and National Association of Testing Authorities (NATA) accredited meter testing.

7.11 Reliability and Quality Improvements—methodology and forecasts

ActewAGL Distribution introduced reliability and quality improvements as a separate capital expenditure category in its submission to the AER in 2008 for the 2009–14 regulatory period. An overview of the expenditures in the 2009–14 regulatory period is provided in Table 7.17 below.

Table 7.17 Historical reliability and quality improvements capital expenditure programs 2009–14

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Sub-transmission	0.5	0.3	0.1	0.0	0.0	0.9
Distribution system	-	-	-	-	-	-
Zone substations	0.0	0.3	0.0	-	-	0.3
Total Electricity Reliability and Quality Improvements	0.5	0.6	0.1	0.0	0.0	1.3
AER Allowance	0.3	0.4	0.5	0.3	0.3	1.8
Variance	**0.3**	**0.2**	**(0.4)**	**(0.3)**	**(0.3)**	**(0.5)**

Expenditure on reliability and quality improvements during the 2009–14 regulatory period was minimal and related primarily to feeder ties and under-frequency relays. However, this was offset by an increase in reliability focused operating expenditure, particularly in respect of vegetation management.

When estimating future reliability and quality improvement expenditures, ActewAGL Distribution has identified specific programs that address the capital expenditure factors (clause 6.5.7(e)). The forecast costs for the 2014–19 regulatory period are presented in Table 7.18 below.

Table 7.18 Forecast reliability and quality improvements capital expenditure 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Sub-transmission	0.2	0.2	0.2	0.2	0.2	1.0
Distribution system	1.4	1.3	2.6	1.8	-	7.1
Zone substations	-	-	-	-	-	-
Total Electricity Reliability and Quality Improvements	1.6	1.5	2.8	2.0	0.2	8.2

The majority ($5.6 million) of forecast expenditure in the 2014–19 regulatory period is attributable to the installation of optical ground wires (OPGW) on the 132 kV transmission network. This infrastructure will replace existing capacity constrained communication networks with a single network and will provide a number of important benefits. Improved speed, security, reliability and functionality will enable ActewAGL Distribution to comply with fault clearing times specified in the National Electricity Rules (NER) for network performance standards.

7.11.1.1 Installation of OPGW on 1322V Network

The existing ActewAGL Distribution communications network is a mix of digital radios, pilot wires and Telstra cables and is extremely limited in capacity. The reliability of this network presents a severe bottleneck. Currently, some of ActewAGL's 132 kV network protection faults clearing times are not compliant with new National Electricity Rules requirements but are considered acceptable because of 'grandfathering' provisions in the Rules. Installation of OPGW fibre optic cables on the entire 132 kV sub-transmission network will:

- replace existing communication networks with a single communication network that provide the speed, security, reliability and functionality required for the electricity networks;
- ensure there is a robust network for protection and real time control operations for the Electricity Network;
- provide a reliable and cost-effective means to achieve the fault clearing times specified in the National Electricity Rules for network performance standards;
- introduce a robust and secure communications technology;
- enable the future expansion of remote monitoring, control and protection functions of the distribution network, and collection of data from smart devices installed in the network and customer premises; and
- provide spare black fibres that can be used by the corporate communication network, reducing corporate service cost to the business.

7.12 Network OT Systems—methodology and forecasts

Network Operation Technology (OT) Systems are those information technology systems that are directly related to the operating and support of the network business.

Expenditure on network OT during the current and future regulatory periods reflects an organisation wide focus on ensuring all OT investment decisions are cost effective, avoid duplication, make the best use of existing services/technology, are aligned to common standards, and deliver real benefits to our consumers in terms of improved safety, reliability, network performance and consumer engagement.

7.12.1 Overview of Network OT expenditure in 2009-2014

An overview of Network OT Systems (previously known as Network IT) capital expenditure over the 2009–14 regulatory period is set out in Table 7.19.

Table 7.19 Historical Network OT Systems capital expenditure programs 2009–14

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Network OT systems	1.5	1.0	2.9	7.5	22.2	35.2
Total Network IT capital expenditure	**1.5**	**1.0**	**2.9**	**7.5**	**22.2**	**35.2**
AER Allowance	6.4	6.4	4.4	4.4	5.7	27.3
Variance	**(4.9)**	**(5.4)**	**(1.5)**	**3.0**	**16.5**	**7.8**

Expenditure on Network OT systems during the 2009–14 regulatory period is expected to be almost $8 million higher than the allowance set by the AER in 2009. At that time, the AER accepted the OT forecast which included $3.7 million to undertake the 'network connectivity solution.' The objective of this project was to deliver accurate and timely data compliant with the AER's reporting requirements and to provide ActewAGL Distribution with the ability to better plan and manage its network assets, resources, reporting, fault resolution and provide customers with improved service.

Subsequent to the AER's Final decision in 2009, ActewAGL Distribution determined that a broader program of operational technology reform was required. ActewAGL Distribution's OT environment comprises various disparate systems with asset information spread through a range of heavily customised, off the shelf IT applications, in house built systems, spread sheets and paper based systems. Interfaces between the systems are limited and integration is almost non-existent leading to extensive manual intervention in order to meet business needs.

Of greater concern was the number of critical network OT systems that were no longer covered by vendor support arrangements, or were approaching end of useful life. A good example of this is ActewAGL Distribution's billing system which had been built in-house and was no longer under a vendor support arrangement. Internal staff who had built the system had left the organisation, and as such the risk of system failure, and its likely impact on the organisation was considered unacceptable.

Indeed, the risk to ActewAGL Distribution of system failure, or poor network performance prompted a shift in ActewAGL Distribution's OT strategy and a major program of 'regenerating' key operational systems. In addition, it was becoming increasingly apparent that existing systems did not have the capacity to meet emerging consumer engagement and regulatory reporting requirements.

In response to these identified risks and emerging obligations, ActewAGL Distribution embarked on the Operational Systems Replacement Program (OSRP) in 2012 which was aimed at refreshing and replacing a number of critical technologies and systems that were nearing capacity or end of useful life.

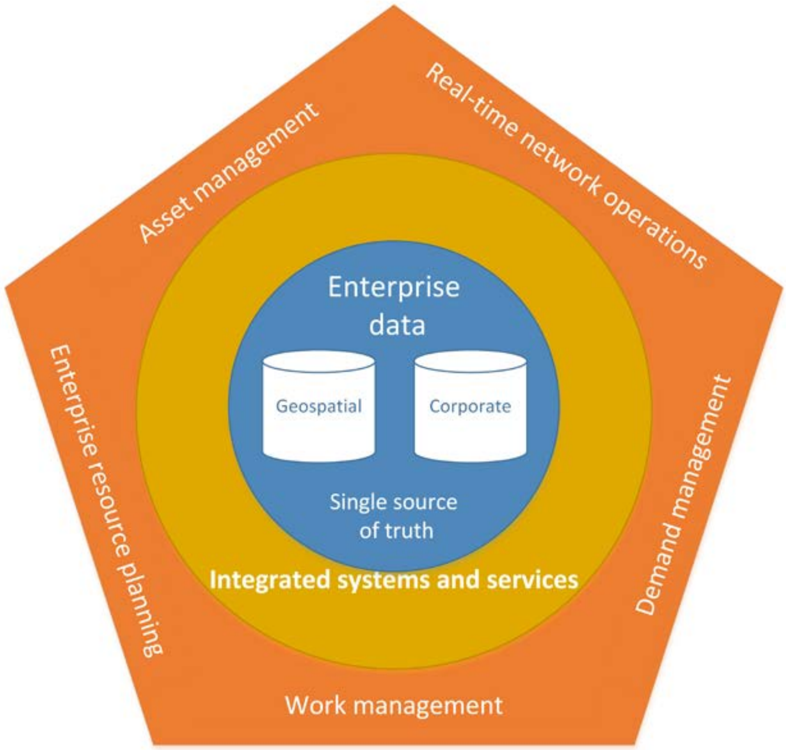
Replacing this technology infrastructure has been key to ensuring that ActewAGL Distribution has a stable technology platform to enable the continued delivery of safe and reliable network services, and to meet emerging consumer engagement and regulatory reporting obligations into the future.

In addition to the Distribution Billing System, key OSRP projects undertaken during the 2009–14 regulatory period include implementation of the following systems:

- Telvent Pilot: Advanced Distribution Management System (ADMS). GIS-centric, the ADMS is a consolidated network modelling system that combines network operations functionalities with network analysis and simulation capabilities;
- Cityworks / Riva: GIS-centric Works and Asset Management System including Strategic Planning; and
- GIS ArcFM: An extension to the existing ESRI ArcGIS system that provides a suite of configurable data models critical to effective asset management.

ActewAGL Distribution's proposed Network OT capital expenditure for the 2014–19 regulatory period will complete this regeneration phase, moving ActewAGL Distribution closer to a future state operating environment that is based on a single, completely integrated system that will deliver an end-to-end, geospatially-enabled platform for controlling the network, managing assets, designing and augmenting the network and delivering services to customers. This is represented in Figure 7.6.

Figure 7.6 Operational Systems Reform Program components



ActewAGL Distribution expects the OSRP to yield significant benefits from the implementation of this ‘single source of truth’ network technology platform. These will include improved network performance including safety and system reliability, improved capital expenditure investment decisions and customer engagement.

7.12.1.1 Improved capital expenditure decision making

Factors providing improved capital expenditure investment decisions are:

- access to industry specific tools to perform robust and thorough analysis of network capacity and performance to ensure targeted asset investment and effective load management;
- constant monitoring of asset condition and lifecycle as well as comprehensive analysis and advanced forecasting ensures that asset management including asset replacement is tailored to each asset class. This leads to targeted investment in new and replacement assets;
- effective use of embedded generation and associated infrastructure such as system monitoring and control along with energy storage will help to align the peak output with the peak load of the network and hence reduce the need for network expansion;

- more appropriate design based on better visibility of existing network loading and impact of new supplies on upstream demand and capacity; and
- probabilistic planning support will enable the cost benefit of network augmentation options to be thoroughly assessed and the most appropriate option selected to meet prescribed performance standards.

7.12.1.2 Improved network performance

Factors providing improved network performance are:

- the integrated operational environment will ensure that outages and network faults are located and attended to more quickly, and optimal alternate network arrangements are made, ensuring minimal interruptions to customer supply;
- improvements in the quality of asset information will allow for condition based maintenance which will reduce asset failures and hence outages; and
- monitoring power quality will allow for targeted power quality correction which will reduce distribution losses, voltage drops and improve customer power quality.

7.12.1.3 Increased customer engagement

Factors providing increased customer engagement are:

- the integrated distribution operational environment will help to provide consumers with more information about their consumption habits to help them better manage their own demand; and
- the integrated operational environment will provide customers with access to accurate and real-time outage information as well as allow customers to report outages and damaged assets, increasing transparency.

7.12.2 Methodology for estimating Network OT capital expenditure

ActewAGL Distribution uses a zero based approach to forecasting Network OT capital expenditure. In planning the expenditure program for the 2014–19 regulatory period, the following process was undertaken:

- 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.

7.12.3 Forecast network OT expenditure in 2014–19

Expenditure on Network OT is forecast to decrease significantly over the 2014–19 regulatory period, as major components of the OSRP are completed.

ActewAGL Distribution's forecast Network OT capital expenditure for the next regulatory control period are set out in Table 7.20.

Table 7.20 Forecast Network Systems capital expenditure program 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Network OT systems	9.7	1.5	1.0	0.7	1.5	14.5

ActewAGL Distributions intends to spend $14.5 million on a number of key network OT initiatives during the 2014–19 regulatory period. These projects and the annual cost for each are set out in Table 7.21 below:

Table 7.21 Key Network OT projects 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
GIS/ArcFM	1.5	-	-	-	-	1.5
ADMS Integrated HV-LV	4.4	-	-	-	0.6	5.0
Cityworks Stage 2	1.2	-	-	-	-	1.2
Mobility	1.1	0.9	0.3	0.1	0.1	2.5
ADMS Enhancements	0.3	-	-	-	-	0.3
Engagement & Information Portal	-	0.4	0.3	0.2	0.5	1.4
Minor OT Projects	0.3	0.3	0.3	0.3	0.3	1.6
Total	8.8	1.6	1.0	0.7	1.5	**13.5**

The OT capital works program for the next regulatory period builds on the foundational OSRP projects by transitioning from legacy systems, integrating and automating workflow processes, enhancing the capability and capacity of the projects. It focuses on further improvements to safety, network reliability, quality and the provision of information to customers. Expenditure during the subsequent period will include the mobility project which is aimed at increasing field force effectiveness and greatly improving the quality and currency of data by capturing information at the source. ActewAGL Distribution also plans to extend the implementation of its ADMS to the LV network and implement an engagement and information portal. These projects are discussed in more detail below.

7.12.3.1 ADMS Integrated HV-LV

During the 2009–14 regulatory period, ActewAGL Distribution commenced implementation of the Schneider-Electric Advanced Distribution Management System (ADMS) High Voltage network primary control system. This is ActewAGL Distribution's primary network operations and analysis tool and supports asset management and real-time network operations. It is expected that implementation of the ADMS will be completed by 30 June 2014.

The ADMS Integrated HV-LV project will extend the functionality of the ADMS HV system to support all network activities (operations and advanced network analytics) on the low voltage network. This project includes:

- **Implementation of ActewAGL's LV network** into the ADMS (from GIS/ArcFM) and integration with the HV Network Model and SCADA system (established as part of the ADMS High Voltage network primary control system project). This includes updates of system reports affected by the establishment of customer connectivity; and
- **Integration with Gentrack Velocity** to associate customer information with each customer connection point represented in the Integrated ADMS HV and LV network model. This will support mapping customer outage calls to network supply points as well as provide lists of customers affected by planned outages to Gentrack Velocity.

ActewAGL Distribution's investment in the ADMS and its extension to the LV network represents the replacement of critical OT systems and software that are currently unsupported and operating on obsolete hardware that is no longer commercially available. In the event of system failure, the control room would lose visibility of remote network sites (loss of SCADA) as well as the current state of the network for managing network operations, increasing the likelihood of extensive outages and potentially exposing utility workers, as well as the public, to safety risks.

The expansion of the ADMS to support the low voltage network will address these significant risks and deliver important benefits including fewer and shorter outages, the provision of detailed interactive information to customers about outages, and a platform for coordinating demand side management. The ADMS will facilitate better consumer engagement by extending ActewAGL Distribution's visibility of individual customers. It will also provide the connectivity required to support a rollout of smart metering in the future.

7.12.3.2 Mobility Project

- The majority of ActewAGL Distribution's field based staff does not have access to asset-related geographical information, network topology information, essential operation systems and other key information whilst in the field because there is only limited mobility within ActewAGL Distribution. Field access to services such as maps is provided to a limited number of staff via Panasonic Toughbook computers. Some groups have established their own mobility solutions to fit their specific needs however due to the organic establishment of this solution; it does not effectively interface with wider ActewAGL Distribution AAD systems.

The objective of the Mobility project is to deliver the ability to deploy works and network information directly to field-based staff for action, removing any avoidable travel between sites and the depot; improving data capture processes and overall productivity of field and office staff. The intention of the Mobility project is to integrate mobility into the distribution operational environment. The scope of this project includes:

- implementation of Cityworks Mobility to deliver field access to the distribution operational environment. This will enable remote access to network geographical information, asset data and works management information (e.g. work orders) via a common interface;
- establishment of a mobile interface into ActewAGL's incident management system (Guardian) to provide a user interface for Guardian via Cityworks mobile, facilitating easier access to Guardian for infrequent users in the field. This will enable linking of incidents to associated work orders and geographical information, providing transparency and visibility of all incident details; and
- purchase of mobile devices and the implementation of all relevant systems on these devices.

7.12.3.3 Engagement and Information Portal

The Engagement and Information Portal will provide customers with significantly improved access to information about the ActewAGL Distribution network and their usage, including current and historical usage information, information regarding outages and planned maintenance in their area as well and tools for customer feedback. The portal will be managed by a secure login system and access will be provided in line with the requirements and login profile of the user. The portal will also facilitate an improved customer initiated works application process as customer will be able to apply for new service connections online and pay for these services through a simple billing platform which is linked to ActewAGL Distribution's customer relationship management system, Gentrack Velocity.

The portal will also facilitate better demand management and demand side engagement. Customers already subscribed to demand management initiatives, will be able to manage their subscription, get access to relevant information, receive notifications and manage any participation rewards (for example, pay off existing bills with financial rewards). Customers not subscribed to demand management initiatives, will have greater access than currently to demand management information and will also be able to subscribe to programs.

7.13 Non Network capital expenditure

Non network capital expenditure relates to facilities, non-system assets, finance lease arrangements and corporate services business support.

7.13.1 Overview of non-network capital expenditure 2009–14

Table 7.22 shows total expected non-network capital expenditure for the 2009–14 regulatory period.

Table 7.22 Historical non-network capital expenditure 2009–14

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Facilities	10.6	11.1	0.9	1.3	1.9	25.9
Non System Assets	1.2	0.6	0.5	0.7	0.7	3.6
Finance Lease Assets	0.0	0.0	0.7	4.7	1.9	7.3
Corporate Services Business Support	5.6	5.2	2.4	4.1	8.9	26.3
Total Non-network capital expenditure	**17.4**	**17.0**	**4.5**	**10.9**	**13.4**	**63.1**
AER Allowance	8.9	2.2	2.4	2.2	2.2	17.9
Variance	**8.5**	**14.8**	**2.1**	**8.7**	**11.2**	**45.2**

ActewAGL Distribution’s total non-network capital expenditure on facilities, non-system assets, finance lease assets and corporate services business support was significantly higher than the combined regulated allowance for each category set by the AER in 2009 due to a number of important initiatives undertaken by ActewAGL Distribution during the 2009–14 regulatory period that were not foreseen at the time of the AER’s determination in 2009. These include:

- the decision to acquire land and construct a warehouse office space at Greenway to accommodate ActewAGL Distribution’s Logistics Branch in 2010/11, as an alternative to re-leasing the Fyshwick logistics site. The existing lease arrangement at Fyshwick was due to expire in March 2010 and rental charges for the property were to increase significantly. Relocating Logistics staff from Fyshwick to Greenway has resulted in improved working conditions for Logistics staff and increased productivity of field crews due to reduced travel time; and
- corporate services business support capital expenditure for the 2009–14 regulatory period was approximately $26 million, exceeding the current determination allowance by around $15 million. This additional expenditure was mostly attributed to the Core System Replacement Program (CSRP).

Neither the decision to purchase land and construct a warehouse at Greenway, nor the CSRP were included in the capital expenditure program that ActewAGL Distribution submitted to the AER at the time of the last determination.

In addition, ActewAGL Distribution commenced transferring Network Division's vehicle fleet operating leases to finance (capital) leases during the period to be in line with standard industry practice.

7.13.1.1 Core Systems Replacement Program

The CSRP was implemented during the 2009–14 regulatory period to address an under investment in corporate ICT from previous periods. Investment in corporate ICT over the past decade has been minimal with systems maintained within tight budgetary constraints. As with the OSRP, the CSRP was also driven by a need to replace and refresh disparate, internally developed, heavily customised, unsupported and ageing systems. The investment in core system replacement will enable ActewAGL Distribution to maintain the provision of standard control services to customers through continued ICT reliability and performance.

The objective of the CSRP is to mitigate the risk associated with this situation by implementing off the shelf/standardised products while providing ActewAGL with a comparable contemporary ICT environment in its Core Applications. In particular, the CSRP will deliver the following:

- replacement of ageing applications for Finance(Oracle) and Billing (Gentrack);
- upgrade of the Human Resources (HR) system (Aurion) and incorporate additional business functionality; and
- transactional reporting tool.

The CSRP is both a business and IT transformation program and was established to enable the business to fulfil its strategic objectives. ActewAGL requires ICT systems to manage its critical operations and address rapid industry change, increased competition and changing regulatory environment.

Furthermore, the CSRP will enable ActewAGL to meet the capital expenditure objectives under clause 6.5.7 of the Rules, as detailed in Table 7.23 below. ActewAGL Distribution recently engaged KPMG to benchmark its expenditure on corporate services ICT during the 2009–14 regulatory period. KPMG found that ActewAGL Distribution's total spend was significantly lower than that of other DNSPs, suggesting a previous underinvestment in corporate services ICT.

Table 7.23 Alignment of CSRP objectives with the capital expenditure objectives

CSRP objectives	*Alignment to the capital expenditure objectives*
Accurately report consumption data to retailers	Meet or manage the expected demand for standard control services over that period.
Maintain compliance with increasing regulatory and statutory requirements	Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.
Mitigate major risks throughout the business Manage stability of the ICT environment Upgrade or implement new solutions without being impeded by outdated systems	to the extent that there is no applicable regulatory obligation or requirement, maintain the quality, reliability and security of supply of standard control services; and maintain the reliability and security of the distribution system through the supply of standard control services.
Consistent management of qualifications that will assist the matching of resources to scheduled work and as a result improving safety management	Maintain the safety of the distribution system through the supply of standard control services.

7.13.2 Methodology for estimating corporate services business support capital expenditure

Forecasts for corporate services business support 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;
- 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.

Corporate services capital expenditure is allocated in accordance with ActewAGL Distribution's cost allocation method (CAM). Under this approach, wherever possible, corporate costs are allocated directly to the business unit (for example, Electricity Network, ActewAGL Retail) that consumed the corporate service or asset. For example, refurbishment/security upgrade at

Greenway depot is directly allocated to Electricity Networks. Consistent with the AER's cost allocation guidelines, where corporate costs cannot be directly allocated using causal drivers, ActewAGL uses a non-causal allocator derived from operating expenditure and full-time equivalents (FTEs) for each division.

7.13.3 Forecast non-network capital expenditure 2014–19

ActewAGL Distribution's forecast non network capital expenditure for the next regulatory period is set out in Table 7.24 below.

Table 7.24 Forecast Non network capital expenditure program 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Facilities	1.9	2.4	3.0	1.2	0.7	**9.2**
Non System Assets	0.5	0.5	0.5	0.5	0.5	**2.6**
Finance Lease Assets	8.5	4.2	2.2	1.4	4.6	**20.8**
Corporate Services Business Support	3.1	2.1	1.5	2.2	1.9	**10.7**
Total non-network capital expenditure	13.9	9.1	7.2	5.3	7.7	**43.2**

Non-network capital expenditure is forecast to be $43.2 million over the 2014–19 regulatory period, or $20 million less than in the 2009–14 regulatory period.

The biggest component of non-network capital expenditure over the 2014–19 regulatory period is finance lease assets which reflects the ongoing transfer of Network Division's vehicle fleet to finance (capital) leases as existing operating leases expire. As discussed earlier in this section, this approach was initiated in the 2009–14 regulatory period and is consistent with standard industry treatment of leased vehicles. It also brings ActewAGL Distribution in line with other DNSP treatment of this expenditure item.

Forecast facilities capital expenditure includes the refurbishment of the Fyshwick Depot control room and refurbishment of the Greenway Depot to accommodate an increase in staff numbers associated with major augmentation projects, and following the restructure of the Electricity Networks division. Built in 1990, many of the building's fixtures and furnishings are in need of replacement. The refurbishment will also include the installation of improved electronic security.

The 2014–19 capital expenditure program includes an estimate of $10.7 million for corporate services business support. Of this, $8.9 million is corporate services ICT capital expenditure comprising of the following business capability initiatives:

- $3.9 million for enterprise wide services;
- $4.1 million for technology management and support; and
- $0.9 million for field force effectiveness.

Of this investment, approximately one third will occur in the 2014/15 comprising Phase 2 of the financial information management system (FIMS) project, and an upgrade of the Fyshwick data centre, currently expected to reach capacity by 2015. Expenditure on the data centre will increase capacity and ensure ongoing compliance with the Payment Card Industry Data Security Standard (PCIDSS). Capital expenditure of $2.8 million on business intelligence will commence in 2016/17. This will deliver enhanced data interrogation and reporting capability, enabling ActewAGL Distribution to respond quickly to changing regulatory reporting demands. These initiatives are detailed in ActewAGL's ICT Expenditure Proposal Summary which can be found at Attachment D10.

The planned initiatives include both recurrent ICT asset replacements and non-recurrent capital programs required in supporting electricity network distribution services.

The independent IT benchmarking survey undertaken by KPMG included an industry comparison of ICT issues and planned investments. The results suggest ActewAGL Distribution's planned ICT programs are generally in line and consistent with industry programs.

7.14 Capital expenditure—Standard Control Transmission Services

The AER in its Framework and Approach Stage 1 stated that it would apply transmission pricing rules to ActewAGL Distribution's dual function assets in the subsequent period. Dual function assets are the parts of a distributor's network that operate in a way that supports the transportation of electricity over the higher voltage transmission network. Specifically, the Rules deem as a dual function asset:[73]

> *Any part of a network owned, operated or controlled by a Distribution Network Service Provider which operates between 66 kV and 220 kV and which operates in parallel, and provides support, to the higher voltage transmission network.*

The Rules allow distributors to address dual function assets in a distribution determination to avoid the need for separate transmission revenue proposals. In making its decision on ActewAGL Distribution's revenue requirement for the 2014–19 period, the AER will determine separate average revenue caps to apply (with different X factors) for the transmission and distribution portions of revenue for standard control services.

Consequently, the allocation of capital expenditure to transmission standard control services has been netted from total capital expenditure to yield capital expenditure for distribution standard control services.

Capital expenditure allocated to ActewAGL Distribution's transmission assets in the 2014–19 regulatory period are set out in Table 7.25.

[73] *National Electricity Rules*, clause 6.24.2(a)

Table 7.25 Capital expenditure allocated to ActewAGL Distribution's transmission assets 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Sub-transmission Overhead	2.70	2.54	11.21	6.67	0.71	23.83
Sub-transmission Underground	-	-	-	-	-	-
Zone substation	3.87	12.22	20.20	15.10	9.08	60.48
Network OT	1.77	0.27	0.18	0.13	0.28	2.62
Non network capex	2.54	1.65	1.30	0.96	1.39	7.83
Total transmission capex	10.9	16.7	32.9	22.9	11.5	94.8

Major transmission projects contributing to capital expenditure in the next regulatory period that have already been discussed in this chapter include:

- Second supply to ACT project—Stage 2; and
- installation of optical ground wires (OPGW) on the 132 kV transmission network.

7.15 Capital Contributions and Relocation Capital Contributions

Under chapter 5A of the Rules and in accordance with the AER's *Connection charge guidelines for retail electricity customers,* (the AER guidelines*)*, an electricity distributor may require a capital contribution for the extension or augmentation of the distributor's electricity network undertaken at the request of the customer. Charges may also apply for relocations (not related to connections), in accordance with *the Electricity Networks Capital Contributions Code (ACT)* (the Code).

ActewAGL Distribution's customer initiated capital works plan provides the basis for determining when *Capital Contributions* and *Relocation Capital Contributions* are likely to occur. Capital contributions for the 2009–14 regulatory period are shown in Table 7.26 below.

Table 7.26 Historical capital contributions 2009–14

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Customer contributions	3.7	8.8	7.8	12.6	9.3	42.1
Relocation contributions	3.6	3.0	1.8	2.1	2.8	13.3
Total capital contributions	**7.3**	**11.8**	**9.6**	**14.7**	**12.1**	**55.5**
AER Allowance	6.3	9.1	8.6	5.0	4.4	33.4
Variance	**1.0**	**2.7**	**1.0**	**9.7**	**7.6**	**22.0**

Capital contributions were significantly higher than forecast in the 2009–14 regulatory period due to a higher than forecast level of customer initiated expenditure. This is discussed in section 7.9.1 above.

Forecast capital contributions are based on the historical levels of capital contributions for each category of customer initiated capital expenditure. ActewAGL Distribution has forecast the level of capital contributions for the 2014–19 regulatory period shown in Table 7.27.

Table 7.27 Forecast capital contributions 2009–14

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Customer contributions	6.1	6.1	5.4	5.9	6.9	**30.4**
Relocation contributions	2.2	2.2	2.3	1.8	2.3	**10.8**
Total capital contributions	8.3	8.4	7.6	7.7	9.2	**41.2**

7.16 Capex deliverability and capability

ActewAGL Distribution has a high degree of confidence in its ability to deliver the capital spend forecast in its regulatory submission. This confidence is based upon:

- its proven ability to deliver against the capital budget for the 2009–14 regulatory period. The amount of the forecast capital expenditure for 2014–19 period is very similar; and
- ActewAGL Distribution is following a process of continual improvement in the governance and process framework of its capital delivery. The organisation is confident that this improvement will continue to deliver further value for money.

These factors are discussed in more detail below.

7.16.1 Capital delivery capacity and capability

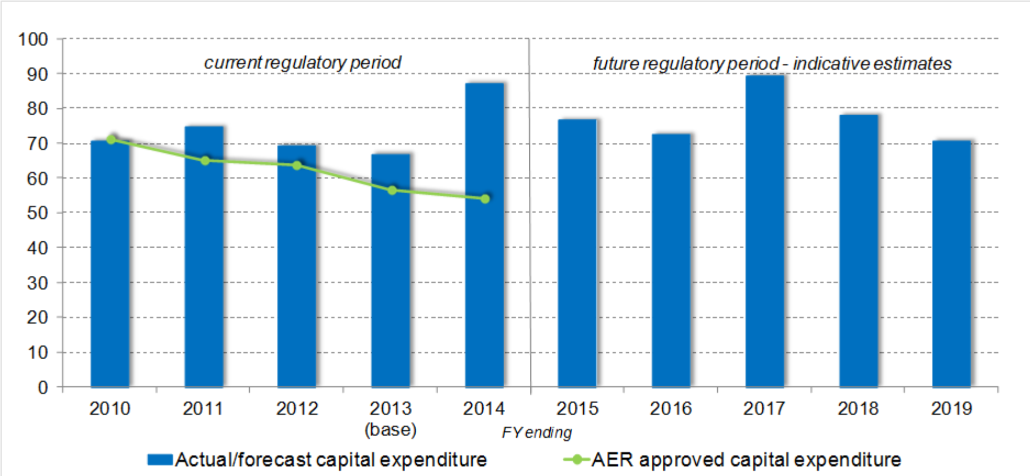
ActewAGL Distribution's capital expenditure for the next regulatory period is anticipated to be only marginally higher than in the 2009–14 period. A comparison of the two periods is provided in Figure 7.7 below. ActewAGL Distribution's two largest projects in the next period are Molonglo Zone Substation with an anticipated capital cost of $23.2 million and Belconnen Zone Substation at a capital cost of $12.7 million.

Figure 7.7 indicates ActewAGL Distribution's capacity to deliver the capital program to the extent of the AER approved capital expenditure. The 2014 year forecast expenditure is similar in magnitude to the highest forecast year of the next period, 2017, indicating that no material changes will be required to ActewAGL Distribution's workforce capacity.

ActewAGL Distribution has taken a continuous improvement approach to the delivery of its capital program and has introduced a number of frameworks and approaches that have increased the efficiency of its delivery processes. This provides ActewAGL Distribution with a high degree of confidence in its ability to meet the proposed forecast capital expenditure. The improvements to capital delivery made by ActewAGL Distribution are referred to throughout the following sections.

Figure 7.7 Net capital expenditure 2009-19

$ million (2013/14)



7.16.2 Enhanced governance arrangements

At its core, capital investment governance is concerned with the decision making framework that governs investments in programs and projects. Rather than a project management approach to programs and projects, capital investment governance takes an investment management approach and seeks to ensure that an organisation receives value for money from its investments.

A robust investment decision making framework indicates that an organisation is actively managing its investment in programs and projects. It means that the organisation is constantly striving to achieve value for money which addresses the two main regulatory goals of prudency and efficiency.

Capital investment is the commitment of money to purchase assets, in ActewAGL Distribution's case through programs and projects. Capital investment *governance* is the organisational framework that enables effective capital investment *decision-making*.

ActewAGL Distribution has been, and continues to refine its capital investment governance arrangements. Capital investment governance is concerned with the decision making framework that governs investments in programs and projects. Rather than a project management approach to programs and projects, capital investment governance takes an investment management approach and seeks to ensure that the organisation receives value for money from its investments.

Effective capital investment governance is important from a regulatory perspective. A robust investment decision making framework indicates that an organisation is actively managing its investment in programs and projects. It means that the organisation is constantly striving to achieve value for money which addresses the two main regulatory goals of prudence and efficiency.

Over the past regulatory period, ActewAGL Distribution has undertaken the following initiatives to strengthen and refine its capital investment governance:

- *introduction of the concept of portfolio account manager with its link to budget accountability:* this approach links ownership of the program or project with ownership of the budget allocated to the program. Alignment of program ownership and budget ownership is a critical success factor in ensuring effective capital investment governance;
- *introduction of the PRINCE2 Project Board concept*: PRINCE2 is a best practice project management methodology. At its core lies the concept of the Project Board comprised of business, user and supplier representatives. This decision making board ensures that the business remains at the heart of project decision making and therefore focuses on the achievement of value for money. This approach, and the ActewAGL project delivery framework, also ensures that key stakeholders remain informed of project developments with the opportunity to shape the project;
- *improving the clarity around roles and responsibilities*: ActewAGL Distribution continues to define the key roles in the project delivery space. As its approach to project governance and delivery becomes more sophisticated, so the roles within the delivery framework need to be assessed and sometimes modified;
- *improved monitoring and control of major projects*: the establishment of the Major Projects office in 2008 was accompanied by an improvement in the processes for the monitoring and control of major projects; and
- *continuous improvement*: ActewAGL Distribution has recently commenced the first step in a further development of its capital investment governance framework. These improvements will strengthen accountability, ensure consistent business ownership of initiatives and enhance the value ActewAGL Distribution—and hence its customers—receive from its investments.

In addition, ActewAGL Distribution is currently in the process of reviewing and upgrading key capital governance policies and procedures as it completes a restructure of its asset management and network services divisions. It is anticipated that this process will further enhance ActewAGL Distribution's capital governance framework, ensuring that customers continue to benefit from investment decisions that are prudent and efficient.

7.16.3 Delivery approach

The quantum of capital works in the next regulatory period is marginally greater than that in the last period. As in the last period, ActewAGL Distribution will utilise a mix of in-house and contract based resources for delivery. This approach maximises workforce flexibility.

ActewAGL Distribution has established a project delivery lifecycle for major projects. The lifecycle provides a clearly defined pipeline for projects and ensures clarity of responsibility throughout the delivery process by identifying which parts of the organisation are responsible for which aspects of the lifecycle. This approach is supported by the introduction of the PRINCE2 project management methodology. This methodology places great importance on the continued justification of a project with a focus on value for money, thereby supporting the prudency and efficiency of investments.

These mechanisms were employed in the delivery of the East Lake Zone Substation. This $32.3 million project was delivered on time and within budget.

Projects worth more than $5 million, as well as complex and high risk projects ($1 million to $5 million in value) are delivered under ActewAGL Distribution's major projects processes and governance framework. Low risk routine works up to $5 million in value are overseen by the Works Enablement Branch in Network Services Division. The overall Program of Work is overseen by the Program of Work Committee which has a membership comprising Asset Management Division, Network Services Division and the Commercial Manager. This Committee's oversight enables end to end performance review and works planning and delivery issue rectification.

7.16.4 Capital Works Procurement

The majority of major capital projects undertaken by ActewAGL Distribution during the 2009–14 regulatory period have been delivered under an alliance contracting arrangement (the Alliance Agreement, which establishes Jemena Asset Management Pty Ltd (now Zinfra) as a major provider of capacity and capability to ActewAGL Distribution in respect of major capital works projects.

The Alliance Agreement commenced in 2009 and contains commercial principles in relation to the cost effective delivery of capital works projects; the open, honest and timely sharing of cost related information by both parties; the implementation of appropriate incentives to promote the efficient and effective delivery of the capital works projects; and the creation of a relationship which reflects the risks and rewards accepted by both parties.

The agreement provides ActewAGL Distribution the discretion to appoint an external reviewer to assess the technical validity of a major project proposal, the proposed implementation methodology and whether the target cost estimates are in accordance with current market prices. This is an important step in ActewAGL Distribution's major capital works delivery framework, as it verifies that the proposal represents value for money to ActewAGL Distribution, and hence its customers.

ActewAGL Distribution has had total cost estimates independently reviewed for all capital works projects delivered under the Alliance Agreement during the 2009–14 regulatory period, and is committed to undertaking this value for money check in respect of any future proposals by Zinfra to undertake major capital works projects for ActewAGL Distribution.

Where ActewAGL Distribution is not satisfied (on the basis of the external party advice) that the total cost estimate represents value for money, then ActewAGL Distribution may seek proposals from other parties through a competitive tender process. This process is conducted in accordance with ActewAGL Distribution's corporate policies *for Procurement, Contracting and Contract Management Policy* and *Procurement and Contracting Procedure*.[74]

This open market competitive tender process is also followed for the procurement of smaller capital works contracts (typically ranging from $1m to $5m).

7.17 Summary of forecast capital expenditure

In summary, ActewAGL Distribution's proposed capital expenditure plan continues key capital expenditure reform programs that were initiated during the 2009–14 period to ensure the ongoing reliability of the network and meet key ACT Government planning and security of supply requirements. An increase in asset replacement expenditure from the current period reflects the need to replace critical components of ActewAGL Distribution's ageing asset base, including underground cables, wooden poles and critical ICT infrastructure that have reached maximum life.

Table 7.28 summarises the total proposed capital expenditure program for 2014–19 including capital contributions.

Table 7.28 Forecast capital expenditure including capital contributions 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Asset renewal/replacement	26.4	28.0	27.9	27.4	25.6	135.3
Customer initiated	22.4	21.7	19.4	20.6	23.8	107.9
Augmentation	9.4	16.9	35.2	26.3	16.5	104.3
Reliability and Quality Improvements	1.6	1.5	2.8	2.0	0.2	8.2
Network OT Systems	9.7	1.5	1.0	0.7	1.5	14.5
Less Capital Contributions	-8.3	-8.4	-7.6	-7.7	-9.2	-41.2
Non-system assets	10.9	7.1	5.7	3.1	5.7	32.5
Corporate Services Business Support	3.1	2.0	1.5	2.2	1.9	10.7
Net Capital Expenditure[75]	**75.32**	**70.32**	**85.79**	**74.50**	**66.25**	**372.2**

[74] ActewAGL Distribution Corporate policy 8.4, p 1

[75] Excludes equity raising costs

As discussed in chapter 6, the potential for capital and operating expenditure optimisation or trade-off is an important component of the capital works planning process. Consequently, 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 Operating expenditure

8.1 Key points

ActewAGL Distribution's operating expenditure proposal for the 2014–19 regulatory period is forecast to remain relatively stable following a period of increasing costs over the 2009–14 regulatory period. This operating expenditure proposal is focussed on improving safety, managing demand, complying with regulatory obligations, and maintaining the quality and security of standard control services. The proposal includes nine step changes above the base expenditure considered necessary to achieve the operating expenditure objectives under clause 6.5.6(a) of the Rules.

8.2 Consumer benefits

ActewAGL Distribution's operating expenditure proposal for the 2014–19 regulatory period will provide a number of long term benefits to consumers. This operating expenditure will:

- enable ActewAGL Distribution to achieve each of the operating expenditure objectives by managing, operating and maintaining the safety, reliability, quality and security of ACT's electricity distribution system;
- improve the safety of ActewAGL Distribution's staff, contractors and the public through the delivery of improved work health and safety programs and improved management of works practices and safety rules and guidelines;
- improve the way ActewAGL Distribution engages with its consumers through the implementation of a formalised consumer engagement strategy; and
- improve the accessibility and scope of information on ActewAGL Distribution's system and business, including information available directly from ActewAGL Distribution as well as information in various reports made available by ActewAGL Distribution's regulators.

8.3 Requirements of the NEL and the Rules

The Rules (Chapter 6 and schedule 6) set out the framework for the AER's assessment of ActewAGL Distribution's operating expenditure forecasts and the necessary components for the regulatory proposal.

Clauses 6.8.1A (Notification of approach to forecasting expenditure) and 11.56.4(o) of the Rules require ActewAGL Distribution to inform the AER of the methodology it proposes to use to prepare the forecasts of operating expenditure and capital expenditure that form part of its regulatory proposal at least 19 months before the expiry of a distribution determination that applies to the Distribution Network Service Provider.[76]

ActewAGL Distribution's operating expenditure forecasting methodology was submitted to the AER in November 2013. An updated version of this document is attached at Attachment B19. The Rules set out the framework for the AER's assessment of ActewAGL Distribution's operating expenditure forecasts and the necessary components of the regulatory proposal. The requirements of the Rules are supplemented by the AER's Regulatory Information Notices (RINs). 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 Rules.

A building block proposal by a DNSP is required by clause 6.5.6(a) of the Rules to include the total forecast operating expenditure for the relevant regulatory control period, which the DNSP considers is required in order to achieve each of the *operating expenditure objectives*. The *operating expenditure objectives* are to:

(1) Meet or manage the expected demand for standard control services over that period;

(2) Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

   - the quality, reliability or security of supply of standard control services; or
   - the reliability or security of the distribution system through the supply of standard control services,

   to the relevant extent:

   - maintain the quality, reliability and security of supply of standard control services; and
   - maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

Clause 6.5.6(c) of the Rules requires the AER to accept the DNSP's operating expenditure forecast if it is satisfied that the forecast reasonably reflects:

(1) The efficient costs of achieving the *operating expenditure objectives;*

[76] *National Electricity Rules*, clause 6.8.1A(b)(1) requires a DNSP to submit its forecasting methodology at least 24 months before the expiry of a distribution determination. Clause 11.56.4(o) of the *Savings and Transitional Measures* takes this timeframe back to at least 19 months before the expiry of the distribution determination.

(2) The costs that a prudent operator would require to achieve the *operating expenditure objectives;* and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the *operating expenditure objectives*.

8.3.1 Operating expenditure objectives and factors

ActewAGL Distribution has considered the *operating expenditure objectives* set out in clause 6.5.6(a) of the Rules, as well as the *operating expenditure factors* set out in clause 6.5.6(e) of the Rules when forecasting operating expenditure for the 2014–19 regulatory period. In doing so, ActewAGL Distribution has:

- forecast operating expenditure consistent with regulatory obligations (and changing obligations) as described in chapter 5 of this proposal, and consistent with the long term plans, strategies and procedures set out in chapter 7 of this proposal, to ensure that the most prudent options are adopted;
- used reputable and considered estimates for escalating cost forecasts (see section 8.7.2);
- considered and analysed the actual and expected regulated network operating expenditure for each category in the 2009–14 and 2014–19 regulatory periods (see section 0 for further details);
- at a total system level, examined the trade-off between capital expenditure and operating expenditure as described in section 6.11 of this proposal; and
- a *procurement, contracting and contract management policy* and a *procurement and contracting procedure* in place that ensure contract arrangements reflect arm's length terms and all goods and services provided to ActewAGL Distribution meet specified performance requirements and minimise the total acquisition cost. The policy and procedure are provided in Attachments D7 and D8.

ActewAGL Distribution has carefully considered the expenditures to ensure that the proposed total regulated network operating expenditure below enables the AER to accept ActewAGL Distribution's forecast of required operating expenditure.

8.4 Overview

ActewAGL Distribution's core network operating expenditure[77] is forecast to be $377.3 million (real 2013/14) for the 2014–19 regulatory period. This includes $3.8 million per annum of non-

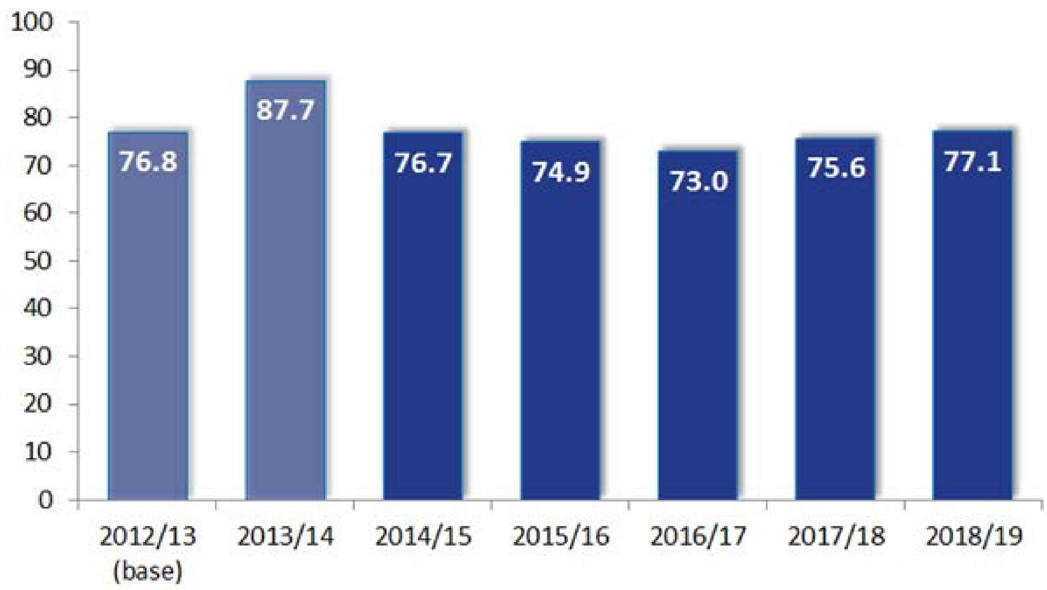
[77] Core network operating expenditure comprises maintenance, operating and other costs and excludes debt raising costs and carry-over amounts.

recurrent costs incurred in the 2012/13 base year or a total of $19 million during the period which have been included to ensure true costs are reflected for EBSS purposes as detailed in section 8.7.1. Following the increase in core network operating expenditure across the 2009–14 regulatory period, forecast operating expenditure will remain relatively stable across the 2014–19 regulatory period. Core network standard control operating expenditure for the period is expected to average $75.5 million per year.

Figure 8.1 shows ActewAGL Distribution's actual and forecast core network operating expenditure across the final two years of the 2009–14 regulatory period, including the 2012/13 base year, and the 2014–19 regulatory period.

Figure 8.1 Actual and forecast operating expenditure, 2013–19

$ million (2013/14)



The 2012/13 base year includes a number of unanticipated increases in operating costs that were incurred during the 2009–14 regulatory period, and not included in the AER's regulatory allowance for operating expenditure in the 2009–14 regulatory period.

Compliance with legislated standards and regulatory reporting requirements is a substantial driver of the costs incurred by ActewAGL Distribution in operating and maintaining its electricity network. Several regulatory obligations introduced during the current period were not anticipated at the time ActewAGL Distribution put forward its proposal and the AER made its decision for the 2009–14 regulatory period. Expenditure driven by these obligations is included in the base year amount. Additional regulatory obligations to be introduced during the 2014–19 regulatory period have been built into the operating expenditure forecasts.

Changes to work health and safety legislation in 2011 have had a material impact on ActewAGL Distribution's operating costs during the 2009–14 regulatory period and will continue to impact costs in the 2014–19 regulatory period. ActewAGL Distribution established an Environment, Health, Safety and Quality (EHSQ) division during the 2009–14 regulatory period to ensure it could effectively fulfil its obligations to employees as required by law. The process required a complete review and rewriting of ActewAGL Distribution's suite of safety policies and procedures which has been highly resource intensive and will continue into the 2014–19 regulatory period.

There has also been a significant increase in the scope of regulatory compliance and effort required in reporting during the 2009–14 regulatory period. Notably:

- the National Energy Customer Framework (NECF) commenced in the ACT on 1 July 2012, introducing a new set of national laws, rules and regulations governing the sale and distribution of energy to consumers. This framework introduced a number of ongoing reporting and audit requirements, and a commitment to oversee process improvement. ActewAGL Distribution's pass through claim for costs associated with the introduction of the NECF was approved as described in section 8.5.4.5;
- the National Planning and Expansion Framework (NPEF) commenced on 1 January 2013. This was initiated by the Ministerial Council of Energy in 2011, and includes new demand side obligations on DNSPs within the Rules. Obligations include requirements for DNSPs to undertake annual planning reviews, publish annual planning reports, undertake demand side engagement, undertake joint planning with TNSPs, and comply with a new regulatory investment test for distribution; and
- increased reporting requirements of the AER to perform or exercise its functions or conferred power under the Law or the Rules including the completion of an increased number and complexity of RINs including annual, 5 year reset, benchmarking and category analysis RINs.

Such new obligations have significantly increased monitoring, reporting, compliance and process improvement activities undertaken by ActewAGL Distribution since the time of the last regulatory determination.

8.5 Overview of historical operating expenditure 2009–14

8.5.1 AER 2009 final decision and 2012 revocation and substitution

In April 2009, the AER released its final decision for electricity distribution services in the ACT for 2009–14. In February 2012, ActewAGL Distribution notified the AER of errors in the distribution determination in relation to ActewAGL Distribution's superannuation calculations and requested that the AER rectify these errors through the revocation and substitution of the 2009 final decision. In April 2012, the AER accepted ActewAGL Distribution's application and substituted a new distribution determination. The substituted decision included the regulated network operating expenditure shown in Table 8.1 below.

Table 8.1 AER conclusion on ActewAGL Distribution's total standard control operating expenditure allowance 2009–14

$ million	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Standard control operating expenditure (2008/09 dollars)	60.8	65.3	69.7	74.5	76.9	**347.1**
Standard control operating expenditure (2013/14 dollars)	69.3	74.4	79.5	84.9	87.6	**395.6**

8.5.2 ActewAGL Distribution's actual total operating expenditure 2009–14

ActewAGL Distribution's total standard control operating expenditure for the current period and the allowance determined by the AER during the current period is shown in Table 8.2 below.

Table 8.2 Total operating expenditure 2009–14

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
AER allowance *	69.3	74.4	79.5	84.9	87.6	395.6
ActewAGL Distribution actual/forecast*†	67.7	79.1	90.3	98.5	109.6	445.2
Variance	-1.6	4.7	10.9	13.6	22.0	49.5

*Includes ancillary services and FiT
†Actual expenditure for 2009-2013, forecast expenditure for 2013/14

ActewAGL Distribution's actual operating expenditure during the 2009–14 regulatory period includes an estimated additional $49.5 million ($2013/14) or 13 per cent above the AER's allowance.[78] This additional prudent and efficient expenditure was necessary to ensure ActewAGL Distribution could continue to meet its increased regulatory obligations and requirements and reflects ActewAGL Distribution's need to focus during the period on improving safety, organisational and network performance, as well as a much tighter labour market resulting in higher labour costs than was allowed by the AER in its 2009 decision in not accepting ActewAGL Distribution's proposal at the time.

8.5.3 Drivers of additional operating expenditure during 2009–14

Details of the key drivers of additional expenditure during the 2009–14 regulatory period that were unforseen at the time of the AER's 2009 final decision are provided below.

[78] ActewAGL Distribution notes that the AER transitional distribution decision 2014-15 of April 2014 (page 85) reports that ActewAGL Distribution underspent its operating expenditure allowance during the 2009–14 regulatory period due to the exclusion of jurisdictional schemes in the actual expenditure reported in the decision.

8.5.3.1 Labour cost escalators

At the time of the AER's final decision in 2009, ActewAGL Distribution had in place the 2008 -11 Enterprise Bargaining Agreement (EBA). This had been negotiated during the 2007/08 financial year, and came into effect on 1 July 2008. The prevailing effective full-employment conditions in the ACT at that time saw negotiated wage increases set at 5 per cent per annum for all ActewAGL staff, and the introduction of a significant retention allowance for all qualified field staff.

In September 2008, the AER engaged KPMG Econtech to update the labour cost model forecast for NSW, Tasmania, the ACT and Australia over the period 2007/08 to 2016/17 and rejected ActewAGL Distribution's proposed labour cost escalators in its draft decision.[79] In the subsequent months, the outlook for economic growth deteriorated markedly as a result of the global financial crisis. The AER engaged KPMG Econtech to again update the labour cost forecast, with the report issued on 25 March 2009. Based on this advice, the AER allowed only a 2.5 per cent real increase for field staff and a 0.5 per cent real increase for corporate staff in its final decision[80] in the 2009/10 financial year as shown in Table 8.3. This coincided with the first year of the regulatory period, resulting in a significant under-recovery of labour costs in all subsequent years of the regulatory period.

Table 8.3 AER conclusion on ActewAGL's real electricity gas and water and general labour escalators

per cent	*2008/09*	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*
EGW labour	2.42	2.50	3.60	2.90	2.50	1.50
General labour	–2.50	0.50	1.30	1.00	0.90	0.20

ActewAGL's subsequent EBA was negotiated in the 2010/11 financial year when prevailing labour market conditions were now substantially stronger than had been predicted by KPMG Econtech in March 2009. Consequently, negotiated wage increases were set at 4 per cent per annum for all staff plus a retention allowance and an annual increase in superannuation contributions of one per cent to 12 per cent in 2013/14. ActewAGL Distribution considers these negotiations were necessary to attract and retain the skilled labour necessary to maintain the safe and reliable electricity supply in the ACT.

