Draft decision

# Australian Capital Territory

# distribution determination 2009–10 to 2013–14

7 November 2008

AUSTRALIAN ENERGY REGULATOR

# Request for Submissions

This document sets out the Australian Energy Regulator's (AER) draft distribution determination for ActewAGL Distribution (ActewAGL) for the period 1 July 2009 to 30 June 2014.

The AER will hold a pre–determination conference on its draft distribution determination on 8 December 2008 in Canberra for the purpose of explaining its draft determination and receiving oral submissions from interested parties. The pre–determination conference for ActewAGL will be held jointly with the pre–determination conference regarding the AER's draft distribution determination for Country Energy. Interested parties can register to attend the pre–determination conference by calling the Network Regulation North Branch of the AER on (02) 6243 1233 or by emailing aerinquiry@aer.gov.au by 2 December 2008.

Interested parties are invited to make written submissions on issues regarding this draft distribution determination and the consultants' reports to the AER by 16 February 2009. The AER will deal with all information it receives in the distribution determination process, including submissions on the draft distribution determination, in accordance with the ACCC/AER information policy. The policy is available at www.aer.gov.au.

Submissions can be sent electronically to aerinquiry@aer.gov.au

Alternatively, submissions can be mailed to:

Mike Buckley
General Manager
Network Regulation North
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

The AER prefers that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are requested to:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non–confidential version of the submission.

All non–confidential submissions will be placed on the AER website, www.aer.gov.au.

A copy of ActewAGL's regulatory proposal, proposed negotiating framework, consultancy reports and submissions from interested parties are available on the AER website.

Inquiries about the draft distribution determination or about lodging submissions should be directed to the Network Regulation North Branch on (02) 6243 1233.

# Contents

# Shortened forms

| | |
|---|---|
| ACCC | Australian Competition and Consumer Commission |
| ActewAGL | ActewAGL Distribution |
| AEMC | Australian Energy Market Commission |
| AER | Australian Energy Regulator |
| capex | capital expenditure |
| CPI | consumer price index |
| current regulatory control period | 1 July 2004 to 30 June 2009 |
| DNSP | distribution network service provider |
| ICRC | Independent Competition and Regulatory Commission |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NER | National Electricity Rules |
| next regulatory control period | 1 July 2009 to 30 June 2014 |
| opex | operating and maintenance expenditure |
| Wilson Cook | Wilson Cook & Co Limited |

# Overview

## A transition to a new regulatory framework

Under the National Electricity Law (NEL) and the National Electricity Rules (NER), the Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution services provided by distribution network service providers (DNSPs) in the National Electricity Market (NEM).

The AER's draft distribution determination for ActewAGL for the 2009–14 regulatory control period is one of the first distribution determinations to be made by the AER under the NEL and the NER.[1] This draft determination is being made under transitional provisions set out at part M of chapter 11 of the NER (the transitional chapter 6 rules) which incorporate key aspects of the new general chapter 6 rules, but also lock in certain aspects of the current determination made by the ACT regulator, the Independent Competition and Regulatory Commission (ICRC).

The AER's considerations in making its draft determination on the efficient levels of future capital and operating expenditures for the next regulatory control period mirror the new general chapter 6 rules. The transitional chapter 6 rules require the AER to maintain the maximum average revenue cap form of control and the classification of services established by the ICRC in its 2004 distribution determination for the current regulatory control period. The transitional chapter 6 rules also establish parameters which the AER must use to determine the weighted average cost of capital.

The transitional chapter 6 rules require the AER to assess the prudence of ActewAGL's capital expenditures for the current regulatory control period as part of the process of setting the opening regulatory asset base (RAB). As part of the process of determining the reasonableness of ActewAGL's forecast capital expenditures for the next regulatory control period, the AER reviewed the reasons for variations between forecast and actual capital expenditure over the current regulatory control period including ActewAGL's overspend of $42 million which is largely attributable to wooden pole replacements.

## Review process

In making its draft determination, the AER assessed ActewAGL's regulatory proposal to determine if it was in accordance with the requirements of the NER. Expert engineering consultants, as well as financial and economic experts, assisted the AER in making its assessment. The AER has considered the past performance of ActewAGL, and the effectiveness of its policies and procedures, both in terms of past performance and in the development of its regulatory proposal.

The process of assessing ActewAGL's regulatory proposal commenced in June 2008. Prior to that time, the AER, in consultation with ActewAGL, developed a regulatory information notice (RIN) which included information templates. ActewAGL was required to complete the information templates in accordance with the RIN and

[1] The AER's distribution determinations for the NSW DNSPs (Country Energy, EnergyAustralia and Integral Energy) were released concurrently with this draft distribution determination.

submit them to the AER in support of its regulatory proposal. These information templates allowed ActewAGL's regulatory proposal to be made in broadly consistent terms with the NSW DNSPs regulatory proposals and allowed comparisons to be made regarding the key drivers underpinning the expenditure proposals.

Following its receipt of ActewAGL's regulatory proposal, the AER conducted a preliminary assessment to establish that it complied with the cost allocation principles, and that asset values and revenue models had been correctly applied in accordance with the requirements of the RIN and the NER. Following this initial assessment, ActewAGL's regulatory proposal was published on the AER's website and submissions were sought from interested parties. One submission was received. The AER's consideration of this submission forms part of this draft decision.

The detailed examination of ActewAGL's regulatory proposal was informed by advice from Wilson Cook and Co. Limited (Wilson Cook). Wilson Cook is an engineering and management consultancy firm, and has considerable experience in reviewing the performance and operating requirements of DNSPs. Wilson Cook had previously undertaken a similar review process for the Independent Pricing and Regulatory Tribunal (IPART) in relation to the NSW DNSPs. Wilson Cook reviewed ActewAGL's regulatory proposal and supporting information supplied throughout the review process. In addition, during the review Wilson Cook and AER staff inspected supporting documentation such as planning documents, manuals and financial models. As part of this process senior ActewAGL staff were questioned in relation to the assumptions underpinning the regulatory proposal and its implementation. This process assisted Wilson Cook and the AER to satisfy itself that the regulatory proposal was soundly based and that appropriate policies and procedures had been established to deliver the proposed capital works.

Wilson Cook assessed the regulatory proposal to establish the necessity of the proposed expenditure and the reasonableness of expected costs. This included a bottom up assessment of ActewAGL's proposed programs and unit costs, as well as benchmark assessments of programs against historical costs and comparative performance of operating expenditures against that of other DNSPs.

The AER has largely accepted the reasons for the need for a substantial increase in capital works by ActewAGL over the next regulatory control period. Amongst other reasons, increased capital expenditure is needed to:

- construct and augment zone substations due to urban and commercial expansion
- augment the ACT network to comply with legislated network security obligations
- conduct asset replacement and renewal driven by regulatory, safety and security requirements
- meet high forecast levels of residential and commercial expansion.

While the AER has accepted the need for ActewAGL's proposed capital works, it has determined that ActewAGL's application of input cost escalators does not reflect a realistic expectation of the efficient cost inputs required to achieve the capital expenditure objectives within the NER.

As part of a recent electricity transmission determination, the AER developed a methodology to assess likely increases in the costs of materials. This methodology sought to ensure that the affect of the commodities boom on metals' prices and labour costs—key inputs for the energy sector—was fully factored into regulatory determinations. For the reasons detailed in this draft decision, the AER has modified the input cost escalators proposed by ActewAGL in its regulatory proposal.

After assessing ActewAGL's regulatory proposal against the requirements of the transitional chapter 6 rules, the AER has determined that the capital expenditure allowance proposed by ActewAGL is greater than the amount needed to meet the capital expenditure criteria in the NER. The AER has therefore determined a capital expenditure allowance of $278 million for ActewAGL for the next regulatory control period.

Wilson Cook assessed ActewAGL's operating expenditure proposal, and confirmed a need for higher operating expenditures over the next regulatory control period. Higher operating expenditures are resulting from the increased size of the network, increased planned maintenance activities and higher labour costs.

In the ten years to 2007–08, real wages growth in the electricity, gas and water sector in the ACT exceeded growth in economy-wide real wages by an average of 1.3 per cent per annum. Labour costs in the utilities sector are forecast to continue to exceed the economy-wide average over the course of the next regulatory control period.

The AER has amended the labour cost escalators proposed by ActewAGL to reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c). The AER has also made amendments to the proposed allowance for self insurance, debt raising costs and the utilities network facilities tax. Accordingly, the AER has amended ActewAGL's proposed operating expenditure. The AER has determined ActewAGL's operating expenditure allowance for the next regulatory control period is to be set at $296 million, representing a reduction of 3 per cent on the total amount proposed.

Over the course of the next regulatory control period, ActewAGL will significantly increase investment on its network, which will result in higher prices for electricity consumers in the ACT. The percentage price increase will be greatest in 2009, reflecting the fact that ActewAGL overspent its capital allowance in the previous regulatory control period by $42 million. However, prices will rise in real terms in each year of the next regulatory control period, in line with increased investment and higher operating costs. As a result of the draft decision, the AER has estimated that the average ACT retail customer's electricity charge is likely to increase by 4.1 per cent in 2009.

In part, higher electricity charges are also the result of maximum demand on ActewAGL's network increasing at a faster rate than overall energy consumption. The need to expand the network to meet higher peaks in demand reduces the efficiency of the network and increases the cost of supplying electricity. Over the next regulatory control period, maximum demand on ActewAGL's network is expected to increase by 1.9 per cent per year. Energy consumption on ActewAGL's network is forecast to grow by 1.6 per cent per year. The discrepancy between maximum demand and energy consumption growth reduces the overall efficiency of the network, and

increases the need for effective demand management. The AER's draft decision supports ActewAGL's development of innovative responses to rising peak demand through the application of the demand management innovation allowance.

The global financial crisis may impact on the price of electricity by raising the weighted average cost of capital used to determine DNSPs' allowed revenues. The cost of capital has fluctuated from around 9 per cent in early 2007, up to around 11 per cent in mid-2008. However, since then the cost of capital has fallen to 9.82 per cent, as at 17 October 2008. The cost of capital used to determine future revenues will be determined closer to the time of the AER's final determination. If global financial conditions improve in the interim period, and the commercial debt risk premium subsequently declines, this will be reflected in a lower cost of capital for ActewAGL and lower electricity prices for consumers.

# Summary

## Introduction

In 2004, the Independent Competition and Regulatory Commission (ICRC) determined ActewAGL Distribution's (ActewAGL) average revenue cap for a five year period from 1 July 2004 to 30 June 2009 (the current regulatory control period).

The AER assumed responsibility for regulating electricity distribution services provided by ActewAGL from 1 January 2008. The distribution determination for the period 1 July 2009 to 30 June 2014 (the next regulatory control period) is the first for ActewAGL to be conducted by the AER under the National Electricity Rules (NER).

The transitional chapter 6 rules took effect on 1 January 2008. The AER must make a distribution determination for ActewAGL according to these rules and with reference to the AER's transitional guidelines for the ACT and NSW.

The AER published ActewAGL's regulatory proposal and proposed negotiating framework on 26 June 2008. Interested parties were invited to make submissions on all documents. One submission was received. ActewAGL presented its regulatory proposal at a public forum held in Canberra on 29 July 2008.

The AER engaged the following consultants to assist in the assessment of ActewAGL's regulatory proposal:

- Wilson Cook & Co Limited (Wilson Cook) to provide technical engineering expertise
- Energy and Management Services Pty Ltd (EMS) to provide additional expert engineering advice
- Econtech to provide wage growth forecasts.

This draft decision should be read in conjunction with these consultants' reports, which are available on the AER's website.

The key decisions addressed in this draft decision are:

- the opening regulatory asset base (RAB) value for ActewAGL
- the AER's assessment of ActewAGL's forecast capital expenditure (capex) program
- the AER's assessment of ActewAGL's forecast operating and maintenance expenditure (opex) program
- an estimate of the efficient benchmark weighted average cost of capital (WACC) for ActewAGL
- ActewAGL's annual revenue requirement for each year of the regulatory control period

- the AER's decision regarding ActewAGL's proposed negotiating framework for negotiable components of direct control services
- the AER's proposed negotiable component criteria (NCC) that will apply to ActewAGL.

The AER's consideration of each of these components is summarised below. Further detail is provided in the relevant chapters and in the appendices attached to this draft decision.

## Regulatory requirements

### National Electricity Law

The National Electricity Law (NEL) sets out the functions and powers of the AER, including its role as the economic regulator of the National Electricity Market (NEM). The NEL states that when performing or exercising a regulatory function or power, the AER must do so in a manner that will or is likely to contribute to the achievement of the national electricity objective. The national electricity objective under 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, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

### National Electricity Rules

The transitional chapter 6 rules of the NER set out the provisions the AER must apply in exercising its regulatory functions and powers for the NSW and ACT distribution network service providers (DNSPs) providing direct control services and negotiated distribution services.

Broadly, the transitional chapter 6 rules:

- specify the classification of services that the AER is to apply —based on the ICRC's classification that applies in the current regulatory control period
- require the AER to assess the DNSP's negotiable components of direct control services, and negotiating framework
- require the AER to propose NCC
- require the AER to assess the DNSP's control mechanism for standard control services
- set out the methodology for establishing the opening RAB
- require the AER to assess the DNSP's demand forecasts and cost inputs to achieve the capex objectives
- set out the requirements for DNSPs' revenue proposals, including the requirement to forecast capex and opex necessary to meet the capex and opex objectives.

These objectives include meeting the expected demand for standard control services, complying with all applicable regulatory obligations or requirements and maintaining the quality, reliability and security of supply of standard control services and the reliability, safety and security of the distribution system through the supply of standard control services

- require the AER to assess whether the forecast capex and opex proposed by a DNSP reflect the efficient costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the capex or opex objectives
- set out the methodology for calculating the estimated corporate income tax
- set out the methodology for calculating depreciation on the assets to be included in the RAB and require the AER to assess whether or not to approve the depreciation schedules submitted by a DNSP
- set out the methodology for calculating the cost of capital
- provide that the AER may develop and publish a service target performance incentive scheme, efficiency benefit sharing scheme and demand management incentive scheme
- require the AER to assess pass through events
- require the AER to specify the DNSP's annual revenue requirement for each year of the regulatory control period and to set the X factor for each year of the regulatory control period
- set out the form of control the AER may apply to alternative control services.

The relevant regulatory requirements set out under the transitional chapter 6 rules are outlined in detail at the beginning of each chapter in this draft decision.

## Classification of services

### ActewAGL proposal

ActewAGL has not proposed any reclassification of direct control services. However, ActewAGL has distinguished between the provision of metering data to retailers from the provision of metering services to small customers. ActewAGL submitted that provision of metering data to retailers is a standard control service while provision of metering services to small customers is an alternative control service.

### AER conclusion

The AER accepts ActewAGL's proposed classification of services as it aligns with that deemed under the NER, and is based on the existing classification of services applied by the ICRC. Accordingly, the provision of metering data to retailers is classified as a standard control service and not an alternative control service. Alternative control services only include the provision of metering services for small customers.

The AER provisions for the procedures for assigning customers to tariff classes, based on the principles in the NER, are set out in appendix A of this draft decision.

# Arrangements for negotiation

## Negotiable components

**ActewAGL proposal**

ActewAGL did not propose any negotiable components of direct control services and did not comment on the AER's proposed NCC.

**AER conclusion**

The AER has decided not to specify any particular components of ActewAGL's direct control services as negotiable components for the next regulatory control period. However, the AER has decided to define a negotiable component of a direct control service as any component of a direct control service (or the terms and conditions on which that direct control service or component are provided) where:

- the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation
- the direct control service, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER or
- the direct control service is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider.

Therefore, components that fall within the scope of the above definition are negotiable components.

## Negotiable component criteria

**ActewAGL proposal**

ActewAGL did not provide comments on the AER's proposed NCC, which is the same as that to apply to the NSW DNSPs during the next regulatory control period.

**AER conclusion**

In response to a submission on the NCC provided by EnergyAustralia, the AER will change the heading of criterion 1 from 'national electricity market objective' to 'national electricity objective'.

The NCC for ActewAGL is set out in appendix B of this draft decision.

### Negotiating framework

#### ActewAGL proposal

ActewAGL stated that its proposed negotiating framework has been prepared in fulfilment of its obligations under the NER and will apply to ActewAGL and any service applicant who applies to receive a negotiable component of a direct control service.

#### AER conclusion

As required by the NER, the AER approves ActewAGL's negotiating framework to apply for the next regulatory control period. The AER has assessed ActewAGL's negotiating framework and considers that the negotiating framework in appendix C of this draft decision complies with the requirements of the NER.

## Control mechanism for standard control services

### ActewAGL proposal

ActewAGL has proposed to recover revenues from its standard control services under a maximum average revenue cap. This constraint is expressed as the maximum allowable average revenue for network services, per kWh. ActewAGL stated that this proposed mechanism is consistent with the AER's standard control services guideline and the transitional chapter 6 rules relating to side constraints and overs and unders adjustment for TUOS charges.

### AER conclusion

The AER considers that ActewAGL's proposed form of control mechanism is compliant with the requirements of the NER and its standard control services guideline. The proposed maximum allowable average revenue cap is the same mechanism that was applied by the ICRC.

The AER's consideration of ActewAGL's building block proposal for standard control services is detailed in the relevant building block element chapters and appendices throughout this draft decision.

In monitoring compliance with the maximum allowable average revenue cap and side constraints, the AER will apply the approach set out in its standard control services guideline.

## Past capital expenditure

### ActewAGL proposal

ActewAGL submitted that its capex for the current regulatory control period will exceed the ICRC's 2004 determination allowance by $42 million ($2008–09) or 34 per cent. The majority of this overspend is attributable to additional wooden pole related expenditure.

### AER conclusion

To assess ActewAGL's past capex the AER:

- assessed the prudence of the expenditure decisions based on the information available to ActewAGL at the time of the investment, and not in hindsight
- observed the approach adopted by the ICRC in ActewAGL's distribution determination for the current regulatory control period
- considered advice from Wilson Cook
- considered written representations made by the ICRC to ActewAGL before 1 January 2008.

Based on its review and advice from Wilson Cook, the AER considers all of ActewAGL's capex in the current regulatory control period to be prudent and that the projects and programs undertaken were required, efficient and consistent with ActewAGL's policies and good industry practice. The AER's decision on the past capex to be rolled into ActewAGL's opening RAB for 2009 is set out in table 1.

**Table 1: AER conclusion on ActewAGL's prudent past capex ($m, nominal)**

| | 2004–05 | 2005–06 | 2006–07 | 2007–08 | 2008–09 | Total |
|---|---|---|---|---|---|---|
| Actual capex | 21.7 | 23.4 | 29.5 | 37.8 | 42.7 | 155.0 |

## Opening regulatory asset base

### ActewAGL proposal

ActewAGL proposed an opening RAB of $593 million as at 1 July 2009. The proposed opening RAB includes a net capex amount of $143 million for the current regulatory control period.

Depreciation has been calculated using the average remaining life as at 30 June 2004, assigning a standard life of 40 years to all new assets acquired since that time and assigning a remaining life of 21.77 years to all existing assets as at 30 June 2004. ActewAGL stated that this approach is in accordance with the approach determined by the ICRC in the previous regulatory control period. The proposed RAB has been reduced by depreciation ($135 million) based on the actual capex and in accordance with the approach determined by the ICRC for the current regulatory control period.

The proposed opening RAB has also been indexed for actual inflation using the CPI, reduced by $3.8 million for the difference between actual and estimated capex for 2003–04, and further reduced by $2.3 million representing the forecast return on the unspent capex.

### AER conclusion

Consistent with the NER, ActewAGL has proposed to roll forward its RAB, established in the ICRC's 2004 determination, to determine an opening RAB for the next regulatory control period. The AER has determined ActewAGL's opening RAB

to be $588 million for the next regulatory control period (as at 1 July 2009). The RAB roll forward calculations are set out in table 2.

**Table 2: ActewAGL's opening RAB for the next regulatory control period ($m, nominal)**

| | 2004–05 | 2005–06 | 2006–07 | 2007–08[a] | 2008–09[b] |
|---|---|---|---|---|---|
| Opening RAB | 510.5 | 520.2 | 532.3 | 554.1 | 576.6 |
| Actual net capex[c] | 21.7 | 23.4 | 29.5 | 37.8 | 30.1 |
| CPI adjustment on opening RAB | 12.2 | 14.2 | 19.4 | 13.4 | 16.0 |
| Straight-line depreciation (adjusted for actual CPI) | –24.3 | –25.5 | –27.1 | –28.6 | –30.0 |
| Closing RAB | 520.2 | 532.3 | 554.1 | 576.6 | 592.7 |
| Less: difference between actual and forecast capex for 2003–04 | | | | | 2.7 |
| Less: return on difference[d] | | | | | 1.6 |
| Opening RAB at 1 July 2009 | | | | | 588.4 |

(a) Based on forecast 2007–08 capex. The actual capex will be updated at the time of the AER final distribution determination.
(b) Based on estimated net capex and forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final distribution determination.
(c) The cash values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $2.7 million for 1 July 2003 to 30 June 2004.

# Demand forecasts

## ActewAGL proposal

ActewAGL has based its load driven expenditure forecasts primarily on summer maximum demand at the 10 per cent probability of exceedence (POE) at the zone substation level.

ActewAGL's energy and maximum demand forecasts for the next regulatory control period are outlined in table 3. ActewAGL's forecast indicates that at 10 per cent POE, its network will transition from winter peaking to summer peaking in 2009–10.

**Table 3: ActewAGL's energy and maximum demand forecasts 2009–14**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average growth 2009–14 |
|---|---|---|---|---|---|---|
| Energy sales (base) – GWh | 2878 | 2925 | 2972 | 3018 | 3066 | 1.6% |
| System maximum demand (10% POE) – MVA[a] | 694 | 708 | 721 | 734 | 748 | 1.9% |

Source: ActewAGL, *Regulatory proposal*, pp. 92–94.
(a) All values are summer maximum demands.

### AER conclusion

To assess ActewAGL's demand forecasts for the next regulatory control period, the AER analysed the key drivers of demand and energy consumption, historical demand trends and elements of good forecasting methodology as highlighted by the AER's consultants.

The AER considers ActewAGL's maximum demand forecast methodology and forecasts are reasonable for the purposes of assessing ActewAGL's proposed capex and opex.

The AER considers ActewAGL's energy forecast methodology is reasonable, however, it considers that the forecasts should be updated to take into account the most recent energy sales data, for calendar year 2008. Accordingly, the AER requests that a revised energy forecast be submitted to the AER for consideration in its final distribution determination.

## Forecast capital expenditure

### ActewAGL proposal

ActewAGL proposed a capex allowance totalling $278 million ($2008–09) for the next regulatory control period. Table 4 sets out ActewAGL's proposed capex by category.