8.5.3.2 Energy Industry Levy (EIL)

The operating expenditure allowance in the AER's 2009 final decision included a forecast for the EIL for each year in the 2009–14 regulatory period.

Before 1 October each year the levy administrator must determine the estimated costs for the year and the actual costs for the previous year. The following costs are determined:

[79] AER 2008, *Draft decision ACT distribution determination 2009/10—2013/14*, November 2008 p 104

[80] AER 2009, *Final decision ACT distribution determination 2009/10—2013/14*, April p 61

- national regulatory costs—the cost to the Territory of meeting its national regulatory obligations for the year;
- local regulatory costs—the cost to the Territory of providing regulatory activities in relation to safety, technical operations, consumer service and environmental behaviour for energy utility services and the administration of the levy; and
- fixed net regulatory costs—the costs incurred for an energy utility that is unrelated to the utility's market share.

These determinations are provided by notifiable instrument.

Each year, ActewAGL Distribution submits an EIL Annual Return. These returns outline a fixed and variable component. The fixed component is simply the fixed net regulatory costs. The variable component is the sum of the national and local regulatory costs minus the fixed net regulatory costs apportioned by the number of megawatt hours distributed. ActewAGL Distribution is the sole electricity distributor in the ACT and therefore pays the entire electricity distribution sector costs. The amount payable is the estimated costs for the current year plus the actual costs for previous year minus the amount paid in the previous year

8.5.3.3 Operational Systems Replacement Program (OSRP)

At the time of the last regulatory review, ActewAGL Distribution's operating technology was comprised of both heavily customised off-the-shelf applications and various in-house developed systems. Interfaces between systems were limited and integration was not feasible, leading to extensive manual intervention in order to meet business needs. This resulted in duplicate information handling, system errors, data integrity issues and substandard system functionality that exposed ActewAGL Distribution to an unacceptable level of risk associated with these deficiencies. Following the initial networks business improvement program in 2009/10 it was decided that in order to mitigate this risk, significant investment in modernising the network technology could no longer be deferred. This resulted in the development of the OSRP. The OSRP is described in detail in section 7.12 of this submission.

8.5.3.4 Energy Networks structural changes and safety improvement costs

In 2011 ActewAGL Distribution underwent a major organisation review of the Energy Networks Division. This review was supported by the engagement of Marchment Hill Consulting (MHC) whose focus was on structural changes, and Deloitte, whose focus was on occupational, health and safety culture, practices and procedures. The primary objectives of the review were to identify, validate and understand key performance issues and improvement opportunities within the division from the management and organisational structure through to the operating model, as well as further develop an organisational culture in which safety is deeply embedded.

MHC's core recommendation was for ActewAGL Distribution to undertake a consultative organisation restructure of the Energy Networks Division and to implement an asset management model whereby the Energy Networks Division was split into two streams—Asset

Management and Network Services. The single General Manager Energy Networks role was replaced with two roles: a General Manager Networks Asset Management and a General Manager Networks Services. Supporting Branch Manager structures were also introduced. These were significantly different from existing roles in terms of accountabilities, span of control, reporting lines, budgetary responsibility, required minimum competencies, and direct and indirect employee numbers. A number of critical business improvement initiatives were also recommended which were aimed at addressing process, competency, systems, data and capability issues within Energy Networks, as well as improving the interfaces between Network Asset Management, Network Services and other ActewAGL divisions.

The Deloitte review identified significant scope for improvement in ActewAGL Distribution's health and safety programs against industry best practice. In particular, improvements were needed in management safety leadership and in communication and consultation between management and field staff. Safety management systems, incident reporting and training needed to be better implemented. Risk management also needed to be significantly upgraded and there needed to be much more focus on controlling high-risk working environments.

In March 2011, the Board approved the findings of the Phase 1 and 2 reports of the Deloitte safety review. Key actions undertaken included:

- the formation of safety improvement project teams;
- the implementation of a safety leadership and governance structure including the appointment of a Director EHSQ Improvement; and
- the creation of the EHSQ Division. The new EHSQ Division was identified as a critical component to providing guidance required to shift the organisation from a reactive to a proactive safety culture.

During the period, there was also significant legislative change relating the work health and safety, further reinforcing ActewAGL Distribution's need to improve its safety management. From January 2012, the new *Work Health and Safety Act 2011* came into effect, bringing ACT health and safety laws into harmony with similar legislation in other jurisdictions. These changes are discussed in detail in chapter 5 of this proposal.

During this period of change, ActewAGL Distribution has continued to refine and streamline the organisational structure to improve its governance processes, to better serve the long term interests of consumers, and prepare for industry changes so that it can continue to achieve the operating expenditure objectives as set out under clause 6.5.6(a) of the Rules.

ActewAGL Distribution considers that successful implementation of these structural and safety reforms was essential to provide an improved and sustainable safety environment in which safety is the number one priority and ensure network reliability over the longer term. This is expected to decrease safety and reliability risks, strengthen management capabilities and disciplines, and deliver an overall improvement in outcomes for customers.

8.5.3.5 Vegetation management program

After a period of dry weather the ACT experienced two very wet years with annual rainfall in 2010/11 and 2011/12 reaching 867 mm and 778 mm respectively, well above the long term average of 620 mm and at a level not exceeded since 1988/89, over 20 years prior.

The scale of vegetation growth and encroachment on clearance zones following these years of high rainfall was not apparent until ActewAGL Distribution's preparation for the 2012/13 bushfire season.

ActewAGL Distribution's ground inspection crews and aerial surveys indicated that the higher rainfall had shortened the time taken for vegetation to regrow into clearance zones. Higher vegetation encroachment required ActewAGL Distribution to increase inspection activities and clear a greater volume of vegetation from clearance zones.

The unexpected and uncontrollable increase in vegetation growth led to additional vegetation management (inspection and clearance) costs during the 2009–14 regulatory period above the allowance in the AER's 2009 final decision.

As noted in section 8.5.4.7, ActewAGL Distribution submitted a pass through claim to the AER for additional vegetation management costs incurred in 2012/13 in November 2013. This pass through claim was for a change in cost of $1.9 million, including only incremental costs which occurred solely as a result of the pass through event. Detailed explanation of the additional vegetation management activities required and associated costs is provided in ActewAGL Distribution's pass through application.[81]

8.5.3.6 Sale of TransACT and Ecowise Environmental

Over the regulatory period 2009-2014, ActewAGL has rationalised non-core investments and associated service provision to enable a greater focus on core operations. This includes the divestment of Ecowise Environmental and cessation of corporate services provided to Ecowise Environmental and Grapevine in 2009/10. Additionally, the corporate services provided to TransACT were also progressively rolled back in 2010/11 with final cessation in early 2011/12.

A change in the structure of corporate services followed, as well as changes to ActewAGL Distribution's contracts management and business development functions. This addressed a significant portion of the impact on the corporate services cost base.

However, a small portion of residual fixed corporate costs led to a greater share being allocated to the remaining ActewAGL divisions, including Electricity Networks.

Despite this, consumers continue to benefit from cost savings provided through ActewAGL's shared services approach that sees corporate services costs shared between ActewAGL Distribution, ActewAGL Retail and ACTEW Water.

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[81] ActewAGL Distribution 2013, *Vegetation management cost pass through,* November

8.5.4 Cost pass throughs 2009–14

ActewAGL Distribution submitted seven cost pass through applications during the 2009–14 regulatory period. Full details of these applications and the AER's decisions can be found on the AER website.

Table 8.4 Cost pass throughs 2009–14

Year incurred	Pass through claim	Value ($ nominal)	Status
2009/10	Utilities Network Facilities Tax	($81,671)	Not approved
2009/10	ACT Feed-in Tariff Scheme	($2,117,614)	Approved
2010/11	ACT Feed-in Tariff Scheme	($3,918,484)	Approved
2011/12	ACT Feed-in Tariff Scheme	($727,564)	Approved
2011/12	National Energy Customer Framework	$1,997,929	Approved
2012/13	Utilities Network Facilities Tax	$739,527	Withdrawn
2012/13	Vegetation management	$2,198,414	Pending *

* AER draft decision did not approve this pass through claim.

8.5.4.1 2009/10 Utilities Network Facilities Tax

In May 2010, ActewAGL Distribution advised the AER of a negative tax change event relating to the ACT Treasurer's determination of the Utilities Network Facilities Tax (UNFT) rate for 2009/10. The value of the negative tax change event was a $46,963 variance between the provision in the AER's final decision and the actual cost incurred. At the request of the AER, a revised cost pass through amount of $81,671 was provided in July 2010, reflecting an amended calculation methodology. The AER did not approve the pass through as it determined that the costs for the provision of direct control services had not materially decreased, and considered the change did not satisfy the definition of a tax change event.

8.5.4.2 2009/10 ACT Feed-in Tariff Scheme

In March 2011 ActewAGL Distribution submitted a negative pass through event application to the AER for the difference between the forecast $3.06 million and actual $1.19 million paid for the ACT's Feed-in Tariff Scheme for 2009/10, providing a change in cost of $1.87 million. The variance was due to lower than expected take-up of the scheme in that year and a lower price paid to generators. The AER approved a negative pass through amount (including tome cost of money and CPI adjustments) of $2.12 million to be incorporated into distribution charges in 2011/12.

8.5.4.3 2010/11 ACT Feed-in Tariff Scheme

ActewAGL Distribution again submitted a negative pass through for the ACT Feed-in Tariff Scheme for 2010/11 in November 2011. A pass through amount of $3.92 million was proposed, based on the difference between the forecast of $6.82 million and actual costs of $3.63 million and adjustments for CPI time cost of money. The AER approved ActewAGL Distribution's negative pass through claim and this amount was passed through to customers in 2012/13 distribution charges.

8.5.4.4 2011/12 ACT Feed-in Tariff Scheme

A negative pass through application was once again submitted for the difference between forecast and actual costs related to the ACT Feed-in Tariff Scheme for 2011/12. An amount of $0.73 million was proposed by ActewAGL Distribution and accepted by the AER to be passed through to customers through 2013/14 distribution charges, which included adjustments for CPI and time cost of money.

8.5.4.5 2011/12 National Energy Customer Framework

The National Energy Customer Framework (NECF), implemented through the *National Energy Retail Law (ACT) Act 2012* and *National Energy Retail Law (ACT) Regulation 2012*, commenced in the ACT on 1 July 2012. In November 2012 ActewAGL Distribution submitted a positive cost pass through application to the AER for costs associated with the implementation of the NECF. ActewAGL Distribution submitted the claim to the value of $1.98 million as a service standard event that materially increased costs for the 2009–14 regulatory period. This pass through amount included additional staff requirements, legal fees, consultant and contractor costs, and an allowance for the time cost of money. In January 2013 the AER approved for ActewAGL Distribution's pass through to be incorporated into distribution charges for the 2013/14 regulatory year.

8.5.4.6 2012/13 Utilities Network Facilities Tax

In May 2013 ActewAGL Distribution submitted an application for a tax change event relating to the Utilities Network Facilities Tax comprising of positive amounts for 2012/13 and 2013/14 and negative amounts for 2009/10, 2010/11 and 2011/12. The total pass through amount, including time cost of money, proposed was $0.74 million. ActewAGL Distribution withdrew its pass through application in June 2013.

8.5.4.7 2012/13 Vegetation management costs

In November 2014 ActewAGL Distribution submitted an application for a positive cost pass through arising from a material increase in vegetation management costs in 2012/13. ActewAGL Distribution responded to requests for further information from the AER in December 2013 and February 2014. On 25 March 2014 the AER wrote to ActewAGL Distribution indicating that the AER had decided to extend the time for making a determination by a period of 60 business days and would make its decision on or before 8 July 2014.

8.6 *Forecast operating expenditure methodologies*

8.6.1 Forecasting approach

There are two predominant forecasting approaches used by distribution network service providers: zero-based and base year methods. The zero-based method assumes a nil budget as the start point, adding the projects or activities required that year in a bottom-up construction of the cost. Base year uses a comparable financial year as the starting point, removing projects or activities no longer relevant and conversely, adding projects or activities required during the forecast period that were not in the base year. These are referred to within the business as step changes.

ActewAGL Distribution uses a combination of zero-based and base year approaches when forecasting, as summarised in Figure 8.2. Corporate overheads are attributed between ActewAGL group businesses based on an enterprise wide corporate attribution model. Further information on ActewAGL Distribution's forecasting approach is provided in the forecasting methodology included at Attachment B19.

Figure 8.2 Operating expenditure forecasting approaches

Cost category	*System source*	*Forecasting/costing approach*
Network operating	Financial Management Information System	Base year
Network maintenance	RIVA asset management software	Zero based
Vegetation management	Financial Management Information System	Zero based
Other operating expenditure	Financial Management Information System	Base year
Corporate overheads	Fixed price service charge (FPSC) model	Attribution

8.6.2 Cost allocation methodologies

8.6.2.1 ActewAGL Distribution cost allocation method

ActewAGL Distribution's CAM governs the manner in which ActewAGL allocates costs to the distribution services that it provides in order to prevent cross-subsidisation between distribution services and other services ActewAGL provides.

On 20 December 2012, ActewAGL Distribution submitted its proposed revised CAM to the AER, which was approved on 7 June 2013, in accordance with chapter 6 of the Rules. The revised CAM replaced ActewAGL Distribution's previous CAM approved by the AER in 2008. This regulatory proposal is the first to have been prepared according to the revised CAM.

The CAM is largely based on ActewAGL Distribution's previous CAM, with some revisions to the allocation of shared network overheads, corporate costs and some costs associated with services provided by ActewAGL Retail. The method involves allocating costs directly to projects wherever possible. Project costs are then aggregated into regulated and unregulated activities and services. Where costs are shared between services, appropriate drivers are used to allocate these across the various business divisions.

ActewAGL Distribution's CAM is provided at Attachment B18.

8.6.2.2 Corporate overhead cost allocation methodology

In 2009, ActewAGL engaged external consultants, Analytics Group, to undertake a review of the validity and appropriateness of ActewAGL's corporate overhead allocation methodology. Analytics Group recommended a more widespread use of specific drivers to directly allocate a greater portion of corporate overheads to achieve a more precise allocation of costs. This results in an increase in the direct allocation of corporate overheads to the electricity distribution business. The change in the corporate overheads allocation methodology will come into effect from 1 July 2014.

This change is reflected in the cost allocation methodology that was submitted to the AER in December 2012 and subsequently approved by the AER.

8.6.3 Allocation of expenditure to transmission and distribution standard control services

ActewAGL Distribution has allocated forecast operating expenditure for the 2014–19 regulatory period to distribution and transmission standard control services directly to these services where possible. For costs not directly attributable to either transmission or distribution, a proportional allocation is used to split the total between transmission and distribution, and for operating expenditure, directly allocated maintenance expenditure is used as the allocation factor. This allocation is consistent with ActewAGL Distribution's CAM.

8.6.4 Operating expenditure categories

For this proposal, ActewAGL Distribution has maintained the operating expenditure categories consistent with its own internal reporting and forecasting processes and used in its previous regulatory proposals. These cost categories have been mapped to the categories as specified by the AER for the purpose of the RIN template.

8.7 Forecast operating expenditure assumptions

8.7.1 Selection of the base year

Under incentive-based regulation, revealed costs provide the efficient level of operating expenditure required to achieve the operating expenditure objectives and reflect the operating expenditure criteria.

ActewAGL Distribution participates in the Efficiency Benefit Sharing Scheme (EBSS) as described in chapter 16 of this proposal. The purpose of the EBSS is to provide DNSPs with a continuous and consistent incentive to reveal its efficient level of expenditure through the retention of efficiency gains (or losses) for the length of a carryover period regardless of the year of the regulatory period in which the gain (loss) was made. As such, a DNSP is provided with a constant incentive to improve efficiency of its operating expenditure and thus reveal its efficient level of operating expenditure.

ActewAGL Distribution has responded to the incentive framework in place to reveal its efficient costs in the base year. As such, ActewAGL Distribution has selected 2012/13 as the base year and contends that efficient costs have been revealed in this year. Expenditure in this year has been used for expenditure forecasting where the base year forecasting approach has been adopted. This is also the latest year for which audited ActewAGL Distribution accounts are available is 2012/13.

ActewAGL Distribution notes the AER's intentions expressed in the expenditure forecast assessment guidelines[82] to assess a DNSP's forecast by examining its revealed costs, as well as by using other techniques including benchmarking to determine whether revealed costs are appropriate. ActewAGL Distribution's views on benchmarking were expressed in its submissions to the AER as well as in the ENA's submissions supported by ActewAGL Distribution during the development of the expenditure forecast assessment guidelines. To summarise these views, ActewAGL Distribution considers benchmarking to be a useful support tool to assist expenditure assessments, rather than a technique on which to base regulatory decisions. In using benchmarking as a support tool ActewAGL Distribution considers it essential for individual circumstances to be taken into account. Due to the relatively small size of ActewAGL Distribution's network, the fixed cost nature of network operations and the cost drivers unique to ActewAGL Distribution detailed in section 8.9, failure to adequately consider the individual circumstances of ActewAGL Distribution relative to industry peers is likely to result in unfavourable outcomes for ActewAGL Distribution. Further to these concerns, ActewAGL Distribution considers further detail is required to clarify exactly how and to what extent benchmarking is intended to be applied to DNSP's expenditure proposals.

Having regard to the shortcomings of benchmarking and the provision in the Rules for incentive mechanisms, ActewAGL Distribution considers incentive based regulation to remain a superior method for efficient expenditure to be determined.

Table 8.5 below sets out the establishment of ActewAGL Distribution's efficient base year operating expenditure. This has been formed by making adjustments to the 2012/13 actual operating expenditure as reporting in ActewAGL's RIN, to remove the costs of jurisdictional schemes, as these will no longer be included in the 2014–19 period, as well as an adjustment for

[82] AER 2013, *Expenditure forecast assessment guideline for electricity distribution*, November, p 8

the change in the CAM. As network maintenance is forecast using a zero-based approach over the 2014–19 regulatory period, this has been excluded to arrive at the adjusted base year efficient operating expenditure for ActewAGL Distribution, which forms the base operating expenditure for each year of the 2014–19 regulatory period.

In addition to the adjustments to base year operating expenditure as included in Table 8.5, the base year includes several non-recurrent operating expenses. These are provided in Table 8.6 and explained in the following sections. ActewAGL Distribution notes that costs for the asset management plan and under-recovery have not been excluded from the base year to ensure true costs are reflected for EBSS purposes as per the current scheme.[83] ActewAGL Distribution confirmed with AER staff that, under the current period EBSS, non-recurring costs should be included in forecasts to avoid double penalty from the negative EBSS carryover effects.

Table 8.5 2012/13 base year core network operating expenditure

Item	*$ million (2012/13)*
Actual 2012/13 operating expenditure	**95.4**
Adjustments	
Feed in tariff	(14.1)
Utilities Network Facilities Tax	(5.5)
Energy Industry Levy	(0.7)
Miscellaneous charges	(2.0)
Cost allocation method adjustment	(5.4)
Actual base year operating expenditure	**67.8**
Less non-recurrent costs	
Comcare exit payment	(1.8)
Actual base year operating expenditure less non-recurrent costs	**66.0**
Includes	
*Network maintenance ($2012-13)**	*(22.5)*
Base year adjusted operating expenditure, excluding network maintenance	**43.5**

*Includes non-recurrent vegetation management expenditure of $1.9 million as noted in Table 8.6.

[83] AER 2008, *Electricity distribution network service providers efficiency benefit sharing scheme—final decision*, June

Table 8.6 Non-recurrent costs in 2012/13 base year

Item	*$million (2012/13)*
Comcare exit payment	1.8
Vegetation management	1.9
Asset management plan *	0.9
Under-recovery *	2.9
Total non-recurrent costs	**7.5**

* Cost included in forecast to offset negative carryover effects

8.7.1.1 Comcare exit payment

ActewAGL Distribution was impacted by the decision of ACTEW Corporation (ACTEW) to exit the ACT Government's Comcare arrangements under the *Safety, Rehabilitation and Compensation Act 1988* (Commonwealth) (the "Comcare Scheme"), effective 1 September 2012. Immediately prior to ACTEW's exit from the scheme there were 175 ACTEW employees seconded to ActewAGL Distribution, which resulted in an agreement for ActewAGL Distribution to compensate ACTEW for a portion of the exit payments (32.6 per cent) associated with exiting the Comcare Scheme. The exit payments were related to the workers compensation claims made whilst under the Comcare Scheme. The benefit of exiting the Comcare Scheme is through lower premium spend by engaging in the private market for workers compensation insurance, and at the time the decision to exit was made, it was expected to become NPV positive after 10 years (from 1 July 2012). The Comcare exit payment is not included in the base year for forecasting purposes as it is excluded by the EBSS.

8.7.1.2 Vegetation management

Non-recurrent operating expenditure in the base year for vegetation management is explained in detail in sections 8.5.3.5 and 8.5.4.7.

8.7.1.3 Asset management plan

Non-recurrent operating expenditure during the base year for the asset management plan was to engage asset management solutions firm, gViz, to supply the Riva software application which assists ActewAGL Distribution in delivering its Asset Management Plan. These costs in the base year were to project manage the implementation.

8.7.1.4 Under-recovery

Cost recovery is the means in which resources are allocated to deliver ActewAGL Distribution's capital, maintenance and operational projects. The collection of resources (cost pool) consists of three elements including direct labour, overhead labour, and plant and equipment. An hourly costing rate is determined based on resource utilisation, the total value of the cost pool and the total numbers of hours required in delivering projects. The cost pool is then allocated to projects through timesheet records. In 2012/13 there was an under-recovery of these costs. Key drivers of such cost recovery variations include the mix between different elements of the cost pool, labour utilisation percentage and the amount of leave taken by staff members.

8.7.2 Cost escalation

In developing its expenditure forecasts ActewAGL Distribution applies price escalation factors for inputs that contribute significantly to operating expenditure but for which escalation by CPI is not appropriate. In preparing expenditure forecasts for the 2014–19 regulatory period, ActewAGL Distribution partnered with NSW DNSPs and Transend (Tasmania) to engage consultants to provide expert advice on suitable escalation factors for the following categories:

- aluminium;
- copper;
- steel;
- crude oil;
- labour, including utilities industry , professional services and general labour; and
- construction—both engineering and non-residential.

The application of labour cost escalation is described below. The other escalation factors are primarily relevant to capital expenditure and are discussed in 7.7.6.

8.7.2.1 Labour costs

In assessing the efficiency of ActewAGL Distribution's costs, the AER will consider the outlook for nominal wage growth and in accordance with Clause 6.5.6(e) of the Rules, the AER must have regard to whether total labour costs are consistent with the incentives provided by the applicable service target performance incentive scheme.

As outlined in section 8.5.3.1, actual labour cost escalators for the 2009–14 regulatory period were significantly greater than those allowed for by the AER.

For the 2014–19 regulatory period ActewAGL Distribution, together with NSW and Tasmanian NSPs, engaged Independent Economics to forecast nominal wage growth rates for Australia, NSW, Tasmania and the ACT economies, as well as the utilities industry and the professional services industry in each of these regions.

For the purposes of this regulatory proposal, ActewAGL Distribution has used labour cost escalators consistent with those applied for the transitional regulatory proposal. Independent Economics will update these forecasts for ActewAGL Distribution's use for the revised regulatory proposal to be submitted to the AER in January 2015. Independent Economics' report upon which ActewAGL Distribution's labour cost escalators have been based is provided at Attachment B13.

Independent Economics' forecasts were used to develop real labour cost escalators for the purposes of preparing operating expenditure forecasts for this regulatory proposal. These are shown in Table 8.7 below.

Table 8.7 Real labour cost escalators 2014–19

Per cent	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Labour cost escalators	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

8.7.3 Step changes

ActewAGL Distribution's operating expenditure forecast for the 2009–14 regulatory period includes nine step changes totalling $35.3 million above the base expenditure. A summary of these step changes is provided in Table 8.8 below. These costs have not been escalated.

Table 8.8 Standard control core network operating expenditure step changes

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
EHSQ	0.7	0.7	0.5	0.5	0.4	**2.8**
Regulatory Compliance and Strategy	2.2	1.1	1.0	2.1	2.1	**8.6**
Technical Standards	0.4	0.3	0.3	0.3	0.3	**1.4**
Works Practices	0.7	0.7	0.7	0.7	0.7	**3.5**
Contractor Management	0.6	0.6	0.6	0.6	0.6	**3.1**
Network Operations and Call Centre	0.4	0.4	0.4	0.4	0.4	**2.1**
Network OT Support	1.3	1.9	0.8	0.8	0.0	**4.8**
Corporate Services charges	1.4	1.7	2.0	2.4	2.7	**10.1**
Capitalisation Corporate Services charges	1.0	0.1	-1.3	-0.8	-0.3	**-1.2**
Total step changes	**8.8**	**7.4**	**5.1**	**7.0**	**6.9**	**35.3**

Activities associated with these step changes are not provided for within the base operating expenditure, nor are they due to any changes in real prices, output growth, or productivity. These step changes are driven by both changes in regulatory obligations and changes in ActewAGL Distribution's policies and strategies. ActewAGL Distribution considers these step changes to be necessary in order to continue to achieve the operating expenditure objectives under clause 6.5.6(a) of the Rules, and reasonably reflect the operating expenditure criteria under clause 6.5.6(c). Brief descriptions of these step changes are provided below, with detailed explanation provided in Attachment B10.

8.7.3.1 EHSQ

This step increase is driven by both changes in regulatory obligations and changes to ActewAGL Distribution's policies and strategies. Since the introduction of the *Work Health and Safety Act (2011)* and *Work Health and Safety Regulation (2011)*, ActewAGL Distribution's costs to comply with WHS legislation have increased, and are forecast to continue to increase in the 2014–19 regulatory period.

To ensure ActewAGL Distribution can continue to maintain the safety of the distribution system and the community within which it operates, additional costs are anticipated in the areas of asbestos management and bushfire mitigation.

Increased EHSQ costs will also be driven by ActewAGL Distribution's continued focus on improving the safety culture and maintaining its responsibility to provide all of its employees with a workplace that is safe, does not impact on the environments in which it operates or affect the health or wellbeing of workers or the public.

Non-recurrent costs included in the EHSQ step change include:

- costs in 2014/15 to understand climate change risk and resilience and for the initial development of an approach consistent with the ENA's climate risk and resilience manual (once developed) to manage this risk and ensure ActewAGL Distribution's network is resilient to climate change issues; and
- a major update of the Bushfire Mitigation Strategy and Management Plan in 2015/16 to ensure its relevance in the current environment and compatibility with the ACT Government's Strategic Bushfire Management Plan, which will be non-recurrent in the 2014–19 regulatory period but is incurred on a periodic basis.

8.7.3.2 Regulatory Compliance and Strategy

This step increase is driven by an increase in regulatory obligations triggered by the recent changes to the Rules relating to economic regulation of network service providers and consequent changes to the AER's approach to economic regulation. Other changes in the regulatory environment have also led to ongoing increases in regulatory obligations, which are in addition to business as usual activities. This step change also includes costs associated with the implementation of ActewAGL Distribution's consumer engagement strategy stage 1 as detailed in section 3.4.1 of this proposal.

Non-recurrent costs included in the regulatory compliance and strategy step change are cyclical rather than non-recurrent in nature. Non-recurrent costs in 2014/15 and 2015/16 include the review of the connection charge framework (2014/15- 2015/16) and the preparation for the 2014–19 regulatory proposal and related activities. Non-recurrent costs in 2017/18 and 2018/19 relate to additional costs incurred for the preparation for the 2019-24 regulatory proposal and related activities.

8.7.3.3 Technical Standards

ActewAGL has a legal and regulatory responsibility to operate an electricity distribution network that maintains minimum service, reliability and safety standards. The Technical Standards section has responsibility for delivering the network construction standards for ActewAGL Distribution.

The operating expenditure step change for the Technical Standards section is for one additional full time equivalent (FTE) compared to base year levels as well as consultancy costs associated with the implementation of the 5 year business plan to ensure that the technical aspects of ActewAGL Distribution's field operations and construction activities are covered by a relevant comprehensive technical standard. At present there are a number of critical areas that are not covered by adequate standards exposing ActewAGL Distribution to potential safety and legal risks. These areas are being addressed under the current business plan.

Non-recurrent costs included in 2013/14 for the technical standards step change are for the initial implementation of the five year technical standards business plan.

8.7.3.4 Safe Work Practices

This step change is for the establishment of a Safe Work Practices team of 4 dedicated FTEs responsible for updating, communicating and standardising electrical safety documentation across ActewAGL Distribution. These officers will be responsible for ensuring all primary and supporting electrical safety documentation is consistent with current Codes of Practice and the *Work Health and Safety Act 2011*. This approach is also consistent with standard industry practice.

Historically there has not been a dedicated central team at ActewAGL Distribution responsible for updating electrical safety documentation and communicating changes to other parts of the business. This is inconsistent with industry standards and other DNSPs.

As electrical safety documentation is used by field workers it is critical the information is consistent with the latest safety regulations to ensure that field workers comply with the latest safety regulations and reduce the risk and occurrence of safety incidents to field workers and the general public.

8.7.3.5 Contractor Management

ActewAGL Distribution manages a large number of contracts, with eight of the largest accounting for around 80 per cent of the total contract spend. It has been identified in independent audit reports that ActewAGL Distribution's framework for contractor management requires strengthening. Specifically these reports identified inadequate review, monitoring and evaluation of existing contractor safety management and contractor performance. Operating expenditure for this step change is for four additional dedicated resources to oversee contractor safety and performance management arrangements, including review, monitoring and evaluation of existing and future contracts.

8.7.3.6 Network Operations and Call Centre

Increased operating expenditure for network operations and call centre functions is driven by both changes in regulatory obligations and changes in ActewAGL Distribution's strategies to continue to manage the quality and reliability of the network.

From July 2014 ActewAGL Distribution will participate in STPIS reporting. This will draw information more heavily from data gathered and stored in ActewAGL Distribution's operational systems. Currently fault call centre staff do not record all calls in the information management system (examples include during out of hours operations or where multiple calls relate to the same fault).

Additionally, the fault call centre, dispatch call centre and systems control operators currently use separate information management systems which are not integrated with other management systems. The fault call centre information management system is based on Windows XP and will no longer be supported by IT upgrades following the implementation of the OSR Program.

To ensure ActewAGL Distribution can continue to manage the quality and reliability of supply of standard control services, additional operating costs will be required for this change in the business requirements of the systems used by the network operations and call centre branch.

8.7.3.7 Network OT Support

Network OT Support includes all operational expenditure relating to system support staff and maintenance costs for network OT systems. This expenditure includes:

- system maintenance and servicing;
- system licencing and hardware leasing;
- 'trouble shooting' and remediation;
- data management and updates; and
- data remediation and integrity (migration from obsolete systems).

ActewAGL Distribution implemented a number of ICT operational support systems during the 2009–14 regulatory period as part of the OSRP and proposes to invest further in operational technology to ensure ActewAGL Distribution can continue to meet its regulatory requirements and operate, manage and maintain its distribution network.

The Network OT Support step change is for greater operational support required as a result of this strategic change to ensure these systems are effectively operated, supported and maintained.

Non-recurrent costs included in the network OT Support step change in 2014/15 and 2015/16 are for additional FTEs for data remediation to improve the performance of systems and quality of output as well as operating expenditure associated with Network OT capital expenditure projects. Non-recurrent costs incurred in 2014/15 to 2017/18 include leases for the Advanced

Distribution Management System (ADMS), which are due to expire in 2017/18 and are planned to be transferred to finance leases.

8.7.3.8 Corporate Services charges

The Corporate Services division of ActewAGL Distribution provide corporate services support to Electricity Networks, Gas Networks, ActewAGL Retail, and ACTEW Corporation. These corporate services include:

- Human Resources (People & Performance);
- Property & Security;
- EHSQ Management;
- Contracts & Procurement;
- Legal & Secretariat;
- Corporate Finance;
- Regulatory Affairs;
- Accounts Payable; and
- Business Systems Division (BSD).

The Electricity Networks share of these costs is calculated based on the approved CAM.

The step change in corporate services operating expenditure over the 2014–19 regulatory period is driven by both changes in regulatory obligations and changes in ActewAGL Distribution's strategies and policies. These include:

- increased operating expenditure associated with the implementation of the critical CSRP. There will be ongoing operating expenditure related to these system replacements such as licences and maintenance costs. These will be somewhat offset by a reduction in project resource FTEs compared to base year levels. This expenditure related to the systems replacement is critical to the maintenance of systems which will allow for compliance with regulatory obligations, and support for the quality and reliability of the distribution system;
- software licence maintenance costs, which historically increases at a higher rate than CPI increases due to the market power of large suppliers. Efforts are being made to manage licence numbers in the business to minimise increases in software licence costs;
- increased operating expenditure associated with corporate capital expenditure across the 2014–19 regulatory period. This is detailed in Attachment D10;
- to facilitate compliance with an increasing number of legislative and regulatory obligations ActewAGL Distribution upgraded its legal compliance framework during the 2009–14 regulatory period by implementing CMO, ActewAGL's legal obligations

management system software. This will require additional costs over the 2014–19 regulatory period to maintain this system;

- Additional costs associated with the revised corporate health strategy led by the People and Performance to provide tailored outcomes for injured employees and for the revision of policies/procedures/reporting tools to enhanced return to work outcomes. This strategy is borne from the legislative requirements under the *Work Health and Safety Act 2011*, *Safety Rehabilitation Compensation Act 1988* and the *Workers Compensation Act 1951* to protect the health and safety of all employees; and
- [redacted]

8.7.3.9 Capitalisation of Corporate Services charges

This step change is due to annual variations in the amount of corporate services charges to be capitalised under the approved CAM. In years that result in positive step changes, this is due to lower expenditure on capital projects subject to an allocation of corporate services charges under accounting rules compared to the base year. In years that result in a negative step change, this is due to a higher allocation to capital expenditure relative to the base year. Depending on the capital expenditure to be incurred year on year, this allocation will fluctuate. It should be noted that any change to the program of work including the step changes listed above will affect the absorption of corporate overheads.

8.7.4 Productivity and output cost drivers

This section outlines ActewAGL Distribution's approach to incorporating productivity and output cost drivers. ActewAGL Distribution used an implicit productivity improvement in developing forecast operating expenditure rather than explicit productivity or output growth factors. ActewAGL Distribution's approach assumed that the increased costs from output growth, illustrated by a forecast 22 per cent increase to the regulatory asset base and an additional 12,000 customers, would be offset by increases to productivity.

Schedule 6.1 of the Rules requires a building block proposal to identify to what extent that forecast expenditure is on costs and to what extent it is on costs that are variable, by well accepted categories.[84] The Rules do not define fixed or variable costs. ActewAGL Distribution considers fixed costs to be those incurred irrespective of the level of business activity and variable costs to be those that vary with activity levels. Schedule 1 of the RIN requires ActewAGL Distribution to information on output growth drivers and productivity measure applied. Over the

[84] *National Electricity Rules*, clause S6.1.2(1)(iii)

2014–19 regulatory period, ActewAGL Distribution considers that variable costs and costs driven by output growth drivers are equivalent.

8.7.4.1 Output growth

The relationship between ActewAGL Distribution's operating costs and 'output growth drivers' (variable costs) is complex. The key short-term driver is capital expenditure resulting in additional maintenance costs.

Riva, ActewAGL Distribution's asset management software, provides a single source inventory listing for all core assets managed and select assets which are expected to be commissioned. Riva produces an Asset Specific Plan for each asset included and forms the basis of the 'zero base' maintenance forecast. As only select assets have been included in Riva not all maintenance costs have not been included in planned maintenance costs.

The amount of total forecast operating expenditure attributable to output growth changes/variable costs for each year of the 2014–19 regulatory period, is given by the included maintenance costs of assets related to output growth to be commissioned.

The proportion of total forecast operating expenditure attributable to output growth changes is small. Maintenance costs for less than 20 assets expected to be commissioned have been included. These costs are summarised in Table 8.9.

Table 8.9 Output growth operating expenditure 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Operating expenditure attributable to output growth changes	0.02	0.07	0.09	0.11	0.13	**0.43**

Table 8.9 shows the extent of variable costs (and as a result, fixed costs) within forecast operating expenditure.

Economies of scale have been taken into account through the application of unit rates used as an input to Riva. As noted in chapter 7, these rates have been reviewed by Jacobs SKM who found that the unit rate estimates for the selected activities are reasonable and efficient. Any possible incremental change to the unit rates due to economies of scale, arising from the small increase in the number of assets included in the operating expenditure forecasts, will be offset by the increase maintenance costs from assets not included in the operating expenditure forecast.

8.7.4.2 Productivity growth

As with output growth, ActewAGL Distribution has incorporated implicit productivity improvements in its operating expenditure proposal. ActewAGL Distribution's forecast operating expenditure does not include additional costs that will be incurred with the forecast expansion of the network, illustrated by an increase of 22 per cent to the RAB and an additional 12,000 new connections. This growth will result in a range of additional costs related to asset management, maintenance and customer service. Instead ActewAGL Distribution's forecast operating expenditure proposal has assumed that productivity growth achieved will offset these additional costs, and thereby imposes an implicit productivity improvement measure.

ActewAGL Distribution notes that any explicit productivity measure imposed by AER would need to account for future changes to regulatory requirements and industry standard practice. ActewAGL Distribution notes that future regulatory requirements and changes to industry standard practice may more than offset any productivity gains that could be achieved over the 2014–19 regulatory period.

8.7.5 Operating expenditure base step trend forecast 2014–19

ActewAGL Distribution's base step trend forecasts for the 2014–19 regulatory period are based on the 2012/13 base year efficient costs and the build-up of step changes and cost escalation as discussed in section 8.7.1 to 8.7.3 is provided in Table 8.10 below.

Table 8.10 Operating expenditure base step trend forecast 2014–19

	2014/15	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
$ million (2012/13)						
Efficient base year operating expenditure (excluding network maintenance)	43.5	43.5	43.5	43.5	43.5	**217.6**
Step changes	8.5	7.2	4.9	6.8	6.7	**34.2**
Operating expenditure (excluding network maintenance)	52.0	50.7	48.5	50.3	50.2	**251.8**
Cost escalation	0.6	0.9	1.3	1.7	2.1	**6.4**
Escalated operating expenditure (excluding network maintenance)	**52.6**	**51.6**	**49.7**	**52.0**	**52.3**	**258.2**
$ million (2013/14)						
Annual efficient standard control core network operating expenditure (excluding maintenance)	54.3	53.3	51.3	53.7	54.0	**266.6**
Network maintenance	22.4	21.6	21.7	21.8	23.1	**110.7**
Includes:						
Output growth	0.0	0.1	0.1	0.1	0.1	**0.4**
Annual efficient standard control core network operating expenditure	**76.7**	**74.9**	**73.0**	**75.6**	**77.1**	**377.3**

8.8 *Forecast core network operating expenditure*

8.8.1 Overview

ActewAGL Distribution's forecast core network operating expenditure for the 2014–19 period is set out in Table 8.11. As explained in 8.6.3, ActewAGL Distribution has allocated future expenditure between distribution and transmission standard control services.

Table 8.11 Overview of forecast core network operating expenditure 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Network maintenance expenditure	22.4	21.6	21.7	21.8	23.1	110.7
Network operating expenditure	27.8	27.3	26.3	27.7	27.1	136.2
Other expenditure	26.5	26.0	25.0	26.0	26.9	130.4
Total core network operating expenditure	**76.7**	**74.9**	**73.0**	**75.6**	**77.1**	**377.3**
Allocated to distribution	***64.0***	***62.5***	***60.9***	***63.0***	***64.3***	***314.7***
Allocated to transmission	***12.7***	***12.4***	***12.1***	***12.5***	***12.8***	***62.6***

ActewAGL Distribution's core network operating expenditure is forecast to be $377.3 million (real 2013/14) for the 2014–19 regulatory period. This includes $3.8 million per annum of non-recurrent costs incurred in the 2012/13 base year or a total of $19 million during the period which have been included to ensure true costs are reflected for EBSS purposes as detailed in section 8.7.1. Core network standard control operating expenditure for the period is expected to average $75.5 million per year.

Detailed forecast for each of the core network operating expenditure activities are provided in sections 8.8.2 through 8.8.4. As required by clause S6.1.2(8) of the Rules, any significant variations in forecast operating expenditure in the 2014–19 regulatory period from historical operating expenditure is explained by the step changes detailed in section 8.7.3 and Attachment B10.

8.8.2 Network maintenance operating expenditure

ActewAGL Distribution's asset maintenance expenditure decisions are based on optimising life cycle costs to ensure a safe and reliable supply of electricity to customers and maintain a safe and healthy working environment for employees and contractors. The level of network maintenance expenditure is largely driven by the number of assets in service, the mix of these assets and their condition. Network maintenance includes maintenance carried out on zone substations, secondary systems, distribution and transmission assets and property. It includes planned and unplanned maintenance as well as condition monitoring, maintenance strategy and planning and vegetation management.

8.8.2.1 Historical network maintenance operating expenditure

An overview of standard control network maintenance expenditure in the 2009–14 regulatory period is set out in Table 8.12 below.

Table 8.12 Historical standard control network maintenance operating expenditure

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*F2013/14*	*Total*
Zone substation						
Planned	2.2	2.3	2.5	2.3	2.5	11.8
Reactive	0.2	0.1	0.2	0.1	0.3	0.9
Total zone substation	**2.4**	**2.4**	**2.7**	**2.4**	**2.8**	**12.8**
Transmission						
Planned	1.0	0.5	1.0	0.0	0.1	2.7
Reactive	0.0	0.0	0.0	0.0	0.0	0.1
Total transmission	**1.1**	**0.5**	**1.0**	**0.1**	**0.2**	**2.8**
Distribution						
Planned	10.4	11.5	12.4	15.0	10.5	59.8
Reactive	4.5	6.3	6.5	7.3	10.6	35.2
Total distribution	**14.9**	**17.9**	**18.9**	**22.3**	**21.1**	**95.1**
Total network maintenance expenditure	18.4	20.8	22.6	24.8	24.0	110.7

Total network maintenance expenditure has increased by an average of seven per cent per annum during the 2009–14 regulatory period in real terms. This has primarily been driven by wage price increases. Increased overhead distribution planned maintenance costs have also been driven by increased minor works arising from the pole inspection program as well as the need to increase vegetation management activities to ensure the safety and reliability of the network. This is explained in detail in section 8.5.3.5. An increase in asset failure as a result of inclement weather during the 2009–14 regulatory period as well as ageing assets and has also driven an increase in reactive maintenance on underground and overhead distribution assets.

8.8.2.2 Forecast network maintenance operating expenditure

An overview of standard control network maintenance operating expenditure in the 2014–19 regulatory period is set out in Table 8.13 below.

Table 8.13 Forecast standard control network maintenance operating expenditure

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Zone substation	3.3	3.2	3.3	3.4	3.4	**16.6**
Transmission	0.3	0.3	0.3	0.3	0.3	**1.3**
Distribution	3.7	3.6	3.7	3.8	3.9	**18.8**
Secondary systems	1.3	1.3	1.4	1.4	1.4	**6.8**
Property services	0.3	0.3	0.3	0.3	0.3	**1.3**
Vegetation management	3.9	3.9	3.9	3.9	3.9	**19.4**
Total network maintenance expenditure	**22.4**	**21.6**	**21.7**	**21.8**	**23.1**	**110.7**
Allocated to distribution	***18.7***	***18.0***	***17.9***	***18.0***	***19.3***	***91.9***
Allocated to transmission	***3.7***	***3.6***	***3.7***	***3.8***	***3.9***	***18.8***

As explained in section 8.6.1, ActewAGL Distribution has used a zero based approach utilising Riva asset management software to develop asset maintenance plans that optimise the safety and reliability of the network whilst optimising life cycle costs. Forecast expenditure is the result of the inputs and parameters of each asset combined with algorithms that prioritise the maintenance schedule. This process is discussed in more detail in Section 4. Being fully zero-based, maintenance costs can be difficult to predict. In instances when maintenance costs are difficult to forecast additional system algorithms help smooth and remove any volatility by bringing forward and pushing back maintenance needs as appropriate with the objective being to minimise the cost over time.

Vegetation costs are also forecast using a zero based approach, however these costs are largely recurrent in nature, with adjustments being made for changes in contractual arrangements. Responsibility for vegetation clearance rests with either the property occupant, ActewAGL Distribution or the ACT Government depending on the location and attributes of the vegetation. ActewAGL Distribution incurs the costs of clearing vegetation from network assets where there is pre-existing vegetation, in natural areas and when urgent clearing is required.

Network maintenance expenditure forecasting including vegetation management is explained in further detail in ActewAGL Distribution's expenditure forecasting methodology provided at Attachment B10.

Standard control network maintenance expenditure in the next regulatory period is forecast to be in line with that of the 2009–14 regulatory period. Expenditure is expected to remain relatively constant across all categories of network maintenance costs over the regulatory period, averaging $22.1 million annually, or $110.7 million in total for standard control asset maintenance for the period.

Clause S6.1.2(4) of the Rules requires ActewAGL Distribution to provide "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." ActewAGL Distribution's expenditure proposal does not include any programs designed to improve the performance of its distribution system. In accordance with clause 6.5.6 of the Rules, the expenditure proposal has been designed to comply with applicable regulatory obligations or requirements.

8.8.3 Network operating expenditure

Network operating expenditure consists of those costs associated with network management, network systems operation and control, network support systems and planning and control.

8.8.3.1 Historical network operating expenditure

An overview of standard control network operating expenditure in the 2009–14 regulatory period is set out in Table 8.14 below.

Table 8.14 Historical standard control network operating expenditure

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*F2013/14*	*Total*
Network control	5.0	5.2	4.6	6.2	5.8	**26.8**
IT planning and operations	2.9	2.5	2.0	3.4	6.1	**16.9**
Network systems operations	3.7	3.9	3.8	3.6	4.0	**19.0**
Quality, environmental and safety systems	2.0	2.4	1.6	1.7	1.7	**9.4**
Executive & financial management	2.4	4.0	2.4	1.3	1.1	**11.3**
Other network operating costs	4.1	5.8	7.4	7.5	8.8	**33.6**
Total network operating expenditure	**20.2**	**23.8**	**21.8**	**23.6**	**27.6**	**117.0**

Total network operating expenditure has increased by an average of nine per cent per annum during the 2009–14 regulatory period in real terms. This has been driven by a number of the factors outlined in section 8.5.3. In addition to wage price increases which have driven increases across all categories of expenditure, key drivers of increasing costs specific to network operating expenditure during the 2009–14 regulatory period are outlined below.

8.8.3.2 Operating expenditure associated with delivery of the OSRP

Increased IT planning and operation costs in the last two years of the 2009–14 regulatory period have been driven by the planning and delivery of the OSRP.

8.8.3.3 Increased focus on safety

As outlined in section 8.5.3.4 and chapter 5, ActewAGL Distribution has increased its focus on environment, health and safety issues over the 2009–14 regulatory period including the establishment of the EHSQ Division. Increased expenditure was also necessitated by changes in the WHS legislation in 2011.

8.8.3.4 Increased regulatory obligations

ActewAGL Distribution has had to increase operating costs to meet its increasing regulatory obligations as detailed in chapter 4. Notably, the NECF commenced in the ACT on 1 July 2012, introducing a new set of national laws, rules and regulations governing the sale and distribution of energy to consumers. This framework introduced a number of ongoing reporting and audit requirements, and a commitment to oversee process improvement. The NPEF commenced on 1 January 2013. This was initiated by the Ministerial Council of Energy in 2011, and includes new demand side obligations on DNSPs within the Rules. Obligations include requirements by DNSPs to undertake annual planning reviews, publish annual planning reports, undertake demand side engagement, joint planning with TNSPs, and a new regulatory investment test for distribution.

The costs associated with participation in extensive other regulatory reviews during the period including Rule changes, the AER's Better Regulation program, and the increased demands of the AER in the preparation of the transitional regulatory proposal as part of the transitional arrangements and this regulatory proposal have also increased during the period. These costs are included in 'other network operating costs'. Further details on these regulatory obligations are provided in chapter 4 (see Table 4.2).

8.8.3.5 Forecast network operating expenditure

An overview of standard control network operating expenditure in the 2014–19 regulatory period is set out in Table 8.15 below.

Table 8.15 Forecast standard control network operating expenditure

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
System Control	3.4	3.5	3.5	3.6	3.7	17.7
Fault Call Centre	2.7	2.8	2.8	2.9	2.9	14.1
Network OT support	4.6	5.2	4.2	4.2	3.4	21.7
Customer Support	3.3	3.4	3.4	3.5	3.5	17.2
Quality, environmental & safety systems	3.1	3.1	2.9	3.0	2.8	14.9
Executive & financial management	1.3	1.3	1.4	1.4	1.4	6.8
Other network operating expenses	9.2	8.0	8.0	9.2	9.3	43.7
Total network operating expenditure	**27.8**	**27.3**	**26.3**	**27.7**	**27.1**	**136.2**
Allocated to distribution	***23.2***	***22.8***	***21.9***	***23.1***	***22.6***	***113.6***
Allocated to transmission	***4.6***	***4.5***	***4.4***	***4.6***	***4.5***	***22.6***

In adopting a base year forecasting approach, ActewAGL Distribution's network operating costs are forecast to be in line with base year expenditure in 2012/13 across the 2014–19 regulatory period, with the exception of step changes forecast within the Environment, Health, Safety and Quality systems, Network OT Support, and other network operating expenses categories. In these categories expenditure is forecast to be higher due to additional resources required to ensure ActewAGL Distribution is able to meet a growing list of regulatory requirements and to further strengthen its safety culture.

In particular, changes to the Work Health and Safety Legislation in 2011 will continue to impact costs in the 2014–19 regulatory period. Detailed information of ActewAGL Distribution's safety obligations is provided in chapter 5. To ensure compliance with important safety requirements, ActewAGL Distribution will continue to require additional resourcing in the next regulatory period. These increased costs are explained in detail in section 8.7.3 and Attachment B10 which addresses ActewAGL Distribution's operating expenditure step changes.

Network OT Support operating expenditure is forecast to increase across the period due to the need for greater operational support as a result of this strategic change to ensure network systems are effectively operated, supported and maintained. This step change is explained in detail in section 8.7.3 and Attachment B10.

There has also been a significant increase in the level of regulatory compliance and reporting during the 2009–14 regulatory period and the increased complexity of the regulatory environment in which ActewAGL Distribution operates will continue to drive other network operating expenses above the base year in the 2014–19 regulatory period. These increased costs are explained in detail in section 8.7.3 and Attachment B10.

8.8.4 Other expenditure

Other expenditure comprise costs such as the apprentice training program, business overheads, and a share of corporate service charges that are allocated to the electricity network business via ActewAGL Distribution's approved cost allocation methodology.

8.8.4.1 Historical other expenditure

An overview of ActewAGL Distribution's actual other expenditure in the 2009–14 regulatory period is set out in Table 8.16 below.

Table 8.16 Historical standard control other operating expenditure

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*F2013/14*	*Total*
Advertising & marketing	1.4	1.4	1.5	1.4	1.4	**7.0**
Corporate service charges	11.1	12.1	11.8	9.4	10.6	**55.0**
Franchise billing and revenue operations	1.6	1.7	1.8	1.8	1.8	**8.6**
Apprenticeship & engineers training	6.3	5.5	5.9	5.7	5.7	**29.1**
Business overhead	1.6	3.9	6.3	9.7	16.4	**37.9**
Overhead recoveries	1.3	1.4	1.6	1.5	1.5	**7.2**
External business	0.2	0.0	0.5	0.5	0.2	**1.4**
Total other expenditure	**23.4**	**25.9**	**29.4**	**29.9**	**37.6**	**146.2**

Increasing other expenditure over the 2009–14 regulatory period has been driven by a number of the factors outlined in section 8.5.3. Significant increases in business overheads across the period have been driven by large increases in the Energy Industry Levy, expenditure relating to restructuring of the networks division, and the Comcare exit payment in 2012/13. From 2011/12, approximately $1 million per annum was also moved from corporate services charges to business overheads for maintenance and rates expenses of ActewAGL Distribution's Greenway site.

8.8.4.2 Forecast other expenditure

ActewAGL Distribution's forecast of other expenditure over the 2014–19 regulatory period for standard control services is provided in Table 8.17.

In adopting a base year forecasting approach, ActewAGL Distribution's other expenditures are forecast to be in line with base year expenditure in 2012/13 (once adjusted for non-recurrent base year costs as detailed in section 8.7.1) across the 2014–19 regulatory period, with the exception of two forecast step changes.

ActewAGL Distribution forecasts a positive step change in corporate services costs and a further step change for increased operating expenditure resulting from lower corporate services charges to be capitalised. These increased costs are explained in detail in section 8.7.3 and Attachment B10 which addresses ActewAGL Distribution's operating expenditure step changes.

In the transitional regulatory proposal, ActewAGL Distribution indicated an anticipated reduction in other expenditure due to an intention to reduce its intake of new apprentices based on a recent review of ActewAGL Distribution's program of work, employee turnover and proposed future work requirements. ActewAGL Distribution proposes to retain base year apprenticeship program expenditure in its forecast for the 2014–19 regulatory period, however may target reductions in the program during this period in response to the incentives provided by the EBSS under the incentive-based approach to regulation employed by the AER.

Table 8.17 Forecast standard control other operating expenditure

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Advertising & marketing	1.4	1.4	1.4	1.4	1.4	**7.1**
Franchise billing and revenue operations	1.8	1.8	1.8	1.8	1.8	**8.8**
Apprenticeships & engineer training	5.3	5.3	5.4	5.5	5.6	**27.1**
Business overhead	2.2	2.2	2.2	2.2	2.2	**10.8**
Overhead recoveries	5.2	5.2	5.2	5.2	5.2	**26.2**
Corporate service charges						
Total corporate service charges	24.3	24.6	24.9	25.3	25.6	**124.7**
Capitalisation of corporate services charge	-13.6	-14.5	-15.9	-15.4	-14.9	**-74.2**
Net corporate service charges opex	10.7	10.1	9.1	9.9	10.7	**50.5**
Total	**26.5**	**26.0**	**25.0**	**26.0**	**26.9**	**130.4**
Allocated to distribution	***22.1***	***21.7***	***20.9***	***21.7***	***22.4***	***108.8***
Allocated to transmission	***4.4***	***4.3***	***4.2***	***4.3***	***4.5***	***21.7***

8.9 Unique cost drivers for ActewAGL Distribution

Chapter 2 provides an overview of the key features of ActewAGL Distribution's network, demand and operating environment. ActewAGL's unique cost drivers makes it necessary to normalise any measures for comparison with other network services providers. Examples including backyard reticulation, economies of scale and the proportion of hardwood poles are discussed below.

8.9.1 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 the norm 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.

This unique cost driver was recognised by Wilson Cook and Company who highlighted backyard reticulation as a matter for the AER's consideration noting that "An unsatisfactory feature of ActewAGL's network is the presences of a considerable amount of 'back yard' overhead reticulation that requires pole replacements and is difficult to access."[85]

8.9.2 Economies of scale

In the National Electricity Market ActewAGL Distribution is the smallest distributor by customer numbers, maximum demand and second smallest in terms of kilometres of line.[86] Although it is difficult to estimate, economies of scale have an impact on costs for support infrastructure such as computer systems, asset databases, maintenance management systems, outage management and system control and corporate and business overheads. ActewAGL Distribution seeks to overcome these cost disadvantages in corporate and support services through the ActewAGL multi-utility structure.

8.9.3 Proportion of natural hardwood poles in service

ActewAGL Distribution has a much larger proportion of natural (untreated) hardwood poles in service than is typical in the electricity supply industry. The pole replacement program, as discussed in detail in chapter 7, is the largest single component of ActewAGL Distribution's forecast capital expenditure.

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

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[85] Wilson Cook and Co 2008, *The Australian Energy Regulator Review of Proposed Expenditure of ACT & NSW Electricity DNSPs*, Volume 5 – ActewAGL Distribution, Final, October, p 43

[86] AER 2013, *State of the Energy Market 2013,* p 63

8.10 Summary of total operating expenditure

Table 8.18 below shows ActewAGL Distribution's total operating expenditure forecast for the 2014–19 regulatory period, including core network operating expenditure, demand management incentive scheme costs, and debt raising costs. Demand management incentive scheme costs are explained in 16.5 and debt raising costs are explained in section 10.10.2 of this proposal.

Table 8.18 Forecast total operating expenditure 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Network maintenance costs	22.4	21.6	21.7	21.8	23.1	110.7
Network operating costs	27.8	27.3	26.3	27.7	27.1	136.2
Other expenditures	26.5	26.0	25.0	26.0	26.9	130.4
Total core network operating expenditure	**76.7**	**74.9**	**73.0**	**75.6**	**77.1**	**377.3**
Demand management incentive scheme	0.1	0.1	0.1	0.1	0.1	0.6
Debt raising costs	1.2	1.2	1.2	1.3	1.3	6.2
Total operating expenditure	**78.0**	**76.2**	**74.3**	**76.9**	**78.5**	**384.0**
Allocated to distribution	***65.1***	***63.5***	***61.9***	***64.0***	***65.4***	***319.8***
Allocated to transmission	***12.9***	***12.7***	***12.5***	***13.0***	***13.1***	***64.2***

9 Regulatory asset base

The RAB is an indexed historical measure of the value of the regulated assets. It is used to allow a regulated business to recover the cost of capital for investments undertaken and to estimate regulatory depreciation, recognising the need to recoup the business' capital cost over the useful life of the asset base. To calculate a RAB as at 1 July 2014, ActewAGL Distribution has used the Roll Forward Model (RFM) developed by the AER. This chapter sets out how ActewAGL Distribution has rolled forward the RAB in the 2009–14 regulatory period to establish the RAB for the next regulatory period and the roll forward of the RAB.

ActewAGL Distribution has rolled forward the RABs for distribution and transmission services consistent with the AER's PTRM and depreciated the RAB going forward based on real depreciation. This will result in a more accurate estimate of the remaining lives. The split between distribution and transmission services is undertaken in a consistent manner with ActewAGL Distribution's Cost Allocation approved by the AER. The capital expenditure added to the RAB is prudent and efficient.

9.1 AER Constituent Decisions

In accordance with clause 6.12.1(6) of the NER, a determination is predicated on the AER making a decision on ActewAGL Distribution's RAB as at 1 July 2014. Allocation between distribution and transmission control services RAB.

The AER in its Framework and Approach Stage 1 stated that it would apply transmission pricing rules to ActewAGL Distribution's dual function assets in the subsequent period. Dual function assets are the parts of a distributor's network that operate in a way that supports the transportation of electricity over the higher voltage transmission network. Specifically, the Rules deem as a dual function asset:[87]

> *Any part of a network owned, operated or controlled by a Distribution Network Service Provider which operates between 66 kV and 220 kV and which operates in parallel, and provides support, to the higher voltage transmission network.*

In making its decision on ActewAGL Distribution's revenue requirement for the 2014–19 period, the AER will determine separate average revenue caps to apply (with different X factors) for the transmission and distribution portions of revenue for standard control services.

[87] *National Electricity Rules*, clause 6.24.2(a)

Consequently, and in line with a recommendation of AER staff,[88] ActewAGL Distribution has estimated the opening RAB value for the relevant dual function assets by separating them from other assets from the beginning of the 2009–14 regulatory period.

At 30 June 2009, immediately before the commencement of the 2009–14 regulatory period, ActewAGL Distribution's RAB comprised a single asset class. In order to split the RAB between distribution and transmission assets, ActewAGL Distribution used an extract of its asset register at 30 June 2009 to allocate this single regulatory asset class to the two services. Assets not directly attributable to either service were allocated in the proportions of assets directly allocated to each service. Using this method, ActewAGL Distribution derived a distribution and a transmission RAB. These values were used as basis for input to the AER's RFM. Attachment B9 includes the derivation of the transmission and distribution RABs as at 30 June 2009.

Similarly, for the period 2009-19 (the current, transitional and subsequent regulatory periods) actual and forecast capex has been directly allocated between distribution and transmission standard control services where possible, or allocated proportionally for costs not directly attributable to either service using the share of directly allocated assets in the RAB as the allocation factor.

This allocation is consistent with ActewAGL Distribution's cost allocation methodology approved by the AER in 2013.

With the addition of the second point of supply to the ACT, transmission assets have been substantially augmented in the 2009–14 regulatory period. As a result, the indirect allocation of expenditure to transmission services has increased from 12.60 per cent in the current period to 18.13 per cent in the 2014–19 period.

9.2 Opening regulatory asset base on 1 July 2014

The total RAB on 1 July 2009 was $574.4 million, as determined by the AER. As discussed in section 9.1, ActewAGL Distribution has split this between distribution and transmission services. The opening RAB values for 1 July 2014 have been calculated by rolling forward respective opening RAB value as at 1 July 2009 using the AER's RFM for DNSPs.

Depreciation has been calculated according to the approach determined by the AER in the previous regulatory control period. ActewAGL Distribution has used actual capital expenditure in accordance with the current determination, which provides as follows:

> *In accordance with clause 6.12.1(18) of the transitional chapter 6 rules [set out in Appendix 1 to the Rules and applying in the current period pursuant to Division 2, Part M of Chapter 11]*

[88] Teleconference with AER officers on 30 October 2013

> *the AER will use actual depreciation for establishing the regulatory asset base for the commencement of the 2014–19 regulatory control period.*[89]

In rolling 2009–14 regulatory period capital expenditure into the RAB, ActewAGL Distribution has used actual capital expenditure for 2009/10 to 2012/13 and a forecast for 2013/14. The opening remaining life for 2008/09 of 20.48 years is consistent with the 2009 final decision RFM.[90] The applied standard and remaining lives for 2009/10 to 2013/14 are consistent with the AER's 2009 final decision (consistent with Rule 6.5.5(b)(3)). Before determining opening RABs on 1 July 2014, ActewAGL Distribution has made an adjustment for the actual capital expenditure in 2008/09, including a return on the difference for the period, consistent with the AER's RFM. The net capital expenditure has been adjusted for the disposal of ActewAGL Distribution's corporate headquarters in 2008/09, that has been allocated to Standard Control Services in accordance with the then cost allocation of corporate assets of 54.75 per cent.[91] Having done this, ActewAGL Distribution calculates opening RABs on 1 July 2014. The roll forward of the Distribution and Transmission RABs is shown in Table 9.1 and Table 9.2 and in Attachments B1 and B4.

Table 9.1 Roll Forward of the distribution RAB 2009–2014

$ million (nominal)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*
Opening RAB	523.3	559.6	603.8	641.1	662.4
***plus* net capital expenditure**	53.5	57.5	49.2	45.0	66.6
***less* regulatory depreciation**	17.1	13.4	11.8	23.8	22.3
Closing RAB	559.6	603.8	641.1	662.4	706.7
Adjustment to opening value					-10.6
Opening RAB 1 July 2014					**696.1**

[89] AER 2009, *AER Final determination—ActewAGL (ACT) determination 2009-10 to 2013-14*, April, p 25

[90] The value is sourced from the AER's 2009 final decision Roll forward Model, ActewAGL RFM, cell H125, consistent with how the AER's PTRM in the 2009 final decision sourced the remaining life value from cell I125 in the same model.

[91] The allocation percentage of 54.75 per cent is consistently used in accordance with the AER's 2009 final decision Roll forward Model, ActewAGL RFM, cell I99.

Table 9.2 Roll Forward of the transmission RAB 2009–2014

$ million (nominal)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*
Opening RAB	75.4	86.0	99.2	117.4	136.3
***plus* net capital expenditure**	13.1	15.1	19.9	22.7	20.8
***less* regulatory depreciation**	2.5	1.9	1.7	3.7	3.4
Closing RAB	86.0	99.2	117.4	136.3	153.8
Adjustment to opening value					0.4
Opening RAB 1 July 2014					**154.2**

9.3 Roll forward of the RAB to 2019

The opening RAB values for the next regulatory period for distribution and transmission services respectively are derived in Table 9.1 and Table 9.2.

ActewAGL Distribution has rolled forward the RAB for each year of the next regulatory period using the following methodology and assumptions:

- adding forecast efficient prudent capital expenditure (exclusive of contributed assets), derived in chapter 7 of the submission;
- deducting depreciation calculated as per the AER's PTRM and consistent with the 2009 final decision; and
- indexing the annual closing RAB with forecast inflation as set out in section 10.9.

ActewAGL Distribution does not forecast any disposals. The roll forward of the respective RAB is shown in Table 9.3 and Table 9.4.

9.3.1 Asset lives

ActewAGL Distribution has reviewed the standard lives and remaining lives for the next regulatory period which underpin the calculation of depreciation. ActewAGL Distribution considers that the standard lives applied to the 2009–14 regulatory period are reasonable and consistent with the service and accounting lives and consistent with rule 6.5.5(b)(1).

In relation to remaining lives, ActewAGL Distribution has adopted an approach that uses real depreciation.

ActewAGL Distribution has calculated the proposed remaining lives by dividing the real asset base (unadjusted for inflation) by real depreciation, with an adjustment for capital expenditure in the 2013/14 financial year. This approach is used to maintain the straight line depreciation in real terms from one period to the next, when the capital expenditure of the 2009–14 period is incorporated into the opening RAB of the 2014–19 period. ActewAGL Distribution considers that this is consistent with Rule 6.5.5(b)(2).

ActewAGL Distribution notes that the AER accepted the use of real depreciation for calculating the remaining lives of assets in ActewAGL Distribution's gas network access arrangement submission.

9.3.2 Depreciation

For the next regulatory control period, ActewAGL Distribution proposes to roll forward the RAB using the depreciation as calculated by the AER's RFM and the standard and remaining lives as set out in section 9.3.1. This is consistent with Rule 6.5.5.

According to rule 6.12.1(18) a distribution determination is predicated on the AER making:

> *a decision on whether depreciation for establishing the regulatory asset base as at the commencement of the following regulatory control period is to be based on actual or forecast capital expenditure.*

For establishing the opening RAB for the next regulatory period after the one to which this submission relates (which for ActewAGL Distribution commences on 1 July 2019) ActewAGL Distribution proposes to adopt a depreciation schedule that has been calculated using *forecast* capital expenditure for rolling forward the RAB from 1 July 2014 to 30 June 2019. ActewAGL Distribution notes that this is consistent with the AER's intention that ,if a CESS is to apply, "forecast depreciation will be the default approach for rolling forward the RAB. "[92]

9.3.3 Forecast RAB 2014-2019

ActewAGL Distribution has rolled forward the RAB into the next regulatory period based on the capital expenditure program described in chapter 7 using the AER's PTRM as demonstrated in Table 9.3 and Table 9.4.

Table 9.3 Roll Forward of the distribution RAB 2014–2019

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Opening RAB	696.1	737.6	765.1	792.7	818.9
plus net capital expenditure	68.5	58.1	58.8	58.8	64.0
less regulatory depreciation	27.0	30.6	31.2	32.6	32.7
Closing RAB	737.6	765.1	792.7	818.9	850.2

[92] AER 2013, Better Regulation, Explanatory Statement, Capital Expenditure Incentive Guideline, November, p 63

Table 9.4 Roll Forward of the transmission RAB 2014–2019

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Opening RAB	154.2	161.7	174.8	206.1	226.6
plus net capital expenditure	11.8	18.1	36.5	26.0	13.4
less regulatory depreciation	4.2	5.0	5.2	5.6	5.8
Closing RAB	161.7	174.8	206.1	226.6	234.1

10 Rate of return, inflation and debt and equity raising costs

This chapter sets out ActewAGL Distribution's proposed rate of return, gamma, forecast inflation as well as debt and equity raising costs to apply to the 2014-19 regulatory period. ActewAGL Distribution's proposed rate or return is summarised in Table 10.1 below.

Table 10.1 ActewAGL Distribution proposed rate of return for 2014-19

Component	*Value*
Return on equity	10.71%
Return on debt	7.85%
Gearing	60%
Gamma	0.25
Nominal vanilla WACC	**8.99%**
Inflation	2.525%

ActewAGL Distribution considers that this proposed rate of return is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the ActewAGL Distribution in respect of the provision of standard and alternative control services, and provides ActewAGL Distribution with:

- a reasonable opportunity to recover the efficient costs it will incur in providing direct control network services; and
- a return commensurate with the regulatory and commercial risks involved in providing its direct control network services.

In addition, ActewAGL Distribution proposes equity and debt raising costs associated with each of its distribution, transmission, and alternative control capital programs.

In primary support of its position, ActewAGL Distribution engaged SFG Consulting (SFG), Competition Economists Group (CEG), and Incenta Economic Consulting (Incenta) to provide the advice as set out in Table 10.2.

Table 10.2 Advice received from expert consultants

Title	Author	Attachment
The required return on equity for regulated gas and electricity network businesses	SFG	E3
Cost of equity in the Black Capital Asset Pricing Model	SFG	E4
The Fama-French model	SFG	E5
Alternative versions of the dividend discount model and the implied cost of equity	SFG	E6
Equity beta	SFG, CEG, ENA	E7, E8, E9
Factors relevant to estimating a trailing average cost of debt	CEG	E12
Debt transition consistent with the NER and NEL	CEG	E11
Debt raising transaction costs	Incenta	E10
An appropriate regulatory estimate of gamma	SFG	E1

10.1 Customer benefits

ActewAGL Distribution considers its proposed rate of return to be in the long term interest of customers as it will facilitate ActewAGL Distribution's access to the capital market in competition with other industries and businesses for funds necessary to undertake investments in the network in the next regulatory period and going forward. If the rate of return ActewAGL Distribution receives is less than that proposed, being that which it considers is required by the benchmark efficient entity with a similar degree of risk to ActewAGL Distribution in respect of the provision of standard control services, then ActewAGL Distribution will need to make decisions about the efficient expenditure it is unable to afford to undertake. This is likely to lead to ActewAGL Distribution not undertaking or deferring some of the efficient, planned network investment. Underinvestment would, in the long term, result in a less reliable network, higher maintenance costs, and ultimately higher prices to customers.

10.2 AER Constituent Decisions

Clause 6.12.1 requires the AER to make a decision on:

(5) the *allowed rate of return* for each *regulatory year* of the *regulatory control period* in accordance with clause 6.5.2;

(5A) whether the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) and, if that is the case, the formula that is to be applied in accordance with clause 6.5.2(l); and

(5B) a decision on the value of imputation credits as referred to in clause 6.5.3.

10.3 Requirements of the NEL and the Rules

Clause 6.5.2(b) of NER states that the *allowed rate of return* is to be determined such that it achieves the *allowed rate of return objective*.

Clause 6.5.2(c) provides that the *allowed rate of return objective* is that the rate of return for a *Distribution Network Service Provider* is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the *Distribution Network Service Provider* in respect of the provision of *standard control services*.

Clause 6.5.2(d) provides that subject to clause 6.5.2(b), the *allowed rate of return* for a *regulatory year* must be:

(1) a weighted average of the return on equity for the regulatory control period in which that regulatory year occurs (as estimated under clause 6.5.2(f) and the return on debt for that regulatory year (as estimated under clause 6.5.2(h); and

(2) determined on a nominal vanilla basis that is consistent with the estimate of the value of imputation credits referred to in clause 6.5.3.

Clause 6.5.2(e) of the Rules requires the following:

In determining the allowed rate of return, regard must be had to:

(1) relevant estimation methods, financial models, market data and other evidence;

(2) the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and

(3) any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.[93]

ActewAGL Distribution must include, in its building block proposal, its calculation of its proposed return on equity, return on debt and allowed rate of return for each regulatory year of the regulatory control period (clause S6.1.3(9)).

A Rate of Return Guideline was published by the AER on 17 December 2013 (clause 6.5.2 (m)). Clause 6.5.2 (n) requires the Rate of Return Guideline to set out:

(1) the methodologies that the AER proposes to use in estimating the allowed rate of return, including how those methodologies are proposed to result in the determination of a return on equity and a return on debt in a way that is consistent with the allowed rate of return objective; and

[93] *National Electricity Rules*, clause 6.5.2(e)(1)-(3)

> (2) *the estimation methods, financial models, market data and other evidence the AER proposes to take into account in estimating the return on equity, the return on debt and the value of imputation credits referred to in clause 6.5.3.*

The Rate of Return Guideline is binding on neither the AER nor ActewAGL Distribution. However, ActewAGL Distribution must identify any departure in its calculation of its proposed return on equity, return on debt and allowed rate of return from the methodologies set out in the Rate of Return Guideline, together with reasons for that departure (clause S6.1.3(9)). Clause 6.2.8 (c) requires the AER, if it makes a distribution determination that is not in accordance with the Rate of Return Guideline, to state, in its reasons for the distribution determination, the reasons for departing from the guideline.

Section 16(2)(a)(i) of the NEL requires that the AER, when exercising a discretion in making those parts of a distribution determination relating to direct control services, must take into account the revenue and pricing principles, including that:

- a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services (s 7A(2) of the NEL);
- a regulated network service provider should be provided with effective incentives in order to promote economic efficiency (being efficient investment in a distribution system with which the operator provides direct control network services) with respect to direct control services the operator provides(s 7A(3)(a) of the NEL);
- a price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which the price or charge relates (s 7A(5) of the NEL);
- regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in a distribution system with which the operator provides direct control network services (s 7A(6) of the NEL).

10.4 Gearing and credit rating

Consistent with the AER's Rate of Return Guideline, ActewAGL Distribution proposes that a gearing ratio of 60 per cent is appropriate for use in the formula to calculate the vanilla WACC for the 2014-19 regulatory period. This is equal to the AER's proposed benchmark efficient entity gearing ratio.

The AER concludes, in its Rate of Return Guideline, that the median credit rating for regulated energy businesses is BBB+, in reliance on its historical analysis of the credit ratings of regulated energy networks operating within Australia over the periods 2002-2012 and 2002-2013.[94] While

[94] AER, Better Regulation | Explanatory Statement | Rate of Return guideline, December 2013, p156

the AER notes there have been some recent credit downgrades (such that the median credit rating for 2013 only is BBB), it maintains the view that credit ratings for regulated energy businesses have been relatively steady 'over a period of time' and therefore states, in its Rate of Return Guideline, that its historical credit rating analysis for the periods 2002-2012 and 2002-2013 produces a more reliable result. Accordingly, it proposes to utilise a BBB+ credit rating in estimating the return on debt.[95] In so doing, the AER advances no principled basis for its use of a historical period commencing in 2002 rather than some other year.

ActewAGL Distribution engaged CEG to assess the AER's credit rating analysis. CEG collected historical Standard & Poor's credit ratings for the AER's sample for the period from 2002 to 2013 inclusive and concluded that:[96]

- contrary to the AER's conclusion that there have been only some recent credit downgrades and that credit ratings for regulated energy businesses have been relatively steady over a period of time, there has been a sustained drop in median credit ratings for the AER sample from A– in 2002 to BBB in each year since 2009; and
- the median credit rating for the AER sample for the 10 year period 2004 to 2013 inclusive (being the period of the 10 year trailing average where the AER's trailing average portfolio approach to the estimation of the return on debt is applied to ActewAGL Distribution and ActewAGL Distribution's nominated averaging period for use in applying that approach) is BBB, not BBB+.

In addition, CEG has estimated a time series of the return on debt for each credit rating during this period, assuming a linear relationship between yields and credit ratings. CEG demonstrates that varying the benchmark credit rating prior to 2008 does not have a significant impact on estimate average yield. However, following 2009 (which is the period when the median credit ratings have been BBB) there is a significant difference in the yield between different credit ratings. CEG concludes that:

> *…adopting a single benchmark credit rating of BBB throughout the period will give a similar estimate to adopting a BBB+ benchmark prior to 2009 and a BBB benchmark from 2009 onwards.*[97]

Accordingly, CEG concludes that, if the AER is to adopt a single credit rating, it should be BBB and not BBB+. Based on CEG's analysis included in Attachment E12, ActewAGL Distribution proposes that a credit rating of BBB be adopted.

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[95] AER, Better Regulation | Explanatory Statement | Rate of Return guideline, December 2013, p156

[96] CEG 2014, Memorandum to ActewAGL Distribution - Factors relevant to estimating a trailing average cost of debt, May, p 1

[97] CEG 2014, Memorandum to ActewAGL Distribution - Factors relevant to estimating a trailing average cost of debt, May, p 3

10.5 Return on equity

10.5.1 The NER requirements

Clause 6.5.2 of the NER states that:

> *(f) The return on equity for a regulatory control period must be estimated such that it contributes to the achievement of the allowed rate of return objective.*
>
> *(g) In estimating the return on equity under paragraph (f), regard must be had to the prevailing conditions in the market for equity funds.*

There is a range of asset pricing models used to measure the return on equity that satisfy these NER requirements, each incorporating different assumptions about the behaviour of investors and measures of risk. The NER does not prescribe which model to use to determine the equity component of the rate of return.

The AER's Rate of Return Guideline sets out how the AER proposes to calculate the return on equity. However, as explained below in section 10.5.2, ActewAGL Distribution disagrees with the AER's approach and proposes, based on advice from SFG, that the AER place weight upon a broader range of evidence in estimating the return on equity.

10.5.2 The AER's Rate of Return Guideline

The AER proposes a six step process to calculate the return on equity. This process is set out in the following sections.

10.5.2.1 The AER's Foundation Model Approach

The first two steps involve identifying possible models and the use to which the AER will put them. The AER summarises its proposal as follows: [98]

Sharpe–Lintner CAPM:	Foundation model
Black CAPM	Inform foundation model parameter estimates (equity beta)
Dividend growth models	Inform foundation model parameter estimates (market risk premium)

The AER proposes that the Fama–French three factor model will have no role.

10.5.2.2 The AER's implementation of its foundation model

As the third step, the AER intends to use as the 'foundation model' a particular implementation of the Sharpe Lintner CAPM (SL-CAPM).

The standard SL–CAPM formula is:

[98] AER, Better Regulation, Rate of Return Guideline, p13

$$E[R_i] = E[R_{\beta=0}] + \beta_i \cdot (E[R_m] - E[R_{\beta=0}]),$$

where $E[R_i]$ is the expected return on the benchmark firm, $E[R_{\beta=0}]$ is the expected return on zero beta equity (the 'risk free' rate of return), β_i is the beta for the asset and $E[R_m]$ is the expected return on the market portfolio.

In contrast, the foundation model the AER proposes to adopt to estimate the return on equity involves:

- using the yield on government bonds as the proxy for the risk free rate ($E[R_{\beta=0}]$); and
- using regression estimates of beta as the basis for estimating β_i.

The AER refers to this particular *implementation* of the SL–CAPM as *the* SL–CAPM. ActewAGL Distribution does not agree that the foundation model the AER proposes to adopt can be so described. In particular, ActewAGL Distribution considers that alternative proxies for the risk free rate and estimation methods for the equity beta are equally consistent with the SL–CAPM (see below). For this reason, in the remainder of this regulatory proposal ActewAGL Distribution refers to the foundation model the AER proposes in its Rate of Return Guidelines as "the AER's SL–CAPM".

While a foundation model approach could be used to take into account the range of evidence available, including by making parameter adjustments informed by models other than the AER's SL–CAPM, the AER proposes to only make adjustments to two parameters:

- equity beta— informed by "Black CAPM"; and
- market risk premium—informed by a dividend growth model (DGM).

These two parameters, in the AER's approach, incorporate only very limited sources of other evidence. This is confirmed by SFG in its report on 'The required return on equity for regulated gas and electricity network businesses,' included at Attachment E3 to this proposal.

If the AER uses its foundation model approach, it should set the parameter values in applying the SL-CAPM to reflect all relevant evidence before it and allow alternative models to be used as cross checks on the overall rate of return on equity, as demonstrated in section 5 of Attachment E3. In particular, rather than being set with reference almost exclusively to regressions of Australian stock market data, the beta parameter should reflect the return on equity evidence from an industry level DGM and the Fama-French model, and properly weight the "Black CAPM" and international evidence on the rate of return required by distribution network businesses. In doing otherwise, the foundation model will rely on too narrow a use of material and, in current market circumstances, it will under estimate the return on equity. As an example of this, Table 15 in Attachment E3 shows that the AER's adjustment of the equity beta for the "Black CAPM" is insufficient.

For the expected market return ($E[R_m] - E[R_{\beta=0}]$ = MRP), the AER proposes to give greater weight to the excess of the historical average stockmarket return over the historical average of the risk free rate, with little weight given to the DGM. ActewAGL Distribution considers that a variety of sources of evidence should be used to estimate the expected market return , including the DGM applied to the market and the Wright approach. Section 3 in Attachment E3 discusses this in further detail.

In estimating the return on equity, models such as the DGM, "Black CAPM" and the Fama French model should be used to inform the overall return on equity. These models should be presented as complete models. The AER's proposed approach to return on equity results in the foundation model missing crucial information that these other models provide. The AER's return on equity estimate is therefore not informed by all relevant information in the market as an estimate of the efficient financing costs.

Further, the AER has not demonstrated why a key benefit of using the AER's SL–CAPM as the foundation model is that "it provides greater predictability of outcomes"[99]. This criterion does not appear in the NER, and in any event:

- ActewAGL Distribution considers that the AER's proposed application of the SL–CAPM does not provide greater predictability of outcomes. In particular, the weight given to a combination of historical average excess returns and prevailing government bond yields makes the AER's estimate of the return on equity highly sensitive to the level of government bond yields; and
- the Rate of Return Guideline's Explanatory Statement concedes that the AER's approach will lead to less stability in outcomes than other approaches, stating:

> *…our implementation of the Sharpe–Lintner CAPM will result in estimates of the return on equity that may vary over time. Alternatively, the DGM and the Wright approach (for implementing the Sharpe–Lintner CAPM) will result in estimates of the return on equity that may be relatively stable over time.*[100]

It is not clear how the AER reconciles this lack of *stability* in outcomes with alleged greater *predictability* of outcomes. Nor does the AER explain why adopting a hybrid of historical MRP and prevailing risk free rate is more consistent with "*theoretical and empirical evidence"* than estimating the return on equity with the DGM, where both the risk free rate and the MRP are based purely on prevailing market conditions.

Figure 10.1 shows that the AER's foundation model estimate of the return on equity is clearly below those of the other return on equity models. ActewAGL Distribution considers there are two main reasons for this:

[99] AER 2013, *Better Regulation: Rate of Return guideline, Explanatory Statement*, December, p 54

[100] AER 2013, *Better Regulation: Rate of Return guideline, Explanatory Statement*, December, p 66

1. As shown in Attachment E7, the AER's adopted equity beta of 0.7 is too low and does not incorporate or have regard to relevant available estimation methods, financial models and market data. SFG considers the equity beta should be 0.91.[101]
2. By using an MRP estimate of 6.5 per cent, the AER relies on historical excess return over the 10 year government bond rates realised over the last century. However, the AER combines this with a prevailing estimate of the government bond rate. This is internally inconsistent. SFG considers the MRP should be 7.21 per cent.[102]

10.5.2.3 Distilling down the point estimate of the expected return on equity

Under step four, other information that may inform the final return on equity point estimate is considered such as to estimate ranges and/or directional information for material used to inform the overall return on equity. The fifth step requires the evaluation of the full set of material that the AER proposes to use to inform the estimation of the expected return on equity, including assessing the foundation model range and point estimate alongside the other information from step four. [103]

Notwithstanding that the AER intends to use the Wright approach to inform its overall assessment of the return on equity, it appears that it will in practice place no weight on the approach. A clear example of this is the AER's rate of return decision for ActewAGL Distribution's transitional year (2014/15) where the AER allowed a return on equity of 8.90 per cent, significantly below the Wright's approach estimate (using ActewAGL Distribution's proposed equity beta) of the return on equity of 10.25 per cent.

The AER's sixth and final step determines the final point estimate for the expected return on equity. As the AER proposes to use the foundation model point estimate as the starting point for estimating the expected return on equity, the final point estimate of the expected return on equity will require the exercise of regulatory judgement utilising the information obtained in step five.

ActewAGL Distribution engaged SFG to review and recommend how the final return on equity should be calculated. SFG's report is at Attachment E3. SFG recommends the approach summarised in section 10.5.4 which provides for a return of equity of 10.71 per cent.[104] ActewAGL Distribution considers that this approach better incorporates the full range of evidence on current market conditions than the AER's foundation model approach.

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[101] SFG 2014, "The required return on equity for regulated gas and electricity network businesses", May 2014, p11. See also SFG, "Equity Beta", May

[102] SFG 2014, "The required return on equity for regulated gas and electricity network businesses", May, p8, 11

[103] AER, Better Regulation, Rate of Return Guideline, p 16

[104] SFG 2014, "The required return on equity for regulated gas and electricity network businesses", May, p 10

Adoption of the SFG approach will also reflect a stable return on equity over time which ActewAGL Distribution considers is in the long term interest of both it and customers as well as meeting the allowed rate of return objective.

10.5.2.4 Summary

In summary, ActewAGL Distribution considers that the AER's proposed return on equity approach omits relevant information and constrains the use of information to the foundation model's parameters. This could result in some information being given disproportionate weight or prevent relevant information from being used. It is also likely to continue to generate a highly variable estimate of the return on equity due to heavy reliance on only a few sources of evidence which are not well adapted to changed market conditions. Some specific issues with the AER's proposed approach are:

- no role is provided for the Fama French model, despite substantial evidence that this model is used widely by market practitioners and that the HML factor in the Fama French model represents a priced risk that the AER's SL–CAPM does not capture (see Attachment E5) (see section 10.4.2.4 below);
- the DGM and "Black CAPM" are not used to inform the overall return on equity estimate notwithstanding that these models also capture risks that the AER's SL–CAPM is able to measure (see section 10.4.2.2 and 10.4.2.3 and Attachment E3); and
- the equity beta of 0.4 to 0.7 with a point estimate of 0.7 places too much weight on unreliable Australian regression data and omits relevant international evidence and evidence from other models, thus resulting in a return on equity estimate which does not reflect the full range of evidence available, as shown in Attachment E7.

The AER's return on equity point estimate is not informed by all relevant information in the market. In contrast, SFG's estimate is informed by various sources of relevant information and is calculated using models that have a sound theoretical basis, and which are robust and superior to utilising the AER's SL-CAPM alone.

SFG's approach to determining a return of equity point estimate addresses the deficiencies in the AER's approach and so represents the return on equity for the benchmark efficient firm better than the AER's approach, and, accordingly, better meets the NER requirements including the allowed rate of return objective.

Further the AER's approach to return on equity fails to take into account the relevant revenue and pricing principles. Using the AER's foundation model approach results in significant risk of underestimating the return on equity going forward, which would hinder, not contribute, to the achievement of the allowed rate of return objective and fails to provide ActewAGL Distribution with a reasonable opportunity to recover at least the efficient costs it will incur in providing direct control network services. Accordingly, the AER should instead adopt SFG's multi-model approach.

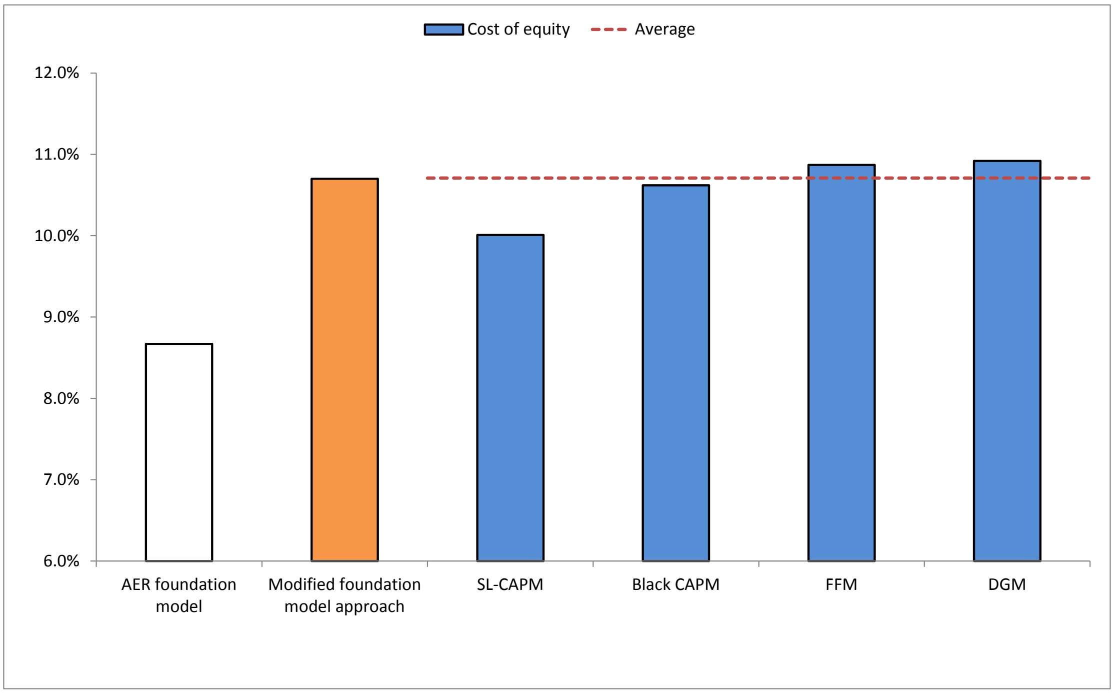
10.5.3 Return on equity models and evidence

ActewAGL Distribution, together with other NSPs, engaged SFG to review a portfolio of models and evidence, including those put forward by the AER during the consultation process of the Rate of Return Guideline. In Attachment E3, SFG considered the strengths and weaknesses of the various models and evidence in proposing a reasonable return on equity point estimate that meets the NER requirements. The four models listed below were found by SFG to have sound theoretical basis and precedent in being applied in regulatory rate of return decisions, and to be capable of implementation:

1. SL-CAPM
2. "Black CAPM"
3. The Fama-French model
4. DGM

Figure 10.1 shows return on equity estimates from each of these models, the AER's foundation model approach and a modified foundation model that incorporates all information from the four return on equity models above.

Figure 10.1 Estimate of the return on equity using different equity models



The values of the models are derived from the following material:

- SL–CAPM: Attachment E3;

- "Black CAPM": Attachment E4;
- Fama French model: Attachment E5; and
- DGM: Attachment E3.

Below, ActewAGL Distribution discusses each of these models and relevant evidence in more detail, including addressing the reasons advanced by the AER for the limited role accorded to the models other than the AER's SL–CAPM in its Rate of Return Guideline.

10.5.3.1 SL–CAPM

The formula for the SL–CAPM is shown in section 10.5.2. The AER's SL–CAPM is the only financial model that was used by the AER before the development of the Rate of Return Guideline. The AER used a version of the SL–CAPM that relied on Australian financial data. The AER's SL–CAPM has simple and intuitive theoretical basis and is widely used. However, the empirical support of the model is weak because:

- the modelled CAPM, implemented using Government bond rate as the proxy for the risk free rate and regression estimates of the equity beta as the proxy for $\beta_{e,}$ understates the return on low beta assets and overstates the return on high beta assets; and
- factors other than regression based estimates of the equity beta have been shown to improve estimates of returns.

The equity beta is a critical input parameter of the SL–CAPM that reflects the systematic risk of the benchmark firm in relation to the average firm (which has an equity beta of 1.0). In its Rate of Return Guideline, the AER proposed to use a value of 0.7 for the equity beta, based on a range of 0.4 to 0.7. SFG's report on the equity beta included in Attachment E7 establishes that:

- the evidence the AER has used to produce the equity beta range to 0.4 to 0.7 is not sufficiently reliable. SFG considers the range is neither a confidence interval, nor is it the maximum-to-minimum range, and concludes that it appears to be an arbitrarily selected band. The selection of this range is critically important because the final estimate of equity beta is constrained to come from within this range;
- the AER has used a very small set of domestic comparables (currently five) to establish this range, resulting in highly variable and unreliable equity beta estimates;
- the nine domestic equity beta estimates is distributed almost uniformly over a wide range while the distribution of equity beta estimates sourced from the significantly larger sample of 56 US firms shows a single, clear peak; and
- the best 'raw' statistical estimate of beta is 0.82, reflecting the evidence from regression analysis to be applied in the SL–CAPM under a multi model approach.

SFG's equity beta estimate of 0.82 is also supported by material submitted by the ENA during the AER's Rate of Return Guideline consultation process in response to the AER's equity beta issues paper. ActewAGL Distribution includes the details of the justification of this equity beta value in

Attachment E9 and CEG's critiques of the AER's reference material on international comparators in Attachment E8.

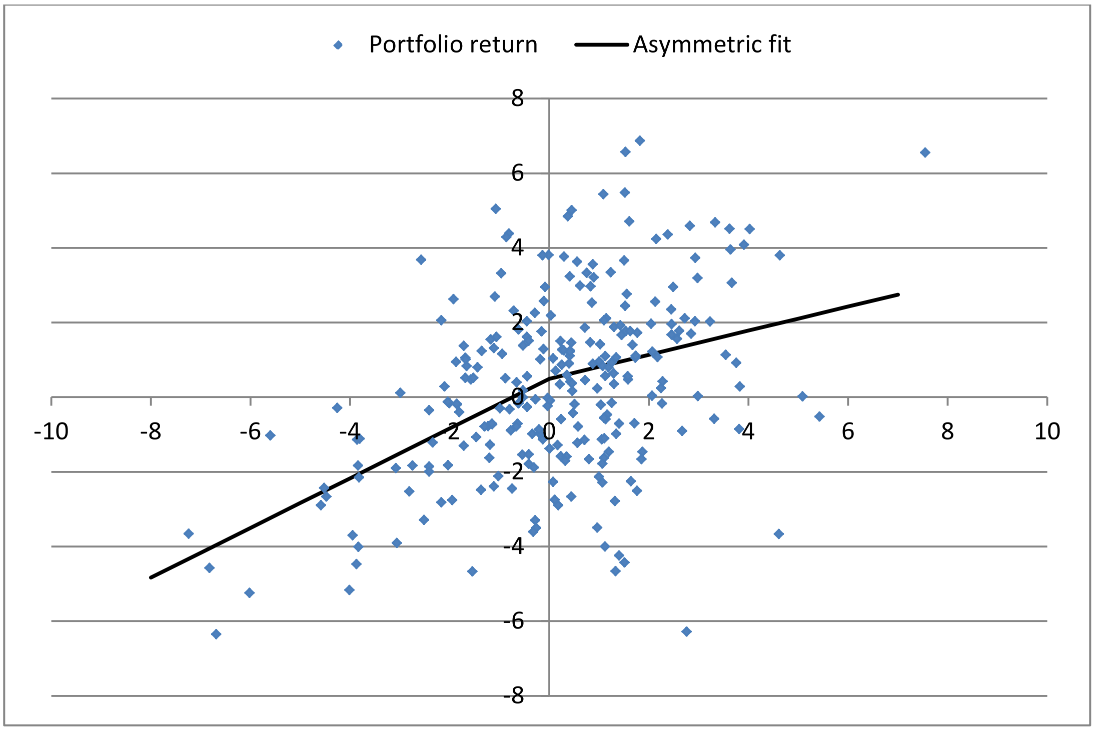
In the AER's foundation model approach, the only place for other relevant evidence to be taken into account is via the equity beta estimate. ActewAGL Distribution's proposal is that the AER should also take into account:

- evidence from raw statistical regression estimates of equity beta;
- evidence that the AER's implementation of the SL–CAPM will underestimate required returns for stocks with low raw statistical regression equity betas;
- evidence that the AER's SL–CAPM systematically understates the required return on high book-to-market stocks; and
- estimates that best reflect the evidence from the DGM.

If the AER adopted this approach to the application of the SL–CAPM as foundation model, the AER's equity beta estimate would be 0.91 as shown in chapter 5 of SFG's paper at Attachment E3.

In addition, ActewAGL Distribution notes, as shown in Figure 10.2 below, that the Australian sample of currently five firms that the AER has relied upon in its estimate of the equity beta appears to face asymmetrical market risk. The observations indicate that businesses may face more exposure to market conditions during 'bad' times, when investors do not want market exposure, than during 'good' times, when investors seek higher exposure to the rising market. Knowing this asymmetric risk, investors will demand a higher return on equity in order to compensate for the risk of down-market exposure that does not carry a corresponding upside. As a result, the return on equity implied by the single, symmetric equity beta model used by the AER, and its regression based beta estimate of 0.4 to 0.7, will typically undercompensate investors for the true risks which they bear and the required rate of return.

Figure 10.2 Demonstration of asymmetric market risk



Note: This figure has been constructed using a return series for an equal weighted portfolio of the five currently listed energy stocks in Australia, with returns calculated weekly over the 24 April 2009 to 18 April 2014 period. The ordinary least squares (OLS) regression of these returns is against the ASX300 market index (the market proxy used by Henry (2014)).

In relation to the expected market return, ActewAGL Distribution has relied on an estimate of 11.32 per cent by SFG detailed in chapter 3 in Attachment E3. This estimate is based on the weighted average of four sources of evidence regarding the expected market return that SFG has judged as relevant to be given weight in the return on equity estimation:

- the Ibbotson Approach (historical excess return);
- the Wright Approach (historical real market return);
- the DGM approach; and
- evidence from independent equity analyst reports.

Based on the above and Attachment E3, estimating the return on equity using the AER's SL–CAPM approach where the equity beta is only based on raw statistical regression data, the return on equity will be 10.01 per cent as shown in Table 10.3.

Table 10.3 Calculation of the return on equity using the AER's SL-CAPM

Method	*Value*	*Comment*
Expected return on the market	11.32%	Consistent with attachment E3
Risk free rate	4.12%	Using an averaging period of 20 days until 12 February 2014
MRP	7.21%	Consistent with attachment E3
Equity beta	0.82	Consistent with attachment E3 and E7
Return on equity	**10.01%**	

10.5.3.2 "Black CAPM"

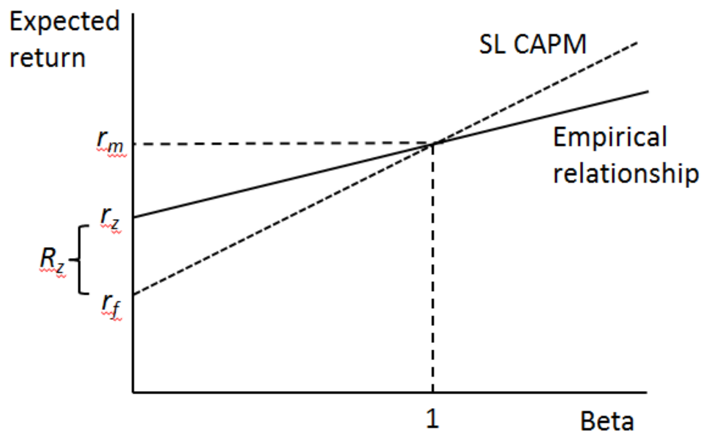
The AER's SL–CAPM (that is, SL–CAPM implemented using the government bond rate as the proxy for the risk free rate and regression based estimates of beta) will underestimate the returns on equity for businesses with low regression estimates of equity betas and overestimate the returns on equity for businesses with high regression estimates of equity betas. Setting the return on equity based on government bond rates as the risk free rate the SL–CAPM with a regression-based equity beta will therefore generally materially undercompensate a network business for its true return on equity. The discussion of the findings of Friend and Blume (1970), Black, Jensen and Scholes (1972) Fama and Macbeth (1973) and Brealey, Myers and Allen in 2011 included in chapter 2 of Attachment E4 is relevant to this point.

Black (1972) relaxes one of the key (and most unrealistic) assumptions of the SL–CAPM—that all investors can borrow or lend as much as they like at a 'pure rate of interest' in order to invest in risky assets. This results in the intercept in the model diverging from the government bond rate and instead being estimated based on market data as the required return on a zero-beta asset. As a result, Black (1972) estimates three parameters for the return on equity (R_e): the expected market return (R_m), the return on the zero beta portfolio (R_z) and the equity beta (β_e). The Black–CAPM formula is:

$$R_e = R_z + \beta_e \times (R_m - R_z)$$

The difference between the SL–CAPM and Black–CAPM is illustrated in Figure 10.3 where the 'Empirical relationship' line represents the Black–CAPM. This is further illustrated and discussed in chapter 2 of Attachment E4.

Figure 10.3 Sharpe-Lintner CAPM versus empirical relationship (Black CAPM)



Source: SFG Consulting, Cost of equity in the Black Capital Asset Pricing Model, p 8

Black (1972) is only one of many papers that have relaxed the restrictive assumptions underpinning the original derivation of the SL–CAPM formula in 1964. As noted by Grundy,[105] relaxation of other restrictive assumptions, such as the assumption that there are zero transaction costs, also lead to the same theoretical result: namely, that the required return on zero beta equity will be above the required return on otherwise riskless government debt. Professor Grundy's report is included at Attachment E13.

Similarly, Grundy notes that, consistent with Roll (1977),[106] implementation of the CAPM with regression based estimates of the equity beta implicitly assumes that the stock market is the entire portfolio of all assets held by investors in the economy. In reality, the market portfolio in the derivation of the SL–CAPM is the portfolio of all equities, bonds and real estate in the economy. Grundy notes that:

> *The cost of equity for zero beta stock when the equity market is used as a proxy for the entire market will exceed the risk-free rate and the cost of equity for all stock with betas with respect to that proxy less than (greater than) one will exceed (be less than) the cost predicted by the Sharpe CAPM.*[107]

In other words, the AER's SL–CAPM will underestimate the required return on stocks that have an (estimated) beta of less than 1.0.

[105] Grundy, B 2011, The Calculation of the Cost of Capital: A Report for Envestra, February

[106] Roll, R 1977, "A critique of the asset pricing theory's tests Part I: On past and potential testability of the theory," *Journal of Financial Economics 4(2)*, pp 129–176.

[107] Grundy, B 2011, The Calculation of the Cost of Capital: A Report for Envestra, February, p 7

In this proposal ActewAGL Distribution uses the short-hand term “Black CAPM” to capture all of these conceptual reasons why the AER’s implementation of the SL–CAPM is biased.

Implementing the “Black CAPM” requires an estimate of the zero beta premium—the difference between the expected return on a zero beta asset and the risk-free rate. The return on a zero beta asset is expected to be above the risk-free rate, which means that low equity beta stocks have higher expected returns under the “Black CAPM” than under the SL–CAPM, and vice versa for high equity beta stocks.

The AER intends to use the “Black-CAPM” only to inform the selection of a point estimate from within its range of equity beta estimates.[108] However, the AER does not explain how it proposes to do this.

As noted in section 10.5.2, ActewAGL Distribution’s view is that the better and more transparent approach is to implement the “Black-CAPM” directly. This involves providing an estimate of the zero-beta premium and using the same equity beta estimate and the same estimate of the required return on the market as otherwise used for the AER’s implementation of SL–CAPM.

As a result, ActewAGL Distribution (together with other NSPs) engaged SFG to estimate the zero-beta portfolio (R_z) and respond to the issues raised in the AER’s Rate of Return Guideline. The report is included at Attachment E4. SFG’s “Black CAPM” report shows that:

- using 774 portfolios between January 1994 to January 2014, SFG estimates a zero beta premium of 3.34 per cent; and
- the Rate of Return Guideline’s range for equity beta of 0.4 to 0.7 adjusted for a “Black CAPM” zero-beta premium of 3.34 per cent corresponds to an adjusted range of 0.71 to 0.85.

Table 10.4 shows the return on equity calculated using the “Black CAPM” approach based on Attachment E4 with a zero-beta premium of 3.34 per cent.

[108] AER, Better Regulation, Rate of Return Guideline, December 2013, p 15

Table 10.4 Calculation of the return on equity using the "Black-CAPM"

Method	*Value*	*Comment*
Expected return on the market	11.32%	See attachment E3 and E4
Risk free rate	4.12%	Using an averaging period of 20 days ending on 12 February 2014
Zero-beta premium	3.34%	See attachments E3 and E4
Equity beta	0.82	See attachments E3 and E7
MRP (measured relative to the zero beta return)	3.87%	(11.32% - 4.12%-3.34%)
Return on equity	**10.62%**	

10.5.3.3 Dividend Growth Model

The Dividend Growth Model (DGM), also referred to as the Dividend Discount Model, is widely used by market practitioners. Under the DGM the return on equity is estimated as the discount rate that sets the present value of all expected future dividends equal to the current stock price. In its Rate of Return Guideline and with reference to Brealey, Myers, and Allen, *Principles of Corporate Finance*, the AER noted that:

> *Given the underlying financial theory of the model—that the price of an asset should be equal to the present value of the expected future cash flows from that asset—is well accepted and sound.* [109]

ActewAGL Distribution disagrees with the AER's conclusion to use the DGM to inform it only in relation to the MRP. [110] ActewAGL Distribution considers that the DGM approach should also be used to inform the overall level of the return on equity.