**Table 4: ActewAGL's capex proposal by category ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Asset renewal/replacement | 20.2 | 21.5 | 18.9 | 18.8 | 19.3 | 98.6 |
| Customer initiated | 21.7 | 23.9 | 20.3 | 15.2 | 12.9 | 94.0 |
| Augmentation | 29.9 | 14.6 | 13.9 | 15.4 | 2.7 | 76.5 |
| Reliability and quality improvements | 0.2 | 0.4 | 0.4 | 0.3 | 0.3 | 1.5 |
| Network IT systems | 4.3 | 4.1 | 3.5 | 3.5 | 5.1 | 20.5 |
| Capital contributions | –5.8 | –8.2 | –7.5 | –4.2 | –3.7 | –29.4 |
| Non-systems assets | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 2.6 |
| Corporate services business support | 7.4 | 1.5 | 1.6 | 1.4 | 1.5 | 13.3 |
| Total | 78.3 | 58.3 | 51.7 | 50.9 | 38.5 | 277.7 |

Source: ActewAGL, *Regulatory proposal*, p.126.
Note: Totals may not add up due to rounding.

## AER conclusion

In assessing ActewAGL's forecast capex the AER reviewed:

- its governance framework, capex policies and procedures
- the methods used to develop the capex proposal, including planning processes, demand forecasts and network planning criteria
- the need for the projects proposed in the regulatory proposal and whether the scope, timing and costs are efficient
- the cost estimation processes employed by ActewAGL
- the deliverability of the forecast capex program.

The AER's conclusion on the ActewAGL's capex allowance for the next regulatory control period is set out in section 8.7 of this draft decision.

The AER has considered ActewAGL's proposed forecast capex allowance and for the reasons set out in chapter 8 of this draft decision, considers that the proposed capital projects and programs reviewed are consistent with the capex objectives in the NER. However, the AER does not consider ActewAGL's forecast capex allowance satisfies the capex criterion at clause 6.5.7(c)(3) of the NER.

While the AER is satisfied that the scope of the forecast capex program is appropriate and necessary, it considers ActewAGL's application of input cost escalators does not reflect a realistic expectation of the cost inputs required to achieve the capex objectives, as required by clause 6.5.7(c). Following its review of the SKM cost escalation methodology the AER has modified the input cost escalators used by ActewAGL in its regulatory proposal.

After applying the amended input cost escalators, the AER considers that a forecast capex allowance that reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to satisfy the capex objectives and capex criteria in the NER is $278 million. The AER's conclusion on ActewAGL's forecast capex is set out in table 5.

**Table 5: AER's conclusion on ActewAGL's capex allowance ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL's proposed net capex[a] | 79.9 | 59.8 | 53.5 | 53.0 | 40.3 | 286.6 |
| AER's adjustments to cost escalators | –2.2 | –1.6 | –1.6 | –1.8 | –1.5 | –8.5 |
| AER's capex allowance | 77.7 | 58.2 | 51.9 | 51.2 | 38.9 | 277.9 |

(a) These amounts reflect an increase of $8.9 million from ActewAGL's published proposal due to a correction of its cost escalation calculations.

## Forecast operating expenditure

### ActewAGL proposal

ActewAGL's forecast opex for the next regulatory control period is $306 million ($2008–09), which is $81 million greater than its expected opex in the current regulatory control period.

### AER conclusion

To assess ActewAGL's forecast opex allowance, the AER:

- considered ActewAGL's regulatory proposal and additional supporting information
- reviewed ActewAGL's planning procedures, policies and forecasting methods and their application to forecast projects and programs
- considered technical advice from Wilson Cook as independent engineering consultants
- considered the opex program and forecast allowance in the context of the objectives and criteria of the NER.

The AER has considered ActewAGL's forecast total opex of $306 million ($2008–09) and for the reasons outlined in chapter 9 of this decision is not satisfied that the total opex forecast proposed by ActewAGL reasonably reflects the opex criteria in the NER, taking into account the opex factors. In drawing this conclusion the AER has had regard to the opex factors set out in the NER.

After considering the advice of Wilson Cook, and undertaking its own analysis of ActewAGL's proposed opex, the AER has applied a reduction of $9.5 million to ActewAGL's proposed opex. This represents a reduction of around 3 per cent of ActewAGL's proposed opex of $306 million and results in a revised forecast opex allowance of $296 million.

This revised estimate represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives specified in the NER. The AER is satisfied that the revised total forecast opex of $296 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. This is shown by opex category in table 6.

**Table 6: AER's conclusion on ActewAGL's total opex allowance ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL proposed opex | | | | | | |
| Controllable opex | 52.9 | 53.9 | 55.0 | 56.8 | 56.8 | 275.3 |
| UNFT | 4.0 | 4.1 | 4.2 | 4.3 | 4.4 | 20.9 |
| Debt raising | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 1.8 |
| Self insurance[a] | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 7.5 |
| Total opex | 58.7 | 59.9 | 61.0 | 63.0 | 63.0 | 305.5 |
| AER revised opex | | | | | | |
| Controllable opex | 52.7 | 53.4 | 54.3 | 55.9 | 55.6 | 271.9 |
| UNFT | 3.9 | 4.0 | 4.1 | 4.2 | 4.3 | 20.7 |
| Debt raising | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 1.8 |
| Self insurance[a] | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 1.7 |
| Total opex | 57.3 | 58.2 | 59.1 | 60.8 | 60.6 | 296.0 |

Note: Totals may not add up due to rounding.
(a) Based on allocation for standard control services.

# Estimated corporate income tax

## ActewAGL proposal

ActewAGL proposed an allowance for tax that was calculated by the post tax revenue model (PTRM), which calculates a tax allowance in accordance with the methodology set out in the NER. It should be noted that the allowance for tax is an output of the PTRM rather than an input to be specified or proposed by the regulated business.

ActewAGL proposed an opening tax asset base derived in a manner consistent with the AER's preferred approach set out in its issues paper on the transition from pre–tax to post–tax.

## AER conclusion

The AER has assessed each of the inputs to the PTRM that are used to calculate the expected cost of corporate income tax in accordance with the NER. The AER considers that ActewAGL's proposed tax remaining and tax standard lives are appropriate. The AER also considers ActewAGL's proposed tax asset base of $473 million appropriate and reasonable. Using these inputs, the AER has used the PTRM to calculate the allowance for corporate income tax presented in table 7.

**Table 7: AER's conclusion on ActewAGL's corporate income tax allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Tax allowance | 5.1 | 6.0 | 6.2 | 5.9 | 6.1 | 29.1 |

# Depreciation

## ActewAGL proposal

ActewAGL proposed to continue using the straight-line approach to calculating depreciation in the PTRM. It proposed the regulatory depreciation allowance set out in table 8.

**Table 8: ActewAGL's proposed depreciation allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Regulatory depreciation | 14.8 | 16.0 | 17.3 | 18.6 | 20.0 |

Source: ActewAGL, *Regulatory proposal*, p. 218.

ActewAGL aggregated its RAB value into a single asset category in the PTRM and applied a single remaining and standard asset life.

Under this approach, ActewAGL's forecast capex incurred over the next regulatory control period is included in the RAB as a single asset category. ActewAGL stated that splitting the RAB into asset classes in the PTRM and assigning them remaining lives that were not used when the assets were first included in the RAB, would be inconsistent with the NER.

## AER conclusion

The AER has assessed each of the proposed asset life inputs to the PTRM that are used to calculate the regulatory depreciation allowance in accordance with the NER. It does not consider ActewAGL's proposed depreciation schedules comply with the NER and therefore has not approved the schedules.

While the AER accepts ActewAGL's approach to depreciate its opening RAB (existing assets) within the single asset category based on the proposed remaining life, the AER considers it appropriate to include a more detailed breakdown of ActewAGL's forecast capex (new assets). ActewAGL has provided the asset classes and standard lives which will apply to its forecast capex from the next regulatory control period onwards. The AER has reviewed these asset classes and standard lives and considers them to be reasonable.

On the basis of these approved asset lives, opening RAB and forecast capex allowance, the AER has determined ActewAGL's regulatory depreciation allowance for the next regulatory control period in accordance with the NER, as set out in table 9.

**Table 9: AER's conclusion on regulatory depreciation allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Regulatory depreciation allowance | 14.5 | 16.2 | 17.7 | 19.3 | 21.1 | 88.8 |

# Cost of capital

## ActewAGL proposal

In estimating the WACC for its regulatory proposal, ActewAGL has used the values for the WACC parameters set out in the NER. For the purposes of its regulatory proposal ActewAGL has calculated a nominal vanilla WACC of 10.70 per cent.

## AER conclusion

For this draft decision, the AER has determined a nominal vanilla WACC of 9.82 per cent for ActewAGL. The WACC is less than that proposed by ActewAGL due to the decline in the risk-free rate and debt risk premium since ActewAGL submitted its regulatory proposal.

Table 10 outlines the WACC parameter values for this draft decision. The AER will update the nominal risk-free rate and debt risk premium, based on the agreed averaging period, and the expected inflation rate at a time closer to its final distribution determination.

**Table 10: AER's conclusion on ActewAGL's WACC parameters**

| Parameter | ActewAGL's proposal | AER's conclusion |
|---|---|---|
| Risk–free rate (nominal) | 6.27% | 5.46% |
| Risk–free rate (real) | 3.67% | 2.84% |
| Expected inflation rate | 2.51% | 2.55% |
| Debt risk premium | 3.38% | 3.27% |
| Market risk premium | 6.00% | 6.00% |
| Gearing | 60% | 60% |
| Equity beta | 1.00 | 1.00 |
| Nominal pre–tax return on debt | 9.65% | 8.73% |
| Nominal post–tax return on equity | 12.27% | 11.46% |
| Nominal vanilla WACC | 10.70% | 9.82% |

## Service target performance incentive arrangements

### ActewAGL proposal

ActewAGL has acknowledged that the details of the service performance data collection process would be settled following the publication of the AER's national distribution service target performance incentive scheme (STPIS). At the time of lodgement of ActewAGL's regulatory proposal on 2 June 2008, the national distribution STPIS had not been published. ActewAGL submitted that, in developing its regulatory proposal, it assumed that the information requirements of the final national distribution STPIS would be similar to those set out in the proposed national distribution STPIS published in April 2008. ActewAGL has proposed that any significant changes to the national distribution STPIS occurring after the date it submitted it regulatory proposal to the AER, which have cost impacts, could be addressed in response to the AER's draft distribution determination, or through ActewAGL's proposed 'transitional period' pass through event mechanism.

ActewAGL has submitted that it expects to incur additional costs to establish new systems and processes, during the next regulatory control period, to prepare for the introduction of the national distribution STPIS from 2014. ActewAGL has included forecast capex and opex amounts in its regulatory proposal to establish these systems and processes.

### AER conclusion

In consultation with ActewAGL, the AER has developed service performance data reporting requirements for the next regulatory control period. As foreshadowed in the AER's final decision on STPIS arrangements for the ACT and NSW determinations, the data reporting requirements have been aligned with the requirements of the national distribution STPIS, published on 26 June 2008.

In accordance with the NER, the AER will collect and monitor ActewAGL's service performance data during the next regulatory control period. Revenue will not be placed at risk under the data collection process during this period.

In implementing the data reporting requirement, the AER expects to accumulate a sufficient data series to allow the application of the national distribution STPIS to ActewAGL from 1 July 2014. The application of the national distribution STPIS for the 2014–19 regulatory control period for ActewAGL will be the subject of consultation under the framework and approach process, prior to the 2014 distribution determination.

## Efficiency benefit sharing scheme

### ActewAGL proposal

ActewAGL has proposed to exclude self insurance costs, debt raising cost, costs of approved pass throughs, and the utilities network facilities tax payable to the ACT Government from the operation of the EBSS.

ActewAGL did not propose a method for adjusting forecast opex for EBSS purposes to account for any difference between forecast demand growth and actual demand growth during the next regulatory control period.

### AER conclusion

The AER will apply the EBSS released in February 2008 to ActewAGL for the next regulatory control period. Recognising ActewAGL's view that to form a relationship between demand growth and opex would be a complex task, the AER will not adjust the EBSS for the consequences of changes in demand growth for ActewAGL for the next regulatory control period.

The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs
- the utilities network facilities tax payable to the ACT Government
- non–network alternatives.

These are in addition to the costs of pass through events which are directly excluded by the EBSS.

## Demand management incentive scheme

### ActewAGL proposal

ActewAGL did not comment on the application of the original demand management innovation allowance (DMIA) in its regulatory proposal. It stated that it would provide its proposal in relation to the application of a DMIA in its annual pricing submission, in accordance with the requirements set out in the AER's final decision on the demand management incentive scheme.

### AER conclusion

The AER's draft decision, subject to the agreement of ActewAGL (as the affected DNSP), is to substitute the original DMIA with a replacement DMIA, published concurrently with this draft decision. Under the replacement DMIA, ActewAGL will have its forecast opex increased by $100 000 in each year of the next regulatory control period.

## Pass through arrangements

### ActewAGL proposal

ActewAGL proposed that, in addition to the four defined events in the NER, the following five events be included as pass through events:

- a major natural disaster event
- a transitional period event
- a smart meter event
- an input price event
- a supply curtailment event.

### AER conclusion

The AER considers that ActewAGL's proposed major natural disaster event meets the AER's assessment criteria for nominated pass through events and therefore the AER accepts ActewAGL's proposal.

The AER considers that the following events do not meet the AER's assessment criteria for nominated pass through events and therefore the AER does not accept ActewAGL's proposals in relation to:

- a transitional period event
- a smart meter event
- an input price event
- a supply curtailment event.

## Building block revenue requirement

### ActewAGL proposal

A description of ActewAGL's calculation of annual revenue requirements and X factors is in chapter 12 of its regulatory proposal. These calculations are contained in the completed PTRM submitted as attachment 8 of its proposal and are summarised in table 11.

**Table 11: ActewAGL's proposed annual revenue requirements and X factors ($m nominal)**

| | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|
| Regulatory depreciation | | 14.8 | 16.0 | 17.3 | 18.6 | 20.0 |
| Return on capital | | 63.4 | 70.8 | 75.9 | 80.2 | 84.5 |
| Tax allowance | | 5.5 | 6.4 | 6.7 | 6.4 | 6.7 |
| Operating expenditure | | 60.2 | 62.9 | 65.7 | 69.4 | 71.4 |
| Annual revenue requirements | | 144.0 | 156.1 | 165.5 | 174.7 | 182.5 |
| Energy sales (MWh) | 2 834 932 | 2 878 338 | 2 925 120 | 2 971 701 | 3 018 337 | 3 066 270 |
| Revenue yield (¢/kWh) | 4.09 | 5.05 | 5.28 | 5.52 | 5.77 | 6.03 |
| Expected revenues | 116.0 | 145.3 | 154.4 | 164.0 | 174.2 | 185.1 |
| Forecast CPI (%) | | 2.51 | 2.51 | 2.51 | 2.51 | 2.51 |
| X factors[a] (%) | | –20.37 | –2.00 | –2.00 | –2.00 | –2.00 |

Source: ActewAGL PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

## AER conclusion

The AER's draft decision results in a total revenue requirement over the next regulatory control period of $779 million as set out in table 12, compared to $823 million proposed by ActewAGL. The main reasons for this difference reflect:

- updated WACC parameters
- minor reductions to opex and capex reflecting escalation reductions
- correction of errors which are discussed in this draft decision.

**Table 12: AER's conclusion on ActewAGL's annual revenue requirements and X factors ($m nominal)**

| | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|
| Regulatory depreciation | | 14.5 | 16.2 | 17.7 | 19.3 | 21.1 |
| Return on capital | | 57.8 | 64.5 | 69.1 | 73.1 | 76.9 |
| Tax allowance | | 5.1 | 6.0 | 6.2 | 5.9 | 6.1 |
| Operating expenditure | | 58.8 | 61.2 | 63.7 | 67.2 | 68.8 |
| Annual revenue requirements | | 136.2 | 147.8 | 156.7 | 165.5 | 172.8 |
| Energy sales (MWh) | 2 834 932 | 2 878 338 | 2 925 120 | 2 971 701 | 3 018 337 | 3 066 270 |
| Revenue yield (¢/kWh) | 4.09 | 4.78 | 5.00 | 5.23 | 5.47 | 5.72 |
| Expected revenues | 116.0 | 137.5 | 146.1 | 155.3 | 165.0 | 175.3 |
| Forecast CPI (%) | | 2.55 | 2.55 | 2.55 | 2.55 | 2.55 |
| X factors[a] (%) | | –13.82 | –2.00 | –2.00 | –2.00 | –2.00 |

Source: PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

# Alternative control services

## ActewAGL proposal

Consistent with the approach applied by the ICRC, ActewAGL has proposed a revenue allowance based on a building block analysis, with maximum allowable revenues to be escalated each year by CPI. The revenue allowance for alternative control services will be established based on the rolled forward value of the relevant metering assets, and an analysis of costs associated with providing the services.

## AER conclusion

The AER is satisfied that ActewAGL has satisfied its obligation to apply and demonstrate compliance with the control mechanism set out in the AER's statement on control mechanisms for alternative control services.

The AER has decided to approve a maximum allowed revenue for ActewAGL of $40 million for alternative control services for the next regulatory control period. This revenue will be recovered through a $P_0$ adjustment in 2009–10 of 31.34 per cent and allowed revenues adjusted in line with CPI each year for the remainder of the regulatory control period. ActewAGL's maximum allowed revenue for alternative control services is set out in table 13.

**Table 13: AER's draft decision on maximum allowed revenue – alternative control services ($m)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Unsmoothed revenue requirement | 7.5 | 7.7 | 8.1 | 8.2 | 8.7 |
| Smoothed revenue requirement | 7.6 | 7.8 | 8.0 | 8.2 | 8.4 |
| X factor (%) | –31.34 | 0.00 | 0.00 | 0.00 | 0.00 |

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# 1 Introduction

## 1.1 Background

Under the National Electricity Law (NEL) and the National Electricity Rules (NER), the Australian Energy Regulator (AER) is responsible for the economic regulation of certain electricity distribution services provided by distribution network service providers (DNSPs) in the National Electricity Market (NEM).

The Independent Competition and Regulatory Commission (ICRC) made ActewAGL's current price direction for a five year period from 1 July 2004 to 30 June 2009 (the current regulatory control period) under the National Electricity Code, which has been replaced by the NER. ActewAGL Distribution (ActewAGL) is the owner and operator of the electricity distribution network in the Australian Capital Territory (ACT).

The AER has made this draft decision and determination according to the relevant transitional provisions within chapter 11 the NER (the transitional chapter 6 rules). The AER's principal task is to set the building block revenues that a DNSP can recover from the provision of direct control services for 1 July 2009 to 30 June 2014 (the next regulatory control period).

Through its distribution determination, the AER is required to provide ActewAGL with the opportunity to recover sufficient revenues to meet the efficient costs of providing its direct control services and complying with regulatory obligations.

On 2 June 2008 ActewAGL submitted to the AER its regulatory proposal and its proposed negotiating framework for the next regulatory control period. On 27 June 2008 the AER published these and its proposed negotiable component criteria for ActewAGL.

### 1.1.1 National Electricity Law

The NEL sets out the functions and powers of the AER, including its role as the economic regulator of utilities operating in the NEM. Section 16 of the NEL states that when performing or exercising a regulatory function or power, the AER must do so in a manner that will or is likely to contribute to the achievement of the national electricity objective. The national electricity objective is:

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to
>
> (a) price, quality, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

Further, the NEL specifies that in performing or exercising its regulatory functions or powers, the AER must ensure that the regulated distribution system operator to which the determination applies and any affected registered participant be:

- informed of material issues under the AER's consideration

- given a reasonable opportunity to make submissions in respect of that determination before it is made.

Section 16 of the NEL also specifies revenue and pricing principles that the AER must take into account in making a distribution determination in relation to direct control network services. These principles are:

> (2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in-
>
> (a) providing direct control network services; and
>
> (b) complying with a regulatory obligation or requirement or making a regulatory payment.
>
> (3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes-
>
> (a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
>
> (b) the efficient provision of electricity network services; and
>
> (c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> (4) Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted-
>
> (a) in any previous-
>
> (i) as the case requires, distribution determination or transmission determination; or
>
> (ii) determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or
>
> (b) in the Rules.
>
> (5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.
>
> (6) 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, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.
>
> (7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.[2]

[2] NEL, clause 7A.

### 1.1.2 National Electricity Rules

The transitional chapter 6 rules set out provisions the AER must apply in exercising its regulatory functions and powers for electricity distribution networks in the ACT and NSW for the next regulatory control period. In particular, the AER must make a distribution determination for ActewAGL that includes a:

- building block determination in respect of standard control services
- determination in respect of alternative control services
- determination relating to the negotiating framework for direct control services
- determination specifying the negotiable component criteria for direct control services.

**Building block determination**

Clause 6.3.2 of the transitional chapter 6 rules requires a building block determination specify for a regulatory control period the following matters:

- the DNSP's annual revenue requirement for each regulatory year of the regulatory control period
- appropriate methods for the indexation of the regulatory asset base
- how any applicable efficiency benefit sharing scheme, service target performance incentive scheme, or demand management incentive scheme are to apply to the DNSP
- the commencement and length of the regulatory control period
- any amounts, values or inputs on which the building block determination is based.

**Negotiating framework determination**

A negotiating framework applies to circumstances where a person seeks to vary the normal terms and conditions relating to the supply of negotiable components of direct control services. Clause 6.7A.3 of the transitional chapter 6 rules states that a determination relating to the negotiating framework of a DNSP must set out requirements that are to be complied with in respect of the preparation, replacement, application and operation of a DNSP's negotiating framework.

Clause 6.7A.5 requires that a DNSP must prepare a negotiating framework setting out the procedure to be followed during negotiations between the DNSP and any person who wishes to be provided with a negotiable component from the DNSP, as to the terms and conditions of access for the provision of a negotiable component.

**Negotiable component criteria**

The negotiable component criteria must give effect to and be consistent with the negotiable component principles set out in clause 6.7A.1 of the transitional chapter 6 rules.

Under clause 6.7A.4 of the transitional chapter 6 rules the AER's determination on the negotiable component criteria must set out the criteria that the DNSP must apply in negotiating the terms and conditions of access including:

- the variations to the prices that are to be charged for the provision of the negotiable component of the direct control service concerned by the DNSP for the relevant regulatory control period
- any access charges which are negotiated by the DNSP during that regulatory control period.

The negotiable component criteria also must include criteria, which the AER will apply in resolving an access dispute, between the DNSP and a person who wishes to be provided with a negotiable component, in relation to terms and conditions of access including:[3]

- the variation of the prices that are to be charged for the provision of the negotiable component of the direct control service concerned by the DNSP
- any access charges that are to be paid to or by the DNSP.

## 1.2 Transitional arrangements

The timing of the changes to the NEL and NER, establishing a national framework for the economic regulation of distribution services, has required that transitional arrangements be included for the ACT and NSW DNSPs. The transitional arrangements have been established in the form of an appendix to chapter 11 of the NER specifying the form in which chapter 6 applies to NSW and the ACT for the next regulatory control period.