The AER was critical in its Explanatory Statement—Rate of Return Guideline of the industry level DGM advanced by the ENA and its advisers, stating:

> *… we do not consider that the same level of data [as used in the calculation of MRP] exists to form robust dividend yield estimates for Australian energy service providers. For example, there are only five sample Australian service providers for which dividend yield data is available. Further, the time series for when these estimates are available are both variable and short. It is also unclear whether a robust method for estimating the growth rate of dividends for service providers has been developed. Of further concern is that DGMs are sensitive to the particular assumptions used. This is particularly relevant for the long term*

[109] AER 2013, Better Regulation, Explanatory Statement, Rate of Return guideline, (Appendices), December 2013, pp 14-15

[110] AER 2013, Better Regulation, Rate of Return Guidelines, December 2013 p 13

growth rate assumption. This is why we do not adopt DGM estimate for estimating the return on equity directly for the benchmark efficient entity.[111] [112]

In response to the AER's concern raised above, ActewAGL Distribution together with other NSPs engaged SFG to provide a DGM estimate of the return on equity for the benchmark efficient entity (and an average firm in the market), and to describe how the model applies in practice in Australia. SFG's report is included at Attachment E6. SFG recommends:

- a gradual transition period from short-term to long-term growth assumptions (which the AER refers to as a three-stage dividend growth model, in which the middle stage is the transition stage);
- using analyst target prices (instead of share prices) as this has the advantage that it reduces the dispersion of market cost of equity estimates over time while there is no adverse impact on the cost of capital from using analyst price targets rather than market prices;
- that earnings and dividend forecasts per share and prices are compiled at approximately the same dates, as this causes a material reduction in the volatility of the return on equity estimates over time; and
- not holding input parameters in the DGM constant, when they could be expected to be associated with share price changes (like growth in dividends) since, otherwise, more of the changes in share prices are transferred to the discount rate, with much higher volatility as a result.

SFG undertakes an estimation technique that does not rely upon an input assumption for long-term dividend growth. Instead, long-term growth is estimated jointly with the cost of equity.

By contrast, the process adopted by the AER requires a long-term dividend growth assumption, where it makes the questionable assumption that long term dividend growth will be 1 per cent less that the historical real GDP growth. SFG demonstrates in its report that in both Australia and the United States, over the last two to three decades since inflation has declined, real earnings per share have grown at rates which match or exceed GDP growth. SFG also critiques the AER's approach to estimating the return on equity using the DGM as the AER uses one equation to estimate the return from dividends in its DGM analysis but uses a different formula in estimating the benefit of imputation credits in the PTRM.[113]

[111] AER 2013, Better Regulation, Explanatory Statement, Rate of Return guideline, (Appendices), December, p 15

[112] ActewAGL Distribution notes that while the AER considers that five service businesses provides sufficient robustness for the equity beta estimate, it is considered too few for dividend yield estimates.

[113] See chapter 6 in Attachment E6.

Furthermore, there is regulatory precedent for SFG's simultaneous estimation technique. In 2013, IPART adopted six techniques to estimate a range for a contemporaneous estimate of the MRP, one of which was SFG's simultaneous estimation technique.[114] Using SFG's DGM approach and assuming a theta of 0.35, in Attachment E3 SFG calculates a return on equity of 10.92 per cent that has been estimated using internally consistent input parameters.

ActewAGL Distribution therefore proposes that the AER should use the DGM to estimate the overall return on equity, not only the required return on the market (as proposed by the AER).

10.5.3.4 Fama French three factor model

According to the Fama-French model, the return on equity for the benchmark firm can be estimated using the following equation:

$$R_e = R_f + \beta_e \times MRP + s \times SMB + h \times HML$$

Where:

R_e = investors' required nominal return on equity;

R_f = the required return by investors on a risk free (zero beta) asset;

β_e = investors' expectation of the equity beta;

MRP = the market risk premium (calculated as the market return less the risk free rate: $R_m - R_f$);

SMB = the expected return to a portfolio of small market capitalisation stocks minus the expected return to a portfolio of large market capitalisation stocks;

HML = the expected return to a portfolio of high book-to-market stocks minus the expected return to a portfolio of low book-to-market stocks;

s = the sensitivity of expected return to the SMB factor; and

h = the sensitivity of expected return to the HML factor.

The Fama-French three factor model has been developed more recently than, and partly in response to, the SL–CAPM. In 1992, Fama and French stated that "[w]e are forced to conclude that the SLB [Sharpe-Lintner-Black] model does not describe the last 50 years of average stock returns."[115] In 1993 Fama and French published results which found a combination of beta, size

[114] ActewAGL Distribution notes that IPART considers a range for the MRP of 7.2 per cent to 8.6 per cent under current market data, as of 26 March 2014: IPART, NSW Rail Access Undertaking – Review of the rate of return and remaining mine life Draft Report, May 2014, p 8.

[115] Eugene Fama, Kenneth French 1993, *The Cross-Section of Expected Stock Returns*, The Journal of Finance, vol XLVII, no 2, June, p 464.

and value explained (R^2) 83-97 per cent of a diversified portfolio's returns.[116] The Fama-French three factor model has since then become widely referenced and used. The model's co-author, Eugene Fama, was recognised with a Nobel Prize in economics in 2013, in part for his work on the three-factor model. The Nobel Prize Committee noted:

> *… the classical Capital Asset Pricing Model (CAPM)—for which the 1990 prize was given to William Sharpe—for a long time provided a basic framework. It asserts that assets that correlate more strongly with the market as a whole carry more risk and thus require a higher return in compensation. In a large number of studies, researchers have attempted to test this proposition. Here, Fama provided seminal methodological insights and carried out a number of tests. It has been found that an extended model with three factors—adding a stock's market value and its ratio of book value to market value—greatly improves the explanatory power relative to the single-factor CAPM model.*[117]

and:

> *… following the work of Fama and French, it has become standard to evaluate performance relative to "size" and "value" benchmarks, rather than simply controlling for overall market returns.*[118]

The ENA put forward evidence from the Fama-French model in an expert report by NERA which found that value firms have a higher return on equity than others, not accounted for by SL–CAPM:

> *our results suggest that for value stocks the benefits of using the FFM relative to the SL CAPM will likely outweigh the costs.*[119]

Despite the substantial evidence brought forward in response to the AER's Draft Rate of Return Guideline, including the expert report from NERA which discussed how the Fama-French model is an example of the Arbitrage Pricing Theory,[120] the AER elected not to give any role to the Fama French model in its Rate of Return Guideline.

The four key limitations of the Fama-French model alleged by the AER are:

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[116] Eugene Fama, Kenneth French 1993, *Common risk factors in the returns on stocks and bonds*, The Journal of Financial Economics, 33, pp 3-56.

[117] Kungliga Vetenskapsakademien, Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, Understanding Asset Prices, compiled by the Economic Sciences Prize Committee of the Royal Swedish Academy of Sciences, 14 October 2013, p 3

[118] Kungliga Vetenskapsakademien, Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, Understanding Asset Prices, compiled by the Economic Sciences Prize Committee of the Royal Swedish Academy of Sciences, 14 October 2013, p 44

[119] NERA 2013, The Fama-French Three-Factor Model, A report for the Energy Networks Association, October, p 39

[120] NERA 2013, The Fama-French Three-Factor Model, A report for the Energy Networks Association, October, p 37

There is no theoretical foundation to identify the risk factors, if any, that the model captures. …

The empirical patterns on which the model was developed may be variable over time, and may not apply in Australia. …

It is complex to implement, insomuch as two additional factor exposures and two additional risk premiums are required to estimate the expected return on equity (relative to the Sharpe-Lintner and Black CAPM)

To our knowledge, the model is not used to estimate future returns on equity in Australia. Instead, it is principally used as an ex-post benchmarking tool. Moreover, even where the factors are observed in ex-post returns, this does not mean that the same factors are priced ex-ante.[121]

In response, ActewAGL Distribution, together with other NSPs, engaged SFG to consider the AER's concerns with the Fama-French model and use the Fama-French model to estimate the return on equity for a benchmark efficient entity. SFG's report is at Attachment E5. SFG notes that:

- the most comprehensive study of the size and book-to-market effects that has been performed, using Australian data, over a 25 year period from 1982 to 2006, demonstrates that high book-to-market stocks have persistently earned higher returns than low book-to-market stocks;
- the AER's Rate of Return Guideline does not address why there is a positive return premium to high book-to-market stocks that has persisted over decades in different markets;
- it is inconsistent for the AER to argue that corporate finance practice is to use the CAPM, but to discard the remainder of corporate finance practice which incorporates additional risks into the discount rate;
- the weight of theoretical and empirical evidence is that the HML exposure represents a priced risk factor in the Australian market which should form part of the estimated return on equity; and
- the estimation result undertaken in the report shows that, if the Fama-French model is given no consideration, and the AER adopts the Sharpe-Linter CAPM with a beta estimate of 0.7 and market risk premium of 6.5 per cent, the return on equity could be understated by around 1.4 per cent to 1.5 per cent, depending upon how much consideration is given to Australian versus US-listed firms.

[121] AER 2013, *Better Regulation, Explanatory Statement, Rate of Return Guideline (Appendices),* December, pp 22-23

ActewAGL Distribution contends that the AER must give weight to the Fama-French model when estimating the return on equity consistent with the NER given the strong empirical evidence, academic references as shown in both NERA's and SFG's reports, and market practitioners' use of the Fama-French model. By giving no role to the Fama-French model, the AER runs a significant risk of under estimating the return on equity going forward, which would hinder, not contribute, to the achievement of the allowed rate of return objective and fail to provide ActewAGL Distribution with a reasonable opportunity to recover at least the efficient costs it will incur in providing direct control network services.

Based on SFG's report at attachments E3 and E5, a return on equity of 10.87 per cent is calculated using the Fama-French model.

10.5.4 Return on equity point estimate

In the previous section, the returns on equity for the benchmark firm have been calculated for:

1. the Sharpe-Lintner CAPM;
2. the "Black CAPM";
3. the Fama-French model; and
4. the DGM.

ActewAGL Distribution (and other NSPs) engaged SFG to calculate a return on equity point estimate. The details of this exercise are provided at Attachment E3. The report considers the range of models and evidence that have been summarised in this chapter and weighs up the evidence to form a single return on equity point estimate. SFG considers that all four models set out above provide evidence that is relevant to the estimation of the required return on equity for the benchmark efficient entity as they all:

- have a sound theoretical basis;
- have the purpose of estimating the required return on equity as part of the estimation of the cost of capital;
- can be implemented in practice; and
- are commonly used in practice.[122]

A summary of SFG's recommended return on equity point estimate is shown in Table 10.5.

[122] SFG 2014, "The required return on equity for regulated gas and electricity network businesses", May, pp 2-3

Table 10.5 SFG recommendations on return on equity calculation

Estimates of the required return on equity	*Required return on equity*	*Weighting*
Sharpe-Lintner CAPM	10.01	12.5
Black CAPM	10.62	25.0
Fama-French Model	10.87	37.5
Dividend discount model	10.92	25.0
Weighted average	**10.71**	**100**

A description of how the return on equity from respective equity models has been calculated is summarised in section 10.5.3 with further details in attachments E3, E4, E5, E6 and E7.

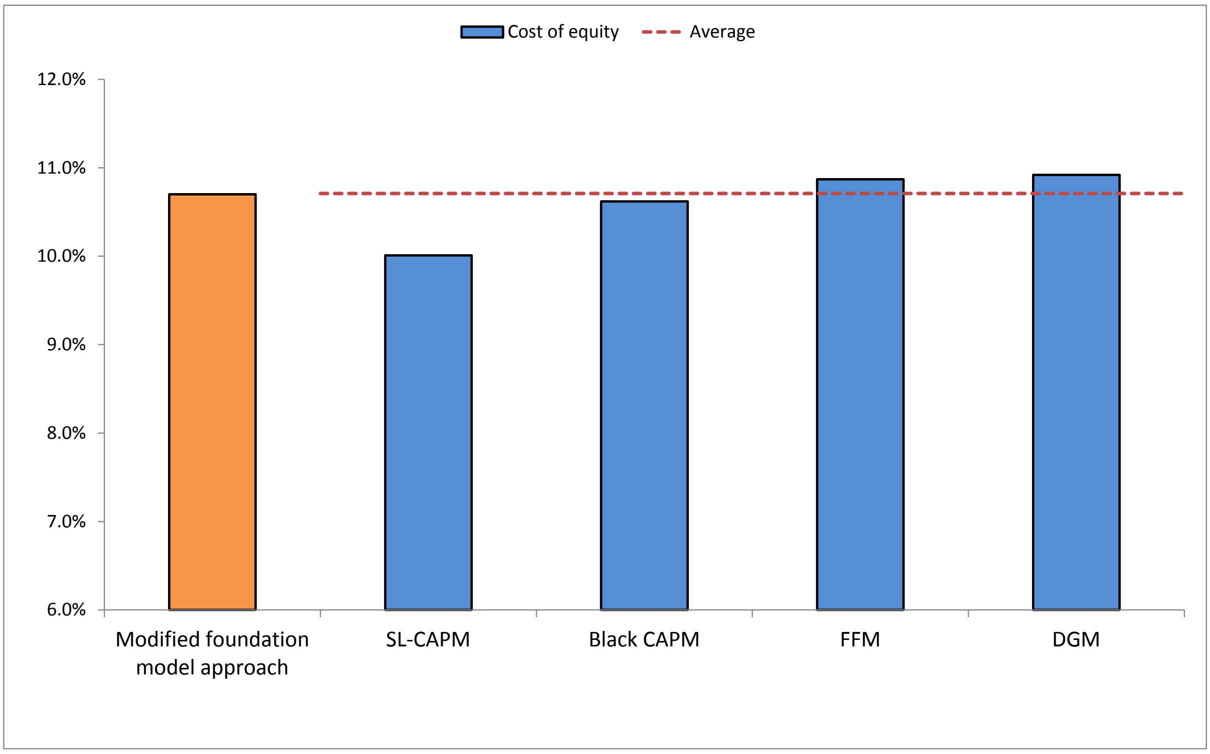
Representing the evidence using a foundation model approach, in order to give the appropriate weight to the range of models and evidence considered, the appropriate equity beta and MRP are 0.91 and 7.21 per cent, respectively. The equity beta of 0.91 is not based solely on a single source of evidence, nor on a single model, but reflects the range of evidence across multiple models on the relative level of the required return on equity of an NSP compared to the required return on the market generally. The MRP of 7.21 per cent is the same as the parameter value used in the SL–CAPM and "Black CAPM", and reflects the full range of evidence available on what investors require to invest in the market, with a beta of 1.

$$R_e = R_f + \beta_e \times (R_m - R_f)$$

$$= 4.12\% + 0.91 \text{ x } 7.21\% = 10.71\%$$

This is illustrated in Figure 10.4.

Figure 10.4 Estimate of the return on equity using different equity models



As all models utilise the risk free rate of return, the calculations[123] will need to be updated to reflect the most recent data at the time the AER makes its determination. For the final decision, ActewAGL Distribution proposes that the return on equity be estimated using the multimodel approach as set out above with each equity model calculated in accordance with this chapter and the accompanying expert reports.

10.5.5 Proposed averaging period

ActewAGL Distribution received a letter from the AER dated 14 April 2014, that sets out the AER's preferred averaging period to be used in the final decision for the risk free rate and the return on equity. If the AER accepts ActewAGL Distribution's method of estimating the return on equity (as set out in this chapter), ActewAGL Distribution does not take issue with the AER's proposed averaging period. In this case, the DGM estimates of the required return on the market must also be carried out over the same period consistent with SFG's approach to distil down a final return on equity point estimate as demonstrated in Attachment E3. In addition, as all four

[123] SFG was instructed to use the sample averaging period of 20 business days to 12 February 2014 to estimate the relevant parameters.

models used by SFG utilise the risk free rate of return, the calculations[124] will need to be updated to reflect the most recent data at the time the AER makes its distribution determination.

ActewAGL Distribution notes that the AER's specification of a narrow averaging period, close to the beginning of the regulatory period, for the risk free rate highlights the flaw in the Rate of Return Guideline approach in that it uses a single 'risk free rate' estimate with MRP estimates drawn from various sources (particularly historical average excess returns). The timing of the AER's preferred averaging period suggests that a mechanical exercise can be undertaken in using the risk free rate estimate in calculating the return on equity. ActewAGL Distribution disagrees that this approach is theoretically sound. For the reasons already discussed, ActewAGL Distribution considers that the AER's foundation model approach omits relevant information and constrains the use of information into the foundation model's parameters which could result in certain information being given disproportionate weight or prevent relevant information from being used, including that the use of a historical MRP, but a prevailing risk free rate, is internally inconsistent, rendering the resultant return on equity rate unreliable.

10.6 Return on debt

10.6.1 Overview

ActewAGL Distribution proposes its return on debt be calculated in accordance with the approach proposed by the AER in its Rate of Return Guideline, with the exception only that ActewAGL Distribution proposes:

- the use of a credit rating of BBB rather than BBB+ as proposed by the AER;
- the immediate adoption of the AER's 10 year trailing average portfolio approach, with no transition of the kind proposed by the AER, in estimating ActewAGL Distribution's return on debt; and
- the averaging period for use in calculating the prevailing rate of return on debt in each of the regulatory years 2016/17, 2017/18 and 2018/19 of the regulatory control period be nominated by ActewAGL Distribution prior to the occurrence of that averaging period and not in this Regulatory Proposal, or in the case of the 2017/18 and 2018/19 regulatory years, prior to the commencement of the regulatory control period.

For the purposes of applying this approach, ActewAGL Distribution proposes:

- the 10 year BBB rated bond yields published by the RBA be used as the published yields from an independent third party service provider (with the consequence that monthly estimates, rather than daily estimates as proposed by the AER in the Rate of Return

[124] SFG was instructed to use the sample averaging period of 20 business days to 12 February 2014 to estimate the relevant parameters. The AER will adopt a 20 business day period that is as close as practically possible to the commencement of the regulatory period.

Guideline, must be used, at least for historical regulatory years, as the RBA currently only publishes monthly data); and

- the use of averaging periods as follows:
  - for use in calculating the prevailing rate of return on debt in the 2005/06 regulatory year, a six month averaging period, being January 2005 to June 2005 inclusive, occurring in the 2004/05 regulatory year (as the RBA series ActewAGL Distribution proposes be used only commenced in January 2005);
  - for use in calculating the prevailing rate of return on debt in each of the 2006/07 to 2014/15 regulatory years inclusive, an averaging period of the twelve months comprising the preceding regulatory year;
  - for use in calculating the prevailing rate of return on debt in the 2015/16 regulatory year, [redacted]; and
  - for use in calculating the prevailing rate of return on debt in the 2016/17 and subsequent regulatory years, an averaging period of at least 10 business days occurring in the period 30 June in the regulatory year immediately prior to the preceding regulatory year to 31 January in the preceding regulatory year inclusive as nominated by ActewAGL Distribution prior to 30 April in the regulatory year immediately prior to the preceding regulatory year under the process set out in section 10.6.6 below.

10.6.2 The NER requirements

The return on debt must be estimated such that it contributes to the achievement of the allowed rate of return objective (clause 6.5.2 (h)). In estimating the return on debt, the NER require that regard be had to:

- the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective;
- the interrelationship between the return on equity and the return on debt;
- the incentives that the return on debt may provide to capital expenditure over the regulatory control period, including as to the timing of any capital expenditure; and
- any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to

estimate the return on debt from one regulatory control period to the next (clause 6.5.2(k)).

The NER provide that the return on debt may be estimated using a methodology that results in the return on debt being the same for the entire regulatory period or different for different regulatory years (clause 6.5.2(i)). Where the methodology for estimation of the return on debt is of the latter type, a resulting change to ActewAGL Distribution's annual revenue requirement must be effected through the automatic application of a formula that is specified in the distribution determination (clause 6.5.2(l)).

The NER also state that:[125]

> *Subject to paragraph (h), the methodology adopted to estimate the return on debt may, without limitation, be designed to result in the return on debt reflecting:*
>
> *(1) the return that would be required by debt investors in a benchmark efficient entity if it raised debt at the time or shortly before the marking of the distribution determination for the regulatory control period*
>
> *(2) the average return that would have been required by debt investors in a benchmark efficient entity if it raised debt over an historical period prior to the commencement of a regulatory year in the regulatory control period; or*
>
> *(3) some combination of the returns referred to in subparagraphs (1) and (2).*

10.6.3 Proposed departures from the AER's Rate of Return Guideline

In the Rate of Return Guideline the AER states that it proposes to:[126]

- use a trailing average portfolio approach with the length of the trailing average to be 10 years;
- for each regulatory year of this ten year period, estimate the prevailing rate of return on debt as a simple average of the prevailing rates observed over an averaging period of 10 or more consecutive business days up to a maximum of twelve months using:
  - published yields from an independent third party service provider;
  - a credit rating of BBB+ from Standard and Poor's; and
  - a term to maturity of debt of 10 years;
- apply equal weights (of 1/10) to all elements of the trailing average;
- automatically update the trailing average (and consequently the return on debt) for every regulatory year within the regulatory control period;

[125] *National Electricity Rules*, clause 6.5.2(j)

[126] AER 2013, Better Regulation, Rate of Return Guideline, December, pp18-22

- adopt transitional arrangements with a 10 regulatory year transition period from the current regulatory approach for the estimation of the return on debt to the 10 year trailing average portfolio approach; and
- use an averaging period that is:
  - specified prior to the commencement of the regulatory control period;
  - nominated prior to the occurrence of any date in that period;
  - as close as practical to the commencement of that regulatory year;
  - the same or different but not overlapping with any averaging period for another regulatory year of that regulatory control period; and
  - confidential.

ActewAGL Distribution accepts all but the following of these principles:

- ActewAGL Distribution considers that the benchmark credit rating should be BBB rather than BBB+;
- ActewAGL Distribution does not consider that a 10 year transition as proposed by the AER is necessary in its case;
- ActewAGL Distribution's proposed use of the RBA's published 10 year BBB rated bond yields predicates the use of monthly estimates rather than daily estimates (at least for historical regulatory years) which, ActewAGL Distribution does not consider likely to result in a materially different estimate of the return on debt where its proposed averaging period is accepted; and
- ActewAGL Distribution proposes that the averaging period for use in estimating the prevailing rate of return on debt in each of the regulatory years 2016/17, 2017/18 and 2018/19 of the regulatory control period be nominated prior to the occurrence of that averaging period and not in this Regulatory Proposal or, in the case of the 2017/18 and 2018/19 regulatory years, prior to the commencement of the regulatory control period.

ActewAGL Distribution considers that the benchmark credit rating should be BBB rather than BBB+ because:

- there has been a sustained drop in median credit ratings for the AER sample in the period since 2009 to BBB;
- the median credit rating in the 10 year period utilised in estimating ActewAGL Distribution's return on debt 2004 to 2013, is BBB; and
- the return on debt is more sensitive to the credit rating in the years since 2009, in which median credit ratings have been BBB, than the credit rating in preceding years.

ActewAGL Distribution supports the adoption of a ten year trailing average portfolio approach. ActewAGL Distribution considers that this portfolio approach has always been an appropriate financing practice, and agrees with the AER's conclusion, in the Rate of Return Guideline, that the benchmark efficient debt management strategy for a regulated energy utility will be to have an evenly staggered issuance of 10 year debt, consistent with the AER's proposed 10 year trailing average portfolio approach to estimating the return on debt.

ActewAGL Distribution considers, however, that a transition to this agreed long-term benchmark efficient debt management strategy is neither desirable nor permissible under the NER. This is because, in circumstances where ActewAGL Distribution has zero debt financing, leaving the issuance of debt funding to its equity investors, and those equity investors have adopted differing debt management strategies, there is no principled basis for the AER to depart from the estimation of ActewAGL Distribution's return on debt consistent with the efficient debt management strategies of the benchmark efficient entity by imposing such a transition, nor is the imposition of such a transition permissible under the NER.

This view is supported by CEG in an expert report included at Attachment E11, which states:

- *if a business is already managing its debt consistent with the agreed long-term benchmark efficient debt management strategy; then*
- *that business should not be required to undergo a transition period prior to being compensated based on the agreed long-term benchmark efficient debt management strategy.* [127]

and concludes in respect of ActewAGL Distribution:

> *ActewAGL … has no debt…*
>
> *In adopting zero debt financing, ActewAGL has essentially left the issue of debt funding to its equity investors who are free to leverage their investment in ActewAGL in any way they see fit. Indeed, ActewAGL's owners do appear to have adopted different debt management strategies.*
>
> *ActewAGL is a 50/50 joint venture between ACTEW Corporation and SGSP (Australia) Assets Pty Ltd (SGSPAA) (with the latter jointly owned by State Grid International Development Australia Investment Company Limited and Singapore Power International Pte Ltd). ACTEW has fixed rate debt (some of which is inflation indexed) with maturities stretching out to 2048 and no interest rate hedging. SGSPAA clearly has used interest rate hedges in the manner the AER envisions for at least some of their regulated assets.*
>
> *In this sense, by leaving different equity investors [in the ActewAGL joint venture] to decide their own the [sic] leverage position (and the type of debt used to gain that leverage), ActewAGL can be thought of as having no, and all conceivable, debt management strategies simultaneously. This means that, there is no unique debt management strategy that*

[127] CEG 2014, Debt transition consistent with the NER and NEL, May p 16

> *ActewAGL can be defined as having undertaken under the previous Rules and regulatory practice. Consequently, I consider that it is reasonable to deem ActewAGL as already funding itself in a manner consistent with the long-run benchmark efficient debt management strategy. Or, perhaps less strongly, it is not reasonable to deem ActewAGL as having a debt management strategy that is different from the long-run benchmark efficient debt management strategy.* [128]

A ten year averaging period would also be more consistent with the longevity of the distribution assets. This is further discussed in section 10.6.4.

While some other NSPs may support the establishment of a transition (that is, from the current regulatory approach to estimation of the return on debt to the trailing average portfolio approach), such a preference does not evidence that such a transition will contribute to the achievement of the allowed rate of return objective, as is required by the NER.

ActewAGL Distribution considers that the benchmark, efficiently financed DNSP would not commit to the raising of debt in a particular period of days several years in advance of debt raising. Such decisions on the timing of debt raising are made closer to the raising date and may depend on the liquidity and depth of the bond market at that time, and feedback from the market closer to the time when the debt may be issued as market conditions constantly change. It follows that, in order for the specification of the averaging period for 2016/17, 2017/18 and 2018/19 to contribute to the achievement of the allowed rate of return objective, the nomination of that averaging period should not occur at this time or, in the case of the 2017/18 and 2018/19 regulatory years, in advance of the regulatory control period but proximate to the time of decision-making on the timing of the raising of debt.

A closer matching of the timing of debt raising and the averaging period used to estimate the return on debt allows the DNSP to nominate an averaging period when it is better informed about its debt requirement, and able to take into account a more current cash position, prevailing and forecast market conditions and prevailing debt portfolio position at the time. By contrast, where averaging periods for all years of the regulatory control period are specified prior to the commencement of that period, the DNSP may have an incentive to raise debt during the specified averaging period to mitigate risk notwithstanding prevailing market conditions at that time.

The contribution to the achievement of the allowed rate of return objective made, and incentives for the adoption of efficient financing practices, created by ActewAGL Distribution's proposal for specification of the averaging periods for 2016/17, 2017/18 and 2018/19 does not give rise to any risk of gaming because, pursuant to that proposal, the averaging period is nominated before the occurrence of any date within that period and is approved by the AER.

[128] CEG , Debt transition consistent with the NER and NEL, May p 41

10.6.4 Application of 10 year trailing average portfolio approach without transitional arrangements

The NER require that ActewAGL Distribution's return on debt be estimated such that it contributes to the achievement of the allowed rate of return objective, namely that the overall rate of return is commensurate with the efficient financing practices of the benchmark efficient entity (clause 6.5.2(h)). Consistent with this requirement, regard must be had by the AER, in estimating that return on debt, to the desirability of minimising any difference between ActewAGL Distribution's return on debt and the return on debt of that benchmark efficient entity (clause 6.5.2(k)(1)).In the Rate of Return Guideline, the AER states:

> *We [the AER] consider that the regulatory return on debt allowance under the trailing average portfolio approach is…, commensurate with the efficient debt financing costs of the benchmark efficient entity.*[129]

Any departure from the trailing average portfolio approach, such as through the establishment of transitional arrangements of the kind contemplated by the AER, must therefore contribute to the achievement of the allowed rate of return objective notwithstanding the AER's conclusion that that approach reflects the efficient debt management strategies of the benchmark efficient entity. ActewAGL Distribution considers that, in the circumstances applicable to it as a consequence of which there is no principled basis for departing from the trailing average portfolio approach, the establishment of such a transitional arrangement will not contribute to the achievement of the allowed rate of return objective.

ActewAGL Distribution is a joint venture and has not raised debt. Given that ActewAGL Distribution has not issued debt and its equity investors have adopted differing debt management practices, there is no reason not to implement the ten year trailing average immediately. ActewAGL Distribution, together with other businesses, engaged CEG to assess the AER's reasoning for applying transition arrangements between the current 'on the day' approach to setting the cost of debt allowance and the 'trailing average' approach and whether this is consistent with the NER. CEG's expert report is included at Attachment E11.

In short, and based on CEG's expert report, ActewAGL Distribution considers that:

- For the return on debt to be commensurate with the rate of return objective, the method used to estimate and set the return on debt should reflect a debt raising strategy that is feasible and efficient for a business with a similar degree of risk as that which applies to a NSP and then estimate the efficient financing costs of implementing the strategy;[130]
- The 'on the day' approach that the AER has relied upon is neither feasible nor efficient and would not meet the current NER. Moreover, the price volatility from the return on

[129] AER 2013, *Better Regulation, Explanatory Statement, Rate of Return Guideline (Appendices),* December, p 102

[130] CEG 2014, Debt transition consistent with the NER and NEL, May, p 9

debt that drove customers to request the adoption of a trailing average benchmark will continue;[131]

- A business that is already managing its debt consistent with the agreed long-term benchmark efficient debt management strategy, should not be required to undergo a transition that is based on the assumption that the business historically has implemented a debt management strategy that is not feasible[132];
- Given that ActewAGL Distribution has no issued debt, there is no unique debt management strategy that ActewAGL Distribution can be defined as having undertaken under the previous NER and regulatory practice. Consequently, CEG considers it is reasonable to deem ActewAGL Distribution as already funding itself in a manner consistent with a ten year averaging trailing average which is consistent with a long-run benchmark efficient debt management strategy and, in any event, that there is no reasonable basis for estimating its return on debt in a manner inconsistent with the AER's conclusions on the long-run benchmark efficient debt strategy .[133]

ActewAGL Distribution therefore proposes that the AER immediately implement the trailing average return on debt in its determination for ActewAGL Distribution as neither the NER, the rate of return objective, nor economic theory provides a proper basis for the AER phase in over a 10-year period in ActewAGL Distribution's case.

The next sections consider the details of estimating and implementing the trailing average portfolio approach.

10.6.5 Data service providers for the return on debt

The AER’s Rate of Return Guideline proposes that the return on debt will be estimated using the published yields sourced from an independent third party data service provider, with extrapolation by means of a method to be specified in the distribution determination where yields at a term to maturity of 10 years are not published by the provider.

There are currently two data service providers that could be used: Bloomberg and RBA. ActewAGL Distribution proposes that RBA's published yields be used in estimating the return on debt and not those of Bloomberg. This is because:

- the RBA publishes a 10 year BBB rated bond yield and its method of estimation is transparent and robust;

[131] CEG 2014, Debt transition consistent with the NER and NEL, May, p 17

[132] CEG 2014, Debt transition consistent with the NER and NEL, May, p 16

[133] CEG 2014, Debt transition consistent with the NER and NEL, May, Appendix C

- in contrast to RBA, Bloomberg does not currently publish a 10 year index of BBB-rated bonds in Australia and it is uncertain whether a reliable method for extrapolation of Bloomberg's 7 year fair value curve into a 10 year yield can be identified;
- Bloomberg has ceased publishing its 7 year fair value curve and the BVAL product which replaces it also does not include a 10 year estimate, nor is it available for the 10 year trailing average period (i.e. the trailing average portfolio approach without transition);
- the RBA and not the Bloomberg fair value curve has behaved as one would expect over the last decade during the two periods of 'financial crisis'; and
- the RBA fair value curve has in the last ten years behaved in a manner more consistent with other estimates of the cost of BBB debt.

10.6.5.1 Bloomberg

Bloomberg's fair value curve for bond pricing has been the primary data source for use in calculating the return on debt in recent years, after another provider, CBA Spectrum, ceased publishing. Bloomberg is generally a trusted data provider and is widely used in the finance industry. Its debt series is published continuously, with daily historical series available. The Bloomberg curve is constructed using a more complicated and proprietary[134] yield curve fitting approach than the RBA's series (see below).

Bloomberg does not currently publish a 10 year index of BBB-rated bonds in Australia. The longest BBB debt tenor available is the 7 year index, which requires extrapolation in order to be used to estimate the allowed return on debt for a 10 year term. The 'paired bonds' approach has been used in decisions in recent years to extrapolate the 7 year return on debt to an appropriate 10-year rate.

Further, Bloomberg has ceased publishing the Fair Value Curve, in favour of the BVAL product, which features some methodological differences from the previous Fair Value Curve and has not been as well tested or accepted by regulators.

10.6.5.2 Reserve Bank of Australia

On 19 December 2013, the RBA commenced publishing a series of corporate bond spreads and yields. The RBA also published a short paper outlining its approach to estimation. RBA's corporate bond yield series provides a weighted average return on debt for BBB rated corporate borrowers in Australia at several maturities extending out to 10 years.

[134] Bloomberg does not provide transparency as the approach to estimation used to derive the yield curve. See CEG, Memorandum to ActewAGL Distribution - Factors relevant to estimating a trailing average cost of debt, May 2014, p 8.

The RBA's model is a kernel weighted average of what bonds are available, the average maturity is generally below the target maturity[135]. ActewAGL Distribution understands that under the kernel weighted averaging methodology the return on debt at a ten year tenor may be negatively biased when the average life of bonds in the sample is significantly below the target life. In a submission to the AER's issues paper regarding the 'Choice of Third Party Data Service Provider' ESQUANT has noted that local linear regression may reduce this bias. ActewAGL Distribution has not attempted to reproduce ESQUANT's calculations at this time and has used the historical RBA series without attempting to take account of such an effect. However, CEG has estimated that historically this involves an underestimation of around 20bp in the 10 year yield estimate. ActewAGL Distribution reserves its position on adjusting for this bias in the event that the AER rejects the immediate adoption of a ten year trailing average and instead begins a transition by giving 100 per cent weight to an "on the day" averaging period proximate to the beginning of the regulatory period.

Whilst the series is relatively new, it is well suited for regulatory purposes. On 24 February 2014, IPART published Fact Sheets, that ActewAGL Distribution includes in attachments E14 and E15, indicating that it intends to adopt the RBA's return on debt series as the base for its regulatory decisions from 1 July 2014. IPART considered that the strengths of using the RBA's series outweighed the weaknesses, including that the RBA publishes monthly rather than daily. Finding strong support among the submissions, IPART opted to adopt the RBA's series immediately—from April 30 instead of waiting until 1 July.

As noted, the RBA's methodology is simpler and more transparent than Bloomberg's proprietary approach. However, the series currently only extends back 9 years, rather than the 10 required to implement a 10 year average. Bloomberg's now discontinued fair value curve extends back more than 10 years (though usually not to a 10 year term to maturity), while the BVAL series extends back only five years.

The AER has expressed a preference for daily estimates in its Rate of Return Guideline, and recently published an Issues Paper on technical issues regarding different third party data sources—including potential interpolation between monthly values published by the RBA. ActewAGL Distribution notes that daily estimates are not a requirement of the NER, and the large number of monthly observations where a 10 year trailing average portfolio approach is applied using ActewAGL Distribution's nominated averaging periods means that it is highly unlikely that average daily estimates would be materially different from monthly average estimates.

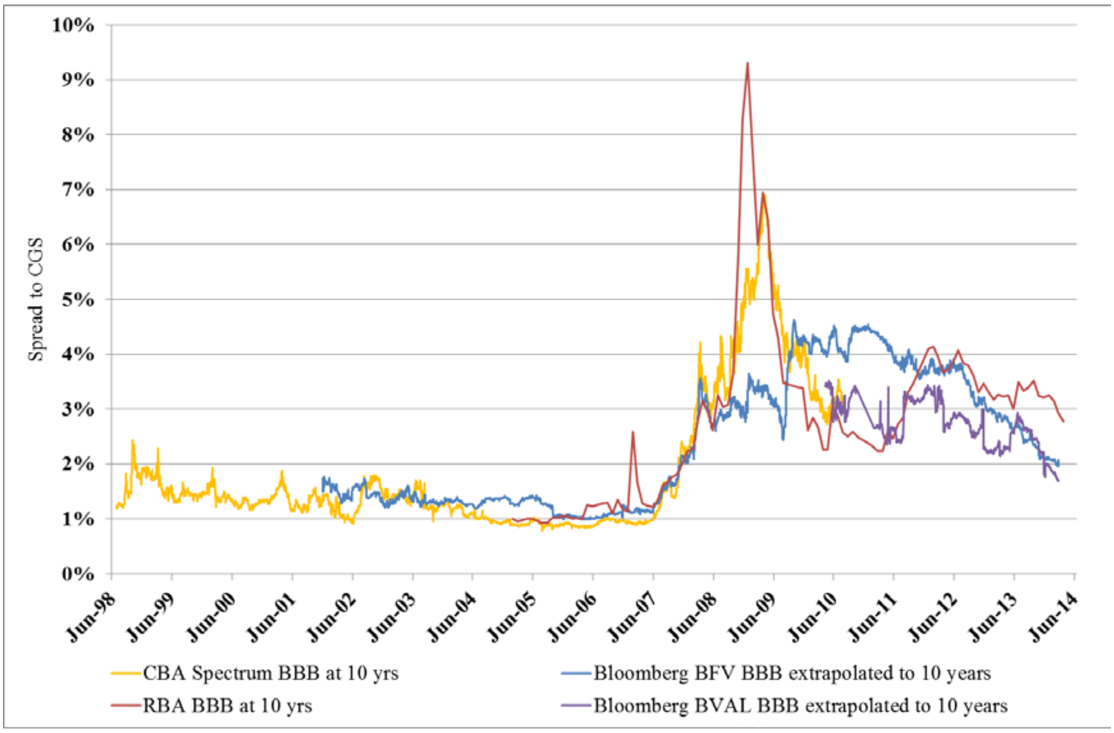
[135] Arsov, Brooks, and Kosev 2013, 'New Measures of Australian Corporate Credit Spreads', *RBA Bulletin*, December

10.6.5.3 The preferred data source provider for the 2014-19 regulatory period

In deciding between the data source providers to propose for use in calculating the allowed return on debt estimate, ActewAGL Distribution engaged CEG. Based on CEG's analysis included in Attachment E12, ActewAGL Distribution proposes that the AER uses RBA as the data source provider.

CEG provides a comparison of the spread to CGS between the data source providers which is reproduced in Figure 10.5.

Figure 10.5 Comparison of the spread to CGS between CBA Spectrum, Bloomberg and RBA BBB 10 years



As noted in section 10.6.4, ActewAGL Distribution proposes that its return on debt be based on a 10 year long term trailing average portfolio approach (without transition). CEG's advice to ActewAGL Distribution is therefore based on the behaviour of Bloomberg and RBA over this historical ten year term.

CEG compared the performance of each of the data service providers, Bloomberg, RBA and another provider, CBA Spectrum (which has now ceased publishing), by asking whether the curve behaved:

- as one would expect over the last decade; and

- in a manner consistent with the other estimates of the cost of BBB debt.[136]

CEG found that over the last decade there have been two periods of 'financial crisis'. The first relates to the period of late 2008 and early 2009 the intensity of which was at its peak following the bankruptcy of Lehman Brothers in September 2008. The second distinct period of financial crisis relates to the period of heightened perceived risk of European sovereign government default and potential exit from the Euro currency area.

CEG notes that RBA's BBB curve has responded to each of these crises in the manner expected—increasing substantially—and in a manner consistent with the CBA Spectrum. In doing so, it has followed more or less the pattern of the CBASpectrum fair value estimate where both were published concurrently and Bloomberg fair value curves for other jurisdictions (such as the USA). Before the 2008 financial crisis the RBA curve also behaved in a manner consistent with Bloomberg and CBA Spectrum. Subsequent to the financial crisis of 2008/09 the RBA estimates fell as expected, consistent with the behaviour of the CBA Spectrum estimates. The RBA curve also responded to the European sovereign debt crisis in the expected manner—rising materially in late 2011 and the first half of 2012 before falling again.

By contrast with the RBA and CBA Spectrum curves, the spread implied by the Australian Bloomberg fair value curve failed to rise correspondingly during the 2008/09 crisis. In addition, while the Bloomberg spread reached its peak levels in late 2010 and then fell modestly during the lead up to the European debt crisis but failed to rise in response to that crisis.

CEG concludes therefore that the RBA fair value curve is the best third party source to use to estimate a cost of 10 year BBB debt over the ten years to December 2013.[137] ActewAGL Distribution also notes:

- the RBA's method is a transparent and robust method of estimating a 10-year BBB rated bond yield;[138]
- the Bloomberg fair value curve has been discontinued and replaced by a new BVAL (which is not available over the same historical period); and
- the uncertainty in relation to finding a method that can reliably extrapolate Bloomberg's 7 year fair value curve into a 10 year yield.

Based on the above, ActewAGL Distribution considers that the RBA 10 year BBB series better represents the return on debt over the last ten years for the benchmark energy firm than

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[136] CEG 2014, Memorandum to ActewAGL Distribution - Factors relevant to estimating a trailing average cost of debt, May, p 5

[137] CEG 2014, Memorandum to ActewAGL Distribution - Factors relevant to estimating a trailing average cost of debt, May, p 7

[138] Arsov, Brooks, and Kosev 2013, 'New Measures of Australian Corporate Credit Spreads', *RBA Bulletin*, December

Bloomberg's fair value curve (extrapolated to 10 years where a 10 year fair value curve is not available), and so better meets the NER requirements and the rate of return objective in representing the return on debt incurred by a benchmark efficient DNSP.

10.6.6 Proposed averaging period

On 17 December 2013, the AER wrote to ActewAGL Distribution requesting it to nominate averaging periods that it proposed be used by the AER in estimating the return on debt in its distribution determinations for the transitional and subsequent regulatory periods.

ActewAGL Distribution replied to the AER by letter dated 24 April 2014 indicating that, in applying the 10 year trailing average portfolio approach, it proposed as follows:

- for use in calculating the prevailing rate of return on debt in the 2005/06 regulatory year, a six month averaging period, being January 2005 to June 2005 inclusive, occurring in the 2004/05 regulatory year (as the RBA series ActewAGL Distribution proposes be used only commenced in January 2005);
- for use in calculating the prevailing rate of return on debt in each of the 2006/07 to 2014/15 regulatory years inclusive, an averaging period of the twelve months comprising the preceding regulatory year;
- for use in calculating the prevailing rate of return on debt in the 2015/16 regulatory year, an averaging period of [redacted] and
- for use in calculating the prevailing rate of return on debt in the 2016/17 and subsequent regulatory years of the regulatory control period, an averaging period as nominated by ActewAGL Distribution prior to the occurrence of the averaging period and the commencement of that regulatory year but not in this regulatory proposal.

On 15 May 2014, AER staff wrote to ActewAGL Distribution expressing a view that ActewAGL Distribution's proposal for determining the averaging period for use in calculating the prevailing rate of return on debt in the 2016/17 and subsequent regulatory years may be inconsistent with clause 6.5.2(l) of the NER. This clause requires that, where the return on debt is to be estimated using a methodology which results in the return on debt being, or potentially being, different for different regulatory years of the regulatory control period (as ActewAGL Distribution proposes), the resulting change to the annual revenue requirement must be effected through the automatic application of a formula that is specified in the distribution determination. The AER stated that:

> *In order for the annual updating of the return on debt to occur through the automatic application of a formula that is specified in the distribution determination, all elements of the return on debt methodology—including the averaging periods for the regulatory years 2016-17, 2017-18 and 2018-19—must be specified in the determination.*

ActewAGL Distribution notes the AER's compliance concerns and the opinion of lawyers DLA Piper Australia confirming the NER compliance of its proposal for the nomination of debt averaging periods as set out in this proposal forms Attachment E17 to this proposal.

10.6.6.1 Reasons for deviation from the guideline

While having set out reasons above for the consistency of ActewAGL Distribution's proposal on the averaging period for debt with the NER, ActewAGL Distribution notes that its proposal—to nominate the averaging period for use in calculating the prevailing rate of return on debt in the 2016/17 and subsequent regulatory years of the regulatory control period prior to the occurrence of the averaging period and the commencement of the relevant regulatory year but not in this regulatory proposal or, in the case of the 2017/18 and 2018/19 regulatory years, in advance of the commencement of the regulatory control period—is a departure from the method set out in the guideline. As such, ActewAGL Distribution is required to provide reasons for that departure under clauses 6.3.1(c)(3) and S6.1.3(9) of the NER.

ActewAGL Distribution considers that the benchmark, efficiently financed DNSP would not commit to the raising of debt in a particular period of days several years in advance of debt raising. Such decisions on the timing of debt raising are made closer to the raising date and may depend on the liquidity and depth of the bond market at that time, and feedback from the market closer to the time when the debt may be issued. It follows that, in order for the specification of the averaging period for 2016/17, 2017/18 and 2018/19 to contribute to the achievement of the allowed rate of return objective, the nomination of that averaging period should not occur at this time or, in the case of the 2017/18 and 2018/19 regulatory years, in advance of the regulatory control period but proximate to the time of decision-making on the timing of the raising of debt.

A closer matching of the timing of debt raising and the averaging period used to estimate the return on debt allows the DNSP to nominate an averaging period when it is better informed about its debt requirement, and able to take into account a more current cash position, prevailing and forecast market conditions and prevailing debt portfolio position at the time. By contrast, where averaging periods for all years of the regulatory control period are specified prior to the commencement of that period, the DNSP may have an incentive to raise debt during the specified averaging period to mitigate risk notwithstanding prevailing market conditions at that time.

The contribution to the achievement of the allowed rate of return objective made, and incentives for the adoption of efficient financing practices created, by ActewAGL Distribution's proposal for specification of the averaging periods for 2016/17, 2017/18 and 2018/19 does not give rise to any risk of gaming because, pursuant to that proposal, the averaging period is nominated before the occurrence of any date within that period and is approved by the AER. As the AER itself acknowledged in the Rate of Return Guideline's Explanatory Statement, regulatory gaming is less likely when the averaging periods are specified and agreed upon in advance of the occurrence of that period and the AER approves those periods.[139]

10.6.6.2 Process for annual nomination of averaging periods for 2016/17, 2017/18 and 2018/19

ActewAGL Distribution proposes the following process to nominate the averaging period for use in calculating the prevailing rate of return on debt in each of the regulatory years 2016/17, 2017/18 and 2018/19 of the regulatory control period, and to calculate the updated smoothed revenue requirement for that regulatory year for pricing purposes, be specified in the AER's distribution determination:

1. The nominated and agreed averaging period for use in calculating the prevailing rate of return on debt in regulatory year (t) must satisfy the following conditions:
    a. the averaging period must be a period of 10 or more business days;
    b. it must occur within the period 30 June in regulatory year (t-2) and 31 January in regulatory year (t-1) inclusive; and
    c. it must be confidential.
2. By 30 April in regulatory year (t-2),[140] ActewAGL Distribution shall provide a confidential letter to the AER nominating the averaging period to be used in the calculation of the prevailing rate of return on debt and the update of the revenue requirement in regulatory year (t).
3. By 31 May in regulatory year (t-2), the AER shall determine whether it agrees to the nominated averaging period by applying the conditions for the averaging period set out in (1) above and inform ActewAGL Distribution by letter. If the averaging period is not consistent with the conditions for the averaging period set out in 1 above, then the AER may request ActewAGL Distribution to re-nominate a compliant averaging period, or it may determine a different averaging period which is compliant with those conditions.
4. In accordance with clause 6.18.2 of the NER, by 30 April in regulatory year t-1, ActewAGL Distribution shall provide its pricing proposal to the AER for regulatory year (t). This pricing proposal shall include and be based on ActewAGL's calculation of the prevailing rate of return on debt in, and updated trailing average return on debt and annual revenue requirement for, regulatory year (t). For this purpose, ActewAGL Distribution must:

[139] AER 2013, *Better Regulation: Rate of Return guideline, Explanatory Statement*, December p 133

[140] So, for example, by 30 April 2015, ActewAGL Distribution must nominate an averaging period for use in the calculation of the prevailing rate of return on debt for the regulatory year 2016/17. This process would continue for three years until the revenue requirement for 2018/19 has been determined.

a. in the event that the RBA series that ActewAGL Distribution proposes, in section 10.6.5 of this proposal, be used in estimating the return on debt continues to be published monthly during the relevant averaging period, calculate the prevailing rate of return on debt in regulatory year (t) by taking the simple average of all published RBA series' month end observations occurring within that averaging period; and

b. calculate the updated annual revenue requirement for that regulatory year by inputting that updated trailing average return on debt into the PTRM applied by the AER in making its distribution determination.

As the above process for nomination of the averaging periods for regulatory years 2016/17, 2017/18 and 2018/19 and the methodology for estimation of the return on debt is to be set out in the AER's distribution determination, the AER's approval of the pricing proposal for that regulatory year in accordance with clause 6.18.8 of the NER will be conditioned on the calculation by ActewAGL Distribution of the prevailing rate of return on debt in, and updated trailing average return on debt and annual revenue requirement for, that regulatory year for the purposes of its pricing proposal in accordance with 1 to 4 above and that methodology.[141] It follows that, if the AER determines that ActewAGL Distribution has not calculated the prevailing rate of return on debt in, and updated trailing average return on debt and annual revenue requirement for, the relevant regulatory year for the purposes of its pricing proposal for that year, the AER can exercise its existing powers under clause 6.18.8(b) of the NER to require ActewAGL Distribution to amend that pricing proposal to correct this or itself make the necessary amendments.

10.6.6.3 Formula to update annual revenue requirement for 2016/17, 2017/18 and 2018/19

ActewAGL Distribution proposes that the annual revenue requirement for each of the 2016/17, 2017/18 and 2018/19 regulatory years be updated by adjusting the return on capital building block for that year by the amount of the change in the trailing average return on debt for that year applied to the opening RAB for that year determined in the AER's distribution determination, multiplied by the gearing ratio specified in the AER's distribution determination, using the PTRM as applied by the AER in making its distribution determination:

$$\Delta RocBlock_t = \Delta cod \times 60\% \times oRAB_t$$

Where:

- $\Delta RocBlock_t$ is the Adjustment to the return on capital building block in regulatory year t;

[141] See clause 6.18.8(1)(a) of the NER which conditions AER approval of a pricing proposal on the compliance of that proposal with any applicable distribution determination.

- Δcod is the change in the trailing average cost of debt in regulatory year t determined in accordance with the process set out in section 10.6.6.2 above relative to the cost of debt for that year applied by the AER in making its distribution determination;
- 60% is the benchmark gearing rate set out in the distribution determination; and
- $oRAB_t$ is the opening RAB in year t set out in the distribution determination.

Further, the updated cost of debt will automatically be used in calculating the half year adjustment of capex rolled into the RAB in the PTRM.

The revenue building blocks in earlier years would remain the same as set in the distribution determination, as adjusted in previous annual updates. ActewAGL Distribution proposes that, when calculating the revenue requirement for year (t), the return on capital applied in the remaining years of the regulatory control period (year t+1 onwards) be the same as that set out in the distribution determination.

When smoothing the revenue requirement, ActewAGL Distribution proposes that the updated return on debt for regulatory year (t) determined in accordance with the process described in section 10.6.6.2 above would be used in the PTRM and only the x-factor for that year would be adjusted. This will help reduce the revenue volatility from these annual updates. That is, the x-factor for that year only would be adjusted to equalise the net present value of the revenue building blocks and the calculated smoothed revenue, and the discounting to present value terms would be done using the nominal vanilla WACC adjusted for the annually updated trailing average for regulatory year (t) and any previous year of the regulatory control period for which annual updating occurred, and the nominal vanilla WACC determined in the distribution determination for any subsequent regulatory year of the regulatory control period (for example, regulatory year (t+1) and so on).

10.6.7 Return on debt point estimate

For this proposal, ActewAGL Distribution has calculated the annualised return on debt from the RBA's BBB corporate yield series with a ten year tenor, averaged over the 9 years and 2 months from the series start until the end of February 2014.[142] This results in a return on debt of 7.85 per cent.

10.7 Gamma

Under the Australian taxation system, tax credits (imputation credit) created by an Australian company may be redeemed by domestic shareholders. An imputation credit is created for each dollar of eligible tax paid by companies. Imputation credits are distributed to shareholders through the payment of franked dividends. Imputation credits therefore represent a benefit to

[142] The use of the 9 years and 2 months (instead of ten years) is because RBA's series commences in January 2005.

domestic shareholders for their investment in the company in addition to dividends (and capital gains). The utilisation of imputation credits is represented by the Greek character γ (gamma). Gamma is defined in the NER as "*the value of imputation credits*".

ActewAGL Distribution considers that it is clear that what is required under the NER is an estimate of the value of imputation credits to investors in the business. This interpretation is consistent with the broader regulatory framework and the task set by the NER to determine total revenue, as well as past regulatory practice, and previous decisions of the Australian Competition Tribunal (Tribunal).

This is also the interpretation that best achieves the National Electricity Objective (NEO), as it ensures that the adjustment for imputation credits in the taxation building block properly reflects the actual value of imputation credits to investors, not merely their notional face value or potential value. Accounting for gamma in this way ensures that the overall return received by investors (including the value they ascribe to imputation credits) is sufficient to promote efficient investment in, and use of, infrastructure, for the long-term interests of consumers.

ActewAGL Distribution proposes to calculate gamma in the orthodox manner, as the product of:

- the distribution rate (that is, the extent to which imputation credits that are created when companies pay tax, are distributed to investors); and
- the value of distributed imputation credits to investors who receive them (referred to as theta, or θ).

ActewAGL Distribution proposes a distribution rate of 0.7, consistent with the AER's Rate of Return Guideline. Recent empirical evidence continues to support a distribution rate of 0.7.

ActewAGL Distribution proposes a value for theta of 0.35. The reasons ActewAGL Distribution is proposing a different value for theta to that in the Rate of Return Guideline include:

- ActewAGL Distribution does not agree with the conceptual framework adopted by the AER for estimating theta, and in particular the focus on utilisation evidence, rather than market value evidence. The AER's approach is not consistent with the NEO. It does not measure the required return for the purposes of promoting efficient investment, and would lead to underinvestment;
- in order to provide an acceptable overall return to equity holders, theta must be estimated as the value of distributed imputation credits to equity-holders. This is the conventional and orthodox approach to estimating theta. It is also the approach which best gives effect to the NEO, as it provides for recognition of the value to equity-holders of imputation credits and provides for overall returns which promote efficient investment;
- there are compelling reasons why the benefit of imputation credits, which is the amount by which the allowable return otherwise calculated in accordance with the NER should be reduced, is significantly less than the face value of imputation credits or the

utilisation of imputation credits. However, these were not considered in the Rate of Return Guideline;

- the value for theta proposed by ActewAGL Distribution accords with what one would expect to be the additional benefit conferred by the system of imputation credits. The value of theta proposed in the Rate of Return Guideline does not;
- there are overwhelming problems with the taxation statistics and other forms of evidence given primary emphasis in the Rate of Return Guideline. They are, and are well recognised to be, simply unreliable. Further, a key piece of evidence used by the AER (Handley and Maheswaran (2008)) is not an empirical study at all (because the data was not available), but merely involves an assumption of full utilisation by domestic investors; any reliance upon it involves obvious error;
- The only source of evidence capable of providing a point estimate for the value of distributed imputation credits to investors is market value studies. Evidence of utilisation rates (or potential utilisation rates, as indicated by the equity ownership approach) can only indicate the upper bound for investors' valuation of imputation credits. The conceptual goalposts approach referred to by the AER provides no relevant information on the actual value of credits; and
- The best estimate of investors' valuation of imputation credits from market value studies is 0.35.

Combining a distribution rate of 0.7 with a theta estimate of 0.35 produces a value for gamma of 0.25.

ActewAGL Distribution's reasons for proposing a different value for theta to that in the Rate of Return Guidelines are elaborated in detail in attachment E2 and further supported in an expert report by SFG at Attachment E1.

10.8 Overall rate of return

As outlined in the above sections, ActewAGL Distribution used 10.71 per cent as the appropriate point estimate of the return on equity, and 7.85 per cent as the appropriate point estimate of the cost of debt.

ActewAGL Distribution notes that the difference between the proposed return on equity and the return on debt is 2.86 per cent. ActewAGL Distribution considers that, for the purposes of the AER's consideration of the interrelationship between the return on equity and the return on debt in accordance with clause 6.5.2(k), this is reasonable to reflect the risk margin required by equity investors to invest in a benchmark entity with a similar degree of risk to ActewAGL Distribution.

At 60 per cent benchmark debt funding this leads to an overall weighted cost of capital of 8.99 per cent, as summarised in Table 10.6.

Table 10.6 Overall rate of return

Parameter	Value
Return on equity	10.71%
Cost of debt	7.85%
Gearing	60%
Gamma	0.25
Nominal vanilla WACC	**8.99%**
Inflation	2.525%

10.9 Forecast inflation

The expected inflation rate is not an explicit parameter within the return on capital calculation. However, it is used to forecast nominal allowed revenues and to index the RAB.

The AER has previously accepted a 10 year inflation forecast derived from the geometric mean of the near-term CPI forecasts published by the RBA in its February Statement on Monetary Policy, and for the remaining years of the 10 year period for which explicit forecasts are not provided, the midpoint (being 2.5 per cent) of the RBA's inflation target of 2 per cent to 3 per cent.[143]

For the next regulatory period, ActewAGL Distribution has applied this method. The RBA's February 2014 Statement on Monetary Policy, [144] includes an inflation forecast for the year to June 2014 of 3.25 per cent, to June 2015 of 2.75 per cent, and for the year to June 2016 of 2.5 per cent. Assuming inflation remains at the midpoint of the target band thereafter, the ten year geometric average is 2.525 per cent. ActewAGL Distribution proposes this average forecast inflation be used in making ActewAGL Distribution's determination for the 2014-19 regulatory period.

10.10 Equity and debt raising costs

10.10.1 Equity raising costs

Companies may raise equity at various times; when the company is founded, to fund major investments, to fund acquisitions or mergers, or to overcome financial stress. When doing so, a company incurs costs such as brokerage fees, legal fees, marketing and registration costs with the stock exchange and other transaction costs. These are upfront expenses for raising the equity. When cheaper sources of funding, such as retained earnings are insufficient, the AER has

[143] For example, AER 2013, *Access arrangement final decision Envestra Ltd 2013-17 Part 2: Attachments*, March, p 151

[144] RBA 2014, *Statement on Monetary Policy*, February, p 60

provided an allowance for equity raising costs.[145] The equity raising costs allowed have been determined using a gearing ratio and other financing decision assumptions consistent with a regulatory benchmark.

As shown at attachments B3, B6 and B8A, ActewAGL Distribution has calculated equity raising costs associated with each of its distribution, transmission, and alternative control capital programs of $0.39, $0.24, and $0.12 million respectively.

10.10.2 Debt raising costs

Many businesses raise debt to partly fund their capital investment programs. In doing so, a company incurs debt financing costs or transaction costs, which, unlike equity raising costs, occur not only when the debt is initially raised, but also when the debt is rolled over.

ActewAGL Distribution engaged Incenta to review the benchmark costs of debt raising for a capital program of ActewAGL Distribution's size. Incenta's report is included in Attachment E10. The report notes that while the benchmark gearing approach is to assume that the debt component of the RAB of the benchmark firm is wholly comprised of bonds, there are actually three components of direct debt raising costs that require compensation:

- the cost of bond issuance for the benchmark debt component of the RAB;
- the cost of maintaining a liquidity reserve in order to satisfy Standard & Poor's requirements for an investment grade credit rating, which lies outside of the benchmark debt component of the RAB, but incurs associated specific direct costs of (bank) debt issuance, and bank commitment fees; and
- the cost associated with securing the issuance of bonds 3 months ahead of the expiry of issued bonds, as required by Standard & Poor's.

Incenta has estimated the costs relating to these three forms debt raising costs, which is summarised in Table 10.7.

Table 10.7 Debt raising costs

	Basis points
Debt raising transaction costs relating to the debt component of the RAB	10.3
Costs associated with S&P's liquidity requirement	8.1
Costs associated with S&P's requirement to finance 3 months ahead	4.9
Total levelised debt raising costs	23.4

[145] For example, the AER included a $0.26 million (2008/09) equity raising allowance in ActewAGL Distribution's 2009 final decision.

Based on total debt raising costs of 23.4bp, ActewAGL Distribution has calculated annual debt raising costs using the AER's PTRM. The annual cost is shown in Table 10.8.

Table 10.8 Forecast debt raising costs 2014-19

$ million (2013/14)	*2014-15*	*2015-16*	*2016-17*	*2017-18*	*2018-19*
Distribution	0.95	0.99	1.00	1.01	1.01
Transmission	0.21	0.22	0.23	0.26	0.28
Alternative control services	0.07	0.07	0.08	0.08	0.09

11 Corporate income tax

This chapter sets out ActewAGL Distribution's calculation of the corporate income tax building block. The key inputs into this method of setting the allowance for corporate income taxes are the tax asset base (TAB), tax standard and remaining lives, and the value of imputation credits (gamma).[146]

The proposed corporate income tax building block has been calculated as part of the AER's PTRM, which ActewAGL Distribution is satisfied will generate an appropriate estimate of the income tax. A key assumption in relation to estimating the income tax revenue building block is the value of imputation credits, which is discussed in chapter 10.

11.1 AER Constituent Decisions

Clause 6.12.1(7) of the 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.

11.2 Requirements of the NEL and the Rules

Clause 6.5.3 states that the estimated cost of corporate income tax for each regulatory year (ETC_t) must be estimated 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/prescribed transmission services if such an entity, rather than the DNSP/TNSP, operated the business of the DNSP/TNSP, 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; and
- γ is the value of imputation credits.

[146] Gamma measures the value of imputation credits to investors. Though it does not enter into the nominal vanilla WACC, it is typically considered part of the cost of capital. ActewAGL Distribution discusses the appropriate rate for gamma in chapter 10.

11.3 Tax asset base

The TAB is rolled forward using the AER's RFM, and uses the same capital expenditure and capital contributions as inputs.

The TAB has been divided into a proportion for distribution and a portion for transmission standard control services on the same basis as the RAB, as discussed in section 0. The TAB has then been rolled forward using capital expenditure in the 2009–14 period directly allocated between transmission and distribution. The same proportional allocation between transmission and distribution, and capital expenditure in the 2009–14 period is used for the calculation of the TAB as for the calculation of the RAB.

The value of the TAB and the roll forward is demonstrated in Table 11.1and Table 11.2. Consistent with the AER's roll forward model, the TAB has been updated for the actual capital expenditure outcome in 2008/09 rather than the forecast capital expenditure amount included in the AER's 2009 final decision. ActewAGL Distribution has calculated depreciation based on the standard and remaining lives as set out in the AER's 2009 final decision. The opening standard and remaining life values for 2008/09 have been calculated using the same methodology as used in the AER's 2009 review to determine the 2009/10 opening tax life values. This tax roll forward model from 2009 is included in Attachment B22.

Table 11.1 Roll Forward of the distribution TAB 2009–14

$ million (nominal)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*
Opening TAB	412.2	452.7	499.1	532.5	563.0
***plus* capital expenditure**	58.0	66.0	55.2	54.2	72.7
***less* depreciation**	17.5	19.6	21.8	23.7	26.6
Closing TAB	452.7	499.1	532.5	563.0	609.1

Table 11.2 Roll Forward of the transmission TAB 2009–14

$ million (nominal)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*
Opening TAB	59.4	69.5	81.0	97.4	118.7
***plus* capital expenditure**	12.6	14.4	19.8	25.2	23.2
***less* depreciation**	2.5	2.9	3.4	3.9	4.8
Closing TAB	69.5	81.0	97.4	118.7	137.1

The forecast TAB over the subsequent regulatory period is calculated by the PTRM and is shown in the Table 11.3 and Table 11.4.

Table 11.3 Roll Forward of the distribution TAB 2014–19

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Opening TAB	609.1	652.5	682.3	710.1	740.1
***plus* capital expenditure**	74.9	65.1	65.1	65.5	72.4
***less* tax depreciation**	31.6	35.2	37.4	35.5	36.4
Closing TAB, distribution	652.5	682.3	710.1	740.1	776.0

Table 11.4 Roll Forward of the transmission TAB 2014–19

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Opening TAB	137.1	142.8	153.9	182.3	200.1
***plus* capital expenditure**	11.5	17.6	35.5	25.3	13.1
***less* tax depreciation**	5.8	6.5	7.1	7.5	8.1
Closing TAB, transmission	142.8	153.9	182.3	200.1	205.1

11.4 Tax standard and remaining lives 2014-2019

ActewAGL Distribution has calculated the tax remaining lives analogously to the remaining lives of the RAB—by using real depreciation to set the remaining lives so as to maintain straight line depreciation between the 2009–14 regulatory period and the next. This is discussed in further detail in chapter 9 and demonstrated in RFMs included in Attachments B1 and B4. The calculated remaining lives as at 1 July 2014 are shown in Table 11.5. As all assets until 2009 were classified under the 'Opening Distribution Assets' subclass, the calculated remaining lives for the other asset classes are high (and similar to the standard tax lives).

ActewAGL Distribution proposes to maintain the existing standard lives for all asset categories in the standard control for the next regulatory period as set out in Table 11.5.

Table 11.5 Tax standard and remaining lives for distribution and transmission assets

Asset class	*Standard life (years)*	*Remaining life (years)*
Opening distribution assets	n/a	18.6
Sub-transmission overhead	47.5	45.1
Sub-transmission underground	47.5	-
Zone substation, distribution	40.0	37.8
Zone substation, transmission	40.0	38.7
Distribution substation	40.0	38.0
Distribution overhead lines	45.0	42.9
Distribution underground lines	50.0	47.9
IT & Communication Systems (Network)	10.0	9.4
Motor vehicles	8.0	7.2
Other non-system assets (networks)	5.8	3.6
IT systems (Corporate)	4.1	3.3
Telecommunications (Corporate)	6.7	3.5
Other non-system networks (corporate)	5.7	2.9
Land	na	na
Buildings	100.0	97.1
Equity raising costs	44.5	40.5

11.5 Corporate income tax building block

Based on the application of the PTRM, ActewAGL Distribution proposes a corporate income tax building block as set out in Table 11.6 below for distribution and transmission. This is based on the application of a utilisation of imputation credits of 25 per cent as set out in section 10.7.

Table 11.6 Corporate income tax building block 2014–19, distribution and transmission

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Tax Payable, Distribution	13.0	13.8	13.4	15.3	16.1
Value of imputation credits	-3.3	-3.5	-3.4	-3.8	-4.0
Tax allowance, Distribution	9.8	10.4	10.1	11.5	12.1
Tax Payable, Transmission	2.0	2.1	2.2	2.7	2.9
Value of imputation credits	-0.5	-0.5	-0.6	-0.7	-0.7
Tax allowance, Transmission	1.5	1.6	1.7	2.0	2.2

12 Revenue requirement

This chapter sets out the revenue requirement for each revenue building block for ActewAGL Distribution's distribution and transmission services.

Clause 6.12.1(2) of the NER states that a determinations require the AER to either approve or refuse to approve the proposed annual revenue requirement and revenue cap respectively for each regulatory year of the regulatory control period.

Pursuant to clause 6.4.3(a) of the NER, the annual revenue requirement for each regulatory year must be determined using a building block approach. The revenue building blocks included in the AER's PTRM are:

1. Return on capital;
2. Depreciation;
3. Cost of corporate income tax;
4. Revenue increments or decrements (if any) arising from the application of any efficiency benefit sharing scheme; and
5. Operating expenditure.

The remaining part of this chapter discusses each of the above revenue building blocks for distribution and transmission services respectively.

12.1 Return on capital and depreciation

Clause 6.5.2(a) states that the return on capital is calculated by applying a rate of return to the value of the RAB as at the beginning of that regulatory year, while clause 6.5.5 of the NER states how the depreciation should be calculated.

ActewAGL Distribution has used the AER's PTRM to estimate depreciation. This sets out the assets classes, details of all depreciation amounts and inputs. The depreciation schedules reflect the economic life of respective asset and will only be depreciated once. When rolling forward the RAB in the 2009–14 regulatory period, ActewAGL Distribution has used standard and remaining live assumptions consistent with the AER's 2009 final decision. For the 2014–19 regulatory period, ActewAGL Distribution has recalculated the remaining lives set discussed in section 9.3.1.

Regulatory depreciation is calculated as the nominal depreciation less the indexation of the asset base each year. A summary of the calculated depreciation is provided in Table 12.1 and Table 12.2.

The movements in the value for respective RABs over the 2014–19 regulatory period are set out in Chapter 9. ActewAGL Distribution's proposed nominal vanilla weighted average cost of capital is 8.99 per cent, as discussed in chapter 10. The return on capital revenue building blocks are shown in Table 12.1 and Table 12.2.

12.2 Corporate income tax allowance

Clause 6.5.3 sets out how the cost of corporate income tax is calculated. ActewAGL Distribution has described the estimation of the corporate income tax in Chapter 11 in more detail. The nominal cost estimate is shown in the Table 12.1 and Table 12.2.

12.3 Revenue adjustments from the EBSS

Clause 6.4.3(b)(5) states that the revenue increment or decrements are those that arise as a result of the operation of an applicable EBSS, CESS, STPIS, small-scale incentive scheme, and for clause 6.4.3(b)(5) only, any DMEGCIS. For the 2014–19 regulatory period, ActewAGL Distribution only has revenue adjustment from the EBSS. The EBSS has been described in detail in section 16.2. The nominal revenue adjustment arising from the EBSS is shown in Table 12.1 and Table 12.2 for distribution and transmission separately.

12.4 Operating expenditure

Clause 6.4.3(b)(7) of the NER states that the forecast operating expenditure for the year is the forecast operating expenditure as accepted or substituted by the AER. The calculation of operating and maintenance costs has been detailed in chapter 8.

12.5 Adjustment due to transitional decision

Clauses 11.56.4(h) to (i) of the NER states that the subsequent regulatory period must include an adjustment to the total revenue requirement. The adjustment is the difference between the notional revenue requirement for the regulatory year that is the transitional regulatory period and the amount of the annual revenue requirement that was approved by the AER for the transitional period, subject to any modifications set out in a framework and approach paper. No such modifications were set out in the AER's framework and approach papers for ActewAGL Distribution.

The AER's decision on the transitional year was published on 16 April 2014 and allowed $145.16 million for distribution and $28.09 million for transmission to be recovered in 2014/15. This is less than the revenue building block requirement as part of this proposal. ActewAGL Distribution has therefore included an adjustment to be recovered over the remaining four years of the subsequent regulatory period.

The adjustment to revenues has been done by setting the smoothed revenue in the first year so it matches the Transitional Decision's allowance, and a P_0 adjustment in the second year so that smoothed revenues from subsequent years make up the shortfall in the first year in NPV terms.

12.6 Revenue requirement

According to clause 6.12.1(11), a determination is predicated on a decision on the form of the control mechanism (including the X factor) for Standard Control Services and on the formulae that give effect to those control mechanisms.

Clause 6.5.9(b)(2) of the NER requires that a building block determination is to include the X factor for each regulatory year. These X factors:

> *must be set such as to minimise, as far as reasonably possible, variance between expected revenue for the last regulatory year of the regulatory control period and the annual revenue requirement for that last regulatory year.* [147]

In the Stage 1 F&A paper the AER decided that an average revenue cap will apply to ActewAGL Distribution's standard control services for the transitional and subsequent regulatory periods.[148] Using the AER's PTRM, ActewAGL Distribution has calculated the X factors set out in Table 12.1 and Table 12.2 to apply to ActewAGL Distribution's distribution and transmission services for the 2014–19 regulatory period. The first year represents the price movement from the previous regulatory period and is consistent with the AER's transitional decision in April 2014. The remaining years represent the X value in the formula CPI–X.

For both distribution and transmission services, ActewAGL Distribution proposes a different X factor in the second year of the next regulatory period to account for the difference in the revenue requirement that arises due to 'trueing up' of the AER's transitional decision for 2014/15 to match ActewAGL's Distribution's proposals. It also lowers the variance between expected revenue in the last regulatory year of the next regulatory period and the annual revenue requirement in that last year.

[147] *National Electricity Rules*, clause 6.5.9(b)(2)

[148] AER 2013, *Stage 1 Framework and Approach—ActewAGL*, March, p 44

Table 12.1 Revenue requirement and x-factors, distribution 2014–19

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Return on capital	62.6	66.3	68.8	71.3	73.6
Regulatory depreciation	27.0	30.6	31.2	32.6	32.7
Operating expenditure	66.7	66.8	66.7	70.7	74.1
EBSS carry over amounts	-9.6	-8.5	-1.5	1.9	0.0
Tax allowance	9.8	10.4	10.1	11.5	12.1
Total revenue building block (unsmoothed)	156.4	165.6	175.3	187.9	192.5
Adjustment to correct under recovery in transitional year	11.3				
Energy forecast (MWh)	2,736,688	2,729,815	2,761,282	2,790,890	2,803,657
Revenue yield ($/MWh)	53.1	62.4	64.9	67.5	70.3
Smoothed revenue requirement	145.2	170.2	179.2	188.5	197.0
X (%) in CPI–X formula, distribution	**19.6**	**-14.7**	**-1.5**	**-1.5**	**-1.5**

Table 12.2 Revenue requirement and x-factors, transmission 2014–19

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Return on capital	13.9	14.5	15.7	18.5	20.4
Regulatory depreciation	4.2	5.0	5.2	5.6	5.8
Operating expenditure	13.3	13.4	13.4	14.3	14.9
EBSS carry over amounts	-1.4	-1.2	-0.2	0.3	0.0
Tax allowance	1.5	1.6	1.7	2.0	2.2
Total revenue building block (unsmoothed)	31.4	33.2	35.8	40.8	43.2
Adjustment to correct under recovery in transitional year	3.3				
Smoothed revenue requirement	28.1	34.9	37.7	40.6	43.8
X (%) in CPI–X formula, transmission	**-2.0**	**-21.2**	**-5.2**	**-5.2**	**-5.2**

It can be noted that the positive X-factor for distribution in the first year relates to the removal of costs related to jurisdictional schemes (Feed-in tariff, UNFT and the Energy Industry Levy), that from 2014/15 do not form part of the distribution revenue building block.

12.7 Annual updating of the trailing average

In the Rate of Return Guideline, the AER indicates that it intends to update the return on debt allowance for recovery in each year by the NSP using a formula that can be applied to automatically update the revenue requirement.

At the time of this proposal, the RBA's cost of debt series do not have a full year of data for the first year in the sample 2004/05, nor for the current year 2013/14.

In order for the return on debt to be updated each year, ActewAGL Distribution provided a letter dated 24 April 2014 that sets out how the averaging period should be made up to reflect a 10 years averaging period.

In relation to the annual updates of the trailing average, ActewAGL Distribution proposes that the return on debt be based on the trailing average referred to in ActewAGL Distribution's letter of 24 April 2014.

In each future year of the forthcoming regulatory period, the oldest year in the sample would be dropped from the trailing average and replaced by the return on debt of the next financial year.

To automatically incorporate the revenue requirement in the future annually updated return on debt, ActewAGL Distribution considers that one approach is to 'freeze' the prior years' figures in the PTRM so that only the future years' revenue requirement in the PTRM are updated. The revenue difference between the nominal revenue building block in the Final Decision and the nominal revenue building block calculated via the annually updated return on debt would be included in the B-factor each year as noted in section 13.2.

ActewAGL Distribution looks forward to consulting with the AER in relation to updating the PTRM so the annual update of the trailing average can be incorporated in the revenue building block in an efficient and practicable way.

13 Control mechanism and indicative prices

This chapter provides ActewAGL Distribution's proposals relating to the control mechanism and indicative prices for distribution *standard control services*. The proposals and requirements for *alternative control services* are addressed in chapter 15. ActewAGL Distribution's proposed pricing methodology for transmission services is provided in Attachment D15.[149]

The control mechanism for standard control services and related matters (including treatment of jurisdictional scheme amounts and designated pricing proposal charges) are addressed in the first part of this chapter (sections 13.2 to 13.6), and indicative prices are addressed in the second part (the final 3 sections). The pricing part of the chapter includes an overview of ActewAGL Distribution's approach to network tariff pricing and current and emerging network pricing issues. This provides context for the indicative prices and estimated bill impacts provided in the final sections of the chapter.

ActewAGL Distribution's proposals for standard control services control mechanisms and pricing are consistent with the NEO and the revenue and pricing principles in the Rules. The proposals are designed to deliver long term benefits to customers by encouraging efficient supply and use of current network services, and providing cost reflective signals to guide future decisions. The proposals will continue to allow customers to choose the tariff option which best suits their needs and load characteristics.

13.1 Regulatory requirements

The Rules set out the regulatory proposal requirements and the constituent decisions that the AER must make in relation to control mechanisms and indicative prices for standard control services.

The regulatory proposal must:

- include indicative prices for direct control services for each year of the regulatory control period (clause 6.8.2(c)(4)); and
- comply with the requirements of, and must contain or be accompanied by the information required by any relevant regulatory information instrument (clause 6.8.2(d)). The requirements in relation to distribution prices and estimated impacts of the regulatory proposal on average customer bills are set out in template 7.6.1 and sections 25 and 26 of Schedule 1 of the RIN.

[149] The AER approved ActewAGL Distribution's proposed transmission pricing methodology in its placeholder determination for 2014/15 (see AER 2014, *ActewAGL, Placeholder determination for the transitional regulatory control period 2014/15*, April, p. 5).

The AER's constituent decisions are set out in clause 6.12.1 of the Rules. The following constituent decisions are relevant for control mechanisms and prices for standard control services:

- a decision on the form of the control mechanisms (including the X factor) for standard control services (to be in accordance with the relevant framework and approach paper) and on the formulae that give effect to those control mechanisms (clause 6.12.1(11));
- a decision on how compliance with a relevant control mechanism is to be demonstrated (clause 6.12.1(13));
- a decision on the procedures for assigning retail customers to tariff classes, or reassigning retail customers from one tariff class to another (including any applicable restrictions) (clause 6.12.1(17));
- a decision on how the Distribution Network Service Provider is to report to the AER on its recovery of designated pricing proposal charges for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges (clause 6.12.1(19)); and;
- a decision on how the Distribution Network Service Provider is to report to the AER on its recovery of jurisdictional scheme amounts for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those amounts. A decision under this subparagraph (20) must be made in relation to each jurisdictional scheme under which the Distribution Network Service Provider has jurisdictional scheme obligations at the time the decision is made (clause 6.12.1(20)).

13.2 The control mechanism for standard control services

In the Stage 1 F&A paper the AER decided that an average revenue cap will apply to ActewAGL Distribution's standard control services for the transitional and subsequent regulatory periods.[150] For the subsequent regulatory period the form of the control mechanism must be as set out in the relevant F&A paper.[151]

The AER's proposed approach to the formulae that give effect to the control mechanism for standard control services is also set out in the Stage 1 F&A paper. The AER must include the proposed formulae in its distribution determination, unless it considers that unforeseen circumstances justify departing from the formulae as set out in the F&A paper.[152]

[150] AER 2013, *Stage 1 Framework and Approach—ActewAGL*, March, p 44

[151] *National Electricity Rules*, clause 6.12.3(c)

[152] *National Electricity Rules*, clause 6.12.3(c1)

The proposed formulae are:

(1) $$MAAR_t \geq \frac{(\sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^{t} q_{ij}^{t-2})}{kWhtransported_{t-2}}$$ i=1,...,n and j=1,...,m and t=1,...,5

(2) $$MAAR_t = AAR_t + \frac{(I_t + T_t + B_t)}{kWhtransported_{t*}}$$

(3) $$AAR_t = AAR_{t-1}(1+CPI_t)(1-X_t)$$

Where:

$MAAR_t$ is the maximum allowable average revenue in year t.

p_{ij}^{t} is the price of component i of tariff j in year t.

q_{ij}^{t} is the quantity of component i of tariff j in year t–2.

AAR_t is the average allowable revenue in year t.

$kWhtransported_{t-2}$ is the total kWh in year t–2.

$kWhtransported_{t*}$ is the forecast total kWh in year t

I_t is the sum of incentive scheme adjustments in year t. To be decided in the final decision.

T_t is the sum of transitional adjustments in year t. To be decided in the final decision.

B_t is the sum of annual adjustments in year t. To be decided in the final decision.

CPI_t is the percentage increase in the consumer price index in year t. To be decided in the final decision.

X_t is the X-factor in year t. To be decided in the final decision.

AAR_1 is the average allowable revenue in year one, to be decided in the final decision.

ActewAGL Distribution does not propose any changes to the formulae for standard control services adopted by the AER in the Stage 1 F&A paper. The annual adjustment for the cost of debt (as discussed in chapter 10) should to be included in the pricing mechanism as a “B” factor.

13.2.1 Compliance with the control mechanism

To demonstrate compliance with the AER’s average revenue cap control mechanism, ActewAGL Distribution proposes to show that the sum of the standard control services revenue using the prices for the pricing year and the quantities for the previous financial year divided by the quantity of energy in kWh transported over the previous financial year is less than or equal to the MAAR for the pricing year.[153] An example is provided in the *ActewAGL Distribution 2014/15 Network Pricing Proposal* (see Sections 3.1 and 3.2).

ActewAGL Distribution's proposed approach to demonstrating compliance with the control mechanism is consistent with the standard control services control mechanism formulae set out in the AER's Stage 1 F&A paper.[154]

For each year after the first year of each regulatory period, side constraints will apply to the weighted average revenue to be raised from each tariff class.[155] In accordance with clause 6.18.6 of the Rules, the permissible percentage increase is the greater of CPI–X plus 2 per cent or CPI plus 2 per cent. Recovery of revenue to accommodate cost pass throughs and pass through of designated pricing proposal charges and jurisdictional scheme amounts is disregarded in deciding whether the permissible percentage has been exceeded.

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[153] AER 2009, *Final decision, Australian Capital Territory distribution determination 2009–10 to 2013–14*, 28 April, p 18

[154] AER 2013, *Stage 1 Framework and Approach—ActewAGL*, March, p 38

[155] Under the Rules, the side constraint only applies to pricing in the second and subsequent regulatory years of the regulatory control period. The transitional regulatory period is not to be treated as the first regulatory year of the subsequent regulatory period for the purpose of applying clause 6.18.6(b) of the Rules. This is because:

(a) clause 6.18.6(b) provides that the expected weighted average revenue to be raised from a tariff class for a particular year of a regulatory control period must not exceed the corresponding expected weighted average revenue for the preceding year in that regulatory control period by more than the permissible percentage. As the side constraint is calculated by reference to the expected weighted average revenue in the preceding year in the regulatory control period, the side constraint cannot apply in the first year of a regulatory control period;

(b) clause 11.56.4(g) provides that nothing in clause 11.56.4 has the effect of actually rendering the transitional regulatory control period as the first regulatory year of the subsequent regulatory control period and, except for the purposes of the application of subparagraphs (b) to (f) in accordance with its terms, the transitional regulatory control period must be treated as a regulatory control period separate from the subsequent regulatory control period. Subparagraphs (b) to (f) of clause 11.56.4 are not relevant to the application of the side constraint by a DNSP for the purposes of its pricing proposals for the subsequent regulatory period. While subparagraph (b) requires a DNSP to prepare and submit the information accompanying its regulatory proposal on the basis that the transitional regulatory period forms part of the subsequent regulatory period, this operates to require the DNSP, in complying with clause 6.8.2(c)(4), to provide indicative prices for the transitional regulatory period as well as each regulatory year of the subsequent regulatory period. That is, it does not require the DNSP in providing those indicative prices in its regulatory proposal to apply the side constraint as though the transitional regulatory period formed part of the subsequent regulatory period. In any event, as clause 11.56.4(b) applies only in relation to the preparation and submission of a DNSP's regulatory proposal and accompanying information, it cannot operate to require a DNSP in preparing and submitting its pricing proposals for the subsequent regulatory period, in which context the side constraint is to be applied, to treat the transitional regulatory period as part of the subsequent regulatory period.

13.3 *Designated pricing proposal charges*

In the Placeholder Determination for 2014/15 the AER determined that ActewAGL Distribution is to report on its recovery of designated pricing proposal charges,[156] and on the adjustments to be made to subsequent pricing proposals, in the same manner as during the current regulatory control period.[157]

ActewAGL Distribution proposes that this approach should continue to apply for the subsequent regulatory period. An example of the proposed approach is provided in the *ActewAGL Distribution 2014/15 Network Pricing Proposal (see Table 3.5)*.

13.4 *Jurisdictional scheme amounts*

The jurisdictional scheme requirements in the Rules, introduced in 2010, designated the ACT feed-in tariff for small scale generation as a *jurisdictional scheme* (under clause 6.18.7A(e)(1)(i)). The jurisdictional scheme arrangements in the Rules also include provision for DNSPs to request the AER to determine that a scheme is a jurisdictional scheme.[158]

ActewAGL Distribution wrote to the AER on 6 January 2014 requesting the AER to determine that the Energy Industry Levy, the Utilities (Network Facilities) Tax and the Feed-in Tariff (Large Scale) are jurisdictional schemes. On 29 January 2014, the AER published its determination that each of these schemes is a jurisdictional scheme.[159] As a result, forecast costs for these jurisdictional schemes are not included in the opex forecasts for 2014–19.

ActewAGL Distribution's proposal on the manner in which ActewAGL Distribution is to report on jurisdictional scheme amounts and to make adjustments to its annual pricing proposal for over and under recovery, for the subsequent regulatory period is identical to that proposed for the transitional regulatory period.

13.4.1 ActewAGL Distribution's proposal for jurisdictional scheme amounts

ActewAGL Distribution proposes to carry out adjustments to jurisdictional scheme amounts for the relevant jurisdictional scheme for the purposes of clause 6.18.7A(b) and report to the AER on the recovery process under clause 6.18.7A(a) to (c) with a jurisdictional scheme overs and unders

[156] Designated pricing proposal charges are defined in chapter 10 of the NER.

[157] AER 2014, *ActewAGL, Placeholder determination for the transitional regulatory control period 2014/15*, April, p 4

[158] *National Electricity Rules*, clause 6.18.7A(f)

[159] AER 2014, *Determination: ActewAGL Distribution's request for schemes to be determined as jurisdictional schemes*, January. AER reference: 53600

account. This approach is based on the method determined by the AER in the *2009–14 ACT Distribution Determination* in respect of designated pricing proposal charges.[160]

As part of the annual pricing proposal for each regulatory year ActewAGL Distribution proposes to provide the following amounts for the most recently completed regulatory year, the current regulatory year and the next regulatory year:

1. the opening balance for each year;
2. the interest accrued on the opening balance for each year, calculated at the rate of the post-tax nominal rate of return as approved by the AER in its distribution determination;
3. either the amount representing the revenue recovered from jurisdictional schemes charges applied in respect of that year or included (as in the case of 2012/13 and 2013/14) in the operating expenditure allowance within the 2009–14 Distribution Determination, less the amounts of all jurisdictional scheme related payments made by ActewAGL Distribution in respect of that year;
4. an adjustment to the net amount in item 3 by six months of interest, accrued at the approved nominal rate of return; and
5. a summation of the above amounts to derive the closing balance for each year.

ActewAGL Distribution has amended item 3 to reflect that there were no approved jurisdictional scheme charges in 2012/13 or 2013/14. Instead ActewAGL Distribution will use the forecast operating expenditure allowances for these years included in the 2009–14 Distribution Determination for the schemes determined to be a jurisdictional scheme.[161] The amendment ensures that ActewAGL Distribution is not able to recover from customers more or less than the jurisdictional scheme amounts it incurs, consistent with clause 6.18.7A(c)(2). ActewAGL Distribution proposes to report on these calculations in the relevant annual pricing proposals.

ActewAGL Distribution proposes to provide details of its calculations in the format set out in Table 13.1. In proposing variations to the amount and structure of jurisdictional scheme charges, ActewAGL Distribution is to achieve a zero expected balance on its jurisdictional scheme overs and unders account at the end of each regulatory year in the next regulatory control period.

ActewAGL Distribution proposes that the basis for estimated and forecast jurisdictional scheme payments for each jurisdictional scheme is set out in each annual pricing proposal (see initial proposal in the *ActewAGL Distribution 2014/15 Network Pricing Proposal*—Table 3.9).

[160] AER 2009, *Final decision, Australian Capital Territory distribution determination 2009–10 to 2013–14*, 28 April, p 182

[161] For the 2009–14 regulatory period forecast amounts for schemes determined to be jurisdictional schemes are included in the operating expenditure forecasts. During the period, ActewAGL Distribution submitted applications for AER approval to pass through in network tariffs differences between forecast and actual payments. Under the jurisdictional scheme arrangements, introduced in 2010, forecast payments for the jurisdictional schemes are not be included in the expenditure forecasts from 2014/15 onwards.

Table 13.1 Example calculation for Jurisdictional Scheme overs and unders account

($'000)	*year t-2 (actual)*	*year t-1 (estimate)*	*year t (forecast)*
Jurisdictional schemes revenue	9,252	9,126	11,494
Jurisdictional scheme 1 payments	1,100	1,091	1,200
Jurisdictional scheme 2 payments	8,545	8,590	9,236
Total Jurisdictional Scheme Payments	9,646	9,680	10,435
Over (under) recovery for financial year	-393	-554	1,059
Overs and unders account			
Annual rate of interest applicable to balances	9.70%	9.70%	8.88%
Semi-annual rate of interest	4.74%	4.74%	4.35%
Opening balance	15	-396	-1,015
Interest on opening balance	1	-38	-90
Over/ under recovery for financial year	-393	-554	1,059
Interest on over/ under recovery	-19	-26	46
Closing balance	-396	-1,015	0

13.5 Assigning customers to tariff classes

In the Placeholder Determination for ActewAGL Distribution for 2014/15, the AER has determined that the procedures for assigning retail customers to tariff classes or reassigning retail customers from one tariff class to another, including any applicable restrictions, will be the same as those specified as part of the distribution determination for the current regulatory control period.[162]

ActewAGL Distribution proposes that the same procedures should continue to apply in the subsequent regulatory period.

ActewAGL Distribution recognises that the AER is required to make a constituent decision on the procedures for assigning customers to tariff classes. However, these procedures should not in any way restrict the flexibility that ActewAGL Distribution provides to its customers that allows them to choose the tariff which best suits their needs (subject to some eligibility requirements). Customer choice is a central element of ActewAGL Distribution's network pricing strategy.

[162] AER 2014, *ActewAGL, Placeholder determination for the transitional regulatory control period 2014/15*, April, p 4

13.6 The regulatory framework for network pricing

Part I of chapter 6 of the Rules contains the *Distribution pricing rules* that apply to direct control services. Together with the control mechanism and other relevant elements of the distribution determination, the pricing rules create the regulatory framework for network pricing.

Major changes to the regulatory framework for network pricing have been proposed by SCER and IPART. The AEMC is reviewing the rule change proposals and a final decision is not scheduled until November 2014, several months after this regulatory proposal is submitted.[163]

A key component of the proposed changes is a new requirement for DNSPs to include in their regulatory proposals a Pricing Structures Statement (PSS). The scope and role of the PSS is to be determined through the AEMC's review process. ActewAGL Distribution sees a potential role for a PSS in informing customers and providing a basis for engagement and consultation on network tariffs.

Therefore, while not a formal requirement at this stage, ActewAGL Distribution provides information on its proposed tariff strategy and structures in the following sections of this regulatory proposal. This provides context for the discussion of indicative prices and estimated bill impacts in the final two sections of the chapter.

13.7 ActewAGL Distribution's network pricing strategy

ActewAGL Distribution has developed and refined its network tariff structure over time, guided by its network pricing strategy. The current high level strategy, as set out in the annual network pricing proposals submitted to the AER, involves:

- Setting prices to signal to customers the economic costs of providing distribution services;
- Providing customers with a choice of flexible and innovative tariffs to best meet their needs;
- Providing incentives and opportunities for demand management;
- Ensuring that tariffs are set to recover costs in a way that encourages efficient use of the network and signals to customers the cost of network expansion; and,
- Offering customers a clear and simple tariff structure, noting the need to take account of the ability of different customer groups to respond to price signals and the need to keep transactions costs low.

ActewAGL Distribution's network pricing strategy has resulted in the introduction of a range of cost reflective tariffs designed to meet the diverse needs of customers. The current network

[163] AEMC 2013, *Consultation paper, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, November

tariff structure already has many of the cost reflective features, including time-of-use and capacity charges that have been advocated by the AEMC, the AER, industry groups and others, in the ongoing public debate about electricity pricing.

- More than 50 per cent of the total load in the ACT (and nearly 80 per cent of the non-residential load) is now subject to time-of-use or controlled load (off-peak) charges. Time-of-use tariffs have been the default tariffs for all new customers since October 2010.
- The application of maximum demand and capacity tariffs in most of our commercial tariff options has further strengthened incentives for efficient use of the network resulting in improved load factors.
- The tariff structure is subject to ongoing review to ensure that the needs and preferences of our customers are met and any emerging network issues are addressed in the most efficient and effective way.

13.7.1 The tariff re-alignment initiative

In preparation for the 2014–19 regulatory period, ActewAGL Distribution has commenced a review of network tariffs. The broad aims of ActewAGL Distribution's tariff re-alignment initiative are to ensure that the tariff structure continues to provide cost reflective price signals to consumers, and to respond to the risks and opportunities created by recent and emerging developments including:

- *Changing patterns of energy consumption and use.* For example, average annual electricity consumption in the ACT has been falling sharply in recent years. For residential customers, average annual consumption was 7,765 kWh in 2012/13, significantly below the average of 8,695 kWh in 2002/03. For new residential customers on the network TOU tariff, average consumption was 4,580 kWh in 2012/13.
- *New technologies for energy supply and use.* For example, the strong growth in rooftop solar photovoltaic (PV) capacity and the ongoing development of battery storage technologies are creating potential network management issues and revenue risks. There are also opportunities associated with new technologies. Advanced metering technology is making more widespread adoption of time-of-use tariffs and capacity or demand charges feasible.
- *Increasing public and regulatory focus on the need for cost reflective tariffs*. In this context it is important for network service providers to examine current and potential tariffs and identify options that may encourage better utilisation of existing networks (particularly at off-peak times), reduce peak demand, delay or reduce the need for capacity expansion, and thereby reduce upward pressure on network prices.

ActewAGL Distribution has identified some areas for potential tariff reform during the coming regulatory period (subject to continuing analysis and consultation):

- Further encouragement of take-up of time-of-use tariffs, particularly for residential customers;
- A gradual rebalancing of charges, to reduce the reliance on flat energy charges and increase the reliance on more cost reflective tariff components including capacity charges, time-of-use charges and supply charges where this best ensures the right economic incentives are provided to customers; and
- A simplification of the tariff schedule, removing tariffs and tariff options which may no longer be relevant or appropriate, in light of changing consumption patterns and load profiles.

ActewAGL Distribution has also been active in pressing for better price signals from TransGrid. There are currently limited economic price signals in the charges from TransGrid, with the main focus on cost recovery.[164]

13.8 Current network tariff structure

ActewAGL Distribution proposes to retain the three current tariff classes: residential, low voltage (LV) commercial and high voltage. Residential customers are offered a choice of four network tariff options (including a time-of-use tariff) plus two controlled load off-peak options and an embedded renewable generation tariff option. Commercial LV customers are offered four main tariff options (including tariffs with time-of-use and capacity charges), as well as controlled load off-peak tariff options and the embedded renewable generation tariff option. Commercial high voltage (HV) customers are offered four tariff options.

Customers have the flexibility to choose the tariff which best suits their needs and load profile, subject to some eligibility requirements (which are set out in the annual network pricing proposal and the *Statement on Network Tariffs*, published on ActewAGL Distribution's website). A copy of the 2014/15 Network Pricing Proposal is provided at Attachment F5.

While some areas for reform have been identified in the tariff re-alignment project, at this stage no major changes proposed to the tariff structures offered within these three classes are proposed. The tariff re-alignment initiatives will largely involve changes to tariff components within the current structures, and measures to encourage adoption of the more cost reflective tariffs. The introduction of more significant changes would depend on outcomes from metering and pricing rule change processes. For example, new requirements for metering may make some new tariff options feasible. However, the outcomes from these rule change processes are unknown at this stage, though they are likely to require an extensive reworking of existing network price modelling to ensure compliance with the new rules.

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[164] ActewAGL Distribution has raised this matter with TransGrid (for example, in a submission of 19 December 2013 to TransGrid's public consultation on transmission pricing) and in submissions to the AEMC.

13.9 Indicative standard control services prices

Indicative distribution use-of-system (DUOS) charges for the subsequent regulatory period are shown in Table 13.2 below. The 2014/15 prices are as submitted to the AER in the *ActewAGL Distribution 2014/15 Network Pricing Proposal.* DUOS prices in 2014/15 have been reduced 17.5 per cent on average, reflecting the AER approved X factor reducing prices by 19.59 per cent and inflation offsetting that by 2.93 per cent. A copy of the proposal is provided at Attachment F5.

In the first year of the subsequent regulatory period (2015/16), prices have been increased to recover an X factor of 14.69 per cent and forecast CPI of 2.53 per cent. In the final 3 years of the period, DUOS prices rise to meet the revenue requirement of a 1.5 per cent X factor and inflation forecast at 2.53 per cent per annum. The relatively high X factor in 2015/16, compared with the following 3 years, reflects in part the need to recover the additional revenue requirement not recovered in 2014/15 under the AER's placeholder determination.

The actual DUOS prices will be approved each year through the AER's annual network pricing approval process. The approved DUOS prices will depart from the indicative prices due to variations in inflation, the number of customers, demand and energy consumption.

Table 13.2 Indicative distribution use-of-system charges 2014/15 to 2018/19 (excluding GST)

Code	Description	Unit	2014/15	2015/16	2016/17	2017/18	2018/19
10	**Residential Basic Network**						
	Network access charge	cents/day	23.16	27.26	28.50	29.75	31.03
	Energy consumption	cents/kWh	4.44	5.22	5.46	5.70	5.94
15	**Residential TOU Network**						
	Network access charge	cents/day	23.16	27.26	28.50	29.75	31.03
	Energy consumption at max times	cents/kWh	7.88	9.27	9.69	10.12	10.55
	Energy consumption at mid times	cents/kWh	4.85	5.70	5.96	6.22	6.49
	Energy consumption at economy times	cents/kWh	3.30	3.89	4.07	4.24	4.43
20	**Residential 5000 Network**						
	Network access charge	cents/day	44.36	52.22	54.60	56.98	59.43
	Energy consumption for the first 60 kWh per day	cents/kWh	2.98	3.50	3.66	3.82	3.99
	Energy consumption above 60 kWh per day	cents/kWh	4.44	5.22	5.46	5.70	5.94
30	**Residential with Heat Pump Network**						
	Network access charge	cents/day	87.06	102.48	107.15	111.82	116.64
	Energy consumption for the first 165 kWh per day	cents/kWh	1.63	1.92	2.01	2.10	2.19
	Energy consumption above 165 kWh per day	cents/kWh	4.44	5.22	5.46	5.70	5.94
40	**General Network**						
	Network access charge	cents/day	42.67	50.23	52.52	54.81	57.17
	Energy consumption for the first 330 kWh per day	cents/kWh	8.33	9.81	10.26	10.70	11.16
	Energy consumption above	cents/kWh	10.58	12.46	13.03	13.59	14.18

Code	Description	Unit	2014/15	2015/16	2016/17	2017/18	2018/19
	330 kWh per day						
60	**Off-Peak (1) Night Network**						
	Energy consumption	cents/kWh	0.10	0.12	0.12	0.13	0.13
70	**Off-Peak (3) Day & Night Network**						
	Energy consumption	cents/kWh	0.23	0.27	0.29	0.30	0.31
80	**Streetlighting Network**						
	Network access charge	cents/day	43.00	50.61	52.92	55.23	57.61
	Energy consumption	cents/kWh	6.20	7.30	7.63	7.96	8.31
90	**General TOU Network**						
	Network access charge	cents/day	42.67	50.23	52.52	54.81	57.17
	Energy consumption at business times	cents/kWh	14.63	17.22	18.00	18.79	19.60
	Energy consumption at evening times	cents/kWh	7.22	8.50	8.88	9.27	9.67
	Energy consumption at off-peak times	cents/kWh	3.34	3.93	4.11	4.29	4.47
Low voltage time of use demand network							
101	**LV TOU kVA Demand Network**						
	Network access charge per connection point	cents/day	50.00	58.85	61.54	64.22	66.99
	Maximum demand charge	c/kVA/day	34.31	40.39	42.23	44.07	45.97
	Energy consumption at business times	cents/kWh	2.73	3.22	3.36	3.51	3.66
	Energy consumption at evening times	cents/kWh	2.09	2.46	2.57	2.68	2.80
	Energy consumption at off-peak times	cents/kWh	1.03	1.21	1.26	1.32	1.38
103	**LV TOU Capacity Network**						
	Network access charge per connection point	cents/day	50.00	58.85	61.54	64.22	66.99
	Maximum demand charge	c/kVA/day	19.61	23.09	24.14	25.19	26.28
	Capacity charge	c/kVA/day	19.61	23.09	24.14	25.19	26.28
	Energy consumption at business times	cents/kWh	3.79	4.46	4.66	4.87	5.08
	Energy consumption at evening times	cents/kWh	2.73	3.22	3.37	3.51	3.66
	Energy consumption at off-peak times	cents/kWh	1.22	1.43	1.50	1.56	1.63
High voltage time of use demand network with ActewAGL low voltage network							
111	**HV TOU Demand Network**						
	Network access charge per connection point	$/day	$19.00	$22.36	$23.38	$24.40	$25.46
	Maximum demand charge	c/kVA/day	11.86	13.96	14.59	15.23	15.89
	Capacity charge	c/kVA/day	11.86	13.96	14.59	15.23	15.89
	Energy consumption at business times	cents/kWh	2.04	2.41	2.52	2.62	2.74
	Energy consumption at evening times	cents/kWh	1.22	1.44	1.51	1.57	1.64
	Energy consumption at off-peak times	cents/kWh	0.49	0.57	0.60	0.62	0.65
112	**HV TOU Demand Network—Customer HV**						

Code	Description	Unit	2014/15	2015/16	2016/17	2017/18	2018/19
	Network access charge per connection point	$/day	$19.00	$22.36	$23.38	$24.40	$25.46
	Maximum demand charge	c/kVA/day	10.96	12.90	13.49	14.07	14.68
	Capacity charge	c/kVA/day	10.96	12.90	13.49	14.07	14.68
	Energy consumption at business times	cents/kWh	2.04	2.41	2.52	2.62	2.74
	Energy consumption at evening times	cents/kWh	1.22	1.44	1.51	1.57	1.64
	Energy consumption at off-peak times	cents/kWh	0.49	0.57	0.60	0.62	0.65
High voltage time of use demand network without ActewAGL low voltage network							
121	**HV TOU Demand Network—Customer LV**						
	Network access charge per connection point	$/day	$19.00	$22.36	$23.38	$24.40	$25.46
	Maximum demand charge	c/kVA/day	11.98	14.10	14.74	15.38	16.05
	Capacity charge	c/kVA/day	11.98	14.10	14.74	15.38	16.05
	Energy consumption at business times	cents/kWh	1.66	1.96	2.05	2.14	2.23
	Energy consumption at evening times	cents/kWh	0.89	1.04	1.09	1.14	1.19
	Energy consumption at off-peak times	cents/kWh	0.35	0.41	0.43	0.45	0.47
122	**HV TOU Demand Network—Customer HV and LV**						
	Network access charge per connection point	$/day	$19.00	$22.36	$23.38	$24.40	$25.46
	Maximum demand charge	c/kVA/day	14.64	17.23	18.02	18.80	19.61
	Capacity charge	c/kVA/day	14.64	17.23	18.02	18.80	19.61
	Energy consumption at business times	cents/kWh	2.39	2.81	2.94	3.06	3.20
	Energy consumption at evening times	cents/kWh	1.44	1.69	1.77	1.85	1.93
	Energy consumption at off-peak times	cents/kWh	0.69	0.81	0.85	0.89	0.93
135	**Small Unmetered Loads Network**						
	Network access charge	cents/day	37.70	44.38	46.40	48.42	50.51
	Energy consumption	cents/kWh	8.93	10.52	11.00	11.47	11.97

13.9.1 Impacts of jurisdictional schemes

In the 2009–14 regulatory period, costs associated with ACT jurisdictional schemes, including feed-in tariffs, the UNFT and the EIL, have been included in DUOS prices. However, in the transitional and subsequent regulatory periods, these costs are to be excluded from DUOS and recovered in a separate jurisdictional scheme charge included in network use of system (NUOS) charges.