## 1.3 Review process

The AER has reviewed ActewAGL's regulatory proposal and proposed negotiating framework in accordance with the review process outlined in part E of the transitional chapter 6 rules. To date, this process has involved:

- Pre–consultation—the AER consulted with ActewAGL about the development of the regulatory information notice, pro forma templates and guidelines.
- Cost allocation method—in March 2008 the AER assessed and approved ActewAGL's cost allocation method under clause 6.15.8 of the transitional chapter 6 rules.
- Proposal—ActewAGL submitted its regulatory proposal and proposed negotiating framework to the AER on 2 June 2008. The AER assessed ActewAGL's proposal against the transitional chapter 6 rules and the AER's transitional guidelines.
- Public consultation—The AER published ActewAGL's regulatory proposal, proposed negotiating framework and the AER's proposed negotiable component criteria for ActewAGL on 27 June 2008. It called for interested parties to make

[3] Transitional chapter 6 rules, clause 6.7A.4.

submissions. The AER also held a roundtable on ActewAGL's proposal on 29 July 2008, where ActewAGL and interested parties made presentations.

- Submissions—the AER received one submission, from Energy Market Reform Group (EMRF), directly relating to ActewAGL's regulatory proposal or the AER's proposed negotiable component criteria for ActewAGL.

- Assessment by technical experts—the AER engaged Wilson Cook to advise it on a number of aspects of ActewAGL's regulatory proposal.

- Wilson Cook has provided its advice to the AER on these matters, representing its independent views based on its assessment of ActewAGL's regulatory proposal. The AER has considered this advice in making its draft distribution determination. The terms of reference guiding Wilson Cook's review are set out in appendix A of volume 1 of its report.

- Additional technical advice—the AER engaged Energy and Management Services (EMS) to provide the AER with technical and engineering advice throughout the review process. EMS assisted the AER in reviewing the technical aspects of material contained in ActewAGL's proposal, submissions and Wilson Cook's report.

- Other specialist advice—the AER engaged Econtech to provide a forecast of ACT and NSW labour costs growth relevant to electricity distribution businesses.

- ActewAGL provided additional information and clarification to the AER and its consultant following submission of the regulatory proposal.

## 1.4 Structure of draft decision

The AER's consideration of ActewAGL's regulatory proposal and proposed negotiating framework together with the negotiable component criteria to apply to ActewAGL, is set out as follows:

- chapters 2 to 4 address the classification of services, arrangements for negotiation and control mechanism for standard control services

- chapters 5 to 12 relate to key elements of the building block calculation

- chapters 13 to 16 set out relevant schemes and pass through arrangements

- chapter 17 sets out the annual building block revenue requirements for the next regulatory control period

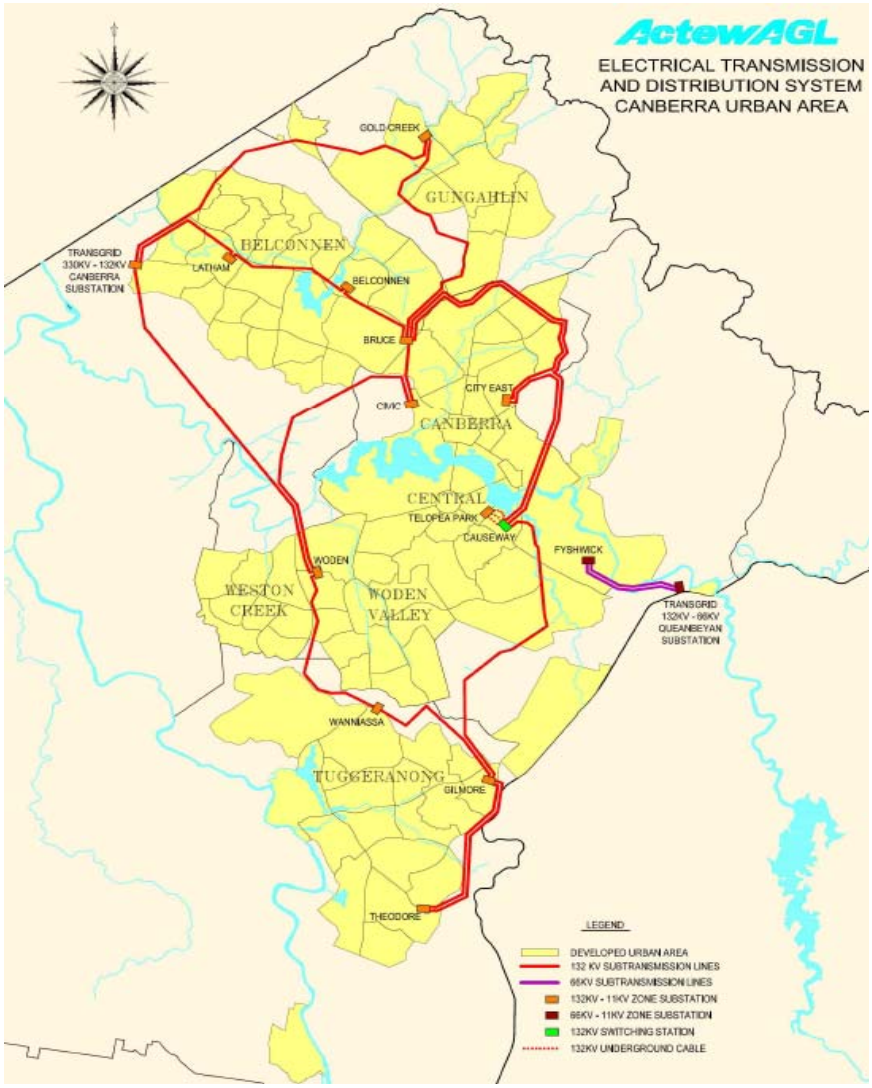
- chapter 18 sets out the control mechanism and AER's review of alternative control services.

## 1.5 Overview of the ACT electricity network

ActewAGL's distribution network delivers electricity to around 156 000 customers in the ACT. The network is supplied by TransGrid's Canberra and Queanbeyan bulk supply points.[4] Figure 1.1 shows ActewAGL's network.

The network comprises 11 zone substations, 2 switching stations, 4700 km of line assets, 4700 transformers and around 53 000 distribution poles. Approximately 50 per cent of ActewAGL's network by line length, is underground.[5] Of the overhead network assets, a significant proportion are reticulated through suburban backyards, rather than street fronts. ActewAGL noted that historically, ACT planning approaches have meant that low voltage reticulation must run along rear property boundaries rather than on street verges as is normal practice elsewhere.[6]

**Figure 1.1 Map of ActewAGL network**




Source: ActewAGL, *Regulatory proposal*, Attachment 3.

4 ActewAGL, *ActewAGL Distribution Determination 2009-14: Regulatory proposal to the Australian Energy Regulator*, June 2008, p. 9.

5 ActewAGL, *Regulatory proposal*, p. 10.

6 ActewAGL, *Regulatory proposal*, p. 17.

# 2 Classification of services

## 2.1 Introduction

A distribution service is a service provided by means of, or in connection with a distribution network, together with the connection assets, which is connected to another transmission or distribution system. There are three classes of distribution services—direct control services; negotiated distribution services and unregulated distribution services.

This chapter sets out the AER's proposed classification of ActewAGL's distribution services for the next regulatory control period.

## 2.2 Regulatory requirements

### 2.2.1 Classification of services

Clause 6.2.3C of the transitional chapter 6 rules specifies the classification of services that the AER is to apply—based on the ICRC's classification that applies in the current regulatory control period.

**Direct control services**

***Standard control services***

For ActewAGL, the ICRC's prescribed distribution services are deemed to be direct control services and further classified as standard control services for the next regulatory control period under clause 6.2.3.C(a) of the transitional chapter 6 rules. Consequently, all distribution services provided by ActewAGL, with the exception of the provision of and servicing of meters for customers consuming less than 160 megawatt hours per annum are deemed to be standard control services.

The AER may vary this classification by agreement with ActewAGL as part of its distribution determination under clause 6.2.3C(c) of the transitional chapter 6 rules.

***Alternative control services***

For the next regulatory control period, clause 6.2.3C(b) deems alterative control services in the ACT to be the same as the ICRC's excluded distribution services, namely, the provision of and servicing of meters for customers consuming fewer than 160 megawatt hours per annum including: meter testing, reading and checking; processing of metering data; and provision of non-standard meters.

The AER may vary this classification by agreement with ActewAGL as part of its distribution determination under clause 6.2.3C(c) of the transitional chapter 6 rules.

**Negotiated distribution services**

Chapter 10 of the NER provides that a negotiated distribution service is a distribution service that is a negotiated network service within the meaning of section 2C of the NEL. Negotiated network service is defined in the NEL as follows:

> A negotiated network service is an electricity network service-

(a) that is not a direct control network service; and

(b) that-

(i) the Rules specify as a negotiated network service; or

(ii) if the Rules do not do so, the AER specifies as a negotiated network service in a distribution determination or transmission determination.

Clause 6.2.3C of the transitional chapter 6 rules does not include any deeming of distribution services as negotiated distribution services.

**Unregulated distribution services**

A distribution service that is not classified as a direct control service or a negotiated distribution service is classified as an unregulated distribution service.

Clause 6.2.3C of the transitional chapter 6 rules does not include any deeming of distribution services as unregulated distribution services.

### 2.2.2 Assigning customers to tariff classes

Under clause 6.12.1(17) of the transitional chapter 6 rules the AER must make a decision on the procedures for assigning and re-assigning customers to tariff classes for direct control services.

A DNSP is required to set out tariff classes as part of its pricing proposal that is submitted after the publication of the distribution determination under clause 6.18.2 of the transitional chapter 6 rules. Clause 6.18.3 of the transitional chapter 6 rules provides that separate tariff classes are constituted for customers who are supplied with standard control services and alternative control services with regard to the need to group customers together on an economically efficient basis and the need to avoid unnecessary transaction costs.

Clause 6.18.4 of the transitional chapter 6 rules outlines the principles that the AER must have regard to when formulating procedures for the assignment or re-assignment of customers to tariff classes. These are:

(a) …

(1) customers should be assigned to tariff classes on the basis of one or more of the following factors:

(i) the nature and extent of their usage

(ii) the nature of their connection to the network

(iii) whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement

(2) customers with a similar connection and usage profile should be treated on an equal basis;

(3) however, customers with micro–generation facilities should be treated no less favourably than customers without such facilities but with a similar load profile;

(4) a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re–assign a customer from one tariff class to another should be subject to an effective system of assessment and review.[7]

## 2.3 ActewAGL proposal

ActewAGL's distribution services comprise:

- standard control services, which include all network use and connection services except the alternative control services
- alternative control services, which comprise the provision and servicing of all meters for customers consuming fewer than 160 MWh per annum
- unregulated services, which include street lighting, training and contestable metering services.

ActewAGL does not provide any services that are classified as negotiated services.[8]

ActewAGL has not proposed any reclassification of direct control services. However, ActewAGL has distinguished between the provision of metering data to retailers from the provision of metering services to small customers. ActewAGL submitted that provision of metering data to retailers is a standard control service while provision of metering to small customers is an alternative control service.[9]

## 2.4 Issues and AER considerations

### 2.4.1 Classification of services

The AER does not propose to vary the deemed classification of services as set out in clause 6.2.3C of the transitional chapter 6 rules. However, in classifying services as alternative control services the AER has considered ActewAGL's interpretation of metering data processing. The AER considers ActewAGL's interpretation reflects the current arrangements in the ACT, and is also supported by the definition of small customers in the NEL.[10]

The AER accepts ActewAGL's distinction between processing of small customers' raw data and provision of metering data to retailers. The provision of metering data to retailers is classified as a standard control service and the provision of metering services to small customers is an alternative control service.

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7 Transitional chapter 6 rules, clause 6.18.4.
8 ActewAGL, *Regulatory proposal,* p. 5.
9 ActewAGL, *Regulatory proposal,* p. 249.
10 NEL, section 16;
*Electricity Act 1996* (SA), section 4;
*Electricity (General) Regulations 1997* (SA), regulation 4B — each customer whose annual electricity consumption level for a connection point is less than 160 MWh is classified as a small customer in relation to electricity supply to the customer through the connection point.

The AER notes that ActewAGL has not classified any services as negotiated distribution services in the next regulatory control period and that it also provides some services that are not regulated under the NER (unregulated services).

### 2.4.2 Assigning customers to tariff classes

The AER notes clause 6.12.1(17) of the transitional chapter 6 rules requires it to make a decision on the procedures for assigning or re-assigning customers to tariff classes as part of its distribution determination. There is no requirement on DNSPs to propose such procedures and consequently the AER must develop the required procedures.

Clause 6.18.4 sets out the principles that the AER must have regard to in formulating procedures for the assignment of customers to tariff classes. The AER, having regard to the principles in clause 6.18.4, proposes the following procedures that ActewAGL is required to follow when assigning customers or re–assigning customers to tariff classes:

**Assignment of existing customers to tariff classes at the commencement of the next regulatory control period**

1. Each customer who was a customer of ActewAGL immediately prior to1 July 2009, and who continues to be a customer of ActewAGL as at 1 July 2009, will be taken to be assigned to the tariff class which ActewAGL was charging that customer immediately prior to 1 July 2009.

**Assignment of new customers to a tariff class during the next regulatory control period**

2. If, after 1 July 2009, ActewAGL becomes aware that a person will become a customer of ActewAGL, then ActewAGL must determine the tariff class to which the new customer will be assigned.
3. In determining the tariff class to which a customer or potential customer will be assigned, or re-assigned, in accordance with section 2 or 5, ActewAGL must take into account one or more of the following factors:
   - the nature and extent of the customer's usage
   - the nature of the customer's connection to the network
   - whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.
4. In addition to the requirements under section 3 ActewAGL, when assigning a customer to a tariff class, must ensure the following:
   a. that customers with similar connection and usage profiles are treated equally
   b. that customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.

**Re-assignment of existing customers to another existing tariff during the next regulatory control period**

5. If ActewAGL believes that an existing customer's load characteristics or connection characteristics (or both) have changed such that it is no longer

appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned or a customer no longer has the same or materially similar load or connection characteristics as other customers on the customer's existing tariff, then ActewAGL may re-assign that customer to another tariff class.

6. ActewAGL must notify the customer concerned in writing of the tariff class to which the customer will be re-assigned, prior to the re-assignment occurring. The notice must include advice that the customer may request further information from ActewAGL, may object to the proposed re-assignment and, if the customer objects to the proposed re-assignment and that objection is not resolved to the satisfaction of the customer, the customer or ActewAGL may request the AER to decide which of ActewAGL's tariff classes the customer should be assigned to.

7. If, in response to a notice issued in accordance with section 6, ActewAGL receives a request for further information from a customer, ActewAGL must reconsider the proposed re-assignment, taking into consideration the factors in section 3 above, and notify the customer in writing of its decision and the reasons for that decision.

8. If, in response to a notice issued in accordance with section 6, a customer makes an objection to ActewAGL about the proposed re-assignment, ActewAGL must reconsider the proposed re-assignment, taking into consideration the factors in section 3 above, and notify the customer in writing of its decision and the reasons for that decision.

9. If the AER received a request in accordance with section 6, then it must decide which of ActewAGL's tariff classes the customer should be assigned to, taking into account one or more of the following factors:

   - the nature and extent of the customer's usage
   - the nature of the customer's connection to the network
   - whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

10. As soon as practicable after being requested to do so by the AER, ActewAGL must provide to the AER a statement setting out which tariff class a particular customer or group of customers has been assigned to and the reasons for ActewAGL's decision.

11. The AER must notify the customer and ActewAGL in writing of its decision and the date from which its decision should be applied.

12. If the AER does not give a written notice under section 11 within 30 business days of receiving the relevant request under section 6 or within such further period that the AER may decide, then the AER is to be regarded as having decided that the customer giving the relevant request under section 6 should not be reassigned.

13. ActewAGL must comply with a decision by the AER under section 9 and 11 in relation to a customer.

**System of assessment and review of the basis on which a customer is charged**

14. Where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile, ActewAGL must set out in its pricing proposal a method of how it will review and assess the basis on which a customer is charged.
15. If the AER considers that the method provided under section 14 does not provide for an effective system of assessment and review of the basis on which a customer is charged, the AER may request additional information or request that ActewAGL revise and resubmit a revised method.
16. If the AER considers the method provided in accordance with section 14 is reasonable it will approve that method by notice in writing to ActewAGL.

### 2.4.3 AER conclusion

The AER accepts ActewAGL's proposed classification of services. The provision of metering data to retailers is classified as a standard control service and not an alternative control service. Alternative control services only include the provision of metering services for small customers.

The AER provisions for the procedures for assigning customers to tariff classes, based on the principles in clause 6.18.4 of the transitional chapter 6 rules, are set out in appendix A of this draft decision.

## 2.5 AER draft decision

In accordance with clause 6.12.1(1) of the transitional chapter 6 rules the AER decides that the following classification of services will apply to ActewAGL for the next regulatory control period:

- a distribution service provided by ActewAGL that was previously determined by the ICRC to be a prescribed distribution service (for the purposes of the current regulatory control period) is deemed to be classified as a direct control service and further classified as a standard control service. Hence, all distribution services provided by ActewAGL (with the exception of those services related to metering as discussed in section 2.4.1 of the draft decision) are classified as standard control services
- a distribution service provided by ActewAGL that was previously classified as an excluded service by the ICRC (for the purposes of the current regulatory control period) is also deemed to be classified as a direct control service and further classified as an alternative control service. The provision of and service of meters for customers consuming below 160MWh per annum is classified as an alternative control service
- there are no services classified as negotiated distribution services
- ActewAGL provides the following unregulated services: street lighting; training; and contestable metering services.

In accordance with clause 6.12.1(17) of the transitional chapter 6 rules the AER decides the procedures for assigning customers to tariff classes or reassigning customers from one tariff class to another are specified in appendix A of the draft decision.

# 3 Arrangements for negotiation

## 3.1 Introduction

This chapter sets out the AER's draft decisions regarding the arrangements facilitating negotiation for certain ActewAGL distribution services for the next regulatory control period. It sets out the regulatory requirements, proposals, and AER's considerations and conclusions on:

- those services, or components of services, which are to be classified as negotiable components during the next regulatory control period
- the negotiable component criteria
- the negotiating framework to apply to negotiable components.

A negotiated distribution service for the purposes of the NER is defined as a distribution service that is a negotiated network service under section 2C of the NEL. In turn, section 2C of the NEL provides that a negotiated network service is a service that is not a direct control service and that the NER specify as a negotiated network service or, if the NER does not do so, that the AER specifies as a negotiated network service in its distribution determination.

There are currently no negotiated distribution services in the ACT. However, clause 6.2.7A of the transitional chapter 6 rules provides that the control mechanism for direct control services for ACT and NSW DNSPs may include negotiable components to be regulated under part DA of the transitional chapter 6 rules. Part DA is a transitional provision and only applies for the next regulatory control period for ACT and NSW DNSPs. Any negotiable components of direct control services will not be applicable in subsequent regulatory control periods. Future classification of services will be governed by the AER's likely approach in its framework and approach paper which must be prepared in anticipation of each distribution determination under general chapter 6 of the NER.

## 3.2 Negotiable components

### 3.2.1 Regulatory requirements

The AER may include in its distribution determination a decision that one or more components of the provider's direct control services are negotiable components (clause 6.7A of the transitional chapter 6 rules). The AER must make a decision on which, if any, components of direct control services are negotiable components as part of its distribution determination under clause 6.12.1(16A) of the transitional chapter 6 rules.

Negotiable components are described in clause 6.7A(b) of the transitional chapter 6 rules as:

> … a negotiable component may be a particular component of the direct control service or may relate to the terms or conditions on which a direct control service or a component of a direct control service is provided.

If the AER decides that one or more components of direct control services provided by a DNSP are negotiable components then the provisions set out in clause 6.7A.1–6.7A.6 of the transitional chapter 6 rules will have effect.[11] These provisions cover:

- principles relating to access to negotiable components
- determination of terms and conditions of access for negotiable components
- negotiating framework determination
- negotiable component criteria determination
- preparation of and requirements for negotiating framework
- confidential information.

### 3.2.2 ActewAGL proposal

ActewAGL did not propose any negotiable components of direct control services. It stated that there is only limited scope for negotiation in relation to direct control services and that it is often difficult to define in advance which components will be negotiable. However, ActewAGL proposed a definition using examples to assist in identifying negotiable components of direct control services, rather than specifically identifying negotiable components.[12]

ActewAGL suggested that a negotiable component of a direct control service should be any component (or terms and conditions on which that component is provided) where some variability can be applied to the provision of the direct control service without interfering with a DNSP's ability to comply with any regulatory obligation or requirement of the NER.[13]

ActewAGL provided the following examples of possible negotiable components:[14]

- location of a substation to support customer load
- location of a customer's connection to ActewAGL's distribution network
- voltage level or capacity of a customer's connection
- distribution access charges for embedded generators
- any increase (or decrease) in the security or reliability of the shared distribution service requested by a customer in excess of that which would otherwise be provided at the customer's point of supply
- provision of standby network connections capacity (often applicable to embedded generation projects)

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11 Transitional chapter 6 rules, clause 6.7A(d).
12 ActewAGL, *Regulatory proposal*, chapter 14.
13 ActewAGL, *Regulatory proposal*, pp. 246–247.
14 ActewAGL, *Regulatory proposal*, pp. 246–247.

- special aesthetic requirements in relation to ActewAGL network equipment
- non-standard substation configuration or use of non-standard equipment.

### 3.2.3 Submissions

The AER called for submissions on ActewAGL's definition and list of examples as part of its *Explanatory Statement and Issues Paper*.[15] No relevant submissions were received.

### 3.2.4 Issues and AER considerations

Clause 6.12.1(16A) of the transitional chapter 6 rules requires the AER to decide which, if any, components of direct control services are negotiable components.

In considering the examples of possible negotiable components provided by ActewAGL, the AER has also considered ActewAGL's claim that the circumstances of the service provision will influence whether or not a particular component of the service may be considered a negotiable component. The AER accepts that differing circumstances may mean that a service component could be treated as negotiable for one customer but not for others.

The AER also notes that ActewAGL has not identified any specific negotiable components of direct control services which they intend to provide during the next regulatory control period.

Given the difficulty of identifying specific negotiable components that are universally applicable to ActewAGL's customers the AER considers it is not appropriate to specify any particular components of direct control services as negotiable components. However, the AER considers that it is appropriate to define negotiable components of a direct control services in order that ActewAGL and its customers have a means by which they can identify negotiable components on a case–by–case basis. The AER considers that this will provide flexibility by allowing negotiation to take place in relation to these types of services (which would not have otherwise occurred). It is envisaged that only sophisticated customers of ActewAGL would seek to negotiate for services which would be considered to be negotiable components of direct control services. Such negotiations are only likely to occur in a small number of circumstances and only in relation to a small element of the total service. The AER would expect the definition of negotiable components of direct control services to cover requests made by customers for aesthetic reasons or convenience.[16]

In developing a definition for negotiable components of direct control services, the AER acknowledges that it is important that a negotiable component does not interfere with a DNSP's ability to comply with any regulatory obligation or requirement of the NER. It is also envisaged that if there are concerns regarding threats to reliability,

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15 AER, *Call for submissions: Proposed negotiable component criteria for ACT and NSW distribution network service providers; Proposed negotiated distribution service criteria for EnergyAustralia,* Explanatory statement and issues paper, Canberra, June 2008.