The exclusion of jurisdictional schemes from DUOS has contributed to the reduction in DUOS charges from the final year of the 2009–14 regulatory period to the transitional regulatory period. In the final year of the 2009–14 regulatory period, jurisdictional scheme amounts were of the order of $23.1 million, and contributed an average of about 0.80 cents per kWh to DUOS charges. In 2014/15, the first year under the new jurisdictional scheme arrangements, the cost of jurisdictional schemes are estimated to amount to $26.9 million (including the refund of over recoveries in previous years) and will contribute an average of 0.98 cents per kWh to network charges.

13.9.2 Impacts of dual function assets on DUOS prices

A further factor influencing the comparison of DUOS prices between the 2009–14 regulatory period and the transitional and subsequent periods is the pricing of services provided by dual function assets.

In March 2012, the ACT network was connected to the TransGrid's transmission network at Williamsdale. Since then, ActewAGL Distribution's 132 kV network has been supporting TransGrid's transmission network. This change in function meant that most of ActewAGL Distribution's 132 kV network became classified as dual function assets.

The AER has approved ActewAGL Distribution's recovery of the costs of these assets in transmission charges.[165] This means that from 2014/15, an amount of $28.1 million, rising to $43.8 million in 2018/19, will be transferred out of DUOS costs and recovered in transmission use-of-system charges. Part of the cost of these dual function assets will be recovered in New South Wales with the remainder recovered from ACT customers through TransGrid's transmission charges. The removal of the cost of the dual function assets from the cost of the distribution network has contributed to the reduction in indicative DUOS charges, from the 2009–14 regulatory period to the transitional and subsequent regulatory periods.

13.10 Estimated impacts of DUOS and metering charges on average bills

DUOS and metering charges are estimated to represent about one third of retail tariffs for consumers on regulated retail tariffs in 2014/15 (excluding carbon tax and GST). Therefore, a change in DUOS and metering charges of 3 per cent will change retail prices by just 1 per cent. With all the network charges included (that is, DUOS plus transmission charges plus jurisdictional scheme amounts), regulated retail tariffs in 2014/15 are forecast to rise on average by 0.8 per cent in real terms (3.8 per cent in nominal terms), assuming that the carbon tax is included in the retail price.

The following tables show the estimated impact of the proposed standard control and alternative control charges on average consumers' bills.[166] The estimated bills for 2013/14 are based on the actual regulated retail prices for that year. The estimated bills for 2014/15 are

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[165] AER 2013, *Stage 1 Framework and Approach—ActewAGL,* March

[166] The proposed prices for alternative control metering services are provided in chapter 15 of this regulatory proposal.

based upon the forecast prices, assuming that the carbon tax is repealed. For subsequent years, the retail component together with TUOS charges and the cost of jurisdictional schemes are assumed to be constant. This allows the impact on consumer bills of the proposed changes to DUOS and metering charges to be assessed. In determining these charges, the CPI applied in 2014/15 was 2.93 per cent and in subsequent years 2.53 per cent. GST is assumed to be 10 per cent over the regulatory period.

For a residential customer consuming 5,000 kWh per annum on the regulated Home Plan tariff, the impact of the proposed standard control and alternative control (metering) charges on their bill is shown in Table 13.3.

Table 13.3 Residential basic bill—5 MWh (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$449	$391	$468	$492	$517	$543
Retail, TUOS & JS	826	$793	$793	$793	$793	$793
Total Bill	$1,275	$1,184	$1,261	$1,286	$1,310	$1,336
% Change		**-7.1%**	**6.6%**	**1.9%**	**1.9%**	**2.0%**

For a residential customer consuming 4,000 kWh per annum on the Home Plan tariff and 2,500 kWh per annum on the off-peak (night and day) tariff, the impact of the ActewAGL Distribution's proposal is shown in Table 13.4.

Table 13.4 Residential basic with off-peak bill—4 MWh basic and 2.5 MWh off-peak (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$392	$348	$418	$440	$463	$486
Retail, TUOS & JS	$969	$902	$902	$902	$902	$902
Total Bill	$1,361	$1,250	$1,320	$1,342	$1,364	$1,388
% Change		**-8.2%**	**5.6%**	**1.7%**	**1.7%**	**1.7%**

For a residential consumer on the residential time-of-use tariff, and consuming 6,000 kWh per annum of which 1,750 kWh p.a. is at max times, 2,540 kWh p.a. is at mid times, and 1,710 kWh p.a. is at economy times, the impact of the proposal is as shown in Table 13.5.

Table 13.5 Residential TOU bill 6 MWh: 1.75/2.54/1.71 MWh (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$559	$508	$607	$638	$669	$702
Retail, TUOS & JS	$874	$792	$792	$792	$792	$792
Total Bill	$1,433	$1,299	$1,398	$1,429	$1,461	$1,493
% Change		**-9.3%**	**7.6%**	**2.2%**	**2.2%**	**2.2%**

For a residential customer on the Home Saver Plan, consuming 9,000 kWh per annum, the impact to this proposal is shown in Table 13.6.

Table 13.6 Residential Home Saver Tariff bill—9 MWh (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$630	$526	$628	$660	$692	$725
Retail, TUOS & JS	$1,383	$1,318	$1,318	$1,318	$1,318	$1,318
Total Bill	$2,013	$1,844	$1,946	$1,978	$2,010	$2,043
% Change		**-8.4%**	**5.5%**	**1.6%**	**1.6%**	**1.7%**

For a customer on the residential Home Saver Plus Plan and consuming 14,000 kWh per annum, the impact of this proposal is as shown in Table 13.7.

Table 13.7 Residential Home Saver Plus Tariff bill—14 MWh (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$840	$655	$790	$829	$867	$907
Retail, TUOS & JS	$2,041	$1,957	$1,957	$1,957	$1,957	$1,957
Total Bill	$2,881	$2,612	$2,736	$2,775	$2,814	$2,854
% Change		**-9.3%**	**4.8%**	**1.4%**	**1.4%**	**1.4%**

For a small commercial customer on the General Tariff and consuming 20 MWh per annum, the impact of the proposal is presented in Table 13.8.

Table 13.8 Commercial—General Tariff bill—20 MWh (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$2,262	$2,098	$2,484	$2,603	$2,722	$2,846
Retail, TUOS & JS	$3,217	$3,033	$3,033	$3,033	$3,033	$3,033
Total Bill	$5,479	$5,132	$5,518	$5,636	$5,756	$5,879
% Change		**-6.4%**	**7.5%**	**2.1%**	**2.1%**	**2.1%**

For an average commercial customer on the General Time-of-Use tariff using 40 MWh per annum, the impact of the proposal is presented in Table 13.9.

Table 13.9 Commercial—General TOU Tariff bill—40 MWh (15/8/17 MWh) (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$4,489	$3,938	$4,650	$4,869	$5,085	$5,310
Retail, TUOS & JS	$5,359	$5,045	$5,045	$5,045	$5,045	$5,045
Total Bill	$9,849	$8,983	$9,695	$9,912	$10,130	$10,356
% Change		**-8.8%**	**7.9%**	**2.2%**	**2.2%**	**2.2%**

Large commercial customers on the low voltage demand tariff face demand as well as time-of use charges. For a customer with an average profile consuming 500 MWh per annum, the proposed prices have the impact shown in Table 13.10.

Table 13.10 Low Voltage Demand Tariff bill—500 MWh (208/72/220 MWh, 130 kVA) (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$36,873	$29,256	$34,556	$36,563	$38,186	$39,843
Retail, TUOS & JS	$71,069	$69,057	$69,057	$69,057	$69,057	$69,057
Total Bill	$107,942	$98,313	$103,613	$105,232	$106,857	$108,538
% Change		**-8.9%**	**5.4%**	**1.6%**	**1.5%**	**1.6%**

For larger commercial customers using the low voltage capacity charge using 1 GWh per annum, the estimated impact of the proposal is shown in Table 13.11.

Table 13.11 Low Voltage Capacity Tariff bill—1 GWh (350/150/500 MWh; 190/225 kVA) (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$60,185	$59,433	$70,077	$73,316	$76,560	$79,910
Retail, TUOS & JS	$136,693	$118,083	$118,083	$118,083	$118,083	$118,083
Total Bill	$196,879	$177,515	$188,159	$191,398	$194,643	$197,993
% Change		**-9.8%**	**6.0%**	**1.7%**	**1.7%**	**1.7%**

14 Arrangements for negotiation

This chapter outlines why ActewAGL Distribution does not require a negotiating framework or Negotiated Distribution Service Criteria (NDSC) for the 2014–19 regulatory period.

14.1 Regulatory requirements

Part D of chapter 6 of the Rules contains the regulatory requirements for negotiated distribution services. Clause 6.7.2 requires DNSPs to comply with:

- the provider's negotiating framework; and
- the provider's Negotiated Distribution Service Criteria (NDSC),

when the provider is negotiating the terms and conditions of access to negotiated distribution services.

Clause 6.7.5(a) requires the provider to prepare a document (the negotiating framework) setting out the procedure to be followed during negotiations between that provider and any person (the Service Applicant or applicant) who wishes to receive a negotiated distribution service from the provider, as to the terms and conditions of access for the provision of the service. The regulatory proposal must include the proposed negotiating framework, "for those services classified as negotiated distribution services" (clause 6.8.2(c)(5)).

Under clause 11.56.3(a)(9), ActewAGL Distribution's 2009–14 negotiating framework continued to apply for the transitional regulatory period. In the Placeholder Determination for the 2014/15 regulatory year the AER determined that the NDSC for ActewAGL Distribution for the transitional regulatory control period "are the negotiated distribution service criteria that were specified as part of the distribution determination for the current regulatory control period for ActewAGL".[167]

Clauses 6.12.1(15) and (16) require the AER to include in its determination for the subsequent regulatory period decisions on the negotiating framework and the NDSC to apply for the subsequent regulatory period, 1 July 2015 to 30 June 2019.

[167] AER 2014, *ActewAGL, Placeholder determination for the transitional regulatory control period 2014/15*, April, p 4

14.2 Negotiated services

In the Stage 1 Framework and Approach (Stage 1 F&A) paper the AER did not classify any of ActewAGL Distribution's services as negotiated services.[168]

In accordance with the Stage 1 F&A paper, neither ActewAGL Distribution nor the AER classified any of ActewAGL Distribution's services as negotiated services in the transitional regulatory proposal or in the Placeholder Determination.

As set out in chapter 2 of this regulatory proposal, ActewAGL Distribution proposes not to have any negotiated distribution services for the subsequent regulatory control period.

14.3 Negotiating framework

In the Placeholder Determination the AER determined that the negotiating framework that was to apply to ActewAGL for the transitional regulatory control period was the negotiating framework that was approved as part of the distribution determination for the 2009–14 regulatory period for ActewAGL Distribution.[169]

As ActewAGL Distribution proposes not to have any negotiated distribution services for the 2014–19 regulatory period to which a negotiating framework would apply, ActewAGL Distribution understands that there is no requirement to include a proposed negotiating framework in this regulatory proposal.

ActewAGL Distribution notes that if it was required to include a proposed negotiating framework in this regulatory proposal, then the proposed negotiating framework would be a version of the negotiating framework that was approved as part of the AER's Placeholder Determination but updated to reflect the terminology under current chapter 6 of the Rules. This updated negotiating framework can be provided if required by the AER.

The chapter 5 and 5A of the Rules contain requirements for negotiation of connection services. As noted in chapter 4 of this regulatory proposal, the chapter 5 Rules were amended by the AEMC in April 2014 and proposed amendments to chapter 5A are currently being assessed. The proposed changes would "increase the level of prescription in the Chapter 5A negotiation process".[170]

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[168] AER 2013, *Stage 1 Framework and Approach—ActewAGL*, March, p 9

[169] AER 2013, *ActewAGL, Placeholder determination for the transitional regulatory control period 2014/15*, April, p 3

[170] AEMC 2014, *Connecting embedded generators under chapter 5A, Information paper*, May, p 1

14.4 Negotiated distribution service criteria

In the Placeholder Determination, the AER determined that the Negotiated distribution service criteria (NDSC) for ActewAGL Distribution for the transitional regulatory control period were the NDSC that were specified as part of the distribution determination for the 2009–14 regulatory period for ActewAGL Distribution.[171]

As ActewAGL Distribution proposes not to have any negotiated distribution services for the 2014–19 regulatory control period to which NDSC would apply, ActewAGL Distribution understands that there is no requirement to prescribe NDSC for the 2014–19 regulatory period.

In any event, ActewAGL Distribution notes that the NDSC that was approved as part of the AER's Placeholder Determination could be adopted for the balance of the 2014–19 regulatory period if the terminology was updated to reflect current chapter 6 of the Rules.

[171] AER 2013, *ActewAGL, Placeholder determination for the transitional regulatory control period 2014/15*, April, p 4

15 Alternative control services

The AER has classified ActewAGL Distribution's metering services (type 5 to 7) and ancillary services as alternative control services for the transitional and subsequent regulatory periods.[172] These services represent a relatively small component of ActewAGL Distribution's services, together accounting for around 5 per cent of total distribution services revenue in the 2009–14 regulatory period.

The Rules regarding alternative control services are less prescriptive than those applying to standard control services. For example, while standard control services revenues and prices must be determined using a detailed building block analysis, as set out in Part C of chapter 6, the control mechanism for alternative control services "may (but need not) utilise elements of Part C".[173]

The different regulatory requirements for alternative and standard control services recognise their different characteristics. As noted by the AER, standard control services are central to electricity supply and are relied on by most, if not all, customers. In contrast, alternative control services may be customer specific or customer requested, and may also have the potential for provision on a competitive basis.[174]

ActewAGL Distribution considers that its proposals for alternative control services, set out in this chapter, will result in benefits for consumers by providing cost reflective prices, set in a transparent way and subject to a defined price path over the regulatory period. Customers will only bear the costs of providing these specific services if and when they require the services.

15.1 Regulatory requirements

The Rules set out the regulatory proposal requirements and the constituent decisions that the AER must make in relation to alternative control services.

The regulatory proposal must:

- include a service classification proposal (clause 6.8.2(c)(1));
- include a demonstration of the application of the control mechanism, as set out in the framework and approach paper, and the necessary supporting information (clause 6.8.2(c)(3));

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[172] Type 1 to 4 metering services are classified by the AER as unregulated services.

[173] *National Electricity Rules*, clause 6.2.6(c)

[174] AER 2013, *Stage 1 Framework and Approach—ActewAGL*, March, p 8

- include indicative prices for each year of the regulatory control period (clause 6.8.2(c)(4)); and
- comply with the requirements of, and must contain or be accompanied by the information required by, any relevant regulatory information instrument (clause 6.8.2(d)). The requirements in relation to alternative control services are set out in sections 12, 13 and 14 of Schedule 1, sections 19 and 20 of Appendix E and templates 4.2, 4.3 and 4.4 of the RIN.

The AER's constituent decisions are set out in clause 6.12.1 of the Rules. The following constituent decisions are relevant for alternative control services:

- a decision on the classification of the services to be provided by the *Distribution Network Service Provider* during the course of the *regulatory control period* (clause 6.18.1(1));
- a decision on the form of the control mechanisms for alternative control services (to be in accordance with the relevant framework and approach paper) and on the formulae that give effect to those control mechanisms (clause 6.18.1(12)); and
- a decision on how compliance with a relevant control mechanism is to be demonstrated (clause 6.8.12(13)).

An overview of ActewAGL Distribution's proposals in relation to the constituent decisions for alternative control services is provided in section 15.2, and further details are provided in sections 15.3 (for metering) and 15.4 (for ancillary services). Indicative prices for the subsequent regulatory period are provided in Attachment F3.

15.2 Overview of ActewAGL Distribution's proposals for alternative control services

15.2.1 Classification of alternative control services

ActewAGL Distribution proposes to adopt:

- the AER's classification, as set out in the Stage 1 F&A paper, of metering services as alternative control services. The services to be covered are described in section 15.3 below;
- the AER's classification, as set out in the Stage 1 F&A paper, of ancillary services as alternative control services. The services to be covered are described in section 15.4 below.

ActewAGL Distribution also seeks clarification from the AER regarding the classification of large scale embedded generation connection services. ActewAGL Distribution proposes that these services be classified as alternative control services. The basis for this proposal is set out in section 15.5 below.

15.2.2 Control mechanisms for alternative control services

The AER's F&A decision on the form of the control mechanism is binding for the subsequent regulatory period, under clause 6.12.3(c) of the Rules. ActewAGL Distribution therefore accepts the AER's determination in the Stage 1 F&A paper that the control mechanism for alternative control services will be price caps on individual services.

While the *form* of the control mechanism for alternative control services must be price caps, as specified in the Stage 1 F&A paper, the *basis* for the control mechanism is to be determined in the distribution determination process.[175]

ActewAGL Distribution proposes the following basis for the control mechanisms:

- For metering services, a limited building block approach, consistent with the approach adopted in the 2009–14 regulatory period; and
- For ancillary services, a cost-build-up approach. Ancillary services related to metering (special meter reads, meter tests, install interval meter at customer request and install meter to facilitate micro renewable energy installation) are included in this group.

ActewAGL Distribution considers that the proposed basis for the control mechanisms are the most appropriate, when assessed against the criteria set out in clause 6.2.5(d) of the Rules (discussed further below)

15.3 Metering services (types 5 to 7)

For the 2009–14 regulatory period the AER classified ActewAGL Distribution's type 5 to 7 metering services as alternative control services and applied a revenue cap control mechanism. A limited building block analysis was used to establish the revenue requirement.[176]

For the transitional and subsequent regulatory periods the AER has retained the alternative control services classification, but changed the control mechanism from the revenue cap to individual price caps.

ActewAGL Distribution accepts the AER's classification of metering services and notes that there are no unforeseen circumstances which could justify a departure from the classification,[177] of the following services as alternative control:

- commissioning of metering and load control equipment;
- provision of types 5 to 7 meters;[178]

[175] *National Electricity Rules*, clause 6.2.6(b)

[176] AER 2009, *Final decision, Australian Capital Territory distribution determination 2009–10 to 2013–14*, 28 April, chapter 18

[177] As permitted under clause 6.12.3(b) of the Rules

- types 5 to 7 metering data services (metering data services involve the collection, processing, storage and delivery of metering data and the management of relevant NMI Standing Data in accordance with the Rules);
- scheduled meter read;
- maintaining and repairing meters and load control equipment;
- meter test during business hours (refunded if meter proves to be faulty);
- special meter reading or check read (refunding if original reading was incorrect);
- install interval meter at customer's request; and
- replace meter to facilitate renewable energy installation.[179]

15.3.1 Proposed basis for the metering control mechanism

ActewAGL Distribution proposes to apply a building block approach to determine the price caps for metering services.[180] ActewAGL Distribution's proposed approach is a continuation of the approach adopted in the 2009–14 regulatory period. The same PTRM, RFM and TAB models are used (although some of the cost categories have changed).[181] An assessment of the proposed approach against the factors the AER is required to consider, under clause 6.2.5(d) of the Rules, is provided in Table 15.1.

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[178] The AER's RIN for the 2014-19 ACT determination includes the following definitions: Type 5 meter—manually read interval meter that records interval energy data, which is not a remotely read interval meter; Type 6 meter—manually read accumulation meter which measures and records electrical energy in periods in excess of a trading interval.

[179] AER 2013, *Stage 1 Framework and Approach—ActewAGL*, March, p 52

[180] Other than ancillary metering services, which are subject to the cost build-up approach, along with other ancillary services.

[181] In addition, as all new meter installations are required to be electronic type 5 meters, the asset lives for regulated meters have been reduced to 15 years. This is consistent with Nutall's advice and the AER's final decision for Aurora Energy in 2012. See: Nutall Consulting 2011, *Aurora Revenue Review*, 11 November, pp 185-187

Table 15.1 Assessment of basis of control against NER factors

NER factor	*Assessment*
The potential for the development of competition in the relevant market and how the control mechanism might influence that potential.	The choice of the basis for the control mechanism is unlikely to affect the potential for competition to develop.
The possible effects on the administrative costs of the AER, the DNSP and users.	Administrative costs will be minimised by continuing to apply the current building block approach. Moving to an alternative such as a cost build-up or annuity approach (as considered but rejected by the AER for Aurora's 2011 determination)[182] would involve higher administrative costs.
Previous regulatory arrangements applicable to the relevant service immediately prior to the start of the distribution determination.	The proposed approach has been used in the ACT for the 2009–14 regulatory period and remains appropriate for the subsequent regulatory period.
Desirability of a consistency between regulatory arrangements for similar services	A building block approach has been applied to metering services across the NEM—separately as alternative control services in the ACT, Tasmania and South Australia, and as part of standard control services in Queensland and New South Wales.[183]
Any other factor	A further relevant factor is consistency with the NEO. This requires that the approach adopted allows ActewAGL Distribution to recover at least the efficient costs of providing the services, including an allowance for efficient capital costs incurred. The building block analysis is best suited to meeting this objective.

15.3.2 Metering services and cost drivers

Under chapter 7 of the Rules ActewAGL Distribution is the responsible person for types 5, 6 and 7 metering installations in the ACT connected to, or proposed to be connected to, ActewAGL Distribution's network.[184] The regulatory obligations set out in the Rules, AEMO's *National Electricity Market Metrology Procedure*, the ICRC's 2005 *Final Decision—Review of Metrology Procedures* and the *Electricity Metering Code 2003* are key drivers of ActewAGL Distribution's metering asset management and expenditure programs. Other regulatory obligations, for example relating to occupational health and safety, are also important drivers of metering expenditures. (Details on the obligations that apply across the electricity distribution business, not only to metering, are provided in chapter 4 of this regulatory proposal.)

[182] AER 2011, *Aurora Energy distribution determination 2010-15, draft decision*, appendix C

[183] The classification of Type 5 to 7 metering services in New South Wales has changed from standard control to alternative control for the transitional and subsequent regulatory periods.

[184] *National Electricity Rules*, clause 7.2.3

ActewAGL Distribution's Meter Asset Management Plan (MAMP), prepared in accordance with AEMO's requirements, sets out the plan for meter installation, replacement, testing and inspection for type 5 and type 6 meters (type 7 metering is unmetered) and LV current transformers (where applicable). A copy of the MAMP is provided at Attachment D6.

In addition to regulatory obligations, other major drivers of ActewAGL Distribution's metering costs include labour costs, meter costs and other input costs. Information on these costs is provided in the RIN templates at Attachment A3. ActewAGL Distribution procures meters and meter reading services through a competitive tender approach. Forecast metering capex and opex is discussed in sections 15.3.6 and 15.3.7 below.

15.3.3 Meter installation

Following the ICRC's *Final Decision, Review of Metrology Procedures* in December 2005, ActewAGL Distribution commenced installing type 5 (interval) meters in March 2007. The ICRC's Final Decision requires ActewAGL Distribution to install interval meters on a new, replacement and customer requested basis.[185]

Type 5 meters have higher capital and recurrent costs than type 6 meters. The higher costs are associated with their purchase price, maintenance requirements, life expectancy and meter reading costs. The standard single element, single phase type 5 meters cost almost double the equivalent type 6 meters currently installed. Type 5 meters have a higher maintenance requirement and less than half the life expectancy of comparable electromagnetic accumulation meters. Details on meter costs by meter type are provided in the RIN templates.

The ongoing implementation of the new and replacement program is reflected in the changing composition of the metering asset base (increasing proportion of type 5 meters) through the 2009–14 regulatory period, as shown in Table 15.2. Further details on historical and forecast meter numbers are provided in the RIN templates (table 4.2.1).

Table 15.2 ActewAGL Distribution's metering assets

Number of meters *	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14**
Type 5	24,402	35,696	47,390	59,074	66,659
Type 6	153,096	147,243	141,484	135,652	131,255
Total meters	177,498	182,939	188,874	194,726	197,914
Type 5 as % of total	13.7%	19.5%	25.1%	30.3%	33.7%
LVCTs	5,400	5,169	5,169	6,369	7,567

* As at March 2014

185 ICRC 2005, *Final Decision, Review of Metrology Procedures*, Report 15, December, p 31

ActewAGL Distribution's estimates of the number of new meter installations are shown in Table 15.3. New meters associated with rooftop photovoltaic (PV) installations are shown separately (in italics) to other new meter installations. The main driver of the indicative estimates of the number of new meter installations (not for PV) is the level of activity in the construction sector in the ACT. The estimated 7,600 new installations each year (8,150 less 550 for PV) include around 600 brownfield upgrades (an upgrade that includes work on the service) and around 1,700 simple meter upgrades, including upgrade to three phase or replacement during a board upgrade, which is not counted in the replacement program. With this factored in, the net increase in the meter population is consistent with the historical trend.

The demand for meters for PV installations is driven by different factors, including government policies and incentives, the cost of PV installations and electricity prices. Demand has fallen significantly from the previous peaks, when the ACT feed-in tariff scheme for small-scale (less than 30 kW) installations was still open to new applicants. The estimates show a take-up rate of approximately 550 meters per annum over the 2014–19 regulatory period. This represents a significant reduction from the almost 2,500 PV meters installed in 2013/14.

Table 15.3 Estimates of new and replacement meter installations

	2014/15	*2015/16*	*2016/17*	*2017/18*	*2018/19*
New meters	8150	8150	8150	8150	8150
New PV meters	*550*	*550*	*550*	*550*	*550*
Meter replacements	3650	3650	3650	3650	3650

ActewAGL Distribution plans to replace approximately 3,650 meters per year over the 2014–19 regulatory period. ActewAGL Distribution has formulated its domestic meter replacement programs and expenditure forecasts based on the MAMP.

The following meters are targeted for replacement:

- Meters that have exceeded their life expectancy of 40 years or older. As at 28 February 2014, ActewAGL Distribution had 16,117 meters in this category;
- Direct or low voltage CT connected type 6 meter populations with less than 8 meters; and
- All meters with jewelled bearings have been identified for disposal. (*Email-BAZ* all variants, *Email-SD*, *Email-SDP*, *W&F-WF2* and *Feranti-TM2C*).

The estimates of new meter installations are subject to a high degree of uncertainty. Major changes to the regulatory framework for metering services were recommended by the AEMC in the November 2012 *Power of Choice* review, and in October 2013 the SCER submitted a set of rule change proposals to implement the recommendations. The AEMC released a consultation paper on the rule change proposals in April 2014.[186]

Under the current Rules, ActewAGL Distribution is the *responsible person* for type 5 and 6 meters in the ACT. Other potential providers are not able to compete to provide type 5 and 6 meters. As SCER explains in its Rule change request, under the proposed changes Local Network Service Providers (LNSPs) would:

- no longer have the exclusive right to provide type 5, 6 or 7 metering services, unless other arrangements are specified by a jurisdiction.
- be required to compete with other accredited metering service providers to supply metering services to small customers.[187]

SCER also says that LNSPs would "have minimal stranding risk on their existing metering assets given an appropriate exit fee that has been approved by the AER".[188] ActewAGL Distribution will consider the introduction of an exit fee during the regulatory period, to manage the risk associated with customers switching from accumulation or manually-read interval meters to alternative metering assets provided by alternative suppliers (see section 15.3.9 below).

Uncertainty about the final form of the metering rules, likely future developments in metering technology and costs, the extent to which competition will develop in markets for metering services, and future policies in relation to PV systems make it difficult to develop indicative estimates over a 5 year horizon.

15.3.4 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 using calibrated portable test equipment. 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 2013 and re-inspected in

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[186] AEMC 2014, *Expanding competition in metering and related services, Consultation paper*, April.

[187] SCER 2013, Metering Rule change proposal, October, p 23

[188] SCER 2013, Metering Rule change proposal, October, p 23

2018. As required by clause S7.3.1(f) of the *Rules*, the officer responsible for electricity meter maintenance will:

- provide the test results to AEMO (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.

Meter population samples are based on “variables” numbers and then checked for normality using the mini tab statistical software package. If the normality criteria are met, then the results will stand, if not, then further tests are carried out to satisfy “attribute” numbers.

15.3.5 Meter reading

ActewAGL Distribution currently has meter reading contracts with Fieldforce Services Pty Ltd (Fieldforce) and Ecowise Services (Australia) 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.

Prior to expiry on 30 June 2015, 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.

15.3.6 Forecast metering capital expenditure

ActewAGL Distribution’s forecast metering capex is shown in Table 15.4. The forecasts have been prepared using ActewAGL Distribution’s expenditure forecasting methodology, as notified to the AER in November 2013, in accordance with clause 6.8.1A of the Rules. The methodology was prepared in accordance with the AER’s guidelines.[189] An updated version of methodology can be found at Attachment B19 to this proposal.

The zero-based methodology used to develop the capital expenditure forecasts applies a *bottom-up* construction of expenditure associated with projects. Expenditure forecasts are then escalated throughout the regulatory period in line with independently verified material and labour cost escalators. The meter cost escalators are shown in chapter 7 (Table 7.4) and the labour escalators are shown in chapter 8 (Table 8.7).

The forecast capex reflects ActewAGL Distribution’s ongoing program of installation of new meters and replacement of aged meters as part of a sustainable asset replacement plan (as set out in the MAMP), using meter equipment procured through a competitive tender process.

[189] AER 2013, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November

Table 15.4 Forecast metering capital expenditure

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
New meters	4.7	4.7	4.7	4.8	4.9	**23.9**
Meter replacements	1.7	1.7	1.7	1.7	1.8	**8.7**
Total	**6.4**	**6.4**	**6.4**	**6.5**	**6.7**	**32.4**

The actual and forecast metering capex for the 2009–14 regulatory period are shown in Table 15.5. The table shows that actual metering capex was less than the forecast for the 2009–14 regulatory period. The major difference, in 2009/10, was due to the discontinuation of the Multi-utility Integrated Metering Infrastructure Project (Project MIMI). In other years the actual and forecast were much closer.

A comparison of the actual and forecast capex in Table 15.4 and Table 15.5 also indicates a step change from 2013/14 to 2014/15. This step change reflects the application of ActewAGL Distribution's new CAM, approved by the AER in June 2013. It also reflects the increase in the forecast number of new meter installations.

Table 15.5 Actual and forecast metering capex 2009–14

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Forecast	7.13	3.96	3.85	3.96	3.73	**22.63**
Actual (net of capital contributions)	3.92	3.77	3.64	4.25	4.36	**19.94**
Difference	**-3.21**	**-0.19**	**-0.21**	**-0.29**	**0.63**	**-2.69**

15.3.7 Forecast metering operating and maintenance expenditure

ActewAGL Distribution's forecast metering opex is shown in Table 15.6. The forecasts have been prepared using ActewAGL Distribution's expenditure forecasting methodology, which is provided as Attachment B19 to this regulatory proposal

Operating costs are primarily for meter reading. As noted above, ActewAGL Distribution contracts out its meter reading services through a competitive tendering process. A base year approach is used to prepare the operating cost forecasts, with 2012/13 as the base year. Maintenance costs are associated with meter testing, condition monitoring and visual inspection. Maintenance costs forecasts are developed using the zero base methodology, or *bottom up* approach. Labour costs are escalated in accordance with the escalators shown in Table 8.7. A further breakdown of metering costs is provided in the RIN templates (see table 4.2.2).

Table 15.6 Forecast metering operating expenditure 2014–19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Network Maintenance Costs	1.22	1.52	1.56	1.60	2.33	**8.22**
Network Operating Costs	1.50	1.53	1.56	1.60	1.63	**7.82**
Other expenditures	0.52	0.56	0.52	0.57	0.75	**2.92**
Total	**3.24**	**3.61**	**3.65**	**3.77**	**4.70**	**18.97**

Actual and forecast metering opex for the 2009–14 regulatory period are shown in Table 15.7. The table shows that ActewAGL Distribution's actual opex increased over the period, reflecting the increasing proportion of type 5 meters (which have higher recurrent costs). Over the period, actual opex was slightly below the forecast. The underspend arises mainly because the meter replacement program was below forecast levels.

A comparison of Table 15.6 and Table 15.7 also indicates that the forecast total opex for 2014/15 is significantly higher than actual (estimate) for 2013/14. The step change in maintenance costs reflects additional meter reading costs arising from the growth in meter numbers and the increasing proportion of type 5 meters. The step change also reflects the new AER approved CAM, under which additional overheads are allocated to alternative control services.

Table 15.7 Forecast and actual and forecast metering operating expenditure 2009–14

$ million (2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Total Forecast	2.49	2.04	2.15	1.92	2.04	**10.64**
Actual Network Maintenance Costs	0.57	0.62	0.40	0.57	0.32	**3.04**
Actual Network Operating Costs	1.14	1.05	1.51	1.45	1.47	**6.62**
Total Actual	1.70	1.66	1.90	2.01	2.35	**9.61**
Difference	**-0.79**	**-0.38**	**-0.25**	**0.09**	**0.31**	**-1.03**

15.3.8 Building blocks and revenue requirement

ActewAGL Distribution's proposed building blocks and revenue requirement for metering services are shown in Table 15.8. As noted previously (in the discussion of the basis for the control mechanism), ActewAGL Distribution's metering services PTRM and RFM have been used to derive the revenue requirement and the X factors. The X factors are the average annual price adjustments (in addition to CPI) necessary to generate the forecast revenue requirement, based on forecast volumes or quantities. The models are provided in Attachment B.

Table 15.8 Metering revenue building blocks

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Return on capital	4.5	5.0	5.4	5.8	6.2
Regulatory depreciation	1.8	2.2	2.7	3.1	3.7
Operating expenditure	3.4	3.9	4.0	4.3	5.4
Tax allowance	0.7	0.8	0.9	1.1	1.2
Total revenue building block (unsmoothed)	10.4	11.9	13.0	14.2	16.4
Smoothed revenue requirement	9.1	12.3	13.5	14.9	16.4
X-factor (%)	0.0	-30.1	-6.0	-6.0	-6.0

15.3.9 Proposed price caps and price path for metering services

The Rules require ActewAGL Distribution to include in the regulatory proposal indicative prices for direct control services for each year of the regulatory control period (clause 6.8.2(c)(4)).

ActewAGL Distribution proposes to retain the metering price structure that has applied for the 2009–14 and transitional regulatory periods. For each of the metering services offered, the X factors to be used in the price cap control mechanism are as shown in the final row in table 15.8. The zero X factor in 2014/15 is consistent with the transitional Rules (which require the 2013/14 prices to be escalated by CPI only, with a zero X factor). In 2015/16, a CPI+30.1 per cent increase is required to recover the revenue requirement. This relatively high increase, compared with the 6 per cent over the following years, reflects the need to recover additional revenues following the CPI only increase in 2014/15, under the AER's placeholder determination.

ActewAGL Distribution's current pricing schedule for metering services involves charges (in cents or dollars per day or per NMI) by the type of meter as shown in Table 15.9. The table shows the 2014/15 prices submitted for AER approval on 21 May 2014. As required by the transitional Rules,[190] these are the 2013/14 prices escalated by CPI. The indicative prices for metering services for each year of the subsequent regulatory period are shown in Attachment F3.

[190] *National Electricity Rules*, clause 11.56.3(j)

Table 15.9 Proposed 2014/15 price schedule for alternative control metering services (excluding GST)

Code	*Description*	*Unit*	*Price*
MP1	**Quarterly basic metering rate**		
	Accumulation and time-of-use meters read quarterly	cents per day per NMI	13.34
MP2	**Monthly basic metering rate**		
	Accumulation and time-of-use meters read monthly	cents per day per NMI	23.33
MP3	**Time-of-use metering rate**		
	Time-of-use meters read monthly	cents per day per NMI	23.33
MP4	**Monthly manually-read interval metering rate**		
	Interval meters recording at either 15- or 30-minute intervals, read manually and processed monthly	$ per day per NMI	1.88
MP6	**Quarterly manually-read interval metering rate**		
	Interval meters recording at either 15- or 30-minute intervals, read manually and processed quarterly	cents per day per NMI	53.73

As noted previously, ancillary metering services such as special meter reads are treated in the same way as other ancillary services, and are subject to a cost build-up approach instead of the building block approach. Metering ancillary services are included in the fee based ancillary services listed below in Table 15.10 below, and the indicative ancillary services prices shown in Attachment F3.

A new metering exit fee may be proposed during the regulatory period, through the annual network pricing approval process, depending on the outcome of rule change processes currently in progress. The role for exit fees, to apply when customers switch from an accumulation meter or manually-read interval meter to a new meter provided by an alternative supplier, has been recognised by the AEMC and SCER. The objective of an exit fee is to help the local distribution network business to recover the stranded (sunk) costs of its existing meters.[191]

The current Rules require that retail and distribution network businesses negotiate in good faith to ensure that the distribution network business is reasonably compensated when a type 5, 6 or 7 metering installation is upgraded. SCER proposes a change to the Rules to remove the existing requirement that compensation for accumulation or manually read interval meters be negotiated between retailers and distribution network businesses. It is proposed that the AER is given the responsibility to determine an appropriate exit fee.[192]

The final form and level of ActewAGL Distribution's exit fee will depend on the outcome of the rule change process. ActewAGL Distribution notes that exit fees are currently applied in some

[191] AEMC 2014, *Expanding competition in metering and related services, Consultation paper*, April, p 51

[192] AEMC 2014, *Expanding competition in metering and related services*, Consultation paper, April, p 51

other jurisdictions, and these fees provide a guide to what may be reasonable for the ACT. For example, the AER approved SA Power Network's exit fee for customers consuming above 100 MWh transitioning from ACS Type 6 service into the competitive market. The exit fee was determined at $232, which reflected a $170 capital cost component and a $62 administrative cost component. [193]

15.3.10 Compliance with the control mechanism

The Rules require ActewAGL Distribution to include in the regulatory proposal a "demonstration of the application of the control mechanism, as set out in the framework and approach paper, and the necessary supporting information" (clause 6.8.2(c)(3)).

The formulae for metering services (which were previously classified as alternative control services), as set out in the Stage 1 F&A paper (p 63) are as follows:

$$\overline{p}_i^t \geq p_i^t \qquad i=1,...,n \text{ and } t=1,..,4,$$

$$\overline{p}_i^t = \overline{p}_i^{t-1}(1+CPI_t)(1-X_i^t)$$

Where:

$\overline{p}_i^t$ is the cap on the price of service i in year t.

p_i^t is the price of service i in year t.

CPI_t is the percentage increase in the consumer price index. To be decided in the final decision.

X_i^t is the X-factor for service i in year t. To be decided in the final decision.

$\overline{p}_i^1$ is the cap on the price of service i in the first year of the subsequent regulatory control period. To be decided in the final decision.

Compliance is to be demonstrated by multiplying the price for each service in the previous year by CPI–X (rounded to the same number of decimal places as currently applied) and comparing that to the proposed price. Prices equal to or less than the calculated price are compliant. Compliance will be demonstrated in ActewAGL Distribution's annual network pricing proposal. The initial schedule of prices was submitted to the AER on 21 May 2014.

[193] AER 2010, *Final decision—South Australia distribution determination 2010–11 to 2014–15,* May, pp 267-272

15.4 Ancillary Services

In the Stage 1 F&A paper the AER has classified ActewAGL Distribution's ancillary network services as alternative control services for the transitional and subsequent regulatory periods. ActewAGL Distribution accepts this classification, and requests that two further services be added to the list of ancillary services: network studies, and provision of services above the least cost technically acceptable standard at the customer's request.

In addition, for pricing purposes the list of ancillary services provided by the AER in the Stage 1 F&A paper needs to be disaggregated further. For example, the AER service classification list includes one service "remove, reposition or disconnect service". This needs to be broken down into several different types of services which may be subject to different prices. The full list of proposed ancillary services, and indicative prices, is provided in Attachment F3 of this regulatory proposal.

The AER has also determined in the Stage 1 F&A paper that the control mechanism for ancillary services will be price caps on individual services. The AER's main consideration in deciding to apply price caps was that they will result in benefits in the provision of cost reflective prices.[194] The AER also indicated in the Stage 1 F&A paper:

> *Through the distribution determination process, we will confirm the basis of the control mechanism for alternative control services. That is, whether we will set prices using a building block approach or another method. Prices for certain ancillary network services will be determined on a quoted basis. ActewAGL will propose the approach to determining quoted prices, which we will consider in our distribution determination. Typically, prices for quoted services are based on quantities of labour and materials with the quantities dependent on the particular task.* [195]

ActewAGL Distribution proposes to adopt a cost build-up approach to determining the price caps for individual ancillary services. The approach differs from the building block approach adopted for metering services. This reflects the different characteristics of the services involved. Metering services involve services delivered from a large asset base, and prices must be sufficient to at least recover the efficient capital costs, as well as ongoing maintenance and operating costs. The building block approach is appropriate in this context.

In contrast, ancillary services largely involve labour inputs, with limited materials or capital inputs in most cases. The cost build-up (or "bottom-up") approach, taking account of the time spent in delivering the service, the required labour types and the labour costs, and any other input costs, including materials and contractor costs, is appropriate for ancillary services. The approach taken depends on whether the services are fee based or quoted.

[194] AER 2013, *Stage 1 Framework and Approach—ActewAGL,* March, p 10

[195] AER 2013, *Stage 1 Framework and Approach—ActewAGL,* March, p 39

15.4.1 Fee based ancillary services

ActewAGL Distribution's proposed fee based ancillary services are listed in Table 15.10. A detailed description of each service is provided in Table F3.2 in Attachment F3.

As required by the transitional Rules,[196], the 2014/15 ancillary services prices are the 2013/14 prices escalated by CPI. The proposed prices for the remainder of the regulatory period are based on a cost build-up model, which is provided in confidential Attachment B21.

Table 15.10 provides a comparison of the price and cost for each service in 2014/15. This shows that for some services the 2014/15 prices are not fully cost reflective (a positive difference indicates that costs exceed prices in 2014/15).

Table 15.10 Fee based ancillary services—comparison of prices and costs in 2014/15

Code	Service	Price	Cost	Difference %
Premise Re-energisation—Existing Network Connection				
501	Re-energise premises—Business Hours	$56.14	$65.49	16.7%
502	Re-energise premises—After Hours	$120.73	$83.01	-31.2%
Premise De-energisation—Existing Network Connection				
503	De-energise premises—Business Hours	$49.59	$65.49	32.1%
505	De-energise premises for debt non-payment	$93.55	$130.98	40.0%
Meter Reconfiguration				
507	Install Interval Meter	$66.55	$130.98	96.8%
509	Install / Replace Meter—Micro Renewable Energy Installation	$66.55	$261.96	293.6%
Meter Investigations				
504	Meter Test (Whole Current)—Business Hours	$69.23	$261.96	278.4%
510	Meter Test (CT/VT)—Business Hours	$350.00	$261.96	-25.2%
Special / Additional Meter Reads				
506	Special Meter Read	$35.55	$35.41	-0.4%
Temporary Network Connections				
520	Temporary Builders Supply—Overhead (Business Hours)	$398.64	$588.08	47.5%
522	Temporary Builders Supply—Underground (Business Hours)	$703.64	$1,284.48	82.5%
New Network Connections				
523	New Underground Service Connection—Greenfield	$0.00	$553.42	
524	New Underground Service Connection—Greenfield Cable Only	$446.00	$588.08	31.9%
525	New Underground Service Connection—Greenfield Metering Only	$0.00	$368.95	
526	New Overhead Service Connection—Brownfield (Business Hours)	$288.18	$772.56	168.1%
527	New Underground Service Connection—Brownfield from Front	$691.82	$1,284.48	85.7%
528	New Underground Service Connection—Brownfield from Rear	$691.82	$1,284.48	85.7%
Network Connection Alterations and Additions				
541	Overhead Service Relocation—Single Visit (Business Hours)	$288.18	$737.89	156.1%
542	Overhead Service Relocation—Two Visits (Business Hours)	$576.36	$1,475.78	156.1%

[196] *National electricity Rules*, clause 11.56.3(j)

Code	Service	Price	Cost	Difference %
543	Overhead Service Upgrade—Service Cable Replacement Not Required	$371.45	$737.89	98.7%
544	Overhead Service Upgrade—Service Cable Replacement Required	$691.82	$772.56	11.7%
545	Underground Service Upgrade—Service Cable Replacement Not Required	$371.45	$1,249.82	236.5%
546	Underground Service Upgrade—Service Cable Replacement Required	$691.82	$1,284.48	85.7%
547	Underground Service Relocation—Single Visit (Business Hours)	$691.82	$1,284.48	85.7%
548	Install surface mounted point of entry (POE) box	$456.00	$592.81	30.0%
Temporary De-energisation				
560	Temporary de-energisation—LV (Business Hours)	$462.27	$392.94	-15.0%
561	Temporary de-energisation—HV (Business Hours)	$462.27	$392.94	-15.0%
Supply Abolishment / Removal				
562	Supply Abolishment / Removal—Overhead (Business Hours)	$288.18	$553.42	92.0%
563	Supply Abolishment / Removal—Underground (Business Hours)	$288.18	$999.85	247.0%
Miscellaneous Customer Initiated Services				
564	Install & Remove Tiger Tails—Per Installation (Business Hours)	$1,085.00	$1,296.59	19.5%
565	Install & Remove Tiger Tails—Per Span (Business Hours)	$560.00	$644.00	15.0%
566	Install & Remove Warning Flags—Per Installation (Business Hours)	$745.00	$1,106.84	48.6%
567	Install & Remove Warning Flags—Per Span (Business Hours)	$480.00	$552.00	15.0%
Embedded Generation—Operational & Maintenance Fees				
568	Small Embedded Generation OPEX Fees—Connection Assets	2%	2%	2%
569	Small Embedded Generation OPEX Fees—Shared Network Asset	2%	2%	2%
Connection Enquiry Processing—PV Installations				
570	PV Connection Enquiry—LV Class 1 (<= 10kW Single Phase / 30kW Three Phase)	$0.00	$0.00	
571	PV Connection Enquiry—LV Class 2 to 5 (> 30kW <= 1500kW Three Phase	$514.55	$514.55	0.0%
572	PV Connection Enquiry—HV	$1,029.09	$1,029.09	0.0%
573	Provision of information for Network technical study for large scale installations	$11,580.00	$11,580.00	0.0%
Network Design & Investigation / Analysis Services—PV Installations				
574	Design & Investigation—LV Connection Class 1 PV (<= 10kW Single Phase / 30kW Three Phase)	$0.00	$0.00	
575	Design & Investigation—LV Connection Class 2 PV (> 30kW and <= 60kW Three Phase)	$3,705.45	$3,705.45	0.0%
576	Design & Investigation—LV Connection Class 3 PV (> 60 kW and <= 120kW Three Phase)	$4,837.27	$4,837.27	0.0%
577	Design & Investigation—LV Connection Class 4 PV (> 120 kW and <= 200kW Three Phase)	$7,925.45	$7,925.45	0.0%
578	Design & Investigation—LV Connection Class 5 PV (> 200kW and <= 1500kW Three Phase)—ActewAGL Network Study	$10,732.73	$10,732.73	0.0%
579	Design & Investigation—HV Connection Class 5 PV (> 200kW and <= 1500kW Three Phase)—Customer Network Study	$11,560.00	$11,560.00	0.0%
Rescheduled Site Visits				
590	Rescheduled Site Visit—One Person	$125.00	$130.98	4.8%
591	Rescheduled Site Visit—Service Team	$375.00	$553.42	47.6%

Code	Service	Price	Cost	Difference %
Trenching charges				
592	Trenching—first 2 meters		$494.50	0.0%
593	Trenching—subsequent meters		$115.00	0.0%
Boring charges				
594	Under footpath		$897.00	0.0%
595	Under driveway		$1,069.50	0.0%

*The costs shown for meter reconfigurations exclude the cost of the meter. The cost of the meter is included in the metering PTRM and recovered in the daily metering charge.

† Trenching and boring services have been added to the list of ancillary services submitted to the AER with the transitional regulatory proposal. A fee based approach is proposed for these services to avoid the cost of sending out staff to prepare a quote.

ActewAGL Distribution proposes to move prices to fully recover costs by the end of the regulatory period. As the AER notes in the Stage 1 F&A paper, one of the key considerations in classifying these services as alternative control and applying price caps was to provide cost reflective prices. Given the significant gap between prices and costs in 2014/15, for some services, a phased approach to full cost recovery is proposed, to avoid significant price shocks for customers.

Labour costs are forecast to escalate at 1.6 per cent in 2015/16 and 2.1 per cent in subsequent years.[197] The cost of providing ancillary services is made up mainly of labour. Therefore, ActewAGL Distribution is assuming that the cost of these fee based ancillary services will rise by 1.5 per cent each year.

The X factors proposed to be applied to fee based ancillary services over the remaining 4 years of the regulatory period are shown in Table 15.11.

Table 15.11 Proposed X factors for fee based ancillary service charges

Code	Service	2015/16	2016/17	2017/18	2018/19
Premise Re-energisation—Existing Network Connection					
501	Re-energise premises—Business Hours	-10.0%	-9.3%	-1.5%	-1.5%
502	Re-energise premises—After Hours	10.0%	10.0%	10.0%	-0.1%
Premise De-energisation—Existing Network Connection					
503	De-energise premises—Business Hours	-10.0%	-10.0%	-10.0%	-5.3%
505	De-energise premises for debt non-payment	-12.5%	-12.5%	-12.5%	-4.4%
Meter Reconfiguration					
507	Install Interval Meter	-25.0%	-25.0%	-25.0%	-7.0%
509	Install / Replace Meter—Micro Renewable Energy Installation	-50.0%	-50.0%	-50.0%	-23.8%
Meter Investigations					
504	Meter Test (Whole Current)—Business Hours	-50.0%	-50.0%	-50.0%	-19.0%
510	Meter Test (CT/VT)—Business Hours	10.0%	10.0%	3.4%	-1.5%
Special / Additional Meter Reads					

[197] ActewAGL Distribution's proposed labour cost escalators are provided in chapter 8 of this regulatory proposal (see Table 8.7).

Code	Service	2015/16	2016/17	2017/18	2018/19
506	Special Meter Read	-1.1%	-1.5%	-1.5%	-1.5%
Temporary Network Connections					
520	Temporary Builders Supply—Overhead (Business Hours)	-12.5%	-12.5%	-12.5%	-10.0%
522	Temporary Builders Supply—Underground (Business Hours)	-20.0%	-20.0%	-20.0%	-12.1%
New Network Connections					
523	New Underground Service Connection—Greenfield				
524	New Underground Service Connection—Greenfield Cable Only	-10.0%	-10.0%	-10.0%	-5.1%
525	New Underground Service Connection—Greenfield Metering Only				
526	New Overhead Service Connection—Brownfield (Business Hours)	-40.0%	-40.0%	-40.0%	-3.7%
527	New Underground Service Connection—Brownfield from Front	-20.0%	-20.0%	-20.0%	-14.0%
528	New Underground Service Connection—Brownfield from Rear	-20.0%	-20.0%	-20.0%	-14.0%
Network Connection Alterations and Additions					
541	Overhead Service Relocation—Single Visit (Business Hours)	-30.0%	-30.0%	-30.0%	-23.7%
542	Overhead Service Relocation—Two Visits (Business Hours)	-30.0%	-30.0%	-30.0%	-23.7%
543	Overhead Service Upgrade—Service Cable Replacement Not Required	-25.0%	-25.0%	-25.0%	-8.0%
544	Overhead Service Upgrade—Service Cable Replacement Required	-10.0%	-4.6%	-1.5%	-1.5%
545	Underground Service Upgrade—Service Cable Replacement Not Required	-40.0%	-40.0%	-40.0%	-30.1%
546	Underground Service Upgrade—Service Cable Replacement Required	-30.0%	-30.0%	-14.9%	-1.5%
547	Underground Service Relocation—Single Visit (Business Hours)	-30.0%	-30.0%	-14.9%	-1.5%
548	Install surface mounted point of entry (POE) box	-10.0%	-10.0%	-10.0%	-3.7%
Temporary De-energisation					
560	Temporary de-energisation—LV (Business Hours)	10.0%	2.7%	-1.5%	-1.5%
561	Temporary de-energisation—HV (Business Hours)	10.0%	2.7%	-1.5%	-1.5%
Supply Abolishment / Removal					
562	Supply Abolishment / Removal—Overhead (Business Hours)	-20.0%	-20.0%	-20.0%	-18.0%
563	Supply Abolishment / Removal—Underground (Business Hours)	-40.0%	-40.0%	-40.0%	-34.2%
Miscellaneous Customer Initiated Services					
564	Install & Remove Tiger Tails—Per Installation (Business Hours)	-10.0%	-10.0%	-3.3%	-1.5%
565	Install & Remove Tiger Tails—Per Span (Business Hours)	-10.0%	-7.7%	-1.5%	-1.5%
566	Install & Remove Warning Flags—Per Installation (Business Hours)	-12.5%	-12.5%	-12.5%	-10.7%
567	Install & Remove Warning Flags—Per Span (Business Hours)	-10.0%	-7.7%	-1.5%	-1.5%
Embedded Generation—Operational & Maintenance Fees					

Code	Service	2015/16	2016/17	2017/18	2018/19
568	Small Embedded Generation OPEX Fees—Connection Assets				
569	Small Embedded Generation OPEX Fees—Shared Network Asset				
Connection Enquiry Processing—PV Installations					
570	PV Connection Enquiry—LV Class 1 (<= 10kW Single Phase / 30kW Three Phase)				
571	PV Connection Enquiry—LV Class 2 to 5 (> 30kW <= 1500kW Three Phase	-1.5%	-1.5%	-1.5%	-1.5%
572	PV Connection Enquiry—HV	-1.5%	-1.5%	-1.5%	-1.5%
573	Provision of information for Network technical study for large scale installations	-1.5%	-1.5%	-1.5%	-1.5%
Network Design & Investigation / Analysis Services—PV Installations					
574	Design & Investigation—LV Connection Class 1 PV (<= 10kW Single Phase / 30kW Three Phase)				
575	Design & Investigation—LV Connection Class 2 PV (> 30kW and <= 60kW Three Phase)	-1.5%	-1.5%	-1.5%	-1.5%
576	Design & Investigation—LV Connection Class 3 PV (> 60 kW and <= 120kW Three Phase)	-1.5%	-1.5%	-1.5%	-1.5%
577	Design & Investigation—LV Connection Class 4 PV (> 120 kW and <= 200kW Three Phase)	-1.5%	-1.5%	-1.5%	-1.5%
578	Design & Investigation—LV Connection Class 5 PV (> 200kW and <= 1500kW Three Phase)—ActewAGL Network Study	-1.5%	-1.5%	-1.5%	-1.5%
579	Design & Investigation—HV Connection Class 5 PV (> 200kW and <= 1500kW Three Phase)—Customer Network Study	-1.5%	-1.5%	-1.5%	-1.5%
Residential Estate Subdivision Services (per block)					
580	Subdivision Electricity Distribution Network Reticulation—Multi-Unit Blocks				
581	Subdivision Electricity Distribution Network Reticulation—Blocks <= 650 m^2	-1.5%	-1.5%	-1.5%	-1.5%
582	Subdivision Electricity Distribution Network Reticulation—Blocks 650—1100m^2 with average linear frontage of 22-25 meters	-1.5%	-1.5%	-1.5%	-1.5%
Upstream Augmentation (per kVA of capacity)					
585	HV Feeder	-1.5%	-1.5%	-1.5%	-1.5%
586	Distribution substation	-1.5%	-1.5%	-1.5%	-1.5%
Rescheduled Site Visits					
590	**Rescheduled Site Visit—One Person**	-6.4%	-1.5%	-1.5%	-1.5%
591	**Rescheduled Site Visit—Service Team**	-12.5%	-12.5%	-12.5%	-10.0%
Trenching charges					
592	**Trenching—first 2 meters**	-1.5%	-1.5%	-1.5%	-1.5%
593	**Trenching—subsequent meters**	-1.5%	-1.5%	-1.5%	-1.5%
Boring charges					
594	**Under footpath**	-1.5%	-1.5%	-1.5%	-1.5%
595	**Under driveway**	-1.5%	-1.5%	-1.5%	-1.5%

ActewAGL Distribution considers that the application of the proposed X factors will result in a cost reflective set of prices. While significant price increases, in percentage terms, will be required for some services, the increase is from a base where prices are well below efficient cost recovery levels. For example, ActewAGL Distribution proposes a—50 per cent X factor for its meter test services for 2015/16. This means that meter test charges will increase by CPI+50 per cent, from $69 in 2014/15 to $103 in 2015/16. This price will still be well below recently proposed 2014/15 prices for a meter test service for some other DNSPs. For example, Energex and Ergon Energy have recently proposed 2014/15 meter test charges of $127 and $474 respectively, in their annual network pricing proposals to the AER.[198] Aurora's approved meter test (single phase) charge for 2013/14 is $291.

ActewAGL Distribution's indicative prices for fee based ancillary services the subsequent regulatory period are shown in Attachment F3.

15.4.2 Quoted ancillary services

ActewAGL Distribution proposes to set prices on a quoted basis for those ancillary services where the service is not typical or standard, or the scope of the service is specific to particular customers' needs.

ActewAGL Distribution proposes to set prices for quoted services using the formula:

$$Price = Labour + Contractor\ Services + Materials + Other\ Costs + Risk\ Margin$$

where:

- Labour (including on costs and overheads)—consists of all labour costs directly incurred in the provision of the service which may include but is not limited to labour on costs, fleet on costs and overheads and other associated delivery costs including overheads. The labour cost for each service is dependent on the skill level and experience of the employee/s, time of day/week in which the service is undertaken, travel time, number of hours, number of site visits and crew size required to perform the service;
- Contractor services (including overheads)—reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred as part of performing the service, for example permits for road closures or footpath access, are passed on to the customer;
- Materials (including overheads)—reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads;

[198] The Energex charge is a potential charge for a quoted service. The actual price will vary depending on the time of day and the customer's requirements.

- Other—consists of costs that arise due to special requirements of the job or services provided at above the least cost technically acceptable standard. This term is consistent with ActewAGL Distribution's approved Connection Policy, under which the customer pays the full costs of special requirements or above standard services;[199] and
- Risk margin—margin agreed with the customer to reflect the risks associated with the project. This will generally only apply to large scale projects, such as relocation or removal of major network assets at the request of a customer. The application of this margin represents a continuation of the approach that has applied under the ACT *Capital Contributions Code*, whereby a "reasonable profit margin" can be charged for relocations, removals and redevelopments.[200]

Price caps will apply to the labour rates used in this formula. ActewAGL Distribution proposes to demonstrate compliance with the formula by providing its annual calculation of labour rates to the AER in its annual pricing proposal. The rates will be approved by the AER in the annual network pricing approval process.

The proposed approach, with price caps to apply to the labour component of the formula, is consistent the approach adopted by the AER in its recent Stage 1 F&A Final Decision for Ergon Energy and Energex.[201] The AER adopted a similar approach in the final decisions for the Victorian DNSPs and Aurora in Tasmania, where approved price caps are applied to labour costs used for quoted services.[202]

The application of price caps to labour costs only, rather than on all cost inputs, helps to reduce administrative costs, as ActewAGL Distribution will not be required to identify, for AER approval, every input cost that may be required in performing a quoted service. This approach will also result in cost reflective charges.

ActewAGL Distribution's proposed charge out rates for labour are shown in Table 15.12.

[199] ActewAGL Distribution 2014, *Connection Policy*, version 2.0, June, p. 4. Services provided outside the scope of the Connection Policy and the chapter 5A Rules (for example services provided in accordance with the chapter 5 Rules) may also be subject to charges for above standard or special requirements.

[200] ICRC 2012, *Electricity Network Capital Contributions Code*, July 2012, clauses 3.7 and 3.8

[201] AER 2014, *Energex and Ergon Energy, Framework and Approach, Final Decision*, April, p 68

[202] AER 2010, *Victorian distribution network service providers, Distribution determination 2011-15, Final decision*, October, p. 901, and AER 2012, *Final distribution determination, Aurora, 2012-17*, April, p 40

Table 15.12 Proposed 2014/15 labour rates for fee based and quoted services

Classification	Rate
Electrical Worker	$87.61
Electrical Worker—Labourer	$71.56
Electrical Apprentice	$65.76
Office Support Service Delivery	$83.70
Project Officer Design Section	$103.17
Senior Technical Officer/ Engineer Design Section	$141.77

Rates do not include overheads or margins. Overheads are allocated in accordance with ActewAGL Distribution's approved CAM.

ActewAGL Distribution proposes to escalate the labour rates in accordance with the escalation rates set out in chapter 8 of this regulatory proposal.

15.5 Proposed classification of large generator connection services

During the process of preparing the connection policy, it has become apparent to ActewAGL Distribution that large scale embedded generator connection services may not have been properly classified by the AER in the Stage 1 F&A paper for the subsequent regulatory period.

The large scale embedded generator connection services provided by ActewAGL Distribution are those connection services provided to registered generators in relation to the connection, operation and maintenance of embedded generating units with a total nameplate rating at a connection point in excess of 5MW (i.e. the level at which AEMO's deemed exemption from the requirement to be registered as a generator cease to apply). These services are not regulated by chapter 5A of the Rules but rather are regulated by chapter 5.

In the 2009–14 regulatory period, large scale embedded generator connection services were classified as negotiable components of direct control services under clause 6.7A of transitional chapter 6. Clause 6.7A of transitional chapter 6 does not form part of current chapter 6 of the Rules so large scale embedded generator connection services are unable to be classified as negotiable components of direct control services for the 2014–19 regulatory period.

Under Part DA of transitional chapter 6, negotiable components of direct control services were regulated in a manner similar to negotiated distribution services under the current chapter 6 of the Rules. Part DA of the transitional Chapter 6 effectively mirrors Part D of the current Chapter 6.

The classification and regulation of negotiable components of direct control services , including large scale embedded generator connection services, were not explicitly addressed in the Stage 1 F&A paper or the Placeholder Determination. It is therefore unclear how large scale embedded generator connection services were intended to be classified for the 2014–19 regulatory period.

In the Stage 1 F&A paper, the AER classified ActewAGL Distribution's 'connection services' as standard control services.[203]

Large scale embedded generator connection services would clearly fall within the definition of 'connection services' in Chapter 10 of the Rules. However, the discussion and analysis of ActewAGL Distribution's connection services in the Stage 1 F&A paper (in section 1.3.2), and the various consultation and discussion papers leading up to the publication of the Placeholder Determination, focused solely on connection services regulated by chapter 5A of the Rules and did not mention large scale embedded generator connection services.[204] There were also numerous references to chapter 5A of the Rules, the connection charge guidelines and to providing 'basic' or 'standard connection services' to retail customers which were unrelated to large scale embedded generator connection services.

Alternatively, large scale embedded generator connection services could have been classified as 'ancillary network services' under the Stage 1 F&A paper, which services were defined as '…non-routine services provided to individual customers on an 'as needs' basis.[205] The AER noted that such services are generally provided for the benefit of an identifiable customer and involve work on, or in relation to, parts of the ActewAGL Distribution network.

In the Stage 1 F&A paper, the AER classified these 'ancillary network services' as alternative control services because they are customer specific, there is a regulatory barrier preventing any party other than ActewAGL Distribution from providing them and there is potential to develop competition in these areas. The large scale embedded generator connection services could fall into this description by virtue of the fact that they are customer specific services which only ActewAGL Distribution can provide.

This conclusion is supported by statements made by the AER in the Stage 1 F&A paper that non-standard connection services (albeit in relation to chapter 5A) should be classified as alternative control services.[206] A similar statement was also made by ActewAGL Distribution in the *Transitional regulatory proposal* that services provided at above the least cost technically acceptable standard and/or to meet special customer requirements should be classified as alternative control services.[207]

Finally, ActewAGL Distribution's indicative prices for ancillary network services 2014/15, as set out in Attachment F of the *Transitional regulatory proposal* and Appendix A of the Placeholder Determination, assume that the operational and maintenance component of connection services

[203] AER 2013, *Stage 1 Framework and Approach—ActewAGL*, March, p 11

[204] See, for example, AER 2013, *Stage 1 Framework and Approach—ActewAGL*, March, pp 19-21

[205] AER 2013, *Stage 1 Framework and Approach—ActewAGL*, March, pp 25

[206] AER 2013, *Stage 1 Framework and Approach—ActewAGL*, March, pp 20

[207] ActewAGL Distribution 2014, *Transitional regulatory proposal 2014/15*, January, pp 7-8

for small generating units is actually being classified as an alternative control service.[208] Once again this suggests that large scale embedded generator connection services could also be classified as alternative control services. Based on this, ActewAGL Distribution proposes that large scale embedded generator connection services should be classified as 'ancillary network services' and alternative control services for the subsequent regulatory period.

The alternative control service classification is more appropriate than the standard control service classification because the large scale embedded generator connection services are clearly services provided at the request of identifiable customers who should bear the cost for providing those services, and it would not be appropriate for the cost of those services to be shared across all distribution network users.

This classification is also consistent with the approach taken by the AER nationally in classifying services similar to ActewAGL Distribution's large scale embedded generator connection services. In the April 2014 Final Framework and Approach papers for SA Power Networks, Energex and Ergon Energy the AER clearly indicated its approach of classifying as alternative control services those services which are customer specific or customer requested, as compared to being relied on by most customers (see Table 15.13 below).

The alternative control service classification seems to be the most appropriate classification for large scale embedded generator connection services. This is supported by the classification of Energex and Ergon Energy's large customer connections as alternative control services in the AER's final *Framework and approach for Energex and Ergon Energy* (although these comments appeared to assume that the relevant connection service would also be regulated by Chapter 5A of the Rules).[209]

[208] ActewAGL Distribution 2014, *Transitional regulatory proposal 2014/15*, January, p F-8

[209] AER 2014, *Energex and Ergon Energy, Final Framework and Approach*, April, pp 32-33

Table 15.13 AER classification of services

Classification	*Description*	*Regulatory treatment*
Direct control service —Standard control service	Services that are central to electricity supply and therefore relied on by most (if not all) customers such as building and maintaining the shared distribution network. Most distribution services are classified as standard control.	[The AER regulates] these services by determining prices or an overall cap on the amount of revenue that may be earned for all standard control services. The costs associated with these services are shared by all customers via their regular electricity bill.
Direct control service —Alternative control service	Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local distributor.	[The AER sets] service specific prices to enable the distributor to recover the full cost of each service from customers using that service.
Negotiated service	Services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient market power to negotiate the provision of those services.	Distributors and customers are able to negotiate prices according to a framework established by the Rules. [The AER] is available to arbitrate if necessary.

Source: AER 2014, SA Power, *Final Framework and Approach,* April, p. 10

Clauses 6.8.1(f) and 6.12.3(b) of the Rules effectively provide that the classification of ActewAGL Distribution's services set out in the Stage 1 F&A paper will apply to the subsequent regulatory period unless the AER considers that unforeseen circumstances justify departing from that classification.

The proposed classification of ActewAGL Distribution's large scale embedded generator connection services, which was not explicitly addressed by the AER in the Stage 1 F&A paper, should therefore be permitted on the basis that the classification set out in the Stage 1 F&A paper is unclear or incorrect and the classification of these services as alternative control services is clearly the most appropriate classification under the Rules.

If large scale embedded generator connection services are classified as 'ancillary network services' and alternative control services then the price for those services should be regulated in the same manner as the quoted services, as described in section 15.4 above.

15.6 Application of cost pass through provisions

The chapter 6 Rules allow elements of Part C, including the cost pass through provisions in clause 6.6.1, to be adopted for alternative control services. The note to clause 6.2.6 says:

> *The distribution determination might provide for the application of clause 6.6.1 to pass through events with necessary adaptations and specified modifications.*

As noted in the discussion above of forecast meter installations, there is currently a high degree of uncertainty about future regulatory requirements and policy settings for metering services. ActewAGL Distribution considers that the cost pass through provisions provide one mechanism for addressing additional unexpected costs arising from new requirements imposed during the 2015-19 regulatory period. Cost pass through applications could potentially be made where the new requirements involve a regulatory change event or service standard event.

ActewAGL Distribution's proposal in relation to pass through events applicable to the 2015-19 regulatory period, including those relating to the provision of alternative control services in the ACT, are set out in chapter 17 of this regulatory proposal.

16 Incentive schemes

16.1 Introduction

In accordance with clauses S6.1.3(3), S6.1.3(3A), S6.1.3(4) and S6.1.3(5) of the Rules, this chapter provides a description of how ActewAGL Distribution proposes AER incentive schemes should apply to it in the regulatory control period. These incentive schemes are:

- the efficiency benefit sharing scheme (EBSS);
- the capital expenditure sharing scheme (CESS);
- the service target performance incentive scheme (STPIS); and
- the demand management and embedded generation connection incentive scheme (DMEGCIS).

Decisions on how these schemes will apply to ActewAGL Distribution are constituent decisions that the AER must make in its determinations under clause 6.12.1(9) of the Rules.

This chapter details several specific proposals in relation to the operation of these schemes, including:

- the exclusion of uncontrollable costs from the EBSS;
- setting the EBSS expenditure allowance for 2014-15 equal to actual expenditure in that year;
- the exclusion of customer-initiated capital expenditure and equity raising costs from the CESS;
- modification of STPIS reliability performance targets to align with regulatory obligations; and
- an alternative value of customer reliability (VCR) for setting STPIS incentive rates, based on research into customer willingness to pay (WTP) in the ACT.

Each of these proposals is in the long term interest of consumers and serves to achieve the national electricity objective. The exclusion from the EBSS and CESS of unforseen costs that are outside the control of the business promotes efficient investment by ensuring that ActewAGL Distribution is provided with reasonable opportunity to recover the efficient costs incurred in providing direct control network services (in accordance with s7A(2)(a) of the Law). Similarly, the proposed modification to reliability performance targets is required to ensure that ActewAGL Distribution has reasonable opportunity to recover the efficient costs of complying with its regulatory obligations in relation to supply reliability (in accordance with s7A(2)(b) of the Law). The proposed VCR and incentive rates for STPIS will benefit consumers by ensuring that

ActewAGL Distribution is provided with an incentive to make investment and operation decisions that are consistent with ACT customers' preferred balance between cost and reliability.

16.2 Efficiency benefit sharing scheme

This section of ActewAGL Distribution's proposal is divided into two parts. The first section describes the calculation of EBSS carryover effects from the 2009-2014 period and their effect on allowable revenue in the forthcoming regulatory period. The second section provides a description of how ActewAGL Distribution proposes the EBSS should apply to it in the forthcoming regulatory control period, in accordance with clause S6.1.3(3) of the Rules.

16.2.1 2009–14 and calculated carryover effects on the 2014–19 period

The purpose of the EBSS is to provide DNSPs with an incentive to seek efficiency gains. It does this by allowing a DNSP to retain any efficiency gains it makes for the length of a carryover period regardless of the year of the regulatory period in which the gain was made. As such a DNSP is provided with a constant incentive to improve efficiency of its opex and thus reveal its efficient level of opex.

In its 2009 final decision, the AER determined that:

> *The AER will apply the EBSS released in February 2008 to ActewAGL for the next regulatory control period* [210]

The following opex categories were excluded from the operation of the EBSS:

- Debt raising costs;
- Self insurance costs;
- Insurance costs;
- Superannuation costs relating to defined benefit and retirement schemes;
- UNFT payments;
- Direct feed-in tariff payments;
- Non-network alternative costs; and
- Pass throughs.

Based on this, the AER determined an allowance subject to the EBSS for the 2009–14 regulatory period.

[210] AER 2009, *Final decision, Australian Capital Territory distribution determination 2009–10 to 2013–14*, 28 April, p 116

On 27 February 2012, ActewAGL Distribution submitted an application for revocation and substitution of its 2009–14 distribution determination, notifying the AER that ActewAGL Distribution had identified two errors in the forecast superannuation costs in the 2009 determination. The second error involved the superannuation exclusions from the EBSS in the 2009 final decision. The reported exclusions from the EBSS were total forecast superannuation payments instead of only defined benefit schemes. Following review, the AER in April 2012 exercised its discretion in accordance with clause 6.13 of the Rules to revoke and substitute the 2009 final decision to rectify the errors. The revocation resulted in adjustments of the EBSS allowance.

Table 6 of the AER's decision document of ActewAGL Distribution's application for revocation and substitution of ActewAGL's distribution determination sets out the updated EBSS forecast controllable opex for EBSS purposes. ActewAGL Distribution draws the AER's attention to an error in this table. The first line, 'Total forecast opex' of $341.4 million (2009–14), is based on the 2009 decision before the correction of the first error of superannuation costs was addressed. As shown in Table 1 of the same document, the total allowed opex after the adjustment for the error is $347.1 million. Applying this starting opex ($347.1 million) to the identified EBSS exclusions results in an opex allowance for EBSS purposes of $250.5 million (2008/09) rather than $246.6 million (2008/09) as set out in the revocation and substitution document by the AER in 2012. Consistent with RIN template 7.5, ActewAGL Distribution in Table 16.1 provides a summary of how the EBSS carryover effects have been calculated. Further details are provided in the RIN template 7.5.

Table 16.1 Operating expenditure subject to the EBSS and carryover effects

$ million	***2009/10***	***2010/11***	***2011/12***	***2012/13***	***2013/14***
Forecast opex for EBSS purposes, $08/09	48.5	49.0	50.0	51.7	51.4
Forecast opex for EBSS purposes, $13/14	55.7	56.3	57.4	59.4	59.1
Total actual operating expenditure, $13/14	68.3	79.9	91.2	98.7	-
Excluded costs, $13/14	-11.1	-14.4	-21.1	-28.5	-
Operating expenditure subject to the EBSS, $13/14	57.2	65.5	70.1	70.2	-
Incremental gain/loss ($2013/14)	-1.5	-7.7	-3.5	1.9	-
$ million (2013/14)	***2014/15***	***2015/16***	***2016/17***	***2017/18***	***2018/19***
Carryover effect	-10.7	-9.2	-1.5	1.9	-
Allocated to distribution	-9.4	-8.1	-1.3	1.7	
Allocated to transmission	-1.3	-1.2	-0.2	0.2	

ActewAGL Distribution notes that its operating expenditure in 2012/13 included some non-recurring expenditure items. These result in negative carryover effects for the next regulatory period. To offset these one off expenditure items, and consistent with the EBSS determined in 2008, ActewAGL Distribution has in its operating expenditure forecast included these one off items (where the cost is not excluded as part of the EBSS exclusions in 2012/13). These non-recurring items are further described in section 8.7.1.

16.2.2 EBSS in the 2014–19 period

This section provides a description of how ActewAGL Distribution proposes the EBSS should apply to it in the forthcoming regulatory control period, in accordance with clause S6.1.3(3) of the Rules.

In accordance with clause 6.5.8 of the Rules, the AER published an EBSS for DNSPs in November 2013 (*the updated EBSS*). The updated EBSS "*remains largely unchanged.*"[211] The AER has proposed in its Stage 2 Framework and Approach paper to apply Version 1 of the EBSS in 2014-15, with specific modifications, and the updated EBSS from 1 July 2015.[212]

ActewAGL Distribution notes the AER proposal and makes two specific proposals for modification of the approach—the exclusion of uncontrollable costs from the EBSS; and, setting the 2014-15 allowance equal to the actual spend in that year.

16.2.2.1 Exclusion of uncontrollable costs

According to the updated EBSS, the AER has proposed not to exclude uncontrollable costs from the EBSS. ActewAGL Distribution fundamentally disagrees with the inclusion of uncontrollable costs in the EBSS. The imposition of unforeseen requirements and obligations that increase costs is more likely than the unforeseen removal of obligations resulting in cost savings. In other words, there is an asymmetric risk that more costs will be added to businesses than removed. Under the AER's proposed approach, ActewAGL bears part of this risk. This outcome would be unfair in the sense that it does not reflect an outcome in which costs arising from exogenous changes affecting all firms would be passed through to customers in full.

Therefore, ActewAGL Distribution considers that the EBSS objective of a fair sharing between DNSPs and customers of differences between actual and forecast opex (clause 1.1 of the EBSS guideline and 6.5.8(a) of the Rules) would be better served by including a predetermined list of exclusions from the EBSS allowance (as for the 2009–14 regulatory period). Pass through events would continue to be excluded from the EBSS. In addition, costs increases associated with the introduction of new obligations that are not foreseeable using a revealed cost approach to forecasting methodology and not part of the operating expenditure forecast should also be excluded from the operation of the EBSS. These adjustments would only reflect changes in circumstances (and therefore costs) outside of the business' control, and which do not therefore represent true efficiency gains (or losses).

[211] AER 2013, *Better Regulation, Explanatory Statement, Efficiency Benefit Sharing Scheme*, November 2013, p 7

[212] AER 2014, *Stage 2 Framework and Approach—ActewAGL*, January, p 27

These adjustments are also necessary to ensure that ActewAGL Distribution is provided with a reasonable opportunity to recover at least the efficient costs incurred in providing reference services, in accordance with s7A(2) of the Law.

For the 2014–19 regulatory control period, ActewAGL Distribution proposes that the following uncontrollable cost items should be excluded from the EBSS:

- Debt raising costs;
- Self insurance;
- Insurance;
- Superannuation (defined benefit);
- Demand management incentive scheme;
- Costs due to new unforseen obligations; and
- Pass throughs.

Apart from the FiT and UNFT being jurisdictional schemes from 2014 and therefore excluded from the operating expenditure that could be subject to the EBSS, and the inclusion of 'costs due to new obligations', the above listed uncontrollable cost items are consistent with the cost items determined to be excluded from the application of the EBSS by the AER for the 2009–14 regulatory period.

ActewAGL Distribution also considers that any change to the capitalisation policy should result in an adjustment of the forecast operating expenditure used to calculate the carryover amounts so that the forecast expenditures are consistent with the capitalisation changes.

ActewAGL Distribution considers that the proposed EBSS will continue to provide it with a strong incentive to seek efficiencies in costs that will be in the long term interest for the customers.

16.2.2.2 The EBSS allowance for 2014-15

Under the AER's proposed application of EBSS to ActewAGL Distribution in the forthcoming regulatory period, the EBSS allowance for 2014-15 will be determined in April 2015, after more than nine months of the year have elapsed. This approach departs from the principle that the application of incentive schemes should be known in advance. This principle is applied by the AER in other contexts; for example, Clause 2.5(f) of the AER STPIS states:

> *An adjustment to a DNSP's allowed revenue can only be made as a result of its performance in a period where parameters and values have been established under the scheme for the DNSP in advance of that period.*[213]

[213] AER 2009, *Electricity DNSP STPIS*, November, pp 7-8

ActewAGL Distribution proposes that the EBSS allowance for 2014-15 be set at the actual level of expenditure for that year. The determination on this matter is to occur sufficiently late in 2014-15 that it would not create perverse incentives to delay efficiencies.

This proposal is consistent with the EBSS objective in clause 1.1 of the EBSS guideline and 6.5.8(a) of the Rules, since, in its absence, the scheme would result in an inequitable sharing of any difference between actual opex and the opex allowance, in the sense that it would be determined by the AER at a time when ActewAGL Distribution's ability to respond to the incentive has substantially passed.

16.3 Capital expenditure sharing scheme

In its Stage 2 Framework and approach paper for ActewAGL Distribution (January 2014), the AER proposed to apply the CESS as set out in its capital expenditure incentive guideline[214] in respect of ActewAGL Distribution's capital expenditure in the subsequent regulatory period. The CESS does not apply to capital expenditure undertaken in the transitional year.[215] This will be the first time a capital expenditure sharing scheme has applied to ActewAGL Distribution.

Under the Rules, a capital expenditure sharing scheme is a scheme that provides DNSPs with an incentive to undertake efficient capital expenditure during a regulatory control period (clause 6.5.8A(a)). How a capital expenditure sharing scheme will apply to ActewAGL Distribution is one the constituent decisions the AER must make as part of its determination on the Subsequent Regulatory Proposal (clause 6.12.1(9)). The AER must:

- make that decision in a manner that contributes to the achievement of the capital expenditure incentive objective (clause 6.5.8A(e)(3));[216]
- take into account the capital expenditure sharing scheme principles set out in clause 6.5.8A(c)(1)-(2), being that:
  - DNSPs should be rewarded or penalised for improvements or declines in efficiency of capital expenditure; and
  - the rewards or penalties should be commensurate with the efficiencies or inefficiencies in capital expenditure, (clause 6.5.8A(e)(4)(i));
- take into account the matters referred to in clause 6.5.8A(d) as they apply to ActewAGL Distribution, including in part the capital expenditure objectives and if relevant, the operating expenditure objectives (clause 6.5.8A(e)(4)(i)); and

214 AER 2014, *Stage 2 Framework and Approach—ActewAGL*, January, p 40

215 AER 2014, *Stage 2 Framework and Approach—ActewAGL*, January, p 40 (in accordance with clause 11.56.3(a)(3))

216 In summary, the capital expenditure incentive objective ensures that only capex that reasonably reflects the capital expenditure criteria as set out in clause 6.5.7 is included in the RAB (clause 6.4A(a)).

- take into account the circumstances of ActewAGL Distribution (clause 6.5.8A(e)(4)(ii)).

ActewAGL Distribution notes the AER's proposed application of CESS outlined in its Stage 2 Framework and Approach Paper and proposes one specific modification—the exclusion of customer-initiated capital expenditure from the scheme; and, the exclusion of equity raising costs from the scheme. The reasons for and explanation of these proposals are set out below.

16.3.1 Customer initiated capital expenditure and the CESS

ActewAGL Distribution proposes that in applying the CESS to ActewAGL Distribution, the AER should exclude customer initiated capital expenditure from the actual capex and from the capex allowance the AER will use in the calculation of efficiency gains/losses under the CESS, as:

- ActewAGL Distribution generally does not control the incurring of customer initiated capital expenditure, which is by its very nature requested by a customer to occur at a particular time; and
- as customer initiated capital expenditure is often outside the control of ActewAGL Distribution (and sometimes driven by government requirements), there is acute uncertainty inherent in forecasting this type of expenditure, particularly in the outer years of the regulatory period.

The acute uncertainty inherent in forecasting customer initiated capital expenditure is best illustrated by examining actual expenditure in the 2009-2014 period. In preparing its customer initiated capital expenditure forecasts for the 2009-2014 period, ActewAGL Distribution took into account the forecast number of new dwellings it anticipated in each year. ActewAGL Distribution also noted that a number of other drivers, not reflected in its forecast for reasons of uncertainty, were likely to result in customer initiated expenditure such as an increasing number of purpose-built data-centre developments, increasing greenfield developer demands for improved aesthetics and reduced street furniture resulting in less efficient servicing arrangements and higher servicing costs per dwelling. ActewAGL Distribution specifically noted that:

> *Several of these are subject to considerable uncertainty, particularly in the latter part of the period ...* [217]

In its proposal, ActewAGL Distribution also stated:

> *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*

[217] ActewAGL Distribution 2008, *Regulatory proposal to the Australian Energy Regulator*, June, p 136

2011/12 to 2013/14. It could be expected that some unanticipated projects would emerge in this period....[218]

The customer initiated capital expenditure allowance determined by the AER and the actual outcome is summarised in Table 16.2 below.

Table 16.2 Customer initiated capital expenditure allowance and actual outcome 2009–14

Year ending 30 June ($ million, 2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Customer initiated capex allowance	23.7	27.0	23.8	18.3	15.8	108.6
Customer initiated capex outcome	26.3	32.7	30.2	24.4	23.4	137.0
Variance	2.6	5.7	6.4	6.1	7.5	28.4

The above table shows that unanticipated projects did arise, with the consequence that customer initiated capital expenditure was significantly higher than forecast in each year of the 2009-2014 period, particularly in the final years as those unanticipated projects began.

Overall, ActewAGL Distribution's actual customer initiated capital expenditure was 26 per cent higher than the allowance set by the AER in 2009. Customer initiated capital expenditure accounted for 37 per cent of the total net capital expenditure program in the 2009-2014 period, and approximately 54 per cent of ActewAGL Distribution's additional total capital expenditure during 2009-2014 was due to unforseen customer initiated projects.

The same acute difficulties inherent in forecasting customer initiated capital expenditure arise in relation to the subsequent regulatory period with the likely consequence that ActewAGL Distribution's total capital expenditure will vary from its capex allowance for this category.

The capital expenditure program proposed by ActewAGL Distribution in this submission is the result of robust asset management planning and prioritisation processes, with projects and programs carefully selected to prioritise the safety and continued reliability of the network. It has been independently verified by external experts and found to be prudent and efficient. Customer initiated capital expenditure forecasts are included in this process, but because the expenditure is initiated by external parties, it simply is not possible to foresee all projects that will take place in the outer years and ActewAGL Distribution has not included any 'contingent' customer initiated capital expenditure that is not based on a known project/program.

Accordingly, it is reasonably likely that, if customer initiated capital expenditure is included in the CESS, a CESS penalty will be applied to ActewAGL Distribution from future projects that will take place, but which currently are unknown to ActewAGL Distribution. In circumstances where ActewAGL Distribution has limited control over incurring customer initiated capital expenditure and any capital expenditure overspend will likely be attributable to the acute difficulties in

[218] ActewAGL Distribution 2008, *Regulatory proposal to the Australian Energy Regulator*, June, p 137

forecasting such expenditure, any penalty attributable to an overspend by ActewAGL Distribution of its customer initiated capital expenditure allowance is unlikely to be related to any decline in ActewAGL Distribution's efficiency of capital expenditure. Conversely, if customer initiated capital expenditure is less than the AER's allowance, then this too would likely not be due to an improvement in the efficiency of capital expenditure but rather to the acute difficulties inherent in forecasting customer initiated capital expenditure.

Further, if customer initiated capital expenditure is not excluded from the CESS and is greater than the AER's allowance, ActewAGL Distribution may be left with an incentive to underspend on capital projects elsewhere in its capital expenditure program to avoid facing a CESS penalty in the next regulatory period. This is because it is unable to control the incurring of greater-than-forecast customer initiated expenditure.

Notwithstanding the fact that ActewAGL Distribution already faces strong incentives to manage its capital expenditure under the existing regulatory framework, ActewAGL Distribution acknowledges the intention of the AER’s CESS. However, it does not believe that customer initiated capital expenditure which is difficult to forecast and often beyond the control of ActewAGL Distribution should be subject to the CESS.

ActewAGL Distribution submits that a decision by the AER on the application of the CESS to ActewAGL Distribution that provides for the inclusion of customer initiated capital expenditure in the calculation of a CESS penalty/reward:

- would not contribute to the achievement of the capital expenditure incentive objective and may instead deter ActewAGL Distribution from incurring efficient capital expenditure contrary to the requirements of clause 6.5.8A(e)(3);
- will likely result in the imposition on ActewAGL Distribution of penalties/rewards that do not reflect and are not commensurate with the efficiencies or inefficiencies in ActewAGL Distribution's capital expenditure contrary to the capital expenditure sharing scheme principles that are mandatory considerations set out in clause 6.5.8A(e)(4)(i);
- will likely compromise ActewAGL Distribution's ability, acting prudently and efficiently to achieve the capital expenditure objectives and the operating expenditure objectives by delivering an expenditure allowance below the prudent and efficient expenditure required to achieve those objectives, contrary to the mandatory considerations set out in clause 6.5.8A(e)(4)(i)) by reference to clause 6.5.8A(d))(2); and
- would involve a failure to take into account the circumstances of ActewAGL Distribution contrary to the mandatory consideration set out in clause 6.5.8A(e)(4)(ii)).

Accordingly, having regard to the circumstances outlined above, a decision by the AER to apply the CESS to ActewAGL Distribution's customer initiated capital expenditure would be incorrect and unreasonable having regard to the purpose of the CESS and the limitations on the AER's application of the CESS established by clause 6.5.8A(e) of the Rules.

16.3.2 Equity raising costs and the CESS

Equity raising costs are not being forecast using the standard forecast methodology as used for the remaining capital expenditure program. Instead the equity raising costs is forecast using a benchmark methodology by the AER. Consistent with the AER's view to exclude debt raising costs from the EBSS, ActewAGL Distribution also considers that equity raising costs should be excluded from the CESS.

16.4 Service target performance incentive scheme

16.4.1 Introduction

In accordance with Section S6.1.3(4) of the Rules this section outlines a description of how ActewAGL proposes the STPIS should apply in the regulatory control period. This section, along with Attachments F1 and F2 and regulatory templates 6.1 to 6.4, also satisfies the information requirements set out in section 23 of Schedule 1 of the Reset RIN.

The Stage 2 Framework and Approach paper of January 2014 set out the AER's proposed approach to applying the STPIS to ActewAGL Distribution in the forthcoming regulatory control period. Under this approach, the STPIS would apply to ActewAGL Distribution with revenue at risk for the first time from 1 July 2015. The applicable parameters under the scheme would be, for the reliability of supply component, the unplanned system average interruption duration index (USAIDI) and the unplanned system average interruption frequency index (USAIFI); and, for the customer service component, telephone answering. For the purpose of the scheme, the ActewAGL Distribution network would be segmented into urban and short rural feeders.

The AER also proposed to set revenue at risk within the range ±5 per cent, set performance targets based on average performance over the past five regulatory years, apply the methodology indicated in the STPIS guideline (November 2009) for excluding specific events from the calculation of annual performance and performance targets, and apply the methodology and value of customer reliability (VCR) values as indicated in the STPIS guideline to the calculation of incentive rates.[219]

The AER noted that distributors can propose to vary the application of the STPIS in their regulatory proposal in accordance with clause 2.2 of the STPIS guideline.[220] The STPIS guideline provides for ActewAGL Distribution to propose variations or modifications to the revenue at risk (clauses 2.5(b) and 5.2(c)), performance targets (clauses 3.2.1(a) and 5.3.1(b)), the VCR used to set incentive rates for the reliability of supply component (clause 3.2.2(d)), the parameter weighting used to set incentive rates for the reliability of supply component (clause 3.2.2(f)(2)), the incentive rates for the telephone answering parameter (clause 5.3.2(a)(2)) and the major event day boundary (Appendix D).

[219] AER 2014, *Stage 2 Framework and Approach ActewAGL*, January, p 19

[220] AER 2014, *Stage 2 Framework and Approach ActewAGL*, January, p 20

16.4.2 Summary of proposed approach

ActewAGL Distribution proposes two modifications to the approach proposed by the AER in its Stage 2 Framework and Approach paper. These modifications relate to:

- performance targets for the reliability of supply component; and
- the VCR used to set incentive rates for the reliability of supply component.

In accordance with clause 2.2 of the STPIS guideline, the remainder of this section sets out the reasons for and explanation of the proposed variations and demonstrates how the proposed variations are consistent with the objectives in clause 1.5 of the STPIS guideline. Further details of the calculation and methodology supporting the variations are provided at Attachment F1 and Attachment F2.

16.4.3 Proposed modification to performance targets for the reliability of supply component

16.4.3.1 The default performance targets are unsuitable

The AER's determinations for ActewAGL Distribution are required in the midst of a number of recent, ongoing, and foreshadowed reviews affecting regulation of reliability, the operation of STPIS, and the role of STPIS in reliability frameworks. These reviews include the AEMC expenditure objectives rule change,[221] the AEMC national reliability frameworks review,[222] and the foreshadowed AER review of STPIS itself.[223] The AEMC has confirmed that the expenditure objectives rule change will apply to ActewAGL Distribution.[224] However, the AER has stated that there is inadequate time to review STPIS to incorporate the findings of the AEMC national reliability frameworks review before finalising its determinations for ActewAGL.[225]

Consistent with this view, the AER indicated its intention to "*set performance targets based on the distributor's average performance over the past five regulatory years*."[226] ActewAGL Distribution's performance in relation to unplanned supply interruptions in each of the past five years and the average performance over that period are set out in Table 16.3.

[221] AEMC 2013, *Network Service Provider Expenditure Objectives*, Rule Determination, 19 September 2013, Sydney

[222] AEMC 2013, *Review of the national framework for distribution reliability—Final Report*, September

[223] AER 2013, *Submission on AEMC consultation paper—Review of national frameworks for transmission and distribution reliability*, August, p 5

[224] AEMC 2013, *Network Service Provider Expenditure Objectives*, Rule Determination, 19 September 2013, Sydney, p iii

[225] AER 2014, *Stage 2 Framework and Approach—ActewAGL*, January, p 21

[226] AER 2014, *Stage 2 Framework and Approach—ActewAGL*, January, p 20

Table 16.3 Network reliability performance after removing excluded events *

Year ending 30 June	*2009*	*2010*	*2011*	*2012*	*2013*	*5-year average*
USAIDI						
Urban	25.4	24.1	43.2	28.8	28.5	30.0
Short rural	18.6	43.7	54.2	41.0	37.4	39.0
Total	24.7	26.2	44.4	30.1	29.5	31.0
USAIFI						
Urban	0.48	0.51	0.75	0.56	0.56	0.57
Short rural	0.28	1.07	0.83	0.70	0.92	0.76
Total	0.46	0.57	0.76	0.57	0.60	0.59

* Includes single-premises faults. Single-premises interruptions are not automatically captured in ActewAGL Distribution's system control interruption recording and have not been incorporated in past annual RINs. They will automatically be captured in ActewAGL Distribution reporting when new systems are implemented later in 2014. To ensure targets are comparable with future performance reporting, ActewAGL Distribution has identified single-premises interruptions using call centre records and included these interruptions in the historical data used to calculate the targets.

ActewAGL Distribution is concerned that applying this approach without modification would result in inconsistency between the reliability levels used to set STPIS performance targets and the reliability levels that underpin ActewAGL Distribution's expenditure proposal.

The rule determination on expenditure objectives by the AEMC on 19 September 2013 clarified that expenditure proposals must be no more than the amount required to comply with regulatory obligations. Specific reference was made by the AEMC to the situation where a DNSP is performing above the required standards. Expenditure proposals in such situations must be based on the required standards, rather than on maintaining reliability of supply.[227] The approach to setting STPIS performance targets set out in Clause 3.2.1 of the STPIS guideline, in contrast, is based on maintaining reliability (the average of the previous five years' performance).[228]

ActewAGL Distribution is in the situation described by the AEMC, since it has outperformed the minimum standards in the Supply Standards Code with respect to SAIFI and SAIDI on average over the past five years (see Figure 16.1).[229] Setting STPIS performance targets based on the average of the last five years' performance would therefore result in a situation in which

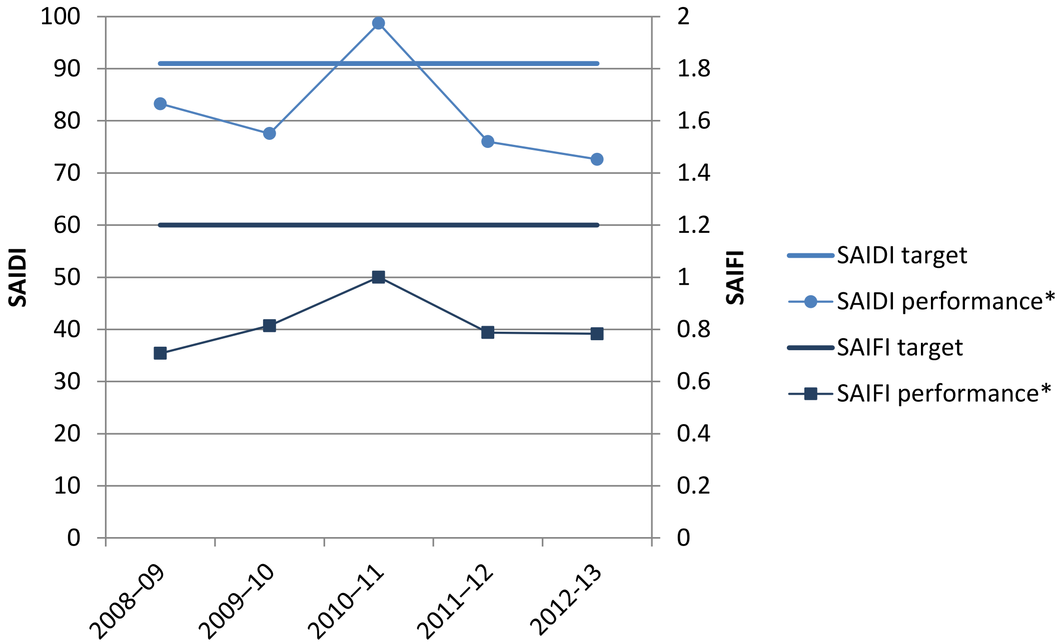
[227] AEMC 2013, *Network Service Provider Expenditure Objectives*, Rule Determination, 19 September 2013, Sydney, pp i-ii

[228] AER 2009, *Electricity distribution network service providers Service target performance incentive scheme*, November, p 9

[229] Australian Capital Territory 2013, *Utilities (Electricity Distribution Supply Standards Code) Determination 2013*, Disallowable Instrument DI2013–221, 22 August

ActewAGL Distribution is funded to achieve a reliability level for which penalties would be incurred under STPIS.

Figure 16.1 SAIDI and SAIFI performance relative to minimum standards



* Adjusted for exclusions allowed under STPIS.

ActewAGL Distribution and other DNSPs raised this inconsistency in March 2013 as part of the AEMC's consultation on the rule change.[230] The AEMC's response to these submissions was that the AER has flexibility in the way that it applies STPIS and can amend the STPIS if necessary.[231]

The AER has acknowledged in its Stage 2 Framework and Approach paper that "*We are aware of policy reviews indicating the need to reform the STPIS.*" The AER also noted the AEMC national reliability frameworks review[232] and stated:

> *We consider there is inadequate time to review our national STPIS to incorporate the findings of these reviews before finalising our determinations for ActewAGL.*[233]

[230] ActewAGL 2013, *National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013—Response to Consultation Paper*, 8 March

[231] AEMC 2013, *Network Service Provider Expenditure Objectives*, Rule Determination, 19 September 2013, Sydney, p 33

[232] AEMC 2013, *Review of the national framework for distribution reliability—Final Report*, September

[233] AER 2014, *Stage 2 Framework and Approach—ActewAGL*, January, p 21

16.4.3.2 Proposed modification

ActewAGL Distribution proposes that the inconsistency discussed above be addressed in the forthcoming regulatory control period by modifying the performance targets for the reliability of supply component of the scheme. Clause 3.2.2(a) of the STPIS guideline provides for ActewAGL Distribution to propose modified performance targets. In particular, clause 3.2.1(a)(2) states that performance targets may be "*modified by… any other factors that are expected to materially affect network reliability performance*." This section sets out ActewAGL Distribution's proposed modified performance targets and, in accordance with Clause 3.2.1(b), provides an explanation of how the targets have been calculated.

In order to avoid inconsistency between STPIS performance targets and the reliability levels underpinning the expenditure proposal, ActewAGL Distribution proposes that reliability performance targets for the STPIS in the 2014–19 regulatory control period be modified to align with regulatory obligations.

ActewAGL Distribution's regulatory obligations are based on total SAIDI and SAIFI, while STPIS performance targets are based on *unplanned* SAIDI and SAIFI. ActewAGL proposes that regulatory obligations be converted to their notional unplanned equivalent by multiplying each measure by the average proportion of unplanned to total levels for that measure over the past five years (see Table 16.4).

Table 16.4 Calculation of notional unplanned reliability standards

Measure	*Minimum Standard (total indices)*	*Proportion of unplanned to total indices over past five years (%)*	*Notional standard for unplanned indices*
SAIDI	91	38.2	34.79
SAIFI	1.2	72.7	0.8726

These notional unplanned standards are disaggregated by feeder type using the numbers of customers and the average performance over 2008-09 to 2012-13 on each feeder type. The data used for this calculation are based on ActewAGL Distribution's recently revised feeder classification (with 20 rural feeders) to provide an accurate reflection of the weighting between urban and rural feeder performance in future reporting.

ActewAGL Distribution's proposed performance targets, based on this approach, are provided in Table 16.5 along with targets calculated in accordance with the default approach outlined in the Stage 2 Framework and Approach paper (average performance over the past five years).

Table 16.5 Performance targets based on minimum standards and the default approach

Measure	*Targets based on minimum standards*	*Default targets*	*Quantum of adjustment*
Urban USAIDI	33.46	30.01	3.45
Short rural USAIDI	43.45	38.98	4.48
Urban USAIFI	0.840	0.57	0.267
Short rural USAIFI	1.116	0.76	0.355

ActewAGL Distribution is not proposing that this approach to setting performance targets should necessarily be applied in future regulatory control periods. The most appropriate approach to setting performance targets in the 2019 determination and beyond will depend on the decision ultimately made by the SCER in relation to a national framework for reliability and the nature and frequency of future revisions to regulatory obligations. ActewAGL Distribution recognises that performance targets will need to be updated over time to ensure that customers share in the benefits of improvements in the balance between cost and reliability.

The following table demonstrates that ActewAGL Distribution's proposed performance targets are consistent with the objectives of STPIS set out in Clause 1.5 of the guideline.

Table 16.6 ActewAGL Distribution's proposed performance targets are consistent with the STPIS objectives

Objective	*ActewAGL Distribution comments*
That the scheme is consistent with the national electricity objective in Section 7 of *National Electricity Law (NEL):* *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -* *(a) price, quality, safety, reliability and security of supply of electricity; and* *(b) the reliability, safety and security of the national electricity system*	ActewAGL Distribution's proposal ensures consistency between reliability levels underpinning expenditure forecasts and STPIS. The alternative of funding a DNSP only to meet its regulatory obligations and then imposing STPIS penalties for performing in line with those obligations would have the effect of providing insufficient funds to efficiently invest in and operate electricity services, which would be inconsistent with the national electricity objective and s7A(2) of the Law.
That the scheme must take into account the need to ensure that benefits to consumers likely to result from the *scheme* are sufficient to warrant any reward or penalty under the *scheme* for DNSPs	Consumers benefit from the scheme via the revision of performance targets. ActewAGL Distribution expects that performance targets will be revised at the next price review and notes that the nature of that revision will depend on the outcomes of the SCER decision on a national reliability framework and the foreshadowed AER review of STPIS.
That the scheme must take into account any *regulatory obligation or requirement* to which the DNSP is subject	ActewAGL Distribution's proposed targets are derived explicitly from its regulatory obligations in relation to reliability performance.
To take into account the past performance of the distribution network	ActewAGL Distribution's proposed targets take account of past performance in relation to the balance between planned and unplanned interruptions and between performance on urban and rural feeders. The regulatory obligations on which ActewAGL Distribution's proposed targets are based were set with reference to past performance.*
That the scheme must take into account any other incentives available to the DNSP under the Rules or a relevant distribution determination	Incentives at the margin are not affected by performance targets. Incentives may be affected by expectations about how performance targets will be updated over time; however, ActewAGL Distribution's proposal relates only to the forthcoming regulatory period.
That the scheme must take into account the need to ensure that the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels	Incentives at the margin are not affected by performance targets. Incentives may be affected by expectations about how performance targets will be updated over time; however, ActewAGL Distribution's proposal relates only to the forthcoming regulatory period.
That the scheme must take into account the willingness of the customer or end user to pay for improved performance in the delivery of services	The incentive rates under the scheme take account of willingness to pay for improved performance. ActewAGL Distribution's proposal in relation to incentive rates is set out in 16.4.4.

Objective	ActewAGL Distribution comments
That the scheme must take into account the possible effects of the *scheme* on incentives for the implementation of non-network alternatives	Incentives at the margin are not affected by performance targets. Incentives may be affected by expectations about how performance targets will be updated over time; however, ActewAGL Distribution's proposal relates only to the forthcoming regulatory period.
That the scheme promotes transparency in the information provided by a DNSP under this *scheme* to the AER	ActewAGL Distribution has detailed the reasoning and method supporting its proposal in this submission.
That the scheme promotes transparency in the decisions made by the AER.	ActewAGL Distribution's proposed approach is a transparent method for setting performance targets.