16 Examples of possible points of negotiation could include a customer seeking a variation to the location of a substation required to support the customer's load, the voltage level at which the connection is made and the provision of alternative supply connections.

safety or security for other network customers posed by a proposed negotiable component then those concerns will need to be assessed.

The AER also notes that the transitional chapter 6 rules regarding negotiable components will cease at the end of the next regulatory control period, and at that time those services will either have to be reclassified as negotiated services or will remain as direct control services not subject to negotiation.

### 3.2.5 AER conclusion

The AER has decided not to specify any particular components of ActewAGL's direct control services as negotiable components for the next regulatory control period. However, the AER has decided to define a negotiable component of a direct control service as any component of a direct control service (or the terms and conditions on which that direct control service or component are provided) where:

- the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation

- the direct control service, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER or

- the direct control service is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider.

Therefore, components that fall within the scope of the above definition, are negotiable components. This approach to defining a negotiable component of a direct control service is based on a definition proposed by Integral Energy in its regulatory proposal for its NSW distribution determination.[17] The AER considers that this definition is consistent with the examples of possible negotiable components provided by ActewAGL and can be used to provide a framework under which the NSW and ACT DNSPs can operate.

## 3.3 Negotiable component criteria

### 3.3.1 Regulatory requirements

The AER may, if relevant, make a decision on the negotiable component criteria (NCC) as part of its distribution determination under clause 6.12.1(16B). The NCC sets out the criteria that are to be applied by the DNSP in negotiating the terms and conditions of access for negotiable components, including variations to the prices that

[17] Integral Energy, *Regulatory proposal to the Australian Energy Regulator 2009 to 2014 – delivering efficient and sustainable network services*, 2 June 2008, Appendix H, section 1.3.

are to be charged for certain direct control services and any access charges which are negotiated by the provider during the regulatory control period.[18]

The NCC will also be used by the AER in resolving any access dispute between a DNSP and a person wishing to be provided with a negotiable component in relation to the terms and conditions of access including the variation of the prices that are to be charged for the provision of the negotiable component of the direct control service and any access charges that are to be paid to or by the provider.[19]

### 3.3.2 AER proposed negotiable component criteria

The AER has developed its proposed NCC based on the principles set out in clause 6.7A.1 of the transitional chapter 6 rules and has developed criteria that give effect to and that are consistent with those principles in accordance with clauses 6.7A.4(b) of the transitional chapter 6 rules. The AER has also included an additional criterion that promotes the achievement of the national electricity objective (see criterion 1 of the proposed NCC).[20]

In accordance with clauses 6.9.3(a) and 6.9.3(b) of the transitional chapter 6 rules, the AER published its proposed NCC and an issues paper in June 2008.[21]

### 3.3.3 Issues and AER considerations

The AER received a submission from EnergyAustralia in response to the AER's proposed NCC. EnergyAustralia proposed that the heading for criterion 1 should be renamed the 'national electricity objective'.[22] The AER's analysis of EnergyAustralia's submission can be found in the AER's draft distribution determination for the NSW DNSPs.[23] The AER considers that this analysis is applicable to any NCC for ActewAGL.

### 3.3.4 AER conclusion

In light of EnergyAustralia's submission, the AER will change the heading of criterion 1 from 'national electricity market objective' to 'national electricity objective'.

The NCC for ActewAGL is set out in appendix B.

## 3.4 Negotiating framework

### 3.4.1 Regulatory requirements

The AER must make a decision on any negotiating framework that is to apply as part of its distribution determination under clause 6.12.1(15) of the transitional chapter 6 rules. Under clause 6.12.3(g) of the transitional chapter 6 rules, the AER must

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18 Transitional chapter 6 rules, clause 6.7A.4(a)(1).
19 Transitional chapter 6 rules, clause 6.7A.4(a)(2).
20 AER, *Call for submissions: NCC and NDSC*, p. 14.
21 AER, *Call for submissions: NCC and NDSC*, p. 15.
22 EnergyAustralia, *Response to AER's request for submissions on AER proposed NCC and NDSC,* 8 August 2006, p. 3.
23 AER, *NSW distribution determination 2009–10 to 2013–14,* Draft decision, Canberra, November 2008.

approve a proposed negotiating framework if it is satisfied that it adequately complies with the requirements of Part DA.

The AER must set out the reasons for its decision to approve, or refuse to approve, the DNSP's proposed negotiating framework.[24] The AER's determination relating to the DNSP's negotiating framework must set out any requirements that are to be complied with in respect of the preparation, replacement, application or operation of the DNSP's negotiating framework.[25] If the AER's decision is to refuse to approve the DNSP's proposed negotiating framework in its final decision, it must include an amended negotiating framework in its final determination. Any amendments made by the AER must be based on the DNSP's proposed negotiating framework and amended only to the extent necessary to enable it to be approved in accordance with the transitional chapter 6 rules.[26]

**DNSP proposal**

In accordance with clause 6.8.2(c)(8) of the transitional chapter 6 rules, a DNSP must submit a negotiating framework if it proposes negotiable components of direct control services as part of its regulatory proposal. Clause 6.7A.5(b) of the transitional chapter 6 rules requires that a DNSP's negotiating framework must comply with the applicable requirements of its distribution determination and the minimum requirements for a negotiating framework set out in clause 6.7A.5(c) of the transitional chapter 6 rules.

**AER negotiating framework determination**

The AER will assess the DNSP's proposed negotiating framework to ascertain whether it satisfies the following minimum requirements:[27]

> (1) a requirement for the provider and a Service Applicant to negotiate in good faith the terms and conditions of access to a negotiable component; and
>
> (2) a requirement for the provider to provide all such commercial information a Service Applicant may reasonably require to enable that applicant to engage in effective negotiation with the provider for the provision of the negotiable component, including the cost information described in subparagraph (3); and
>
> (3) a requirement for the provider:
>
> (i) to identify and inform a Service Applicant of the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the negotiable component; and
>
> (ii) to demonstrate to a Service Applicant that the charges for providing the negotiable component reflect those costs and/or the cost increment or decrement (as appropriate); and
>
> (iii) to have appropriate arrangements for assessment and review of the charges and the basis on which they are made;

24 Transitional chapter 6 rules, clause 6.12.2(4).
25 Transitional chapter 6 rules, clause 6.7A.3.
26 Transitional chapter 6 rules, clause 6.12.3(h).
27 Transitional chapter 6 rules, clause 6.7A.5(c).

*Note:*

*If (for example) a charge, or an element of a charge, is based on a customer's actual or assumed maximum demand, the assessment and review arrangements should allow for a change to the basis of the charge so that it more closely reflects the customer's load profile where a reduction or increase in maximum demand has been demonstrated.*

(4) a requirement for a Service Applicant to provide all commercial information the provider may reasonably require to enable the provider to engage in effective negotiation with that applicant for the provision of the negotiable component; and

(5) a requirement that negotiations with a Service Applicant for the provision of the negotiable component be commenced and finalised within specified periods and a requirement that each party to the negotiations must make reasonable endeavours to adhere to the specified time limits; and

(6) a process for dispute resolution which provides that all disputes as to the terms and conditions of access for the provision of negotiable components are to be dealt with in accordance with the relevant provisions of the Law and the Rules for dispute resolution; and

(7) the arrangements for payment by a Service Applicant of the provider's reasonable direct expenses incurred in processing the application to provide the negotiable component; and

(8) a requirement that the Distribution Network Service Provider determine the potential impact on other Distribution Network Users of the provision of the negotiable component; and

(9) a requirement that the Distribution Network Service Provider must notify and consult with any affected Distribution Network Users and ensure that the provision of negotiable components does not result in non-compliance with obligations in relation to other Distribution Network Users under the Rules; and

(10) a requirement that the Distribution Network Service Provider publish the results of negotiations on its website.

### 3.4.2 ActewAGL proposed negotiating framework

ActewAGL has submitted its proposed negotiating framework for negotiable components of direct control services.[28]

ActewAGL's proposed negotiating framework would apply to ActewAGL and any service applicant who has made an application in writing for a negotiable component of a direct control service.[29] Any service applicant should apply and comply with the requirements of the negotiating framework. The requirements of the negotiating framework are additional to any requirements of clauses 5.3, 5.4A and 5.5 and chapter 6 and chapter 6A of the NER and if any inconsistencies exist, the requirements of the NER prevail.[30] The negotiating framework also requires that both parties involved in

28 ActewAGL, *Regulatory proposal*, attachment 9.

29 ActewAGL, *Proposed negotiating framework for negotiable components of direct control services: 2009–14 regulatory control period,* clause 2.1, p. 1.

30 ActewAGL, *Proposed negotiating framework,* clause 2.4, p. 2.

the negotiating process should negotiate, in good faith, the terms and conditions of access for the negotiable component.[31]

The proposed negotiating framework contains clauses that allow the provision of commercial information to both parties to facilitate effective negotiation and also contains safeguards for confidential information and disclosure by consent.[32]

ActewAGL's proposed negotiating framework also requires it to provide a reasonable estimate of the costs of providing the negotiable component and demonstrate how the charges reflect those costs, including any increases or decreases.[33] It also provides arrangements for assessment and review of charges and the basis of the charges.[34]

The timeframes for commencing, progressing and finalising the negotiation are set out in the negotiating framework.[35] The proposed timeframes can be modified with the agreement of both parties. The negotiating framework states that once an application is received from a service applicant both parties must use their reasonable endeavours to adhere to the proposed timeframes.[36]

The stated timeframes do not commence until the service applicant has paid the application fee. In addition, the timeframes can recommence if there is a material change in nature of the negotiable component sought.[37]

The application fee is not specified in the negotiating framework although it states that the application fee will be deducted from the reasonable costs incurred by ActewAGL in processing the application for the negotiable component.[38] ActewAGL may issue the service applicant with a notice setting out the reasonable costs incurred and requesting payment of amounts above the application fee.[39] Within 20 business days, the service applicant is required to pay ActewAGL any amount requested in the notice.[40] Further, ActewAGL may require the service applicant to enter into a binding agreement regarding the payment of ongoing costs.[41]

ActewAGL's proposed negotiating framework includes an obligation to determine the potential impact on other network users and notify and consult with any affected network users to ensure that the provision of negotiable components does not result in non–compliance with other obligations.[42] It also refers to the relevant dispute resolution mechanisms[43] and ActewAGL's obligation to publish results of negotiations on its website.[44]

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31 ActewAGL, *Proposed negotiating framework,* clause 3.1, p. 2.
32 ActewAGL, *Proposed negotiating framework,* clauses 5–7, pp. 4–8.
33 ActewAGL, *Proposed negotiating framework,* clause 7.1, p. 7.
34 ActewAGL, *Proposed negotiating framework,* clause 8.1, p. 8.
35 ActewAGL, *Proposed negotiating framework,* clause 4.4, table 4.1 p. 4.
36 ActewAGL, *Proposed negotiating framework,* clause 4.4, pp. 2–3.
37 ActewAGL, *Proposed negotiating framework,* clause 4.5, p. 4.
38 ActewAGL, *Proposed negotiating framework,* clause 12, p. 10.
39 ActewAGL, *Proposed negotiating framework,* clause 12.3, p. 10.
40 ActewAGL, *Proposed negotiating framework,* clause 12.4, p. 10.
41 ActewAGL, *Proposed negotiating framework,* clause 12.5, p. 10.
42 ActewAGL, *Proposed negotiating framework,* clause 9, p. 8.
43 ActewAGL, *Proposed negotiating framework,* clause 11, p. 9.
44 ActewAGL, *Proposed negotiating framework,* clause 15, p. 12.

### 3.4.3 AER considerations

The AER notes that ActewAGL's proposed negotiating framework contains the requirements set out in clause 6.7A.5(c) of the transitional chapter 6 rules.

The AER notes that the distribution determination must set out the requirements that are to be complied with in respect of the preparation, replacement, application or operation of a DNSP's negotiating framework.[45]

The AER considers that ActewAGL has prepared its proposed negotiating framework in accordance with the requirements of clause 6.7A.5 of the transitional chapter 6 rules and that the proposed application or operation of the framework is also in accordance with clause 6.7A.5.

However, the transitional chapter 6 rules do not explicitly state how or when a DNSP should prepare or replace its negotiating framework. In absence of a specific rule, the AER considers that a DNSP's negotiating framework will apply for the duration of the regulatory control period to which the distribution determination relates. The preparation of the negotiating framework for 2014–2019 regulatory control period must be undertaken in accordance with the framework and approach processes for that regulatory control period.

### 3.4.4 AER conclusion

As required by clause 6.12.3(g) of the transitional chapter 6 rules, the AER approves ActewAGL's negotiating framework to apply for the next regulatory control period. The AER has assessed ActewAGL's negotiating framework and considers that the negotiating framework in appendix C of this draft decision complies with the requirements of Part DA of the transitional chapter 6 rules.

[45] Transitional chapter 6 rules, clause 6.7A.3.

## 3.5 AER draft decision

In accordance with clauses 6.12.1(15) and 6.7A.3 of the transitional chapter 6 rules the AER decides the negotiating framework in appendix C of the draft decision is to apply to ActewAGL for the next regulatory control period. The preparation of the negotiating framework for 2014–2019 regulatory control period must be undertaken in accordance with the framework and approach processes for that regulatory control period.

In accordance with clauses 6.12.1(16A) and 6.7A of the transitional chapter 6 rules the AER decides the components of ActewAGL's direct control services which are negotiable components are any component of a direct control service (or the terms and conditions on which that direct control service or component are provided) where:

- the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation
- the direct control service, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or schedule 5.1 of the NER or
- the direct control service is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider.

In accordance with clauses 6.12.1(16B) and 6.7.4(a) of the transitional chapter 6 rules the AER decides the NCC for ActewAGL is at appendix B of the draft decision.

# 4 Control mechanism for standard control services

## 4.1 Introduction

A distribution determination imposes controls over the prices, and/or revenues, that ActewAGL may recover from providing direct control services. Direct control services are categorised as either standard control services or alternative control services. Classification of ActewAGL's direct control services is discussed in chapter 2 of this draft decision.

The AER has published guidelines under clause 6.2.8(a)(2) of the transitional chapter 6 rules setting out the control mechanisms it proposes to apply to ActewAGL's direct control services for the next regulatory control period. For ActewAGL's standard control services this mechanism is a maximum average revenue cap. This chapter discusses how this mechanism will be applied and sets out how the AER will determine compliance with this mechanism during the next regulatory control period.

The control mechanism and assessment of ActewAGL's proposal regarding alternative control services is considered in chapter 18 of this draft decision.

## 4.2 Regulatory requirements

Clause 6.12.1 of the transitional chapter 6 rules requires the AER to make the following constituent decisions which are related to the form of control mechanism for standard control services:

- a decision on the control mechanism (including the X factor) for standard control services (clause 6.12.1(11))
- a decision on how compliance with the relevant control mechanism is to be demonstrated (clause 6.12.1(13))
- a decision on how the DNSP is to report to the AER on its recovery of transmission use of service (TUOS) charges for each regulatory year and adjustments to prices in subsequent years to account for TUOS over or under-recoveries (clause 6.12.1(19)).

For standard control services, clause 6.2.6(a) of the transitional chapter 6 rules requires that the control mechanism must be of the prospective CPI minus X form, or some incentive–based variant of that form, in accordance with the building block approach.

Clause 6.2.5(c1)(2) of the transitional chapter 6 rules provides that the control mechanism for ActewAGL's standard control services must be substantially the same as the control mechanism determined by the ICRC for the current regulatory control period (the ICRC control mechanism). The ICRC control mechanism is based on the prospective CPI minus X form and the objectives and principles outlined in the

National Electricity Code. The ICRC control mechanism is a maximum average revenue cap.

The AER published a guideline for standard control services (the standard control services guideline) that sets out the operation of the maximum average revenue cap mechanism to apply to ActewAGL's standard control services during the next regulatory control period.[46] This mechanism is substantially the same as the ICRC control mechanism, with the following exceptions:

- The AER will apply a side constraint formula to each tariff class[47], as required under clause 6.18.6 of the transitional chapter 6 rules.
- In assessing compliance with the side constraint, the AER will disregard the recovery of revenue to accommodate the pass through of charges for TUOS services to customers.

The AER may allow adjustments to this formula to recognise any demand management incentive and/or service target performance incentive schemes.

The standard control services guideline is not binding on the AER or ActewAGL, however, if the AER's distribution determination is not in accordance with the guideline it must state the reasons for its departure.[48]

## 4.3 ActewAGL proposal

ActewAGL has proposed to recover revenues from its standard control services under a maximum average revenue cap.[49] This constraint is expressed as the maximum allowable average revenue for network services, per kWh. ActewAGL stated that this proposed mechanism is consistent with the AER's standard control services guideline and the transitional rules relating to side constraints and overs and unders adjustment for TUOS charges.[50]

ActewAGL proposed to demonstrate compliance with the maximum allowable average revenue in each financial year (e.g. 2009–10) through the following steps:

- multiply the maximum allowable average revenue for that particular year by total kWh sales in the previous calendar year (e.g. 2008) to derive a total revenue cap
- make adjustments to this total revenue cap to:

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46 AER, *Guideline on control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations*, February 2008.

47 The standard control service guideline was written using terminology from ICRC, *Final decision - Investigation into prices for electricity distribution services in the ACT* (March 2004). The terminology used in this chapter reflects the terminology used in the NER. For example, references in this chapter to 'side constraints for tariff classes' equates to the concept of 'side constraints to the distribution component of individual network tariffs' which is used in the standard control service guideline.

48 Transitional chapter 6 rules, clause 6.2.8(c).

49 ActewAGL, *Regulatory proposal*, p. 239.

50 ActewAGL, *Regulatory proposal*, p. 5.

- deduct revenues from regulated miscellaneous standard control services (calculated by applying prices for the next financial year to the sales quantities from the previous calendar year)

- adjust for any under and over recoveries of the Utilities Network Facilities Tax (UNFT) with respect to forecast tax payable for the next financial year

- propose prices for standard control services for the next financial year, which, when multiplied by sales volumes in the previous calendar year, must not result in notional revenues exceeding the adjusted total revenue cap.

ActewAGL proposed to report TUOS under and over recoveries on an annual basis to the AER. It stated the revenue will be calculated on the basis of the proportion of TUOS to total network prices. For any given year (e.g. 2010–11) ActewAGL proposed to make adjustments to TUOS in each prospective year (e.g. 2011–12) to reflect under or over recoveries of the previous year (e.g. 2009–10).

Where historical data is required in the above calculations, ActewAGL proposed to use independent data which can be verified.[51]

## 4.4 AER considerations

**Maximum allowable average revenue cap**

The AER notes that ActewAGL has proposed a constraint on maximum average revenue. The AER considers this to be substantially the same mechanism as that applied by the ICRC and therefore consistent with clause 6.2.5(c1)(2) and the AER's standard control services guideline. The AER considers that some amendments to the expression of the mechanism are required which are explained below.

To distinguish this form of control from the term maximum allowed revenue (MAR) as used in transmission, the AER will use the term 'maximum allowable average revenue' (MAAR) to describe this constraint in this draft decision.[52]

The control mechanism to be implemented by the AER is a MAAR (expressed as cents per kilowatt hour) adjusted according to the following formula:

$$\text{MAAR}_t = \text{MAAR}_{t\text{-}1} \times (1 + CPI_t) \times (1 - X_t)$$

Where:

- $\text{MAAR}_{t\text{-}1}$ is the maximum allowable average revenue for the previous regulatory year

- CPI means the all groups index number for the weighted average of eight capital cities as published by the Australia Bureau of Statistics (ABS), or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER

[51] ActewAGL, *Regulatory proposal*, p. 239.

[52] Note this terminology represents a departure from the AER's standard control services guideline, however the meaning in the guideline is retained.

considers is the best estimate of the index. CPI is determined from the following formula:

$$CPI_{(t)} = \frac{CPI_{March(t-2)} + CPI_{June(t-2)} + CPI_{Sept(t-1)} + CPI_{Dec(t-1)}}{CPI_{March(t-3)} + CPI_{June(t-3)} + CPI_{Sept(t-2)} + CPI_{Dec(t-2)}} - 1$$

- Xt is the X factor value for regulatory year t, specified in table 17.5 of this draft decision.

The formula for adjusting the MAAR differs slightly from the expression used by the ICRC and the AER's standard control services guideline by:

- recognising X values as negative amounts in accordance with the 'CPI minus X' expression required under clause 6.2.6 of the transitional chapter 6 rules (previously was expressed as (CPI+X))

- incorporating X in a multiplicative sense i.e. (1+CPI)*(1-X), as per standard regulatory practice and consistent with the form envisaged in the application of side constraints under clause 6.18.6 of the transitional chapter 6 rules (was previously expressed as (1+CPI-X)).

The AER notes that these changes are not substantive and are also consistent with ActewAGL's proposed calculation of X factors in its PTRM.

To determine compliance with the MAAR for standard control services the AER will assess ActewAGL's proposed tariffs for all standard control services based on the formula as applied by the ICRC and replicated in the AER's standard control services guideline.[53] However, the AER notes that the tariffs for standard control services need to include the revenues received from miscellaneous services as intended by the ICRC and proposed by ActewAGL.[54] The miscellaneous standard control services are described in appendix D of this draft decision.

Regarding approved pass through amounts, the AER notes that the ICRC explicitly excluded consideration of these amounts when assessing compliance with the control mechanism, but did not specify how these would be taken into account when new tariffs were proposed.[55] In this context the AER considers that the control mechanism should incorporate a minor amendment to recognise pass through amounts, as well as miscellaneous services revenue, as per the following formula:

$$\text{MAAR}_t \geq \frac{\sum_{i=1}^{n} p_i^t \times q_i^{t-1} + \text{MSR}_t \pm \text{pass through}_t}{\text{Kilowatt hours transported}_{t-1}}$$

Where:

53 ICRC, *Final decision*, pp. 132.
54 ICRC, *Draft decision– Investigation into prices for electricity distribution services in the ACT*, November 2003, pp. 113–114.
55 ICRC, *Final decision,* p. 139.

- $p_i^t$ is the price for each tariff component for standard control services (excluding miscellaneous services) proposed for regulatory year t (e.g. 2009-10)

- $q_i^{t-1}$ represents sales quantities for standard control services (excluding miscellaneous services) sold by ActewAGL in the previous calendar year t-1 (e.g. 2008) that correspond to the proposed tariff components

- i represents individual tariff components of a total of n components across all tariffs

- kilowatt hours transported$_{t-1}$ are the amounts of energy for the previous calendar year delivered by ActewAGL for standard control services

- $MSR_t$ is miscellaneous services revenue, calculated by multiplying the proposed miscellaneous services charges for regulatory year t with the quantities of these services sold in the previous calendar year

- pass through$_t$ represents approved pass through amounts relating to regulatory year t as determined by the AER in accordance with clause 6.6.1 of the transitional chapter 6 rules and chapter 16 of this draft decision.