* Utilities (Technical Codes) Determination 2000, Electricity Distribution (Supply Standards) Code, p6 (accessed on 29 April 2014 at http://www.legislation.act.gov.au/di/2000-369/default.asp)

16.4.4 Proposed alternative VCR used to set incentive rates for the reliability of supply component

The Stage 2 Framework and Approach paper indicated the AER's intention to "apply the methodology and value of customer reliability (VCR) values as indicated in our national STPIS to the calculation of incentive rates." [234]

Clause 3.2.2(d) of the STPIS guideline provides for distributors to propose an alternative VCR to the calculation of incentive rates. The AER also noted in its Stage 2 Framework and Approach paper that "distributors may propose an alternative VCR estimate, supported by details of the calculation methodology and research, in their regulatory proposals."[235]

One of the principles underpinning the STPIS and its application is that "the scheme should reflect customer preferences regarding service performance and willingness to pay for service improvements".[236] The AER has stated:

> *The rate at which rewards and penalties are assigned is based on customer willingness to pay, which has been derived from customer surveys and previous economic studies. The rationale for this approach is based on the economic notion that the schedule of rewards and penalties should mimic customers' marginal willingness to pay for improved service performance. This allows a DNSP to change its service performance up to the point where the optimal level of service performance is attained, that is, the marginal cost of improving performance equals the reward for doing so.*[237]

[234] AER 2014, *Stage 2 Framework and Approach—ActewAGL*, January, p 20

[235] AER 2014, *Stage 2 Framework and Approach—ActewAGL*, January, p 24

[236] AER 2008, *Final decision—Electricity distribution network service providers service target performance incentive scheme*, p 2

[237] AER 2008, *Final decision—Electricity distribution network service providers service target performance incentive scheme*, p 6

16.4.4.1 Evidence with respect to customer willingness to pay in the ACT

ActewAGL Distribution has been an industry leader in conducting research into customers' preferred balance between cost and supply reliability. Two major studies of customer willingness to pay (WTP) for changes in reliability have been undertaken in the ACT. The first, by NERA and ACNielsen in 2003, included both residential and non-residential customers (the NERA study).[238] A second, by the Australian National University (ANU) in 2012, included only residential customers (the ANU study).[239]

The NERA study was conducted around a decade ago and the results remain relevant today as evidenced by the estimates of residential WTP from the ANU study which were broadly consistent with those from the NERA study after adjusting for inflation. The ANU researchers stated:

> *Overall, the estimated cost of an outage does not appear to be very different across the two studies after adjusting for inflation. In fact, considering the differences in the design of the choice tasks used in the two studies, the estimates are remarkably similar for most duration levels, giving further confidence that the choice modelling valuation technique can produce consistent estimates across different surveys applied in the utilities services context.*[240]

These two studies represent the best available evidence of customer WTP in the ACT. Incentive rates based on these studies are more likely to reflect the preferences of ACT consumers than the studies undertaken in Victoria that form the basis of the default VCR and incentive rates in the STPIS guideline (the *Victorian studies*). There are reasons to expect that preferences may differ across the two regions; for example, due to differences in income, climate and the make-up of the non-residential sector.

The NERA and ANU studies are also based on a methodology that is better supported by the economics literature on non-market valuation than the methodology used in the Victorian studies. The methods used in the NERA and ANU studies were endorsed by expert peer reviewers, Professors David Hensher and Riccardo Scarpa. For example, in relation to the ANU study, Professor Riccardo Scarpa stated:

> *… I am satisfied that the report goes further than the state of practice in commercial consultancy environments in non market valuation studies via stated choice data. In fact, the techniques used in this study go beyond commonly established practice and include*

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[238] NERA and ACNielsen 2003, *Willingness to pay research study*, A report for ACTEW Corporation and ActewAGL, September

[239] McNair, B.J. and Ward, M.B. 2012, *Willingness to pay research project*, Final Report to ActewAGL Distribution, March

[240] McNair, B.J. and Ward, M.B. 2012, *Willingness to pay research project*, Final Report to ActewAGL Distribution, March, p 31

> *approaches at the forefront of the discipline, which many, including myself, would consider state of the art.*[241]

The choice modelling methodology used in the ACT studies is consistent with the economic principles of Hicksian compensating and equivalent variation. The 'economic principle of substitution' (or 'preparatory action') approach used for residential consumers in the Victorian studies, by focusing on financial expenses, is likely to omit significant non-financial economic costs associated with inconvenience and may also include values that should be excluded, such as the excess value of a restaurant meal over a home meal. ActewAGL Distribution notes that Charles River Associates, in its 2002 assessment of VCR for VENCorp, identified that a lesson learnt for future studies was that a 'tradeoff method' (choice modelling) should be considered for estimating residential VCR.[242] ActewAGL Distribution also notes that choice modelling has now been adopted by AEMO for the residential and commercial components of the national VCR study it is currently undertaking, in favour of the direct worth and economic principle of substitution approaches used by its predecessor VENCorp in the Victorian studies (which are the basis of the AER default incentive rates).[243] For further discussion of the merits of using a choice modelling approach in favour of a preparatory action approach for residential consumers, refer to Attachment F1.

16.4.4.2 Proposed VCR

ActewAGL Distribution has estimated a proposed VCR estimate and STPIS incentive rates based on evidence from the NERA and ANU studies. This section provides a summary of the analysis underlying the VCR estimate, with further detail provided in Attachment F1.

The proposed VCR estimate is derived from estimated customer utility functions from the ANU study and the non-residential segment of the NERA study. These utility functions were used to estimate average customer WTP for a large number of hypothetical reliability change scenarios. These scenarios were defined at a customer level and represented changes of up to ±10 per cent in the average frequency of supply interruptions. The durations of the interruptions used in the scenarios were based on the historical distribution of interruption duration in the ACT network. In addition to average WTP, average customer lost load was calculated for each scenario using customer billing records or customer-reported bill amounts, where available. Figure 16.2 illustrates these two outputs for all 1000 reliability change scenarios analysed for the residential sector.

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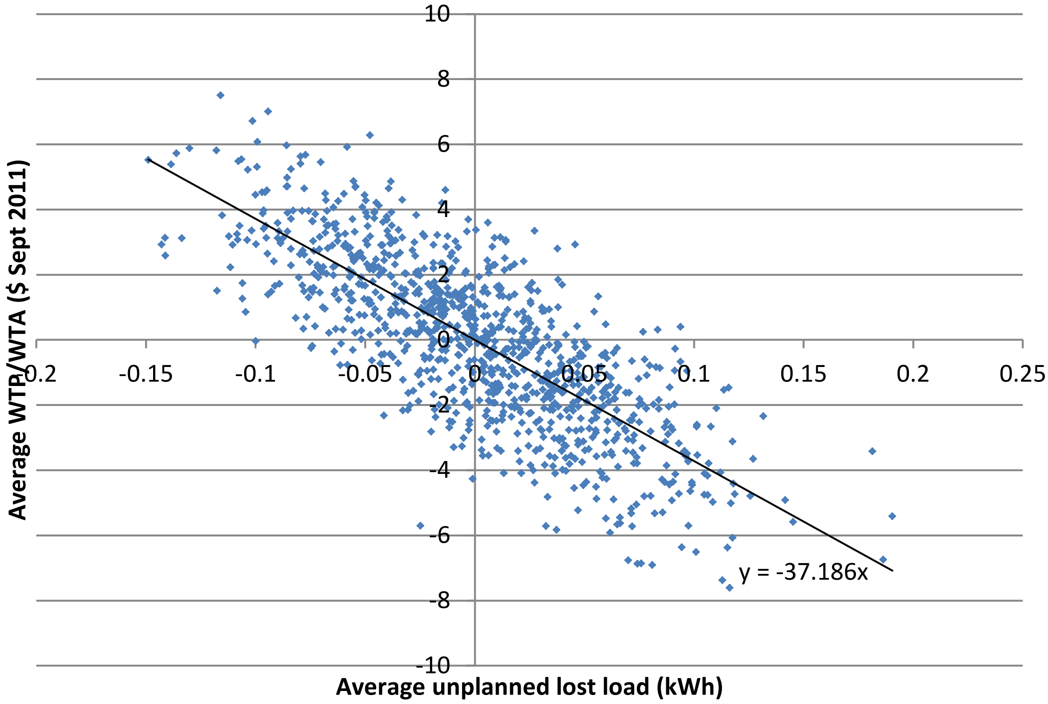
[241] McNair, B.J. and Ward, M.B. 2012, *Willingness to pay research project*, Final Report to ActewAGL Distribution, March, p 126

[242] CRA 2002, Assessment of the Value of Customer Reliability (VCR), Final report submitted to VENCorp, December, p 7 and p 45

[243] AEMO 2013, *Value of customer reliability*, Directions Paper, May

Figure 16.2 Average WTP and unplanned lost load for hypothetical reliability change scenarios for residential customers



An average value of lost load for the residential sector was calculated by fitting a line through these points (using ordinary least squares regression), subject to the constraint that the line must pass through the origin (0, 0). The slope of that line represents a value of lost load of $37.19/kWh ($ Sept 2011). This process was repeated for the non-residential sector, resulting in a VCR estimate of $62.70/kWh ($ June 2003). The ACT-wide VCR estimate was calculated by indexing the estimates to 2014-15 dollar terms from the time at which the surveys took place using the Consumer Price Index and by weighting the sector-specific estimates by annual consumption as shown in Table 16.7. The resulting estimate of VCR for the ACT is $67.26/kWh ($2014-15).

Table 16.7 Proposed VCR estimate by sector

	Sector VCR ($/kWh 2014-15)	*Weighting based on 2012-13 consumption*	*Contribution to ACT VCR ($/kWh 2014-15)*
Residential	40.15	40.82%	16.39
Non-residential	85.96	59.18%	50.87
Total		100.00%	67.26

The evidence in Attachment F1 indicates that VCR in the ACT is clearly higher than the default VCR for non-CBD feeder types set out in clause 3.2.2(b)(2) of the STPIS guideline of $55.62/kWh in 2014-15 dollar terms. The VCR of $67.26/kWh proposed by ActewAGL Distribution is the lower bound of a range of estimates derived from different specifications of reliability change scenarios. The analysis indicated that the value of lost load would be considerably higher if evaluated on the basis of increases in the duration of interruptions, as distinct from increases in the frequency of interruptions with the distribution of duration held constant.

The use of the lower bound estimate is considered an appropriate precautionary step in the right direction at this time, since a higher VCR estimate would create a level of inconsistency with the default VCR under the current STPIS. However, ActewAGL Distribution notes the AEMC VCR estimate for NSW derived by Oakley Greenwood in 2012 of $94.99/kWh is within the range of estimates for the ACT. A less conservative approach to the use of the ACT specific data may prove to be warranted if further studies continue to confirm VCR estimates that are significantly higher than the default VCR in the current STPIS.

The following table demonstrates how ActewAGL Distribution's proposed incentive rates are consistent with the objectives of STPIS set out in Clause 1.5 of the guideline.

Table 16.8 ActewAGL Distribution's proposed incentive rates are consistent with the STPIS objectives

Objective	*ActewAGL Distribution comments*
That the scheme is consistent with the national electricity objective in Section 7 of *National Electricity Law (NEL):* *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -* *(a) price, quality, safety, reliability and security of supply of electricity; and* *(b) the reliability, safety and security of the national electricity system*	Efficient investment and operation will not be promoted unless incentive rates accurately reflect consumer preferences with respect to the trade-off between price and reliability. ActewAGL Distribution's proposal achieves this accurate reflection by utilising high-quality studies of the preferences of ACT consumers. The default VCR under the STPIS would not promote efficient investment and operation, because: (a) it does not reflect any differences in preferences of Victorian and ACT customers; and (b) the survey method used to derive the residential component of the default VCR is inconsistent with the economic concept of WTP.
That the scheme must take into account the need to ensure that benefits to consumers likely to result from the *scheme* are sufficient to warrant any reward or penalty under the *scheme* for DNSPs	The social benefits from the scheme depend on accurate reflection of consumer preferences in incentive rates. See ActewAGL Distribution comments in relation to the national electricity objective above.
That the scheme must take into account any *regulatory obligation or requirement* to which the DNSP is subject	No regulatory obligation or requirement is relevant to adjustments to the VCR and incentive rates.
To take into account the past performance of the distribution network	The reliability scenarios used to derive ActewAGL Distribution's proposed VCR and incentive rates are based on past performance of the ACT distribution network.

Objective	ActewAGL Distribution comments
That the scheme must take into account any other incentives available to the DNSP under the Rules or a relevant distribution determination	By accurately reflecting the preferences of ACT consumers, ActewAGL Distribution's proposed VCR and incentive rates would result in an appropriate balance between incentives to reduce expenditure and improve service levels.
That the scheme must take into account the need to ensure that the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels	Lower incentive rates than those proposed by ActewAGL Distribution would provide an incentive to deliver service levels below the socially optimal level.
That the scheme must take into account the willingness of the customer or end user to pay for improved performance in the delivery of services	ActewAGL Distribution's proposed incentive rates are calculated directly from surveys of ACT customer willingness to pay.
That the scheme must take into account the possible effects of the *scheme* on incentives for the implementation of non-network alternatives	ActewAGL Distribution's proposed modification to the VCR would not alter the balance between incentives for network and non-network alternatives.
That the scheme promotes transparency in the information provided by a DNSP under this *scheme* to the AER	ActewAGL Distribution has detailed the reasoning and method supporting its proposal in this submission.
That the scheme promotes transparency in the decisions made by the AER.	ActewAGL Distribution's proposed approach is a transparent method for setting incentive rates, detailed in Attachment F1.

16.4.4.3 Proposed incentive rates

Incentive rates based on ActewAGL Distribution's proposed VCR are calculated in accordance with clause 3.2.2 of the STPIS guideline. The inputs used in these calculations are set out in Table 16.9 along with a description of the source of the inputs. The calculations set out in clauses 3.2.2(h) and (i) of the STPIS guideline require average annual energy consumption by feeder type. ActewAGL Distribution does not possess data on consumption by feeder type. In the absence of this data, ActewAGL Distribution has disaggregated the total forecast by feeder type on the assumption that average consumption per customer is constant across feeder types. ActewAGL Distribution's recently revised feeder classification (with 20 rural feeders) has been used in this calculation for consistency with future reporting.

Table 16.9 Assumptions underlying ActewAGL Distribution's proposed incentive rates

Item	*Amount*		*Source*
Average of smoothed revenue requirement ($2014-15 '000s)	166,990		ActewAGL Distribution proposal (see section 12.6)
Feeder type	*Urban*	*Short rural*	
VCR ($2014-15 / MWh)	67,258	67,258	This section and Attachment F1
Weighting	0.97	0.92	STPIS guideline, p11
Average annual energy consumption (MWh)	2,464,134	300,332	ActewAGL Distribution forecast (see section 5.2.3)
Average USAIDI target	33.46	43.45	ActewAGL Distribution proposal (see section 16.4.3.2)
Average USAIFI target	0.840	1.116	ActewAGL Distribution proposal (see section 16.4.3.2)

ActewAGL Distribution's proposed incentive rates, based on these assumptions, are presented in Table 16.10.

Table 16.10 ActewAGL Distribution proposed STPIS incentive rates

Parameter segment	*Incentive rate (%)*
Urban USAIFI	3.82
Urban USAIDI	0.093
Short rural USAIFI	0.47
Short rural USAIDI	0.011

16.4.5 Other information

16.4.5.1 Performance targets for telephone answering parameter

In relation to telephone answering performance, ActewAGL Distribution accepts the approach indicated by the AER in its Stage 2 Framework and Approach paper to "set performance targets based on the distributor's average performance over the past five regulatory years."[244]

Over the 2009–14 regulatory period, ActewAGL Distribution has improved its call centre performance as measured by the proportion of calls answered within 30 seconds (see Table

[244] AER 2014, Stage 2 Framework and Approach, ActewAGL, January, p 20

16.11). The average performance over the past five years and the performance target for the 2015-2019 period is 75.2 per cent.

Table 16.11 Telephone answering performance

	2008–09	2009–10	2010–11	2011–12	2012–13
Proportion of calls answered within 30 seconds (%)	70.2	72.9	75.7	80.1	77.2

ActewAGL Distribution proposes that the AER apply the approach proposed in its Stage 2 Framework and Approach paper of applying the incentive rate for the telephone answering parameter set out in clause 5.3.2(a)(1) of the STPIS guideline of -0.04 per cent.

16.5 Demand management and embedded generation connection incentive scheme

As detailed in Chapter 6, ActewAGL Distribution supports the AER's proposal, as specified in the Stage 2 Framework and Approach, to apply the DMEGCIS in the same manner as in the previous regulatory period as an interim measure.

17 Cost pass through

This Chapter describes the events ActewAGL Distribution proposes should be treated as nominated pass through events in the subsequent regulatory control period.

Clause 6.6.1 of the Rules provides for a DNSP to pass through costs associated with certain events. Clause 6.6.1(a1) specifies the pass through events for a distribution determination, being:

- A regulatory change event;
- A service standard event;
- A tax change event;
- A retailer insolvency event; and
- Any other event specified in a distribution determination as a pass through event for the determination.

The Rules allow a DNSP to nominate events that it considers should be classified as pass through events in the next regulatory control period. Clause 6.5.10 of the Rules permits ActewAGL Distribution to include in its building block proposal a proposal as to the events that should be defined as pass through events under clause 6.6.1(a1)(5) having regard to the nominated pass through event considerations defined in Chapter 10 of the Rules.

ActewAGL Distribution proposes that the following events be defined as pass through events under clause 6.6.1(a1)(5):

- A general pass through event;
- An insurer credit risk event;
- An insurance cap event; and
- A Demand Management and Embedded Generation Connection Incentive Scheme event.

In proposing these pass through events ActewAGL Distribution has had regard to the nominated pass through event considerations under the Rules:

(a) whether the event proposed is an event covered by a category of *pass through event* specified in clause 6.6.1(a1)(1) to (4);

(b) whether the nature or type of event can be clearly identified at the time the determination is made for the service provider (**Consideration (b)**);

(c) whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;

(d) whether the relevant service provider could insure against the event, having regard to:

(1) the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or

(2) whether the event can be self-insured on the basis that:

(i) it is possible to calculate the self-insurance premium; and

(ii) the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide *network services*; and

(e) any other matter the *AER* considers relevant and which the *AER* has notified *Network Service Providers* is a nominated pass through event consideration.

As at the date of this proposal the AER has not notified NSPs of any other matter that is a nominated pass through consideration.

The AER is required to take these considerations into account in determining whether to accept ActewAGL Distribution's proposed pass through events (Rule 6.5.10(b)). A decision by the AER on the additional pass through events that are to apply in the subsequent regulatory control period is a constituent decision for a distribution determination (Rule 6.12.1(4)).

The AER must also, in performing or exercising an AER economic regulatory function or power, perform or exercise that function of power in a manner that will or is likely to contribute to the achievement of the National Electricity Objective[245] which is:

to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –

(a) price, quality, safety, reliability, and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system.[246]

ActewAGL Distribution provides a summary of each proposed pass through event below and how regard has been given to the nominated pass through event considerations.

17.1 General pass through event

Positive cost pass throughs exist in the Rules as a mechanism to allow network service providers (NSPs) to recover their efficient costs incurred as a result of events that could not be forecast as part of their regulatory or revenue proposal. Without the pass through mechanism the events

[245] *National Electricity (South Australia) Act 1996,* Part 3 Clause 16(1)(a)

[246] *National Electricity Law*, section 7

would have a significant financial effect on the ability of networks to invest in and operate their networks.[247]

As the AEMC has noted, cost pass throughs exist as an important mechanism under the Rules to allow network service providers (NSPs) to recover efficient costs. [248] The AEMC has identified that "[cost pass throughs] are needed because of the inability of NSPs, and the AER, to forecast all possible events that could affect the ability of NSPs to provide network services at the time of setting the revenue or regulatory determinations."[249]

At the time of a distribution determination NSPs and the AER can identify possible events that will have an impact but are too uncertain to be included as part of a determination. Examples include regulatory change and tax change events. Some other events cannot be forecast or identified ahead of time. For the pass through mechanism to meet its objective, allowing NSPs to recover their efficient costs incurred as a result of events that could not be forecast as part of their regulatory proposal, it must be sufficiently robust to allow the pass through of both types of event.

If NSPs cannot recover efficient costs from events with a material impact then, as the AEMC notes, there will be significant effects on the ability of NSPs to invest in and operate their networks. [250] In turn efficient investment will not occur and the National Electricity Objective will not be achieved.

For these reasons, ActewAGL Distribution proposes to include a general nominated pass through event to ensure that costs from events unable to be forecast are recovered. Without such a pass through event ActewAGL Distribution would not be able to recover its efficient costs of events which cannot be identified at the time of the distribution determination. An inability to recover those costs will impact upon its ability to invest in and operate its network.

The event is defined to be:

> A general nominated pass through event occurs when:
>
> (1) ActewAGL Distribution could not reasonably prevent the event from occurring or substantially mitigate the cost impact of the event; and

[247] AEMC 2012, *National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012*, Rule Determination, p.2

[248] AEMC 2012, *National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012*, Rule Determination, p.9.

[249] AEMC 2012, *National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012*, Rule Determination, p 9

[250] AEMC 2012, *National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012*, Rule Determination, p.9.

(2) the event does not fall into any definition listed in clause 6.6.1(a1)(1) to (4) of the NER

For a positive or negative change event to occur then the cost increase or decrease must be material. For this reason, ActewAGL Distribution has not included a materiality definition in any proposed pass through events.

17.1.1 Previous Determinations

In previous determinations for the ACT, New South Wales, Queensland and South Australia[251] the AER has included a general nominated pass through event.[252] This event appropriately provides a mechanism for NSPs to recover efficient costs from events unknown to occur and that cannot be forecast at the time of the distribution determination.

In deciding to include a general nominated pass through event in the previous determinations for the ACT, New South Wales, Queensland and South Australia, the AER correctly recognised the possibility of events occurring during a regulatory control period that are uncontrollable, unforseen and have a material impact on costs. The AER further recognised that the costs of events not anticipated at the time of the determination which have a material impact on the ability of a DNSP to provide distribution services should be able to be recovered through the mechanism of a general nominated pass through event.

In the Victorian distribution determination, the AER recognised the possibility of high magnitude events and identified regulatory certainty as a potential mitigation:

> *... the possibility of high magnitude events occurring places a level of risk on DNSPs. This level of risk is such that, should the event occur, the associated costs of the event could threaten the financial viability of the DNSP. This is clearly an undesirable outcome, and can, in part be mitigated by regulatory certainty provided in the relevant decision of determination.*[253]

The AER considered that regulatory certainty can be provided by requiring that pass through events are clearly identified and defined at the time of the relevant determination.[254] The AER applied a criterion which required that an event be foreseeable, such that it:

> *…can be clearly identified and defined at the time of the relevant determination. This provides regulatory certainty for the service provider, by reducing the discretion of the regulator within*

[251] Formerly ETSA Utilities

[252] AER 2009, *ACT Distribution determination 2009/10-2013/14*, Final Decision, p.128-129; AER 2009 *NSW Distribution determination 2009/10-2013/14*, Final Decision, p.278-280; AER 2010 *Queensland Distribution determination* 2010/11-2014/15, Final Decision, p.311-312; AER 2010 *South Australia Distribution determination 2010/11-2014/15,* Final Decision, p.234-235.

[253] AER 2010, *Victorian electricity distribution network service providers Distribution determination 2011-2015*, Draft Decision p 719

[254] AER 2010, *Victorian electricity distribution network service providers Distribution determination 2011-2015*, Draft Decision p 720

> *the regulatory period. Although arguable some costs, particular those relating to exogenous events, cannot be accurately predicted or forecast, the types of events that would trigger these costs can be predicted and hence defined in advance.*

In this analysis the AER recognises only event types that are known to occur, thereby preventing the pass through mechanism from addressing events that both the AER and NSPs are unable to forecast. This approach leaves NSPs exposed to unexpected events, not forecast at the time of a distribution determination, which could not reasonably be prevented or the cost mitigated.

Recent events in South Australia and the ACT illustrate the limitations of the AER and NSPs to forecast and define events in advance. SA Power Networks and ActewAGL Distribution both experienced material increases in vegetation management costs due to uncontrollable and unexpected increases in vegetation growth.[255] The AER accepted SA Power Networks claim that a pass through event occurred with the Chair of the AER commenting that "The Rules and the Determination allowed for a recognition of this type of unexpected expense."[256] In accepting the claim the AER recognised that events can occur which materially affects the costs of a NSP and which could not be prevented or forecast at the time of the Distribution Determination.

Requiring events to be clearly identified and defined at the time of the Distribution Determination ignores the possibility of unexpected expenses from unknown events. This results in, as the AER has noted, the possibility of a high magnitude event threatening the financial viability of a NSP.[257]

17.1.2 Consideration (b)

On 2 August 2012 the AEMC made a Rule Determination which included a set of nominated cost pass through considerations,[258] distilled from the factors the AER considered in the Victorian Distribution Determination.[259] The AEMC noted that the "nominated pass through event considerations are of a high level and do not stipulate any specific action"[260] and that "these are considerations only, therefore the NSP and the AER can come to a mutual understanding that a cost pass through event is inconsistent with the factors for consideration, but may still be the

[255] SA Power Networks 2013, *Vegetation clearance pass through application,* p.2 and ActewAGL 2013, Vegetation management cost pass through, p 4

[256] Indaily 2013, *Koutsantonis sparks up over energy price hike,* 1 August

[257] AER 2010, *Victorian electricity distribution network service providers Distribution determination 2011-2015*, Draft Decision, p 719

[258] AEMC 2012, *National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012,* Rule Determination, p 20

[259] AEMC 2012, *National Electricity Amendment (Cost pass through arrangements for network service providers) Rule 2012*, Draft Rule Determination, p 16

[260] AEMC 2012, *National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012,* Rule Determination, p 19

more efficient mechanism."[261] ActewAGL Distribution notes that the AER has advised that further prescription regarding the assessment of proposed nominated pass through events in the Rules is unnecessary and not appropriate.[262]

Consideration (b) is whether the nature or type of event can be clearly identified at the time the determination is made for the service provider. ActewAGL Distribution considers that the nature of a general nominated pass through event can be clearly identified through the following clauses embodied in its proposed definitions:

1. ActewAGL Distribution could not reasonably prevent the event from occurring or substantially mitigate the cost impact of the event; and
2. the event does not fall into any definition listed in clause 6.6.1(a1)(1) to (4) of the NER

ActewAGL Distribution understands that the AER is of the view that a general nominated pass through event's nature or type cannot be clearly identified.[263] Although clear identification of a pass through event can be useful for events known to occur, this consideration is not relevant in providing a mechanism for NSPs to recover costs for events that cannot be forecast at the time of a revenue determination.

If the AER maintains its view that the nature of a general nominated pass through event cannot be clearly identified, then to contribute to the achievement of the National Electricity Objective and facilitate the recovery of efficient costs, the AER should determine a cost pass through event inconsistent with Consideration (b). As noted above, in deciding to prescribe considerations which the AER must take into account in deciding whether to accept an NSP's nominated pass through event, the AEMC contemplated that the AER could decide to accept a nominated pass through that was inconsistent with those considerations.[264]

17.1.3 Pass through consideration matrix

The following table sets out how ActewAGL Distribution has had regard to each of the pass through event considerations in nominating the general nominated pass through event. Consideration (b) has been dealt with in further detail above.

[261] AEMC 2012, *National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012,* Rule Determination, p 20

[262] AER 2012, *Draft determination on cost pass through arrangements for network service providers,* p 1

[263] AER 2010, *Victorian electricity distribution network service providers Distribution determination 2011-2015*, Draft Decision, p 722

[264] AEMC 2012, *National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012,* Rule Determination, p.20

Table 17.1 Assessment of the general nominated pass though event against the pass through event considerations

Pass through event consideration	*How ActewAGL has had regard*
whether the event proposed is an event covered by a category of *pass through event* specified in clause 6.6.1(a1)(1) to (4);	The proposed general pass through event does not apply if any pass through event specified in clause 6.6.1(a1)(1) to (4) applies.
whether the nature or type of event can be clearly identified at the time the determination is made for the service provider (consideration (b));	As set out above, ActewAGL Distribution considers that the nature of a general cost pass through event is clearly identified. If the AER maintains its view that the nature of a general nominated pass through event cannot be clearly identified, then to contribute to the achievement of the National Electricity Objective and facilitate ActewAGL Distribution's recovery of efficient costs, the AER should accept the nominated event irrespective of its inconsistency with consideration b.
whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;	The pass through event only applies if an event occurs during the next regulatory control period, the effect of which ActewAGL Distribution could not have reasonably prevented an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;
whether the relevant service provider could insure against the event, having regard to: (1) the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or (2) whether the event can be self-insured on the basis that (i) it is possible to calculate the self-insurance premium; and (ii) the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide *network services*; and	ActewAGL Distribution cannot obtain insurance for events it is unable to forecast that might occur. Under clause 6.6.1(j)(7) of the Rules the AER on a pass through application must take into account whether the costs of the pass through event have already been factored into the calculation of the ActewAGL Distribution's annual revenue requirement for the regulatory control period in which the pass through event occurred or will be factored into the calculation of the ActewAGL Distribution's annual revenue requirement for a subsequent regulatory control period. Accordingly, if the event which occurs has in fact been insured against and factored into ActewAGL Distribution's annual revenue requirement, the AER can take that into account in making its determination on the pass through application.
any other matter the *AER* considers relevant and which the *AER* has notified *Network Service Providers* is a nominated pass through event consideration.	The AER has not notified NSPs of any nominated pass through event considerations.

17.2 Insurer credit risk event

ActewAGL Distribution proposes an insurer credit risk event defined as:

> An insurer credit risk event occurs if as a result of the insolvency of an insurer, ActewAGL Distribution:
>
> (a) Incurs higher or lower costs for insurance premiums than those allowed for in the distribution determination; or/and
>
> (b) In respect of a claim for a risk that would have been insured by ActewAGL Distribution's insurers, is subject to higher of lower claim limit or higher of lower deductible than would have applied under that policy
>
> (c) Incurs additional costs associated with self funding an insurance claim, which would have otherwise been covered by the insolvent insurer.

This event is based on the insurer credit risk event in the recent Distribution Determinations for the Victorian and Tasmanian DNSPs.[265] The pass through event has been simplified to reflect the requirements of the positive and negative change event definitions in the National Electricity Rules.

17.2.1 Pass through consideration matrix

The following table sets out how ActewAGL Distribution has had regard to each of the pass through event considerations in nominating the insurer credit risk event.

[265] AER 2010, *Victorian electricity distribution network service providers Distribution determination 2011-2015,* Final Decision, p.783-784, 797; AER 2012, *Aurora Energy Pty Ltd Distribution determination 2012/13-2016/17 ,* Final Decision, p.183.

Table 17.2 Assessment of the insurer credit risk pass though event against the pass through event considerations

Pass through event consideration	*How ActewAGL has had regard*
whether the event proposed is an event covered by a category of *pass through event* specified in clause 6.6.1(a1)(1) to (4);	This event is not covered by any category of pass through event specified in clause 6.6.1(a1)(1) to (4).
whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;	The type of event, being the insolvency of an insurer, can be clearly identified at the time of the determination is made.
whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;	ActewAGL Distribution cannot reasonably prevent the insolvency of an insurer.
whether the relevant service provider could insure against the event, having regard to: (1) the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or (2) whether the event can be self-insured on the basis that (i) it is possible to calculate the self-insurance premium; and (ii) the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide *network services*; and	ActewAGL Distribution as part of its insurance review processes has not identified insurance for insurer credit risk failure available on reasonable commercial terms. Due to the low probability and high magnitude of any event that exceeded the policy limit of insurance, it is not possible to calculate a self-insurance premium.
any other matter the *AER* considers relevant and which the *AER* has notified *Network Service Providers* is a nominated pass through event consideration.	The AER has not notified network service providers of nominated pass through event considerations.

17.3 An insurance cap event

ActewAGL Distribution proposes a liability above insurance cap event defined to occur if

(a) ActewAGL Distribution makes a claim on an insurance policy that it holds;
(b) ActewAGL Distribution incurs costs beyond the policy limit for the relevant insurance policy; and
(c) ActewAGL Distribution must bear the costs that are in excess of the policy limit.

The AER has noted these events tend to be low probability, potentially high cost risks[266] and approved similar events in Aurora Energy's 2012-2017 and in Victorian DNSPs' 2011-15 regulatory determinations.[267] The pass through event has been simplified to reflect the requirements of the positive and negative change event definitions in the National Electricity Rules.

17.3.1 Pass through consideration matrix

The following table sets out how ActewAGL Distribution has had regard to each of the pass through event considerations in nominating the insurance cap event.

[266] AER 2011, *Draft Distribution Determination Aurora Energy Pty Ltd 2012-13 to 2016-17,* p 287

[267] AER 2010, *Victorian electricity distribution network service providers Distribution determination 2011-2015,* Final Decision, p.794, 797; AER 2012, *Aurora Energy Pty Ltd Distribution determination 2012/13-2016/17* , Final Decision, p.183.

Table 17.3 Assessment of the insurance cap pass though event against the pass through event considerations

Pass through event consideration	*How ActewAGL has had regard*
whether the event proposed is an event covered by a category of *pass through event* specified in clause 6.6.1(a1)(1) to (4);	This event is not covered by any category of pass through event specified in clause 6.6.1(a1)(1) to (4).
whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;	ActewAGL Distribution agrees with the AER's previous assessment[268] that such an event can be tightly defined.
whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;	ActewAGL Distribution agrees with the AER's previous assessment that this event would largely be triggered by circumstances beyond the control of a DNSP.[269]
whether the relevant service provider could insure against the event, having regard to: (1) the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or (2) whether the event can be self-insured on the basis that (i) it is possible to calculate the self-insurance premium; and (ii) the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide *network services*; and	The proposed pass through event supports the provision of insurance against various events on reasonable commercial terms. Due to the low probability and high magnitude of any event that exceeded the policy limit of insurance, it is not possible to calculate a self-insurance premium.
any other matter the *AER* considers relevant and which the *AER* has notified *Network Service Providers* is a nominated pass through event consideration.	The AER has not notified NSPs of any nominated pass through event considerations.

17.4 Demand Management and Embedded Generation Connection Incentive Scheme event

As per clause 11.56.4(l)(2) and 6.8.1(b)(2)(vi) of the Rules the AER set out a proposed approach to the application of any DMEGCIS to ActewAGL Distribution for the subsequent regulatory control period in the Stage 2 F&A. The AER stated that:

[268] AER 2010, *Victorian electricity distribution network service providers*, Distribution determination 2011-2015, p 725

[269] AER 2010, *Victorian electricity distribution network service providers*, Distribution determination 2011-2015, p 725

We propose to continue applying the DMIS (that is, Part A only) to ActewAGL from the transitional regulatory control period onwards.

We acknowledge the need to reform the existing demand management incentive arrangements in the ACT. The Standing Council on Energy and Resources (SCER) is currently considering a series of rule changes proposed by the AEMC in its Power of Choice review examining distributor incentives to pursue efficient alternatives to network augmentation. This will include new rules and principles guiding the design of a new DMIS. We intend to develop and implement a new DMIS for the subsequent regulatory control period, depending on the progress of the rule change process.[270]

It is unclear to ActewAGL how a new DMEGCIS can apply once the distribution determination for the subsequent regulatory control period has been made. ActewAGL Distribution therefore proposes that a pass through event is included in the Distribution Determination to allow recovery of any change in costs, including incentives, incurred by ActewAGL Distribution in implementing demand management projects under a new DMGECIS.

The purpose of this event is to allow ActewAGL Distribution to participate in the new DMEGCIS. As SCER notes the proposed rule will promote the National Electricity Objective by strengthening incentives for DNSP's to undertake efficient demand management projects that reduce the overall long term costs of supplying electricity to consumers.[271]

The proposed event DMEGCIS pass through event is defined to occur if:

(a) ActewAGL Distributions incurs or is likely to incur an increase or decrease in costs as a result of participation in a replacement of the demand management and embedded generation connection incentive scheme at the time of the subsequent regulatory proposal; and

(b) the event does not fall into any definition listed in clause 6.6.1(a1)(1) to (4) of the NER.

17.4.1 Pass through consideration matrix

The following table sets out how ActewAGL Distribution has had regard to each of the pass through event considerations in nominating the DMEGCIS pass through event.

[270] AER 2014, *Stage 2 Framework and approach ActewAGL*, p.44. Note that the AER refers to the DMEGCIS as a Demand Management Incentive Scheme (DMIS).

[271] SCER 2013, *Reform of the Demand Management and Embedded Generation Connection Incentive Scheme,* Rule change request, p 2

Table 17.4 Assessment of the DMEGCIS pass though event against the pass through event considerations

Pass through event consideration	*How ActewAGL has had regard*
whether the event proposed is an event covered by a category of *pass through event* specified in clause 6.6.1(a1)(1) to (4);	As the new DMEGCIS has not been developed or published it is unknown whether a new DMEGCIS could be covered by one of the categories of pass through event specified in clause 6.6.1(a1)(1) to (4) of the Rules. It would likely not fall within a service standard event, a tax change event or a retailer insolvency event. As to a regulatory change event, however, it is unknown whether the Rule Change will substantially affect the manner in which ActewAGL provides direct control services and may not satisfy the regulatory change event definition.
whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;	The nature and type of event can be clearly identified. The cost pass through event will occur if a new DMEGCIS scheme is introduced and ActewAGL Distribution incurs a change in cost.
whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;	A DMEGCIS event could be prevented from occurring by no participation in the scheme, if ActewAGL Distribution is given the option of participating in this regulatory period. However, as outlined by SCER by participating in the scheme ActewAGL Distribution will reducing the overall long term costs of supply electricity to consumers. ActewAGL Distribution considers that to contribute to the achievement of the National Electricity Objective the AER should accepted the nominated pass through event irrespective of any possible inconsistency with consideration c. As noted in the section concerning the general nominated pass through event, the AEMC has contemplated that the AER could decide to accept a nominated pass through that is inconsistent with the nominated pass through event considerations.
whether the relevant service provider could insure against the event, having regard to: (1) the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or (2) whether the event can be self-insured on the basis that (i) it is possible to calculate the self-insurance premium; and (ii) the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide	ActewAGL Distribution is not aware of any insurance available for changes to the DMEGCIS. It is not possible to calculate a self-insurance premium for a change to the DMEGCIS.

Pass through event consideration	*How ActewAGL has had regard*
network services; and	
any other matter the *AER* considers relevant and which the *AER* has notified *Network Service Providers* is a nominated pass through event consideration.	The AER has not notified NSPs of any nominated pass through event considerations.

18 Connection policy

This chapter provides an overview of the regulatory requirements and the key elements of ActewAGL Distribution's proposed connection policy for 2015-19. The proposed connection policy is provided as Attachment D13 to this regulatory proposal.

In accordance with the transitional provisions in chapter 11 of the Rules, ActewAGL Distribution submitted a proposed 2014/15 connection policy for AER approval, as part of the transitional regulatory proposal. The AER approved the proposed policy, with some minor amendments and clarifications, as part of its Placeholder Determination for the transitional regulatory period.[272]

ActewAGL Distribution has made the following amendments to the approved policy (version 1.0) in developing the proposed policy for the subsequent regulatory period (2015-19):

- The application of the shared network augmentation charge has been clarified. The charge will not apply to subdivision estate reticulation. This amendment is necessary to avoid situations where the shared network augmentation may be applied twice—first when the estate is connected and again when the load is connected.
- The proposed shared upstream augmentation charges have been updated (table 4). These will be escalated by CPI for each of the remaining years of the 2015-19 regulatory period; and
- References to dates and AER determinations and approvals have been updated.

18.1 Rule requirements

Clause 6.8.2(c)(5A) of the Rules requires that a regulatory proposal include the proposed connection policy. Clause 5A.A.1 of the Rules defines a connection policy in the following terms:

> ***connection policy*** *means a document, approved as a connection policy by the AER under Chapter 6, Part E, setting out the circumstances in which connection charges are payable and the basis for determining the amount of such charges*

Chapter 6 of the Rules contains the connection policy requirements, that is, what must be submitted and the approval process. Clause 6.7A.1 states:

> *(a) A Distribution Network Service Provider must prepare a document (its proposed connection policy) setting out the circumstances in which it may require a retail customer or real estate developer to pay a connection charge, for the provision of a connection service under Chapter 5A.*

[272] AER 2014, *ActewAGL, Placeholder determination for the transitional regulatory control period 2014/15*, April, p 5

(b) The proposed connection policy:

(1) must be consistent with:

(i) the connection charge principles; and

(ii) the connection charge guidelines; and

(2) must specify:

(i) the categories of persons that may be required to pay a connection charge and the circumstances in which such a requirement may be imposed; and

(ii) the aspects of a connection service for which a connection charge may be made; and

(iii) the basis on which connection charges are determined; and

(iv) the manner in which connection charges are to be paid (or equivalent consideration is to be given); and

(v) a threshold (based on capacity or any other measure identified in the connection charge guidelines) below which a retail customer (not being a non-registered embedded generator or a real estate developer) will not be liable for a connection charge for an augmentation other than an extension.

The connection charge principles referred to in 6.7A.1(b)(1)(i) are set out in Chapter 5A of the Rules. The connection charge guidelines referred to in 6.7A.1(b)(1)(ii) are the AER's *Connection charge guidelines for retail electricity customers, under Chapter 5A of the National Electricity Rules, version 1.0.*

18.2 Proposed connection policy

ActewAGL Distribution's proposed connection policy for 2015-19 is provided at Attachment D13 to this regulatory proposal.

ActewAGL Distribution applies the following principles when determining the charges for connection services:

- Connection applicants will not be required to make a capital contribution toward the cost of shared network augmentation where the connection is a basic connection service or the customer's estimated demand is below the threshold specified in the connection policy;
- Connection applicants may be required to make a capital contribution toward the cost of premises connection assets and network extensions. These charges will be based on the difference between the estimated incremental costs and incremental revenues associated with the connection (consistent with the AER connection charge guidelines). Depending on the type of connection, this assessment (known as the incremental cost-

revenue-test) is applied to a category of connections (for example residential services) or to specific connection requests. No capital contribution for premises connection assets and extensions will be required for the majority of typical services and low voltage connections provided at the least cost technically acceptable standard;

- Connection applicants requesting a connection service of a higher standard than the least cost technically acceptable standard will be required to pay the additional costs of the higher standard service. Customers with special connection requirements (for example difficult site access) will also be required to pay the additional costs;
- Connection applicants will also be required to pay for ancillary services, such as temporary connections, required as part of their connection and metering costs associated with new or changed connections. These charges will be set on a cost reflective basis, with standard charges applying to typical services while non-typical services will be offered on a quoted basis. The charges will be approved by the AER in the relevant ACT distribution determination.

Glossary

All terms used in this subsequent regulatory proposal that are defined in Chapter 10 or clause 11.55.1 of the Rules are intended to take that defined meaning unless the context otherwise requires.

Term	Meaning
2009–14 regulatory period	Regulatory control period from 1 July 2009 to 30 June 2014
2014–19 regulatory period	The 5 year period (1 July 2014—30 June 2019) including both the transitional regulatory period and the subsequent regulatory period
ABN	Australian Business Number
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
ACTEW	ACTEW Corporation Ltd
ActewAGL Distribution	Trading name of the partnership of Jemena Ltd and ACTEW Corporation Ltd via their respective subsidiary companies, Jemena Networks (ACT) Pty Ltd and ACTEW Distribution Ltd. As well as the electricity network in the ACT, ActewAGL Distribution owns and controls the gas distribution networks in the ACT/Queanbeyan/Palerang, and Shoalhaven regions.
ACTPLA	Australian Capital Territory Planning and Land Authority
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	AGL Energy Ltd
AMP	Asset Management Plan
ANU	Australian National University
ARPANSA	Australian Radiation Protection and Nuclear Safety Agency
ASIO	Australian Security Intelligence Organisation
ATO	Australian Tax Office
AWE	Average weekly earnings
B2B	Business to Business
BSD	Business Systems Division
CAIDI	Customer Average Interruption Duration Index

Term	*Meaning*
CAM	Cost allocation method
capex	capital expenditure
CAPM	Capital Asset Pricing Model
CBA	Cost benefit analysis
CBD	Central business district
CCA	Creosote and Tanalith
CEG	Competition Economists Group
CEO	Chief Executive Officer
CESS	Capital expenditure sharing scheme
CGS	Commonwealth Government Securities
CMO	CMO legal compliance database
COAG	Council of Australian Governments
CPI	Consumer Price Index
CSRP	Core Systems Replacement Project
CT/VT	Current transformer/voltage transformer
CUSP	Canberra Urban Solar Project
Cwth	Commonwealth
DGM	Dividend Growth Model
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DOFA	Department of Finance and Administration
DPAR	Draft Project Assessment Report
DRC	Depreciated replacement cost
DRP	Debt risk premium
DSM	Demand side management
DUOS	Distribution Use of System
EBA	Enterprise Bargaining Agreement/Enterprise Bargain Agreement
EBSS	Efficiency Benefit Sharing Scheme
EGW	Electricity gas and water
EHSQ	Environment, Health, Safety and Quality
EHV	Extra high voltage

Term	Meaning
EIL	Energy Industry Levy
EMF	Electric and magnetic fields
ENA	Energy Networks Association
esaa	Energy Supply Association of Australia
ESDD	Environment and Sustainable Development Directorate
FFM	Fama-French three factor model
FiT	Feed-in tariff
FM	Facilities Management
FPAR	Final Project Assessment Report
FPI	Fault passage indicators
FPSC	Fixed Price Service Charge
FTE	Full time equivalent
GDP	Gross domestic product
GIS	Geographic Information System
GP	General purpose
GSL	Guaranteed service level
GST	Goods and services tax
GWh	Gigawatt hours
HSE	Health, safety and environment
HV	High voltage
ICRC	Independent Competition and Regulatory Commission
ILUA	Indigenous Land Use Agreement
IPART	Independent Pricing and Review Tribunal
IT/ICT	Information technology/ information and communication technology
km	Kilometre
kV	Kilovolt
kVA	Kilovolt amperes
kWh	Kilowatt hours
LNSP	Local Network Service Provider
LV	Low voltage
m	Million
MAMP	Metering Asset Management Plan
MAR	Maximum average revenue

Term	Meaning
MCE	(former) Ministerial Council on Energy (now SCER)
MD	Maximum demand
MMA	McLennan Magasanik Associates
MRP	Market risk premium
MSATS	Market Settlement and Transfer Solution
MVA	Megavolt amperes
MW	Megawatt
MWh	Megawatt hours
NATA	National Association of Testing Authorities, Australia
NCA	National Capital Authority
NDSC	Negotiated Distribution Service Criteria
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NERA	NERA Economic Consulting
NMI	National Metering Identifier
NPEF	National Planning and Expansion Framework
NPV	Net present value
NSP	Network Service Provider
NSW	New South Wales
NTER	National Tax Equivalent Regime
NUOS	Network Use of System
OP	Off-peak
opex	operating expenditure
OSRP	Operational Systems Replacement Project
OT	Operational technology
pa	per annum
PCBs	polychlorinated biphenyls
PoE	Probability of exceedence
POE	Point of Entry
PTRM	Post Tax Revenue Model
PV	Photovoltaic

Term	Meaning
QCA	Queensland Competition Authority
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
RC	Replacement cost
RFM	Roll Forward Model
RIN	Regulatory Information Notice
RIS	Regulatory Impact Statement
RIT-D	Regulatory investment test for distribution
RNSP	Regulated Network Service Provider
Rules	National Electricity Rules
SAHA	SAHA International
SAIDI	System Average Interruption Duration Index
SAIFI	Supply Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCER	Standing Council on Energy and Resources
SFG	Strategic Finance Group
SKM	Sinclair Knight Merz, now SKM Jacobs
Stage 1 F&A	AER Stage 1 Framework and Approach (paper)
Stage 2 F&A	AER Stage 2 Framework and Approach (paper)
STPIS	Service Target Performance Incentive Scheme
Subsequent proposal/ Subsequent regulatory proposal	This regulatory proposal which covers the transitional regulatory period and the subsequent regulatory period and
Subsequent regulatory period	1 July 2015—30 June 2019
TAB	Tax asset base
TAMS	ACT Department of Territory and Municipal Services
TNSP	Transmission Network Service Provider
TOU	Time-of-use
Transitional period	Transitional regulatory period of one year commencing 1 July 2014 and ending 30 June 2015

Term	Meaning
Transitional proposal/ Transitional regulatory proposal/ TRP	Transitional regulatory proposal submitted by ActewAGL Distribution on 31 January 2014 for the transitional regulatory period
TUOS	Transmission use of system
UMA	Utilities Management Agreement
UNFT	Utilities Network Facilities Tax
USAIDI	unplanned system average interruption duration index
USAIFI	unplanned system average interruption frequency index
VAh	Volt ampere hours
VCR	Value of customer reliability
VHF	Very high frequency
WACC	Weighted average cost of capital
WASP	WASP asset management system
Wh	Watt hours
WHS	Work health and safety
WMS	Work Method Statement
WPI	Wage price index
WTP	Willingness to pay

List of tables

List of figures

List of attachments

The following is the list of attachments referred to in the document and which form part of ActewAGL Distribution's Subsequent Regulatory Proposal.

Reference	Title	Confidential
A Regulatory Information Notice Requirements		
A1	Compliance with the Regulatory Information Notice Schedule 1	No
A2	Supplementary Information to address items specified in the Regulatory Information Notice	In part
A3	Regulatory Templates (Microsoft excel workbooks)	In part
A4	Special Purpose Financial Report and Review Report	No
A5	Statutory declaration	No
A6	Board resolution	No
A7	Confidentiality template	No
B Expenditure		
B1	Roll Forward Model (distribution standard control)	No
B2	Post Tax Revenue Model (distribution standard control)	No
B3	Equity raising cost PTRM model (distribution standard control)	No
B4	Roll Forward Model (transmission standard control)	No
B5	Post Tax Revenue Model (transmission standard control)	No
B6	Equity raising cost PTRM model (transmission standard control)	No
B7	Roll Forward Model (metering services)	No
B8	Post Tax Revenue Model (metering services)	No
B8A	Equity raising cost PTRM model (metering services)	No
B9	RAB allocation methodology (transmission and Distribution 30 June 2009)	No
B10	Operating expenditure step changes	In part
B11	Unit rates—SKM Independent Verification report	In part
B12	Cost escalation report—CEG	In part
B13	Cost escalation report—Independent Economics	In part
B14	Total forecast opex model	Yes
B15	Total forecast capex model	Yes
B16	Major capex project justifications	In part
B17	Major capex program justifications	In part
B18	Cost Allocation Methodology (December 2013)	No
B19	ActewAGL Electricity Distribution Network Expenditure Forecasting Methodology (May 2014)	No
B20	ACT light rail electricity demand and infrastructure assessment (AECOM and ActewAGL Distribution 2013)	No
B21	Ancillary Services costing model	Yes
B22	Tax roll forward model 2001-2009	Yes

Reference	Title	Confidential
C Customer and demand forecasts		
C1	2013 Peak Demand Forecast	No
C2	Review of Demand Forecast Methodology (Jacobs SKM)	No
C3	Trends in ACT Electricity Consumption (Jacobs SKM)	No
D Policies, Strategies, Plans		
D1	Asset Management Corporate Policy 8.1	No
D2	Asset Management Strategy v.2.11	No
D3	Customer Initiated capital works plan (Jacobs SKM), Network Augmentation capital works plan (Jacobs SKM), Asset Management capital works plan (Jacobs SKM)	No
D4	Appendix to Distribution Annual Planning Report 2013 (DAPR)	No
D5	Distribution Network Augmentation Standard	No
D6	Metering Asset Management Plan v 2.5	No
D7	Procurement, Contracting and Contract Management Policy	No
D8	Procurement and Contracting Procedure	No
D9	ActewAGL ICT Strategy 2014–19	In part
D10	ActewAGL Distribution ICT Expenditure Proposal Summary	No
D13	Connection policy	No
D14	Risk Management and Legal Compliance Policy	No
D15	ActewAGL Distribution Transmission Pricing Methodology	No
D16	Electrical data manual	No
D17	ActewAGL Distribution Demand Side Engagement Strategy	No
E Return on capital expert reports		
E1	An appropriate regulatory estimate of gamma– SFG Consulting	No
E2	Gamma—detailed proposal	No
E3	The required return on equity for regulated gas and electricity network businesses- SFG Consulting	No
E4	Cost of equity in the Black Capital Asset Pricing Model—SFG Consulting	No
E5	The Fama French model—SFG Consulting	No
E6	Alternative versions of the dividend discount model and the implied cost of equity—SFG Consulting	No
E7	Equity beta—SFG Consulting	No
E8	AER equity beta issues paper: international comparators—CEG	No
E9	Response to the Equity Beta Issues Paper of the Australian Energy Regulator—ENA	No
E10	Debt raising transaction costs—Incenta	No
E11	Debt transition consistent with the NER and NEL—CEG Consulting	No
E12	Factors relevant to estimating a trailing average cost of debt—CEG Consulting memorandum	No
E13	Professor Grundy—The Calculation of the Cost of Capital	No
E14	IPART—Fact Sheet: New Approach to Estimating the Cost of Debt	No
E15	IPART—IPART's New Approach to Estimating the Cost of Debt	No
E16	Index of referenced documents on return on capital	No
E17	DLA Piper Australia—Opinion on NER compliance of averaging period proposal	No

Reference	*Title*	*Confidential*
F Other		
F1	STPIS Reliability Incentive Rates 2015-2019	Yes
F2	STPIS reliability performance targets	No
F3	Alternative control services and indicative prices	No
F4	Key Assumptions	No
F5	ActewAGL Distribution 2014/15 Network Pricing Proposal	No