The AER considers that the addition of miscellaneous services revenue and pass through amounts does not substantively change the control mechanism applied by the ICRC and is a more explicit recognition of the adjustments that need to be considered when proposing and assessing tariffs for each regulatory year. The revised expression also represents the same compliance calculation envisaged by ActewAGL.[56]

**Recovery of transmission use of system costs**

Clause 6.18.7 of the transitional chapter 6 rules allows each DNSP to recover its actual transmission related payments, through TUOS charges. Transmission related payments include:

- transmission charges paid to TNSPs for use of transmission system

- avoided TUOS paid to embedded generators

- payments made to another DNSP for use of its network,

and are net of transmission settlement residue payments.[57]

TUOS charges are based on a forecast of the transmission related payments for each year, as well as a pass through of any under or over recovery of charges for the previous regulatory year.[58] Because the amount of any under or over recovery for a particular year is not known at the time prices for the following year are set, there is typically a lag of one year in correcting for this difference. For example, where there is a difference between the forecast and actual transmission related payments,

56 ActewAGL, *Regulatory proposal*, pp. 239–240
57 AER, *Guideline on control mechanisms ACT and NSW*, appendix B, p. 12.
58 Transitional chapter 6 rules, clause 6.18.7(b).

resulting in an over or under recovery of TUOS charges for year *t-2*, DNSPs will only be able to recover or return this amount when setting prices for year *t*.

ActewAGL is not currently subject to an overs and unders adjustment for TUOS. Unders and overs will be monitored from the commencement of the next regulatory control period. Given the two year time lag, the first overs and unders adjustments for ActewAGL will occur in settling prices for year 3 of the next regulatory control period.[59] The reporting and administration of unders and overs balances is detailed in appendix E of this decision and reflects AER's decision to use only actual (and not estimated) data on under or over-recoveries.[60]

**Recovery of Utilities Network Facilities Tax**

ActewAGL proposed that where a difference between the forecast UNFT liability and the actual tax paid to the ACT Government occurred in a regulatory year, the net amount of any difference should be incorporated into expected revenues for the next regulatory year when determining compliance with the control mechanism.[61] The AER considers that the transitional chapter 6 rules do not allow for the adjustment proposed by ACTEWAGL and hence does not accept ActewAGL's proposal. The AER's reasons are given in chapter 9 of this draft decision.

**Use of historical sales quantity data**

ActewAGL stated that while the data used to determine the total energy sales for a particular calendar year was not audited it was independent data that could be verified. The AER's final decision relating to the standard control services guideline states that in determining compliance with side constraints and the control mechanism for standard control services audited quantity data is required.[62] However, should a DNSP verify the quality of their unaudited quantity data in writing to the AER, then the AER may accept unaudited quantity data. The AER considered that where a DNSP provided an audit of relevant internal procedures or a statement that demonstrated internal quality assurance processes were sufficient in place of audited quantities it may be willing to accept unaudited quantity data.[63]

The AER asked ActewAGL to provide further information regarding the independence of its energy sales data. ActewAGL advised the AER that:[64]

- ActewAGL's Meter Asset Management Plan (MAMP) (NEMMCO approved) describes how ActewAGL tests the accuracy of the meters. NEMMCO will be undertaking annual audits for ActewAGL meter provider accreditation in accordance with the service level agreement. ActewAGL expects the first of these annual audits in 2009. ActewAGL has already had two MAMP audits

- interval meters record consumption data every half hour. Interval metering data is downloaded directly onto a handheld computer so there is little room for human error (nearly half the ACT load is measured using interval meters see below)

59 AER, *Guidelines on control mechanisms ACT and NSW*, appendix B, p. 12.
60 AER, *Guidelines on control mechanisms ACT and NSW*, appendix B, p. 12.
61 ActewAGL, *Regulatory proposal*, p. 242.
62 AER, *Guidelines on control mechanisms ACT and NSW*, appendix A, p. 11.
63 AER, *Guidelines on control mechanisms ACT and NSW*, appendix A, p. 11.
64 ActewAGL, email from ActewAGL to AER, 14 October 2008.

- residential accumulation meters are read quarterly and commercial accumulation meters are read monthly. Each time the meter is read, the total throughput of energy through the meter is recorded. The previous meter reading is deducted from the latest meter reading to calculate the energy consumed over the period. Any error in one month (or quarter) would be rectified in the next month (or quarter)

- all readings (accumulation and interval) undergo a rigorous validation process in accordance with the National Metrology Procedure part B

- for franchise customers with accumulation meters, ActewAGL uses billing data from ActewAGL Retail. The retail billing system is subject to independent external audit/checking processes. ActewAGL's electricity, water and gas meters are read concurrently. ActewAGL uses the ActewAGL Retail Gentrack system for premise and site management and for read route management.

In these circumstances, the AER is satisfied that ActewAGL has demonstrated that its internal quality assurance processes are sufficient (in place of audited quantities) and the AER is willing to accept unaudited quantity data.

Where ActewAGL proposes new tariffs for which there are no historical sales quantities (as otherwise required when demonstrating compliance with the MAAR in each year) ActewAGL will be required to provide best estimates of sales quantities in accordance with appendix F of this draft decision.

**Side constraints**

Clause 6.18.6(b) of the transitional chapter 6 rules 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 previous year's weighted average revenue by more than the permissible percentage. The permissible percentage is defined in clause 6.18.6(c) of the transitional chapter 6 rules as the greater of:

1. CPI-X limitation on any increase in the DNSP's expected weighted average revenue between the two years plus 2%; or
2. CPI plus 2%.

In determining compliance with the side constraint the AER must disregard:

- the recovery of revenue to accommodate a variation to the distribution determination under clauses 6.6 and 6.13 of the transitional chapter 6 rules[65]

- the recovery of revenue to accommodate pass through of charges for TUOS services to customers.[66]

The side constraint formula applicable to ActewAGL is outlined in appendix A of the AER's standard control guideline.[67] The side constraint formula applicable to each tariff class of standard control services is as follows:[68]

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65 Clause 6.6 relates to cost pass throughs, service target performance incentive scheme and demand management incentive scheme and clause 6.13 relates to revocation and substitution of a distribution determination for wrong information or error.

66 Transitional chapter 6 rules, clause 6.18.6(d).

$$\frac{\sum_{k=1}^{m} d_k^t \times q_k^{t-2}}{\sum_{k=1}^{m} d_k^{t-1} \times q_k^{t-2}} \leq (1 + \Delta CPI) \times L_t \qquad k = 1, \ldots, m.$$

Where: The tariff class has up to *m* components:

$d_k^t$ is the proposed price for component *k* of the tariff class for year *t*

$d_k^{t-1}$ is the price charged by the DNSP for component *k* of the tariff in year *t–1*

$q_k^{t-2}$ is the audited/verifiable quantity of component *k* of the tariff that was charged by the DNSP in year *t–2*

$L_t$ is the permissible real percentage change in the expected weighted average revenue of a tariff class from year *t–1* to year *t* of the regulatory control period, being the greater of (1 – X)×(1 + 2%) or (1 + 2%), as per clause 6.18.6(c) of the transitional chapter 6 rules

$\Delta CPI$ means the number derived from the application of the following formula:

$$\Delta CPI = \left[ \frac{CPI_{March(t-2)} + CPI_{June(t-2)} + CPI_{September(t-1)} + CPI_{December(t-1)}}{CPI_{March(t-3)} + CPI_{June(t-3)} + CPI_{September(t-2)} + CPI_{December(t-2)}} - 1 \right]$$

Where:

*CPI* means the all groups index number for the weighted average of eight capital cities as published by the Australia Bureau of Statistics (ABS), or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index

$CPI_{(month),(year)}$ means the CPI for the quarter and the year indicated.

**Changes to tariff structure–compliance with the MAAR**

If ActewAGL changes any of its tariffs, introduces new tariffs or moves customers between tariffs, it will be necessary for ActewAGL to use a reasonable estimate of sales quantities for the purposes of demonstrating compliance with the MAAR constraint. This is necessary because audited historical sales quantity data will not be available at the time the MAAR constraint is calculated. The requirement for

67 AER, *Guidelines on control mechanisms ACT and NSW*, appendix A, p. 10.

68 AER, *Guidelines on control mechanisms ACT and NSW*. appendix A, p. 10. The guideline was written using terminology from ICRC, *Final decision*. The terminology used in the equations for this decision reflects the terminology used in the NER.

demonstrating compliance with the MAAR is set out in appendix F of this draft decision.

## 4.5 AER conclusion

The AER considers that ActewAGL's proposed form of control mechanism is compliant with the relevant NER requirements and its standard control services guideline. The proposed maximum allowable average revenue cap is the same mechanism that was applied by the ICRC.

In monitoring compliance with the maximum allowable average revenue cap and side constraints the AER will apply the approach set out in its standard control services guideline and appendix F of this draft decision.

## 4.6 AER draft decision

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the AER decides that the control mechanism for standard control services is a maximum allowable average revenue (expressed as cents per kilowatt hour) for each regulatory year represented by the following formula:

$$\text{MAAR}_t = \text{MAAR}_{t\text{-}1} \times (1 + CPI_t) \times (1 - X_t)$$

Where:

- $\text{MAAR}_{t\text{-}1}$ is the maximum allowable average revenue for the previous year
- CPI means the all groups index number for the weighted average of eight capital cities as published by the Australia Bureau of Statistics, or if the Australia Bureau of Statistics does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index. CPI is determined from the following formula:

$$CPI_{(t)} = \frac{CPI_{March(t-2)} + CPI_{June(t-2)} + CPI_{Sept(t-1)} + CPI_{Dec(t-1)}}{CPI_{March(t-3)} + CPI_{June(t-3)} + CPI_{Sept(t-2)} + CPI_{Dec(t-2)}} - 1$$

- $X_t$ are the X factor amounts as determined by the AER in table 17.5 of the draft decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the AER decides that the side constraint formula applicable to ActewAGL is:

$$\frac{\sum_{k=1}^{m} d_k^t \times q_k^{t-2}}{\sum_{k=1}^{m} d_k^{t-1} \times q_k^{t-2}} \leq (1 + \Delta CPI) \times L_t \qquad k = 1, \ldots, m.$$

Where: The tariff class has up to m components:

$d_k^t$ is the proposed price for component k of the tariff class for year t

$d_k^{t-1}$ is the price charged by the DNSP for component k of the tariff in year t–1

$q_k^{t-2}$ is the audited/verifiable quantity of component k of the tariff that was charged by the DNSP in year t–2

$L_t$ is the permissible real percentage change in the expected weighted average revenue of a tariff class from year *t–1* to year *t* of the regulatory control period, being the greater of (1 – X)×(1 + 2%) or (1 + 2%), as per clause 6.18.6(c) of the transitional chapter 6 rules

$\Delta CPI$ means the number derived from the application of the following formula:

$$\Delta CPI = \left[ \frac{CPI_{March(t-2)} + CPI_{June(t-2)} + CPI_{September(t-1)} + CPI_{December(t-1)}}{CPI_{March(t-3)} + CPI_{June(t-3)} + CPI_{September(t-2)} + CPI_{December(t-2)}} - 1 \right]$$

Where:

CPI means the all groups index number for the weighted average of eight capital cities as published by the Australia Bureau of Statistics (ABS), or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index

$CPI_{(month),(year)}$ means the CPI for the quarter and the year indicated.

In accordance with clause 6.12.1(13) of the transitional chapter 6 rules the AER decides that compliance with the maximum allowable average revenue cap for standard control services must be demonstrated by ActewAGL using the following formula in accordance with appendix F of the draft decision:

$$\text{MAAR}_t \geq \frac{\sum_{i=1}^{n} p_i^t \times q_i^{t-1} + \text{MSR}_t \pm \text{pass through}_t}{\text{Kilowatt hours transported}_{t-1}}$$

Where:

- $p_i^t$ are the prices for each tariff component for standard control services (excluding miscellaneous services) proposed for regulatory year t (e.g. 2009–10)

- $q_i^{t-1}$ represent sales quantities for standard control services (excluding miscellaneous services) sold by ActewAGL in the previous calendar year t-1 (e.g. 2008) that correspond to the proposed tariff components
- i represent individual tariff components of a total of n components across all tariffs for standard control services
- kilowatt hours transported$_{t-1}$ are the amounts of energy for the previous calendar year delivered by ActewAGL for standard control services
- $MSR_t$ is miscellaneous services revenue, calculated by multiplying the proposed miscellaneous services charges for regulatory year t with the quantities of these services sold in the previous calendar year
- pass through$_t$ represents approved pass through amounts relating to regulatory year t as determined by the AER in accordance with clause 6.6.1 of the transitional chapter 6 rules and chapter 16 of the draft decision.

In accordance with clause 6.12.1(19) of the transitional chapter 6 rules the AER decides that ActewAGL must submit, as part of its annual pricing proposal, a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with appendix E of the draft decision.

# 5 Past capital expenditure

## 5.1 Introduction

This chapter sets out the AER's assessment of ActewAGL's actual capex incurred during the current regulatory control period. From this assessment, the AER has established an appropriate value of capex to be rolled into ActewAGL's opening regulatory asset base (RAB) for the next regulatory control period.

The AER has reviewed ActewAGL's actual capex incurred during the current regulatory control period and established an amount it considers to be prudent, given the information available to ActewAGL at the time the capex was undertaken. This value has been rolled into ActewAGL's opening RAB at 1 July 2009.

## 5.2 Regulatory requirements

Clause 6.5.1(g) of the transitional chapter 6 rules provides that, in establishing the opening RAB for the next regulatory control period, the AER must:

- apply the approach adopted by the ICRC in ActewAGL's distribution determination for the current regulatory control period
- consider any written representations made by the ICRC to ActewAGL before 1 January 2008.

The ICRC's 2004 determination was based on the framework contained in its investigation into prices for electricity distribution services in the ACT (the ICRC approach).[69]

### Prudence Test

The ICRC's 2004 determination notes that ActewAGL will be subject to a prudence test on all capital expenditures at the end of the current regulatory control period.[70] The ICRC envisaged that this prudence test would assess whether particular investment decisions were reasonable and efficient based on the information available at the time the decision was made. In assessing the prudence of past capex, the ICRC indicated that it would give consideration to all aspects of ActewAGL's capex planning and approval processes, and would likely include reference to ActewAGL's willingness to pay study and its results.[71]

The AER must adopt the ICRC approach in establishing ActewAGL's opening RAB for the first year of the next regulatory control period. Hence any capex that it considers to be prudent and efficient (including expenditure above the ICRC's allowance) will be rolled into ActewAGL's opening RAB. In accordance with the ICRC's 2004 determination, the relevant assets will be indexed to an inflation–adjusted value for the purposes of calculating the return of and on the assets from the

69 ICRC, *Final Decision*.
70 ICRC, *Final Decision*, p. 46.
71 ICRC, *Final Decision*, p. 51.

commencement of the next regulatory control period.[72] This process is addressed at chapter 7 of this draft decision.

## 5.3 ActewAGL proposal

ActewAGL submitted that its capex for the current regulatory control period will exceed the ICRC's 2004 determination allowance by $42 million ($2008–09) or 34 per cent. The majority of this overspend is attributable to additional pole related expenditure.[73] ActewAGL stated that poles inspected since 2003 have been condemned at a significantly higher rate than anticipated creating an urgent priority to replace poles and minimise risk by pole reinforcement.[74] ActewAGL submitted that it forecast $17 million ($2008–09) in pole replacement expenditure for the current regulatory control period, however, it will actually spend $53 million ($2008–09).

Table 5.1 illustrates the actual capex outcomes during the current regulatory control period against the ICRC allowances.

**Table 5.1: ActewAGL actual capex ($m, 2008–09)**

| | 2004–05 | 2005–06 | 2006–07 | 2007–08 (estimate) | 2008–09 (estimate) | Total |
|---|---|---|---|---|---|---|
| Net capital expenditure (less capital contributions)* | 24.3 | 25.6 | 31.3 | 38.9 | 42.7 | 162.7 |
| ICRC allowance^ | 24.1 | 23.8 | 26.4 | 22.9 | 23.9 | 121.1 |
| Overspend (underspend)* | 0.1 | 1.8 | 4.9 | 16.0 | 18.8 | 41.6 |
| Overspend (underspend) excluding pole related expenditure* | –5.4 | –3.9 | –4.4 | 6.7 | 12.4 | 5.5 |

Sources: * ActewAGL, *Regulatory proposal*, p.24;
^ ICRC, *Final Decision, Investigation into prices for electricity distribution services in the ACT*, March 2004, p.51. Note ICRC figures have been inflated from 2002–03 dollar terms.

In addition to the pole replacement program, ActewAGL noted that the following drivers have contributed to the current regulatory control period capex overspend:[75]

- cost increase of $1 million arising from the requirement to connect the ACT distribution network to a new Southern Bulk Supply Point
- increased network augmentation expenditure as a result of higher than anticipated incidence of development approvals for high–voltage cable construction requiring boring, rather than open trenching, to meet requirements of the *Tree Protection Act 2005*
- increased metals prices impacting on the price of copper and aluminium cables

72 ICRC, *Final Decision*, pp. 46–47.
73 ActewAGL, *Regulatory proposal*, p. 122.
74 ActewAGL, *Regulatory proposal*, p. 122.
75 ActewAGL, *Regulatory proposal*, pp. 122–123.

- real wages growth in the general construction sector outstripping movements in the consumer price index (CPI) and wage growth assumed in the ICRC's 2004 determination
- materials cost growth greater than movements in CPI
- significantly increased customer initiated expenditures resulting from residential and commercial development on a scale above that expected, particularly in Civic, South Canberra Parliamentary Triangle, Canberra International Airport, Gungahlin and Kingston Foreshore.

ActewAGL proposed to roll forward all actual capex incurred during the current regulatory control period to establish the opening RAB for the next regulatory control period. Table 5.2 sets out the actual capex incurred by ActewAGL during the current regulatory control period.

**Table 5.2: ActewAGL's actual capex ($m, $2008–09)**

| | 2004–05 | 2005–06 | 2006–07 | 2007–08[a] | 2008–09[a] | Total |
|---|---|---|---|---|---|---|
| Asset renewal/replacement | 11.4 | 12.3 | 16.5 | 16.5 | 18.6 | 75.2 |
| Growth (including customer capital contributions) | 14.4 | 11.3 | 15.9 | 17.6 | 21.8 | 81.0 |
| Augmentation | 1.5 | 3.4 | 1.1 | 3.2 | 4.7 | 13.9 |
| Reliability and quality improvements | 0.0[b] | 0.0[b] | 0.1 | 0.6 | 0.4 | 1.2 |
| Network IT systems | 0.5 | 0.8 | 0.8 | 1.8 | 2.2 | 6.1 |
| Less capital contributions | –6.3 | –3.7 | –4.4 | –5.1 | –7.9 | –27.3 |
| Non-system assets | 0.4 | 0.5 | 0.4 | 0.5 | 0.5 | 2.3 |
| Corporate services business support | 2.4 | 1.0 | 0.8 | 3.7 | 2.4 | 10.3 |
| Total capex | 24.3 | 25.6 | 31.3 | 38.9 | 42.7 | 162.7 |

Source: ActewAGL, *Regulatory proposal*, p. 122.
Note: Totals may not add up due to rounding.
(a) Estimates.
(b) Capex incurred may total less than $100 000.

## 5.4 Consultant review

The AER engaged Wilson Cook to review ActewAGL's past capex in accordance with clause 6.5.1(g) of the transitional chapter 6 rules. Specifically, Wilson Cook was required to assess the prudence of ActewAGL's past capex:

- based on a sample of projects to be agreed with the AER, considering each of the main areas where expenditure was made and projects and programs that are material within each area
- in a manner consistent with the review envisaged by the previous regulator, as set out in its relevant determination[76]
- based on the information available at the time the investment decisions were made, not in hindsight.

Wilson Cook identified four major projects and programs for sample review. These represent 48 per cent of total capex incurred during the current regulatory control period, net of capital contributions. The expenditures associated with these projects and programs are set out at table 5.3.

**Table 5.3: Major projects and programs reviewed by Wilson Cook ($m, nominal)**

| | 2004–05 | 2005–06 | 2006–07 | 2007–08[a] | 2008–09[a] | Total |
|---|---|---|---|---|---|---|
| Distribution substation replacement | 1.4 | 1.5 | 1.5 | 0.9 | 1.8 | 7.0 |
| Overhead service cable replacement | 0.7 | 0.5 | 0.4 | 0.3 | 0.6 | 2.5 |
| Pole replacement and reinforcement | 8.7 | 8.9 | 12.6 | 12.7 | 9.9 | 52.8 |
| Distribution pole substations | 0.0 | 0.0 | 0.0[b] | 1.0 | 1.6 | 2.7 |

Source: ActewAGL RIN, proforma 2.2.3.
Note: Totals may not add due to rounding.
(a) Estimates.
(b) Capex incurred totalled less than $100 000.

Wilson Cook noted that the distribution substation replacement project was aimed at replacing ground mounted substation equipment and the overhead service cable program was primarily to deal with deteriorated PVC insulation that had failed due to ultra–violet light exposure. The pole replacement and reinforcement program addressed condemned wooden poles requiring attention. The distribution pole substation replacement program was required partly to address condemned poles, but also to address unsafe transformer platforms, cross–arms and other defective items.[77]

Following its review and discussions with ActewAGL, Wilson Cook concluded that these projects and programs were reasonable.[78] In summary, Wilson Cook's review of ActewAGL's past capex concluded:

[76] While the ICRC's 2004 determination noted that the review of prudence of past capital expenditure may include reference to ActewAGL's willingness to pay study, Wilson Cook did not consider it appropriate to consider this in its review.
[77] Wilson Cook, *Review of proposed expenditure of ACT & NSW electricity DNSPs, Volume 5 – ActewAGL Distribution*, October 2008, p. 8.
[78] Wilson Cook, Volume 5, p. 8.

- ActewAGL's decision–making processes appeared reasonable and that the expenditure reviewed was for conventional purposes
- expenditure on reliability and quality improvement, replacement, growth driven, non-system and metering capex was reasonable[79]
- the expenditure would have been incurred by a prudent operator, in ActewAGL's circumstances acting efficiently, and observing good industry practices at the time
- no adjustments are required for the purpose of the review.[80]

## 5.5 Issues and AER considerations

The AER has considered Wilson Cook's findings and considers that its review of ActewAGL's past capex provides sufficient evidence to demonstrate that the network investment undertaken during the current regulatory control period, while in excess of that approved by the ICRC, was prudent and efficient, given that:

- the projects and programs reviewed were considered reasonable and necessary in the prevailing circumstances
- internal policies and procedures appear to have been followed and decision–making processes appeared reasonable
- a significant portion (87 per cent) of the capex overspend from the current regulatory control period is attributable to addressing safety and reliability concerns, most notably rectifying condemned wooden poles, which remains a priority for ActewAGL in the next regulatory control period
- the pole condemning rate has increased significantly during the current regulatory control period to a level higher than that expected by ActewAGL or the ICRC at the 2004 regulatory determination. This has resulted from the introduction of more stringent pole inspection procedures in response to serious pole failures, and the progressive ageing of wood poles which constitute around 73 per cent of ActewAGL's pole population.

The AER also considers that non–network options would not have represented feasible alternatives to the expenditure reviewed, as this expenditure appears predominantly reactive in nature.

The AER notes that for future AER distribution determinations ActewAGL will not be subject to an ex post prudence review of actual capex incurred. From 1 July 2014, distribution determinations for ActewAGL will be made under chapter 6 of the NER, rather than the transitional chapter 6 rules. The general chapter 6 rules establish an ex ante framework for capex, which requires all actual capex incurred during a regulatory control period to be rolled into the RAB.

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79 Wilson Cook advises that it was not within its competence to examine the corporate expenditure item of ActewAGL's past capex.

80 Wilson Cook, Volume 5, p. 8.

## 5.6 AER conclusion

The AER considers all of ActewAGL's capex in the current regulatory control period to be prudent and that the projects and programs undertaken were required and consistent with ActewAGL's policies and good industry practice. The AER's decision on the past capex to be rolled into ActewAGL's opening RAB for 2009 is set out in table 5.4. The inclusion of this nominal expenditure in the opening RAB is dealt with in chapter 7 of this draft decision.

**Table 5.4: AER conclusion on ActewAGL's prudent past capex ($m, nominal)**

| | 2004–05 | 2005–06 | 2006–07 | 2007–08 | 2008–09 | Total |
|---|---|---|---|---|---|---|
| Actual capex | 21.7 | 23.4 | 29.5 | 37.8 | 42.7 | 155.0 |

# 6 Demand forecasts

The transitional chapter 6 rules require DNSPs to provide a realistic expectation of the maximum demand forecast as part of addressing the capex and opex objectives and criteria. The transitional chapter 6 rules also require the AER, as part of its draft distribution determination, to make a decision on appropriate amounts, values or inputs, under clause 6.12.1(10). Appropriate energy consumption and customer number forecasts are necessary inputs into the AER's post tax revenue model (PTRM).

Peak or maximum demand forecasts (MW or MVA) play an important role in the AER's assessment of DNSPs' load driven capital expenditure (capex), as DNSPs plan network augmentation to enable them to meet expected maximum demand on their networks. Energy forecasts (GWh) are used to determine the amount of electricity transported over a period of time, and are a key input into determining X factors under average price cap regulation.[81]

This chapter discusses the AER's considerations of whether ActewAGL's maximum demand and energy forecasts reflect a reasonable expectation of the demand for standard control services over the next regulatory control period, and therefore the extent to which they can be relied upon for the purposes of assessing ActewAGL's proposed load driven capex and determining its revenue.

The AER's assessment of ActewAGL's demand forecasts is focussed on the expected summer and winter maximum (or peak) demands and energy sales over the next regulatory control period.

## 6.1 ActewAGL proposal

ActewAGL based its load driven expenditure forecasts primarily on summer maximum demand at the 10 per cent probability of exceedence (POE) at the zone substation level.

ActewAGL's energy and maximum demand forecasts for the next regulatory control period are outlined in table 6.1. ActewAGL's forecast indicates that at 10 per cent POE, its network will transition from winter peaking to summer peaking in 2009–10.[82]

[81] This is because the AER must take the notional building block requirement and convert this into an average price cap based on energy growth forecasts.

[82] The AER notes that ActewAGL plans to a 10 per cent POE in conjunction with emergency equipment ratings. While the NSW DNSPs are required to plan to a 50 per cent POE, they use cyclical equipment ratings. Emergency ratings are generally higher than cyclical ratings meaning that, on balance, ActewAGL and the NSW DNSPs plan to a similar level.

**Table 6.1: ActewAGL's energy and maximum demand forecasts 2009–14**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average growth 2009–14 |
|---|---|---|---|---|---|---|
| Energy sales (base) – GWh | 2878 | 2925 | 2972 | 3018 | 3066 | 1.6% |
| System maximum demand (10% POE) – MVA[a] | 694 | 708 | 721 | 734 | 748 | 1.9% |

Source: ActewAGL, *Regulatory proposal*, pp. 92–94.
(a) All values are summer maximum demands.

ActewAGL's demand and energy forecasts for the next regulatory control period were developed by Sinclair Knight Merz (SKM). SKM's report was submitted by ActewAGL as attachments to its regulatory proposal and is discussed below.[83]

### 6.1.1 Review of past forecasts

ActewAGL engaged SKM to conduct a review of the variation between ActewAGL's 2003 forecasts (prepared as part of the ICRC's 2004 review), and actual demand and energy consumption over the current regulatory control period to date. SKM found that summer and winter maximum demand exceeded ActewAGL's forecasts by around 30 or 40 MW (approximately 5 per cent) per annum in years 2005–07, and that energy consumption exceeded forecasts by 90 to 100 GWh (approximately 3 per cent) per annum in years 2005–07.[84] SKM noted that stronger than expected growth in the commercial sector and increasing summer peak demand driven by air conditioner penetration were the key reasons for the variation from the 2003 forecast.[85] SKM recommended a number of improvements to ActewAGL's methodology for future forecasts, including the application of weather correction, and separate one off major developments from underlying growth at the zone substation level.[86] These recommendations were applied by SKM in preparing ActewAGL's energy and demand forecasts for the next regulatory control period.[87]

### 6.1.2 Key drivers of demand

SKM identified the key drivers of maximum demand growth and energy consumption on ActewAGL's network, revealing the following implications for maximum demand and energy consumption in the ACT:

- while there are short term concerns for the global economy following the financial instability in the United States, SKM found that in the medium to long term Australia and the ACT will see a broad continuation of recent economic growth, which will drive increasing energy demand growth[88]

83 ActewAGL, *Regulatory proposal*, p. 85.
84 SKM, *ActewAGL Demand and Energy Forecast 2008*, Brisbane, June 2008, p. 5.
85 SKM, *ActewAGL Demand and Energy Forecast 2008*, pp. 6–9.
86 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 9.
87 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 9.
88 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 20.

- population growth in the ACT has slowed. SKM found that this will drive down commercial energy consumption in the ACT[89]

- household size (i.e. family size) is falling nationally, leading to lower energy consumption per household, and an increase in the total number of houses. Houses are also increasing in area, which increases heating, cooling and lighting energy requirements per capita. Increased efficiency of appliances is offset by the growing number of appliances per capita, which for ACT residents is higher than the national average. Houses in the ACT are generally newer and more energy efficient than the national average, and future regulations are likely to improve household energy efficiency. Overall, SKM considered that residential energy consumption per capita will continue to rise at 1 per cent per annum[90]

- ACT workers receive higher than average wages, which are also growing at a faster rate than the national average, indicating a potential for increasing energy consumption[91]

- ACT residents have higher levels of education than other states, which SKM considered makes them more likely to be environmentally aware, leading to greater demand side responses and fuel switching in response to rising electricity prices[92]

- SKM found that Australian and ACT Government greenhouse gas policies are likely to increase the price of electricity, and lead to a corresponding fall in demand for energy. Energy efficiency policies, including hot water heating and lighting initiatives are also likely to lower energy consumption.[93]

### 6.1.3 Methodology

In preparing demand forecasts for ActewAGL, SKM used long term weather data to identify the POE temperatures at 10 per cent, 50 per cent and 90 per cent values for Canberra, and heating and cooling degree days.[94] SKM then determined a diversity factor and temperature correlation for each zone substation, based on a regression of daily temperatures with demand.[95]

A bottom up trend maximum demand forecast was developed for each zone substation, including known past and future spot loads, and weather correction based on the determined temperature coefficients.[96] A bottom up energy forecast was

89 ActewAGL, *Email response to the AER's questions of 1 September 2008*, 5 September 2008.
90 SKM, *ActewAGL Demand and Energy Forecast 2008*, pp. 28–30.
91 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 28.
92 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 21.
93 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 32–33.
94 10 per cent POE temperatures are those that are expected to be equalled or exceeded on average one year in ten, 50 per cent POE temperatures are expected to be equalled or exceeded on average one year in two, while 90 per cent POE temperatures are expected to be equalled or exceeded on average every year. SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 12.
95 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 12.
96 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 12.

developed for each zone substation based on historical energy consumption, and weather correction based on annual historical heating and cooling degree days data.[97]

A top down econometric demand and energy forecast was developed via regression analysis of economic and demographic variables, taking into account factors which may shift future demand patterns away from past trends.[98] Both maximum demand and energy bottom up forecasts were reconciled with the top down econometric forecasts to ensure consistency. SKM used long term weather data to identify the summer high and winter low temperatures that represent 10 per cent POE.[99] The 10 per cent POE temperatures were then combined with the zone and energy temperature coefficients, and used to modify weather corrected (50 per cent POE) trends to determine the likely long term average one in ten year demand and energy forecasts.[100]

SKM noted limitations in the data available to determine demand forecasts, which may impact on the forecast accuracy.[101] SKM noted daily demand data was only available for the past 18 months. In addition, SKM suggested that a time series of temperature sensitivity would allow the increase in air conditioning take up to be built into the model.[102]

## 6.2 Submissions

The AER received a submission from the Energy Markets Reform Forum (EMRF) that discussed ActewAGL's demand forecasts in the context of the AER's broader review of the ACT and NSW DNSPs' regulatory proposals.

The EMRF stated that the AER must undertake careful analysis of the demand forecasts to determine whether the DNSPs are manipulating the forecasts to increase their revenues. The EMRF stated that it would like to review and independently verify any work of consultants commissioned by the AER to review demand forecasts. The EMRF also submitted that it would be useful to aggregate all of the DNSPs' demand forecasting claims against values used by the National Electricity Market Management Company (NEMMCO) and TransGrid.[103]

## 6.3 AER considerations

This section outlines the AER's analysis and considerations in reviewing ActewAGL's maximum demand and energy forecasts for the next regulatory control period. It describes the AER's consideration of key drivers, historical trends and other forecasts and elements of good methodological practice.

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97 SKM, *ActewAGL Demand and Energy Forecast 2008*, pp. 7, 12. Cooling and heating degree days are calculated by taking the number of degrees celsius above or below a certain temperature (generally 12 degrees for winter heating and 24 degrees for summer cooling), and adding these over a given period (typically a month).

98 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 12.

99 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 14.

100 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 14.

101 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 15.

102 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 15.

103 EMRF, *NSW electricity distribution revenue reset, EnergyAustralia, Country Energy and Integral Energy application*s, August 2008, p. 36.

The AER did not engage a consultant specifically to assist it in reviewing ActewAGL's maximum demand and energy forecast methodologies. However, the AER's review of ActewAGL's forecasts was carried out concurrently with its review of the NSW DNSPs' demand forecasts, for which the AER engaged McLennon Magasanik Associates (MMA) to assist its review. Accordingly, the AER has reviewed ActewAGL's forecasting methodology in conjunction with the forecasting methodologies applied by the NSW DNSPs, and elements of good methodological practice as highlighted by MMA.

Maximum demand forecasts are used to determine growth capex requirements. ActewAGL's proposed capex program for the next regulatory control period includes four major expenditure projects. System demand growth, however, is not the primary driver for any of the projects. Consequently, ActewAGL's proposed capex program is not sensitive to its maximum system demand forecasts.

The AER notes that, while the NSW DNSPs are subject to a weighted average price cap form of control for the next regulatory control period, ActewAGL's standard control services will be subject to an average revenue cap. While energy forecasts are used to calculate X factors under an average revenue cap, they are not a key input parameter within the form of control.

Accordingly, the AER considers that its internal review of ActewAGL's demand forecasts (without requiring assessment by a consultant) is appropriate in the circumstances.

### 6.3.1 Key drivers

SKM undertook a desktop economic outlook study on drivers of energy consumption and demand in the ACT, drawing heavily upon a June 2007 paper published by the National Institute of Economic and Industry Research (NIEIR), prepared on behalf of NEMMCO.[104] SKM's study revealed a number of economic implications for ACT energy demand, outlined in section 6.1.2 above, which were taken into account in developing its top down econometric forecast model for maximum demand and energy. The AER considers the assumptions made by SKM in determining the impact of key drivers on maximum demand and energy are reasonable.

The AER notes that while customer numbers are a key input into a weighted average price cap, customer numbers are not used in determining revenues under an average revenue cap. However, customer numbers are considered an important input in generating energy forecasts. ActewAGL stated that it does not routinely forecast customer numbers as part of its planning process, as it does not consider customer numbers to be a good indicator of the future network demand or other parameters of the network such as capex and opex.[105] However, ActewAGL's commercial energy forecast model takes into account population trends, and its domestic energy and domestic off-peak energy models take into account growth in household numbers.[106]

[104] SKM, *ActewAGL Demand and Energy Forecast 2008,* p. 20.
[105] ActewAGL, response to AER questions of 21 July 2008, 8 August 2008.
[106] ActewAGL, email response to AER questions, 5 September 2008.

ActewAGL forecast customer number growth of 1.4 per cent between the 2007–08 and 2008–09 regulatory years.[107]

SKM noted that, following the completion of its economic outlook study (December quarter State Final Demand for 2007), the ACT, showed a significant slowing as compared to the previous six months.[108] SKM took the recent slowing of demand into account when preparing ActewAGL's energy forecast for the next regulatory control period.

ActewAGL stated that domestic air conditioner penetration, in particular an increase in the use of reverse cycle air conditioners, is driving increasing summer maximum demand.[109] Use of reverse cycle air conditioners is also reducing winter peak demands and energy consumption, due to the increased efficiency of reverse cycle heating as compared to conventional electrical heating.[110] In addition, fuel switching is impacting on winter demand for electricity, as an increasing number of ACT residents are switching to gas heating.[111]

The AER considers that SKM has conducted a thorough analysis of the economic and demographic outlook for the ACT, and implications for maximum demand and energy consumption. SKM used a variety of independent source materials in developing its analysis of the outlook for key drivers, and considered a wide number of potential impacts on energy consumption.

The AER acknowledges that significant falls in international financial markets, and corresponding falls in economic growth associated with the failure of the United States sub–prime lending market, have occurred largely subsequent to the lodgement of ActewAGL's regulatory proposal on 2 June 2008. The AER notes SKM's finding that (regardless of whether the United States falls into recession), in the medium to long term Australia can expect a continuation of recent economic growth and therefore a continuation of recent maximum demand growth and energy consumption. The AER considers this projection to be reasonable. As SKM's forecasts account for a December quarter 2007 slow down in State Final Demand in the ACT, the AER considers that the forecasts may account somewhat for recent changes in global economic growth.

The AER considers SKM's assumptions and findings on key drivers of maximum demand and energy for ActewAGL's network provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the transitional chapter 6 rules and produce reasonable inputs for the AER's PTRM.

### 6.3.2 Historical trends and other forecasts

#### 6.3.2.1 Maximum demand

ActewAGL's regulatory proposal indicated that summer maximum demand growth has exceeded winter maximum demand growth over recent years, largely

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107 ActewAGL, *Regulatory proposal, proforma table 2.3.8*, confidential, June 2008.
108 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 33–34.
109 ActewAGL, *Regulatory proposal*, p. 89.
110 ActewAGL, response to AER questions of 21 July 2008, 8 August 2008.
111 ActewAGL, *Regulatory proposal*, p. 90.

corresponding to the increased use of air conditioning by ACT residents. In addition, ActewAGL forecast winter peak demand growth to decline over the next regulatory control period, due to the increased take up of reverse cycle air conditioning and gas hot water and space heating. ActewAGL forecast that summer maximum demand will exceed winter maximum demand from regulatory year 2009–10, moving ActewAGL from a winter peaking to a summer peaking network.

The AER considered ActewAGL's summer and winter maximum demand growth forecasts in light of the NSW DNSPs' maximum demand forecasts, and the forecasts within TransGrid's 2008 Annual Planning Report (2008 APR), which was released subsequent to the development of ActewAGL's demand forecasts.[112] The summer maximum demand forecast for ActewAGL's network within the 2008 APR is in line with ActewAGL's regulatory proposal.[113]

The AER notes there is a discrepancy between the 2008 APR winter maximum demand forecast and ActewAGL's winter maximum demand forecast.[114] ActewAGL has advised the AER of an error in the forecast shown in the 2008 APR.[115] The AER also notes ActewAGL's network is forecast to transition from winter peaking to summer peaking in 2009–10, and as such the AER considers the discrepancy between the 2008 APR and ActewAGL winter maximum demand forecasts to be immaterial for the purposes of assessing ActewAGL's capex proposal for the next regulatory control period.

The trends underlying ActewAGL's maximum demand forecast are in line with the historical data and forecasts of the NSW DNSPs and TransGrid, and reflect a growing summer peak demand trend evident across the NEM.

#### 6.3.2.2 Energy

Historically, energy consumption growth on ActewAGL's network has experienced significant fluctuation from year to year. The AER understands that the small number of customers in the ACT may accentuate the impact of changes in energy consumption on the network, as compared to networks with a large number of customers and more diverse geographical areas.

The AER reviewed ActewAGL's energy forecast in light of TransGrid's 2008 APR, and found that similar growth trends are evident in both forecasts.[116]

ActewAGL has forecast average energy consumption growth of 1.6 per cent per annum over the next regulatory control period, which is similar to the forecast for the current regulatory control period of 1.5 per cent per annum.

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112 TransGrid, *2008 New South Wales Annual Planning Report*, 20 June 2008.
113 ActewAGL, *Regulatory proposal,* proforma 2.3.8, TransGrid, *2008 APR*, p. 30, figure 4.11.
114 ActewAGL, *Regulatory proposal,* proforma 2.3.8, TransGrid, *2008 APR*, p. 30, figure 4.12.
115 ActewAGL, email to the AER, 24 November 2008.
116 ActewAGL, *Regulatory proposal,* proforma 2.3.8, TransGrid, *2008 APR*, p. 20–21.

**Table 6.2: Energy consumption average growth per annum – actuals and forecasts**

| 2002–03 to 2006–07 (last five years actuals) | 2004–05 to 2006–07 (current period actuals) | 2004–05 to 2008–09 (current period forecast)[a] | 2009–10 to 2013–14 (next period forecast) |
|---|---|---|---|
| 2.3% | 2.1% | 1.5% | 1.6% |

Source: ActewAGL, *Regulatory proposal,* proforma table 2.3.8.
(a) Data for years up to 2006–07 are actuals, data for years 2007–08 onwards are forecasts.

As table 6.2 demonstrates, the last five years of actual energy data indicates that between 2002–03 and 2006–07, energy consumption grew by, on average, 2.3 per cent.[117] However, ActewAGL has forecast energy consumption growth to be just 0.8 per cent in 2007–08, and 1.2 per cent in 2008–09. It has forecast average energy growth over the current regulatory control period to be 1.5 per cent per annum, which is in line with ActewAGL's energy growth forecast for the next regulatory control period.[118]

The AER considers that given the fluctuations in annual energy growth evident within ActewAGL's historical energy data there would be merit in ActewAGL providing a revised energy forecast for the next regulatory control period that incorporates the latest available data, for consideration in the AER's final determination. Incorporating the latest available data within a revised forecast will enable the AER to ensure that the forecast reflects the most recent trends in energy consumption. The AER notes that it does not consider ActewAGL's forecast methodology to be unreasonable, but rather the forecasts themselves to be out of date.

The AER's draft decision is to reject the energy forecast provided within ActewAGL's regulatory proposal under clause 6.12.1(10) of the transitional chapter 6 rules, as the forecast is an inappropriate input into the AER's PTRM.

The AER requests that ActewAGL produce a revised energy forecast once weather corrected financial year 2007–08 verifiable energy data is available. The revised forecast is to use financial year 2007–08 verifiable energy data as a starting point. The new data is to be weather corrected and allocated according to the methodology applied in generating ActewAGL's original energy forecast. The AER requests that ActewAGL provide this revised energy forecast as an update to the energy delivered forecast table within the input sheet of ActewAGL's post tax revenue model for standard control services, by COB on 20 February 2009.

### 6.3.3 Elements of good methodological practice

The AER reviewed ActewAGL's maximum demand and energy forecast methodologies in light of criteria for good forecasting methodology, as highlighted by MMA as part of its review of the NSW DNSPs' forecasting methodologies.[119]

117 ActewAGL, *Regulatory proposal,* proforma 2.3.8.
118 ActewAGL, *Regulatory proposal,* proforma 2.3.8.
119 MMA, *Final report to the Australian Energy Regulator – Review of EnergyAustralia's maximum demand forecasts*, 1 August 2008, confidential, pp. 21–22, 29–30.

#### 6.3.3.1 Maximum demand

***Weather normalisation***

Weather normalisation of historical maximum demands is a key element of demand forecasting. Weather normalisation is typically carried out by first establishing relationships between summer and winter network demand and temperature, determining 'normal' weather for each season (according to appropriate POE), and using this information to estimate weather normalised maximum demand over an historical period.[120]

SKM analysed long term weather data to identify 10 per cent, 50 per cent and 90 per cent POE temperatures for summer and winter.[121] Using spatial load data from the most recent summer and winter only (due to data limitations), SKM determined a diversity factor and temperature coefficient for each zone substation, and normalised the historical demand data against diversity and temperature variations.[122] The AER considers SKM's weather normalisation process reflects good methodological practice, however, it notes that the temperature demand correlation was carried out using a very limited data set.[123] The AER notes that the forecast accuracy could be expected to improve over time as ActewAGL's data set grows.

***Disaggregation and appliance usage or sales surveys***

As part of general good forecasting practice, MMA considered load research to determine residential and non-residential customers' contributions to maximum demand should be conducted on a regular basis, to measure variations in the structure of maximum demand. MMA also recommended regular customer surveys or appliance sales information be used to establish air conditioner and other appliance penetration rates. This information should then be related to historical weather normalised maximum demand in each year as part of a global maximum demand model.[124]

The AER understands that SKM's demand forecast model does not separate residential and commercial customers' contributions to maximum demand. SKM's overall forecast methodology included separate demand and energy econometric forecasts for maximum demand and energy, generated through a multivariate regression of economic and demographic variables, including Australian Bureau of Statistics (ABS) data on average ACT earnings and appliance ownership.[125] The AER considers that load research and customer appliance surveys would add value to ActewAGL's maximum demand forecasts (and energy forecasts, as discussed below), however the AER acknowledges that due to the small number of customers connected to ActewAGL's network, and particularly limited number of large industrial customers, such information may have limited value in forecasting changes in maximum demand trends, relative to the cost of carrying out such research.

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MMA, *Regulatory proposal 2009–14 – Review of EnergyAustralia's customer number and energy forecasts*, 26 September 2008, confidential, pp. 24–25.

120 MMA, *EnergyAustralia's maximum demand forecasts*, p. 21.

121 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 12.

122 SKM, *ActewAGL Demand and Energy Forecast 2008*, pp. 12–14.

123 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 15.

124 MMA, *EnergyAustralia's maximum demand forecasts*, p. 21.

125 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 26–31.

***Treatment of spot loads***

Appropriate treatment of spot loads, and consistency between top down (econometric or global) and bottom up (spatial) forecasts are considered important elements of maximum demand forecasting. In developing ActewAGL's maximum demand forecast, SKM separated spot loads from historical underlying growth, and used trend analysis to develop underlying demand growth forecasts at summer and winter 50 per cent POE temperatures.[126] Anticipated future spot loads were then added in to develop a total zone forecast, which was then used, along with appropriate diversity factors for each zone, to construct a system peak demand forecast for both summer and winter.[127] The forecasts were then reconciled with the econometric maximum demand forecast. The AER considers SKM's treatment of spot loads and reconciliation between spatial and global maximum demand forecasts to be appropriate.

#### 6.3.3.2 Energy

***Disaggregation***

MMA advised that energy forecasts should be carried out to a suitable level of disaggregation, between customer types (for example residential, commercial, large and small) and geographical locations on the network.[128] SKM's forecasting methodology developed separate energy forecasts for domestic peak, domestic off–peak and commercial customers.[129] Given the size and number of customers connected to ActewAGL's network, the AER considers the level of disaggregation applied within SKM's energy forecasting methodology to be appropriate.

***Accounting for historical trends***

MMA stated that energy forecasts should review historical trends in consumption and key drivers, balance trends against expected changes in key drivers, and explain if, why and how the future should be different to the recent past.[130] SKM's top down econometric forecast methodology takes into account recent trends and underlying key drivers of energy consumption. Following analysis of key drivers of domestic and commercial customers' energy consumption, SKM has forecast that energy consumption on ActewAGL's network is unlikely to vary from recent historical trends.[131] The AER considers SKM has incorporated good quality information on key drivers of energy consumption appropriately into its forecasting model.

***Key economic and demographic drivers***

Energy forecasts should take into account current demand, demographic and economic conditions. SKM's overall forecast methodology included a separate econometric or top down forecast, generated through a multivariate regression of economic and demographic variables, which was reconciled with a bottom up energy forecast for each customer type.[132] The AER considers the assumptions and inputs within SKM's econometric forecast model to be appropriate, and that the econometric

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126 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 12.
127 SKM, *ActewAGL Demand and Energy Forecast 2008*.
128 MMA, *EnergyAustralia's customer number and energy forecasts*, p. 24.
129 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 13.
130 MMA, *EnergyAustralia's customer number and energy forecasts*, p. 25.
131 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 12.
132 SKM, *ActewAGL Demand and Energy Forecast 2008*, p. 12.

model has been applied appropriately for the purposes of generating ActewAGL's energy forecast.

However, the AER notes that ActewAGL does not have data on its customers' average appliance penetration and usage rates. Instead SKM has relied upon ABS data on ACT residents' appliance ownership in developing its top down econometric forecast, which was reconciled with the bottom up energy forecast.[133] As noted above in section 6.3.3.1, the AER considers that conducting customer appliance surveys would add value to ActewAGL's energy consumption forecasts. However, it acknowledges that due to the size of its network and small number of customers, the information may have limited value in forecasting changes in energy consumption trends, given the costs of conducting such surveys.

### 6.3.4 Response to submissions

The EMRF stated that it would like to review and independently verify any work of consultants commissioned by the AER to review demand forecasts, and that it would be useful to aggregate the ACT and NSW DNSPs' demand forecasts for a comparison against NEMMCO's and TransGrid's forecasts.[134]

The AER did not engage a consultant to review ActewAGL's demand forecasts for the next regulatory control period. The AER notes that it has reviewed ActewAGL's demand forecasts by comparison to the NSW DNSPs' and TransGrid's 2008 APR forecasts for the next regulatory control period, as well as MMA's criteria for good methodological practice. The AER has also reviewed ActewAGL's demand forecasts in light of trends in demand and energy consumption evident across the NEM, and considers that ActewAGL's forecasts are in line with general network trends, such as rising summer maximum demand and slowing growth in energy consumption.

## 6.4 AER conclusion

The AER notes that ActewAGL has improved its forecasting methodologies through implementing changes recommended by the ICRC's consultant at the time of the 2004 determination.

The AER considers ActewAGL's maximum demand forecast methodology and forecasts provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the transitional chapter 6 rules.

The AER's draft decision is to reject the energy forecast provided within ActewAGL's regulatory proposal, under clause 6.12.1(10) of the transitional chapter 6 rules, as it considers that the forecast is outdated and therefore is an inappropriate input into the AER's PTRM.

The AER considers ActewAGL's energy forecast methodology is reasonable, however, it notes the yearly fluctuations in historical energy consumption on ActewAGL's network. The AER considers that the forecasts should be updated to take into account the most recent energy sales data, for financial year 2007–08, to

133 SKM, *ActewAGL Demand and Energy Forecast 2008,* pp. 28–31.
134 EMRF, p. 36.

enable the AER to ensure that the forecast reflects the most recent trends in energy consumption. Accordingly, the AER requests that a revised energy forecast be submitted to the AER for consideration in its final determination.

The revised energy forecast is to use financial year 2007–08 verifiable energy data as a starting point. The new data is to be weather corrected and allocated according to the methodology applied in generating ActewAGL's original energy forecast. The AER requires ActewAGL to provide the revised energy forecast as an *Energy delivered forecast*, within the input sheet of ActewAGL's *post tax revenue model for standard control services*, by COB on 20 February 2009.

## 6.5 AER draft decision

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the AER has decided that the other appropriate amounts, values or inputs with respect to energy consumption demand forecasting are to be provided by ActewAGL as a revised *Energy delivered forecast*, within the input sheet of ActewAGL's *post tax revenue model for standard control services*, by COB on 20 February 2009.

# 7 Opening asset base

## 7.1 Introduction

This chapter sets out the method used by the AER to determine ActewAGL's closing regulatory asset base (RAB) for the current regulatory control period. The closing RAB becomes the opening RAB for the next regulatory control period and is used to calculate ActewAGL's annual building block revenue. For its draft determination, the AER has assessed ActewAGL's actual capex during the current regulatory control period to be prudent and has included it in establishing the opening RAB for 1 July 2009. The review of ActewAGL's past capex is discussed in chapter 5 of this draft decision.

## 7.2 Regulatory requirements

Clause 6.5.1 and schedule 6.2 of the transitional chapter 6 rules outline the approach that is used to determine the opening RAB for a distribution determination. The AER also uses its asset base roll forward model (RFM) to determine the roll forward of the RAB.

Schedule 6.2.1(c) of the transitional chapter 6 rules provides that the RAB for the first year of the regulatory control period must be determined by rolling forward the RAB values set out in the schedule. For ActewAGL, this value is $511 million (as at 1 July 2004). This value is adjusted to allow for the difference between estimated capex and actual capex in the previous regulatory control period. Schedule 6.2.1(e) of the transitional chapter 6 rules outlines how this value is further adjusted to roll forward and calculate the value of the RAB at the beginning of the first year of the next regulatory control period. Schedule 6.2.1(c)(3) provides that when rolling forward the RAB:

> the AER must take into account the derivation of the values in the above table [schedule] from past regulatory decisions and the consequent fact that they relate only to the RAB identified in those decisions.

Under schedule 6.2.1(e)(1A) of the transitional chapter 6 rules the AER must roll forward ActewAGL's RAB in a manner consistent with the approach envisaged by the ICRC in its current determination for ActewAGL. This approach requires an assessment of ActewAGL's actual capex during the current regulatory control period.

## 7.3 ActewAGL proposal

ActewAGL proposed an opening RAB for the next regulatory control period of $593 million as at 1 July 2009. The proposed opening RAB includes a net capex amount of $143 million for the current regulatory control period.[135]

Depreciation has been calculated using the average remaining life as at 30 June 2004, assigning a standard life of 40 years to all new assets acquired since that time and assigning a remaining life of 21.77 years to all existing assets as at 30 June 2004. ActewAGL stated that this approach is in accordance with the approach determined

[135] ActewAGL, *Regulatory proposal,* attachment 6.

by the ICRC in the previous regulatory control period. The proposed RAB has been reduced by depreciation ($135 million) based on the actual capex and in accordance with the approach determined by the ICRC for the current regulatory control period.

The proposed opening RAB has also been indexed for actual inflation using the consumer price index (CPI), reduced by $3.8 million for the difference between actual and estimated capex for 2003–04, and further reduced by $2.3 million representing the forecast return on the unspent capex.

## 7.4 Issues and AER considerations

### 7.4.1 Opening asset value—1 July 2004

Schedule 6.2.1(c) of the transitional chapter 6 rules states that ActewAGL's opening RAB (as at 1 July 2004) must be rolled forward to determine the opening RAB as at 1 July 2009, subject to schedule 6.2.1(c)(2) and (3) of the transitional chapter 6 rules.

The timing of a distribution determination requires that a revenue/price cap for a future regulatory control period must be set before the end of the current regulatory control period. This means that the actual capex for the final year of the current regulatory control period is not known before the closing RAB is established. This, in turn, means that ActewAGL's opening RAB value of $511 million, prescribed in schedule 6.2.1(c)(1)—which was taken from the 2004 ICRC determination—is based on estimates of capex in the later part of the previous regulatory control period.

Schedule 6.2.1(c)(2) of the transitional chapter 6 rules is designed to deal with this situation. It provides that, once the actual capex for the final part of the previous regulatory control period (in the case of ActewAGL, this is the period from 1 July 2003 to 30 June 2004) is known, the opening RAB at 1 July 2004 must be adjusted for the difference between the forecast and actual expenditure.

The AER's RFM makes the adjustments to the opening RAB as required under schedule 6.2.1(c)(2).

**ActewAGL proposal**

The transitional chapter 6 rules prescribe the opening RAB value for ActewAGL as $511 million as at 1 July 2004. ActewAGL has used the AER's RFM and has adjusted the opening RAB for differences between actual and forecast capex in 2003–04 and proposed an opening RAB value of $507 million.

**AER considerations**

The AER notes the transitional chapter 6 rules require that:

- the opening RAB for ActewAGL is to be determined by rolling forward the value given to the RAB at a date specified in the table in schedule 6.2.1(c)(1)
- the value of $511 million prescribed in the table is to be adjusted for the difference between actual and forecast capex for any part of a previous regulatory control period

- this adjustment must remove any benefit or penalty on the returns associated with any difference between actual and forecast capex.

The AER reviewed inputs to the RFM for the previous regulatory control period—1 July 2003 to 30 June 2004—and identified the following anomalies:

- the estimated capex amount in the RFM of $23 million for the 2003–04 regulatory year was not consistent with the value of $22 million approved in the ICRC determination
- the RFM has erroneously adjusted for the difference between actual and estimated capex in the 2003–04 regulatory year, when the adjustment should have been made in the 2008–09 regulatory year
- the method used to calculate inflation inputs to the RFM for adjusting the opening RAB is not consistent with that approved by the ICRC.

After consultation with ActewAGL on the above matters the AER has made the following corrections to the RFM to account for these anomalies:

- the value for the estimated capex for the 2003–04 regulatory year has been adjusted to reflect the value of $22 million as approved in the ICRC determination[136]
- the RFM has been corrected to reflect that the adjustment for the difference between actual and estimated capex is made in the 2008–09 regulatory year (this is consistent with the AER's RFM for NSW distribution). This amendment requires three adjustments:
  - ActewAGL's proposed adjustment for the difference between actual and estimated capex for 2003–04 of $3.8 million is added back to its proposed adjusted opening RAB value of $507 million resulting in an opening RAB value of $511 million as prescribed in schedule 6.2.1(c) of the transitional chapter 6 rules
  - a reduction of $2.7 million as a result of the amended value for the ICRC approved capex forecast—to reflect the adjustment to the RAB for the difference between actual and estimated capex in 2003−04—to the closing RAB at the end of the current regulatory control period (2008−09)[137]
  - ActewAGL's proposed adjustment in the 2008–09 regulatory year—for the return on the difference between the actual and estimated capex in 2003−04 ($2.3 million)—is reduced by $0.7 million to $1.6 million.
- the ICRC's approved method to calculate inflation used for indexation of the control mechanism during the current regulatory control period has been adopted as required under clause 6.5.1(e)(3) of the transitional chapter 6 rules.

[136] ActewAGL, email to AER, 13 August 2008, p.1. ActewAGL acknowledged that the ICRC decision document value should be used in the calculation of the 2004–05 opening asset value under schedule 6.2.1.

[137] Transitional chapter 6 rules, clause S6.2.1(c)(2).

Table 7.1 sets out the corrections to ActewAGL's RFM in relation to the opening RAB as at 30 June 2004.

**Table 7.1: AER's corrections to ActewAGL's proposed RFM ($m, nominal)**

| Opening RAB component | Proposed | Approved | Reason |
|---|---|---|---|
| Estimated capital expenditure for 2003–2004 | 23.1 | 21.9 | In accordance with ICRC determination |
| Opening asset base 1 July 2004 | 506.8 | 510.5 | As prescribed by S6.2.1(c) of the transitional chapter 6 rules |
| Adjustment to the regulatory asset base for the difference between actual and estimated capital expenditure | nil | –2.7 | In accordance with S6.2.1(c) of the transitional chapter 6 rules |
| Adjustment to the regulatory asset base for the return on the difference between actual and estimated capital expenditure | 2.3 | 1.6 | Resulting from changes to the indexation method and to the estimated capital expenditure |
| Indexation method | March-on-March quarter change in CPI | Change in the sum of four quarters to December CPI | In accordance with ICRC determination |

### 7.4.2 Roll forward methodology

Under the AER's RFM and based on the transitional chapter 6 rules, the closing RAB (nominal) for each year of the current regulatory control period is calculated by:

1. increasing the opening RAB by the amount of capex incurred (including estimated capex for the remaining part of the current regulatory control period)
2. reducing the opening RAB by the amount of regulatory depreciation using the rates and methodologies allowed in the 2004 ICRC determination[138]
3. reducing the opening RAB by the amount of disposal value of any disposed assets.

At the end of the current regulatory control period, as discussed in section 7.4.1 of this draft decision, the closing RAB is adjusted for the difference between estimated capex during the previous regulatory control period and actual capex for that part of the period, and the return on the difference.

[138] Regulatory depreciation is calculated by determining the straight–line depreciation for the RAB less the CPI indexation adjustment on the opening RAB.

**ActewAGL proposal**

Applying the AER's RFM ActewAGL stated that its opening RAB as at 1 July 2009 is $593 million.

**AER considerations**

As noted in section 7.4.1 of this draft decision ActewAGL did not apply the ICRC's indexation method and this has also impacted on the CPI inputs to the RFM for the current regulatory control period. The AER has amended these inputs to reflect the ICRC indexation method. Based on these updated inputs and the amendments for the anomalies identified in section 7.4.1 the AER has determined ActewAGL's opening RAB to be $588 million for the next regulatory control period (as at 1 July 2009). This value is used as an input for the AER's post tax revenue model for the purposes of determining ActewAGL's maximum allowable average revenue during the next regulatory control period.

### 7.4.3 RAB roll forward for the next regulatory control period.

Clause 6.12.1(18) of the transitional chapter 6 rules requires the AER to determine whether the depreciation for establishing the opening RAB for the following regulatory control period (i.e. as at 1 July 2014), is to be based on actual or forecast capex (referred to here as the use of 'actual' or 'forecast' depreciation). This contrasts to the requirement of the transitional provision in schedule 6.2.1(e)(5) of the transitional chapter 6 rules which requires the use of actual depreciation when rolling forward the RAB for the current regulatory control period.

The use of actual or forecast depreciation relates to whether the return of capital forms part of the capex incentive framework. For example, in the case of an overspend in capex, under the actual depreciation framework, the opening RAB would be reduced by a higher amount of depreciation (reflecting the higher capex) than if forecast depreciation was applied. In this case, the DNSP loses the return on the capital in excess of the capex allowance and incurs faster depreciation of its RAB. The situation is reversed for capex underspends where the reward is potentially higher.

ActewAGL did not comment on this issue in its regulatory proposal.

**AER considerations**

The AER notes that the NER does not offer any criteria regarding its decision on the use of actual or forecast depreciation, or on the capex incentive framework generally. Section 7A(3) of the NEL provides general guidance with respect to incentives:

> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> (a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
>
> (b) the efficient provision of electricity network services; and

(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

The AER considers that the decision to use actual depreciation would provide a stronger incentive to seek out efficiencies and invest less than the approved capex allowance.

The AER considers that EnergyAustralia's statement on this issue, made as part of its recent regulatory proposal, is relevant:

> There are significant uncertainties that EnergyAustralia must face during the regulatory control period (cost escalation, resourcing etc) that would warrant a lower power methodology.[139]

When applied generally, EnergyAustralia's argument is that the presence of such uncertainties in combination with a stronger incentive framework would result in potentially higher windfall gains and losses, and therefore a lower powered mechanism is one that is that is more likely to promote economic efficiency in accordance with section 7A of the NEL.

Without necessarily agreeing with this argument, the AER does not regard such uncertainties to be present for ActewAGL. As illustrated in chapter 8 of this draft decision (table 8.1 in particular), ActewAGL's capex proposal is comprised of expenditures which are relatively stable from year to year. In particular, 20 per cent of the proposed capex is attributed to the pole replacement program, which represents a continuation of investment from the current regulatory control period. The only expenditure subject to significant variation relates to the four large augmentation projects of which over half of this expenditure is forecast to occur in the first two years of the next regulatory control period. The AER expects the timing and value of these project expenditures to be relatively accurate.

Furthermore, by contrast to the observed overspend with respect to the capex allowance set by the ICRC, the AER has approved expenditure for ActewAGL in recognition of the need for ongoing pole replacements and also compensation for expected changes in input costs for the next regulatory control period. The AER therefore expects that any future windfall gains or losses arising from uncontrollable factors will be minimised.

The AER finally notes the general concern expressed by stakeholders on the significant rise in ActewAGL's expenditure proposal from its current historical levels. In this context the AER considers it important to provide effective incentives for ActewAGL to seek out efficiencies wherever possible throughout its program, and that a high powered incentive is therefore appropriate. The AER's draft decision is to therefore use actual depreciation to establish the opening RAB for the 2014–19 regulatory control period.

## 7.5 AER conclusion

Consistent with the transitional chapter 6 rules, ActewAGL has proposed to roll forward its RAB, established in the ICRC's 2004 determination, to determine an

[139] EnergyAustralia, *Regulatory proposal*, p. 156.

opening RAB for the next regulatory control period. Applying the RFM, the AER has determined ActewAGL's opening RAB to be $588 million for the next regulatory control period (as at 1 July 2009).

The RAB roll forward calculations are set out in table 7.2. The AER will update the roll forward of ActewAGL's RAB with the most recent forecast of capex for 2008–09 and the latest actual CPI data, at a time closer to its final distribution determination.

**Table 7.2: ActewAGL's opening RAB for the next regulatory control period ($m, nominal)**

| | 2004–05 | 2005–06 | 2006–07 | 2007–08[a] | 2008–09[b] |
|---|---|---|---|---|---|
| Opening RAB | 510.5 | 520.2 | 532.3 | 554.1 | 576.6 |
| Actual net capex[c] | 21.7 | 23.4 | 29.5 | 37.8 | 30.1 |
| CPI adjustment on opening RAB | 12.2 | 14.2 | 19.4 | 13.4 | 16.0 |
| Straight-line depreciation (adjusted for actual CPI) | –24.3 | –25.5 | –27.1 | –28.6 | –30.0 |
| Closing RAB | 520.2 | 532.3 | 554.1 | 576.6 | 592.7 |
| Less: difference between actual and forecast capex for 2003–04 | | | | | 2.7 |
| Less: return on difference[d] | | | | | 1.6 |
| Opening RAB at 1 July 2009 | | | | | 588.4 |

(a) Based on forecast 2007–08 capex. The actual capex will be updated at the time of the AER final decision.
(b) Based on estimated net capex and forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.
(c) The cash values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $2.7 million for 1 July 2003 to 30 June 2004.

## 7.6 AER draft decision

In accordance with clause 6.12.1(6) of the transitional chapter 6 rules the AER has decided that the opening regulatory asset base at 1 July 2009 for ActewAGL is $588.4 million, as set out in table 7.2 of the draft decision.

In accordance with clause 6.12.1(18) of the transitional chapter 6 rules the AER has decided to use actual depreciation for establishing the regulatory asset base for the commencement of the 2014–19 regulatory control period.

# 8 Forecast capital expenditure

## 8.1 Introduction

This chapter sets out the AER's conclusion on ActewAGL's forecast capex allowance for the next regulatory control period. The AER and its consultants have assessed ActewAGL's capex proposal by examining whether:

- its governance framework, capex policies and procedures are likely to result in investment decisions, which constitute the capex proposal, that are consistent with the capital expenditure objectives
- the methods and assumptions used to develop the capex proposal, including demand forecasts and estimates of unit costs, are robust and reflect a realistic expectation of the demand forecasts and cost inputs required to achieve the capex objectives
- estimates of real cost escalators and their application reflect a reasonable expectation of input cost forecasts
- the projects and programs that form part of the regulatory proposals generally reflect the capex criteria, including with respect to their scope, timing and costs
- the capex programs are deliverable and are therefore commensurate with what a prudent DNSP would require to achieve the capex objectives.

The AER's conclusion on the ActewAGL's capex allowance for the next regulatory control period is set out in section 8.7 of this chapter.

## 8.2 Regulatory requirements

Clause 6.12.1(3) of the transitional chapter 6 rules provides that the AER must make a decision to accept, or reject and form its own estimate of, the total of forecast capex included in a building block proposal in accordance with the capex objectives, criteria and factors outlined in clause 6.5.7 of the transitional chapter 6 rules.

### 8.2.1 Capex objectives

Clause 6.5.7(a) of the transitional chapter 6 rules provides that a DNSP must include the total forecast capex for the regulatory control period in order to achieve the following capex objectives:

> (1) meet or manage the expected demand for standard control services over that period;
>
> (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
>
> (3) maintain the quality, reliability and security of supply of standard control services;
>
> (4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

### 8.2.2 Capex criteria and factors

Clause 6.5.7(c) of the transitional chapter 6 rules also provides that the AER must accept the capex forecast included in a regulatory proposal if it is satisfied that the total of the capex forecast for the regulatory control period reasonably reflects:

> (1) the efficient costs of achieving the capex objectives;
>
> (2) the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the capex objectives; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives. [140]

In making this assessment the AER must have regard to the capex factors contained in clause 6.5.7(e) of the transitional chapter 6 rules:

> (1) the information included in or accompanying the building block proposal;
>
> (2) submissions received in the course of consulting on the building block proposal;
>
> (3) analysis undertaken by or for the AER and published before the distribution determination is made in its final form;
>
> (4) benchmark capex that would be incurred by an efficient DNSP over the regulatory control period;
>
> (5) the actual and expected capex of the DNSP during any preceding regulatory control periods;
>
> (6) the relative prices of operating and capital inputs;
>
> (7) the substitution possibilities between opex and capex;
>
> (8) whether the total labour costs included in the capex and opex forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;
>
> (9) the extent the forecast of required capex of the DNSP is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms;
>
> (10) the extent the DNSP has considered, and made provision for, efficient non–network alternatives.

Clause 6.5.7(d) of the transitional chapter 6 rules states that, if the AER is not satisfied that a DNSP's forecast capex reasonably reflects the capex criteria, then the AER must not accept the forecast capex in a building block proposal. If the AER does not accept the total forecast capex proposed by a DNSP, clause 6.12.1(3)(ii) of the transitional chapter 6 rules requires the AER to include in its draft decision:

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[140] Transitional chapter 6 rules, clause 6.5.7(c).

> …an estimate of the total of the DNSP's required capex for the regulatory control period that the AER is satisfied reasonably reflects the capex criteria, taking into account the capex factors.

## 8.3 ActewAGL proposal

ActewAGL proposed a capex allowance totalling $278 million ($2008–09) (net of capital contributions and disposals) for the next regulatory control period. Table 8.1 sets out ActewAGL's proposed capex by category.

**Table 8.1: ActewAGL's proposed capex by category ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Asset renewal/replacement | 20.2 | 21.5 | 18.9 | 18.8 | 19.3 | 98.6 |
| Customer initiated | 21.7 | 23.9 | 20.3 | 15.2 | 12.9 | 94.0 |
| Augmentation | 29.9 | 14.6 | 13.9 | 15.4 | 2.7 | 76.5 |
| Reliability and quality improvements | 0.2 | 0.4 | 0.4 | 0.3 | 0.3 | 1.5 |
| Network IT systems | 4.3 | 4.1 | 3.5 | 3.5 | 5.1 | 20.5 |
| Capital contributions | –5.8 | –8.2 | –7.5 | –4.2 | –3.7 | –29.4 |
| Non-systems assets | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 2.6 |
| Corporate services business support | 7.4 | 1.5 | 1.6 | 1.4 | 1.5 | 13.3 |
| Total | 78.3 | 58.3 | 51.7 | 50.9 | 38.5 | 277.7 |

Source: ActewAGL, *Regulatory proposal*, p.126.
Note: Totals may not add due to rounding.

ActewAGL forecast an increase in capex of approximately 71 per cent from the current regulatory control period. The key drivers of ActewAGL's forecast capex program were identified as:[141]

- zone substation augmentation requirements due to urban expansion
- asset replacement and renewal driven by regulatory, safety and security requirements
- high forecast levels of residential and commercial expansion.

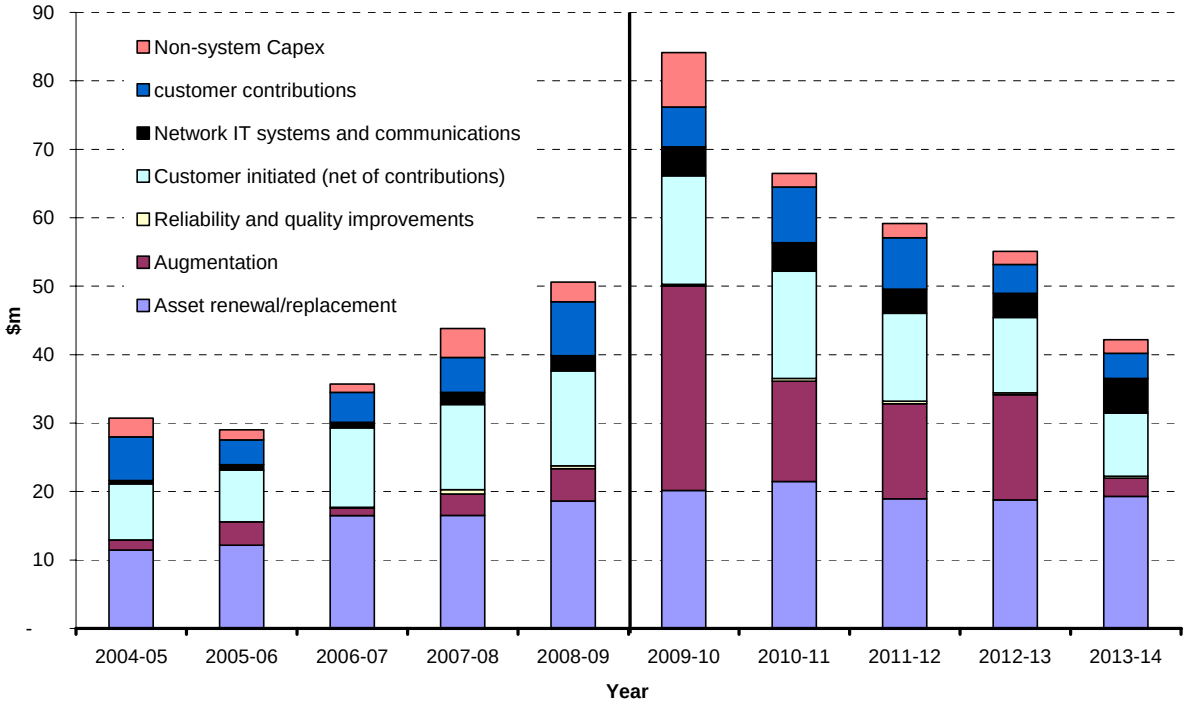
ActewAGL's proposed augmentation capex for the next regulatory control period is nearly five times higher than its current regulatory control period augmentation capex. ActewAGL noted most of this increase is attributable to four major augmentation projects – Civic zone substation augmentation, connection of the new southern bulk

[141] ActewAGL, *Regulatory proposal,* p. 121.

supply point, and new zone substations and feeders at Eastlake (Fyshwick) and Molonglo.

Figure 8.1 compares ActewAGL's actual and proposed capex by category.

**Figure 8.1: ActewAGL's actual and proposed capex by category ($m, 2008–09)**




Source: ActewAGL, *Regulatory proposal*, RIN proforma 2.2.1.

Renewal and replacement expenditure is forecast to increase by around 31 per cent from the current period. This category of expenditure totals $99 million for the next regulatory control period (around 35 per cent of the total capex program) and is largely driven by continued expenditure on replacement and reinforcement of poles ($51 million) and ground substation replacement ($8 million).

ActewAGL forecast customer initiated (growth related) capex to increase by 16 per cent from the current period. This category of expenditure totals $94 million (34 per cent of the total forecast capex program) with over half of this attributable to commercial and new urban development expected during the next regulatory control period. ActewAGL expected to recover approximately 31 per cent of these costs through customer contributions.[142]

In estimating the cost of its identified capital requirements, ActewAGL developed bottom up expenditure estimates in 2007–08 dollars and has escalated these using selected escalation rates developed by Sinclair Knight Merz (SKM).[143] ActewAGL used three models to identify and develop its capital investment requirements:

- pole asset replacement/refurbishment model

[142] ActewAGL, *Regulatory proposal,* p. 137.

[143] ActewAGL, *Regulatory proposal*, attachment 18. The AER's assessment of input cost escalators used by ActewAGL is set out at appendix G to this draft decision.

- network assets replacement/refurbishment model
- network capex/opex trade-off model.

## 8.4 Submissions

The AER received a submission from the Energy Market Reform Forum (EMRF) on ActewAGL's forecast capex. EMRF submitted that ActewAGL has consistently expended an increasing amount of capex over the past period, and that the claimed forecast capex is in excess of the growth demand trend. The EMRF submitted that ActewAGL's overall capex is some $10 million per year (or $50 million overall) in excess of needs.[144]

## 8.5 Consultant review

The AER engaged Wilson Cook to review ActewAGL's forecast capex. Wilson Cook concluded that it does not consider any adjustments to ActewAGL's system or non-system capex forecasts are required.

In forming a view on ActewAGL's forecast capex, Wilson Cook considered the following key factors:[145]

- prudence and efficiency of the proposed expenditures[146]
- external obligations imposed on ActewAGL
- consistency with demand forecasts proposed by ActewAGL and reviewed by the AER
- unit costs, escalation rates and methodologies for materials cost estimation
- expenditure drivers including the need to address demand growth, ageing assets and safety and environmental issues
- appropriateness and consistent application of policies and procedures.

## 8.6 Issues and AER considerations

### 8.6.1 ActewAGL policies, procedures and methods

**Capital planning practices**

Wilson Cook concluded that ActewAGL had followed reasonable policies and procedures, including the identification of need and least-cost solutions when making

144 EMRF, p.18.
145 Wilson Cook, Volume 1, pp. 7–11.
146 Wilson Cook, Volume 1, p. 9. Where Wilson Cook has considered there was an appropriate balance between the factors it considers comprise 'prudence' and 'efficiency', it has concluded in its report that the expenditure is 'reasonable'.

investment decisions.[147] Wilson Cook further concluded the following regarding ActewAGL's network planning procedures:[148]

- ActewAGL's planning team followed current international planning practice and had adopted sound network planning concepts and policies
- ActewAGL considers zone substation diversity and load transfers when planning its zone substation augmentation
- non–network and demand side alternatives are considered as potential alternatives to network augmentation and are provided for in ActewAGL's procedures
- ActewAGL appeared to be using appropriate methods for the construction and installation of its assets
- the particular types of assets to be used in the capex program during the next regulatory control period are appropriate for the purpose.

During meetings with ActewAGL planning staff and Wilson Cook, AER staff had the opportunity to review the application of ActewAGL's planning processes in the context of a sample of key projects which are major contributors to the proposed capex program. As a result of this review, the AER and Wilson Cook are satisfied that ActewAGL had observed appropriate processes and procedures in determining the scope, timing and need for these projects.

**Cost estimation processes**

In developing its forecast capex allowance ActewAGL has applied unit rates developed to reflect efficient estimated expenditures in 2007–08 dollars. ActewAGL commissioned SKM to undertake a comparative review of its ten most important unit rates based on independent estimates for these costs.[149] In its report, SKM concluded that, overall, the unit rate estimates used by ActewAGL were an accurate representation of costs in the competitive marketplace.

Wilson Cook reviewed ActewAGL's unit rates in the context of its circumstances, and the SKM comparative estimates, and considers the cost estimates to be reasonable.[150]

Although ActewAGL's unit rates do not accord with SKM's in all cases, the variation is typically immaterial, and in a number of cases, ActewAGL's rates are lower than those put forward by SKM. Where ActewAGL's unit rates are higher than those developed by SKM, the AER considers ActewAGL and SKM have offered reasonable explanations as to why this is the case.[151]

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147 Wilson Cook, Volume 5, p. 15.

148 Wilson Cook, Volume 5, pp. 15–16.

149 ActewAGL, *Regulatory proposal*, confidential attachment 17.
SKM, *Comparative unit rate estimates for selected works/activities, final report,* 30 May 2008.

150 Wilson Cook, Volume 5, p. 17.

151 For example, ActewAGL's unit rate estimate for 132kV lines is around 10 per cent higher than SKM's estimate. This variation is attributable to ActewAGL's rate being inclusive of easement transaction costs while SKM's rate is not.

ActewAGL submitted that it has not included expenditure for contingencies in its capex forecasts.[152]

The AER has reviewed ActewAGL's proposed unit rates and SKM's comparative review of them and is satisfied that their application ActewAGL's would likely produce forecasts that reasonably reflect the efficient costs a prudent operator would require to achieve the capex objectives under clause 6.5.7(a) of the transitional chapter 6 rules.

***Application of SKM input cost escalators***

ActewAGL commissioned SKM to develop input cost escalation factors to apply to specific components of its forecast system capex program.[153] These escalators were developed to recognise that some input prices have been growing at a faster rate than general price growth (as measured by the consumer price index) in recent times. ActewAGL has applied these input cost escalators to particular expenditure components, to reflect its expectation that the costs of these components will increase in real terms during the next regulatory control period.

Wilson Cook did not review the application of cost escalators to the base capex estimates, and has relied on ActewAGL's assurance that these have been applied in the manner stated by it.[154]

The AER's detailed consideration and conclusions on ActewAGL's proposed input cost escalators as developed by SKM, and the methodologies underpinning those escalators, is set out at appendix G to this draft decision. While the AER is generally accepting of the SKM methodology for deriving input cost escalators, it has made some adjustments to the proposed methodology and also considers that more recent data is reflective of the input costs ActewAGL is expected to face during the next regulatory control period.

The SKM methodology applied by ActewAGL assumes that price changes in some input cost components will not be reflected immediately in the cost of capex components purchased. Specifically, the input cost factor weightings applied to transformers, switchgear, conductor, e-wire and copper and aluminium cables assume a 12 month lag before expected real cost increases in raw input materials are reflected in the price of these components. The input cost factors which are assumed to have a delayed price impact are aluminium, copper, steel and oil.[155]

The issue of assuming a lag between real input cost increases and real increases in capex is addressed at appendix G of this draft decision. In summary, the AER does not consider this is a reasonable assumption based on observed movements between commodity and producer prices.

On 1 October 2008 ActewAGL advised the AER that errors had been identified by SKM in its input cost escalators.[156] The AER requested that ActewAGL resubmit its

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152 ActewAGL, *Regulatory proposal*, p. 131.

153 ActewAGL has not proposed to apply real cost escalation to its non-system capex. These expenditure items will be escalated annually by inflation only.

154 Wilson Cook, Volume 5, p. 17.

155 ActewAGL, response to information request, 12 September 2008.

156 ActewAGL, email to AER, 1 October 2008.

capex forecasts and post tax revenue model, which revealed an increase of $8.9 million from the forecast capex allowance included in its regulatory proposal of 2 June 2008.[157] The correction of this error has been incorporated into the AER's consideration of ActewAGL's capex proposal.

The AER does not consider ActewAGL's cost escalation assumptions reflect a realistic expectation of the cost inputs required to achieve the capex objectives, as required by clause 6.5.7(c). Therefore, it does not consider the resulting allowance fully satisfies the capex criterion at clause 6.5.7(c)(3) of the transitional chapter 6 rules. The AER has required ActewAGL to remodel its capex proposal to address the AER's decisions on input cost escalators, as set out at appendix G of this draft decision. The effect of this remodelling is illustrated in table 8.5 at section 8.7 of this chapter.

### Growth capex

ActewAGL proposed augmentation expenditure of $76 million ($2008–09) representing around 27 per cent of the total forecast capex program. Around 87 per cent of this expenditure is attributable to four major augmentation projects:

- Civic zone substation augmentation ($6.8 million)
- connection to the new southern bulk supply point ($23 million)
- new zone substation and feeders at Eastlake ($22 million)
- new zone substation and feeders at Molonglo Valley ($15 million).

**Table 8.2 Major augmentation capex projects ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Eastlake zone substation and associated feeders | 9.4 | 9.8 | 0.6 | 1.4 | 0.8 | 22.0 |
| Civic zone substation | 3.7 | 3.1 | 0.0 | 0.0 | 0.0 | 6.8 |
| Molonglo zone substation and associated feeders | 0.0 | 0.3 | 7.3 | 7.4 | 0.0 | 15.0 |
| Southern bulk supply point 132kV feeders and upgrades | 14.2 | 0.0 | 3.9 | 4.4 | 0.0 | 22.5 |
| Total | 27.3 | 13.2 | 11.9 | 13.1 | 0.8 | 66.3 |

Source: ActewAGL, *Regulatory proposal*, p.140

Wilson Cook reviewed each of the four major augmentation projects and is satisfied they are prudent and efficient, as is the indicative timing of the expenditure. It further concluded that that the projects were consistent with ActewAGL's network

[157] ActewAGL, email to AER, 9 October 2008.

development strategy and that demand management alternatives would not allow for material deferral of the proposed investment.[158]

The AER notes that the timing of these major projects is not affected by growth in peak demand. The AER's consideration of ActewAGL's demand forecast is set out at chapter 6 of this draft decision.

***Southern bulk supply point project***

In 2006, the ACT Government passed legislation mandating the construction of a second electricity bulk supply point (BSP) in the ACT, to enhance security of supply to the ACT.[159] The legislation created an obligation for TransGrid to construct a new BSP in the ACT, to be situated in the locality of Williamsdale, south of Canberra.[160] In order to make use of this second point of supply, ActewAGL is required to establish assets to connect the Williamsdale BSP to the ACT distribution network.

TransGrid and ActewAGL have jointly developed two possible investment scenarios for this project and have applied the regulatory test to these options.[161] ActewAGL submitted that the chosen option has the lowest present value of costs in all cases.[162] To connect to the Williamsdale BSP, ActewAGL proposed to undertake the following work at an estimated cost of $23 million ($2008–09), including easement acquisition costs:

- construction of two 132kV circuits from the Williamsdale BSP to the Gilmore/Theodore area during 2009–10
- any works necessary to upgrade the ActewAGL sub-transmission network capacity to match supply capabilities from the Williamsdale BSP, during 2011–12 to 2012–13.

The AER sought advice from the ACT Government on the scope and timing of this project, which confirmed that the works proposed by ActewAGL are required and that the proposed timing is consistent with ACT Government policies and expectations.[163]

The AER has reviewed the timing and need for ActewAGL's contribution to the southern supply point project and considers it is necessary and efficient. This view is based on advice received from the ACT Government and the outcomes of Wilson Cook's review. The AER notes that ActewAGL's proposed works are consistent with the expectations of the ACT Government in terms of timing and scope, and are necessary during the next regulatory control period. The AER is satisfied that this aspect of ActewAGL's forecast capex reasonably reflects the efficient costs a prudent

158 Wilson Cook, Volume 5, pp. 13-14.
159 Utilities Exemption 2006 (No.1), Disallowable instrument DI2006–47.
160 The AER notes that TransGrid's revenue proposal for the next regulatory control period includes a proposal to construct the Williamsdale bulk supply point during 2009–10. Additional works to connect the Williamsdale bulk supply point to the TransGrid transmission network (stage 2 works) have been proposed as contingent on planning approvals. *See*, TransGrid, *Meeting customer needs for transmission services, TransGrid revenue proposal 1 July 2009 – 30 June 2014*, p. 63 and appendix I, p. 9.
161 ActewAGL and TransGrid, *Final report, Proposed new large transmission network asset, proposed new large distribution network asset, Southern supply to the ACT*.
162 ActewAGL, *Regulatory proposal*, p. 143.
163 ACT Chief Minister's Department, letter to AER, 25 August 2008.

operator would require to achieve the capex objectives under clause 6.5.7(a) of the transitional chapter 6 rules.

***Molonglo Zone Substation***

ActewAGL identified a need to establish a new zone substation in the Molonglo Valley region to support expected land releases during the next regulatory control period. It proposed to incur expenditures on the new zone substation (and associated feeders) between 2011–12 and 2012–13 at a forecast total cost of $15 million ($2008–09).

ActewAGL submitted that while there are four existing zone substations within 10 km of the proposed new Molonglo zone substation, it would be impractical to supply the new development from these existing facilities due to distance, geographical limitations and future capacity constraints.[164] ActewAGL identified that Woden zone substation could supply the initial stages of the Molonglo Valley release, however, based on forecast load growth, it is expected to reach its summer emergency rating capacity by 2015, by which time an alternative supply would be required to supply the Molonglo development.

ActewAGL submitted that construction of the Molonglo Valley zone substation, before Woden zone substation reaches capacity, will allow some load from Weston Creek (currently supplied from Woden) to be transferred to the new Molonglo substation. ActewAGL noted that this could defer the need to upgrade Woden zone substation for 10 years or more.[165]

The AER sought advice from the ACT Government on the timing and scope of the future Molonglo Valley land releases. This advice confirms that ActewAGL's proposed timeline for construction and commissioning of the Molonglo zone substation is consistent with ACT Government policy and its timing expectations for the land releases. [166] The ACT Government has indicated it supports the establishment of the Molonglo Zone substation based on advice from ActewAGL that existing infrastructure has sufficient capacity to service only the initial releases of land in the Molonglo Valley.[167] It further advised that it considers it essential that the new zone substation is operational by 2012–13 to enable the full release of land as planned.[168]

The AER reviewed the application of ActewAGL's planning processes to the establishment of the Molonglo zone substation project. AER considers that ActewAGL has demonstrated a genuine need for the new investment due to existing network constraints. Sound policies and practices have been observed in determining the need and timing for this expenditure, as well as in the consideration of alternative solutions. The AER considers this project is required during the next regulatory control period and is satisfied that this aspect of ActewAGL's forecast capex

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164 See ActewAGL, *Electricity networks 10 year network augmentation plan, 2008/09 to 2017/18*, p. 57.

165 ActewAGL, *10 year network augmentation plan*, p. 58.

166 ACT Chief Minister's Department, letter to AER, 25 August 2008.

167 ACT Chief Minister's Department, letter to AER, 25 August 2008.

168 The ACT Government has advised the AER that it intends to commence initial land releases in the Molonglo Valley region from 2008–09. It is expected that initial land releases between 2008–09 and 2012–13 will total 4000 lots, with around 25000 dwellings to be developed in the next 15 to 20 years.

reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives under clause 6.5.7(a) of the transitional chapter 6 rules.

***Civic Zone Substation***

ActewAGL proposed expenditures to augment its Civic zone substation, which supplies commercial and residential buildings located in Canberra city. ActewAGL submitted that, based on demand forecasts, the substation's cyclic rating would be exceeded by 2008 given a one in 10 year weather event, and its emergency rating will be exceeded by the summer of 2012. ActewAGL submitted that the substation must be augmented and that its preferred solution to address the constraint is to install a third transformer.[169]

The AER reviewed the application of ActewAGL's planning processes to the Civic zone substation works program. During this review, ActewAGL's timing assumptions for the investment need were tested against alternative demand forecasting scenarios (10 per cent, 50 per cent and 90 per cent probability of exceedence), and in each case, the expected emergence of capacity constraints did not shift sufficiently to enable this augmentation investment to be deferred beyond the next regulatory control period.

Based on its review, and advice from Wilson Cook, the AER considers that ActewAGL has demonstrated a genuine need for this augmentation expenditure. Sound policies and practices have been observed in determining the need and timing for this project, as well as in the selection of the most efficient investment solution. The AER considers the project is required to meet demand during the next regulatory control period and is satisfied that this aspect of ActewAGL's forecast capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives under clause 6.5.7(a) of the transitional chapter 6 rules.

***Eastlake Zone substation***

ActewAGL submitted that capacity constraints are emerging in the South Canberra area as a result of a sustained high level of land development and redevelopment, causing diminution of spare capacity at the two existing zone substations in the area (Fyshwick and Telopea Park). ActewAGL submitted that Telopea Park zone substation has reached its emergency rating, but will undergo a transformer cable upgrade to enable it to meet projected load until 2011.[170] It also noted that current developments at Aero Park, Brindabella Park and the EpiCentre will mean all spare capacity at Fyshwick zone substation will be used within two years. ActewAGL had expected the total load to exceed this substation's emergency rating by 2011 and has estimated that an additional 35 MVA capacity will be required in the Fyshwick and Telopea Park areas to meet the supply requirement within ten years.[171]

ActewAGL proposed the following works for the Eastlake zone substation project: [172]

- a 50 MVA zone substation by 2011
- 132kV line work by 2011

[169] ActewAGL, *Regulatory proposal*, p. 142.
[170] ActewAGL, *10 year network augmentation plan*, p. 79.
[171] ActewAGL, *10 year network augmentation plan*, p. 79.
[172] ActewAGL, *Regulatory proposal*, p. 141.

- provisions for a capacity upgrade to 100MVA in the future
- high voltage network roll-out over a period of 15 years.

ActewAGL submitted that load from the existing Fyshwick zone substation (a temporary facility, built in 1982) will be progressively shifted to Eastlake, as will some load from Telopea Park zone substation. This will enable the Telopea Park zone substation to supply new developments on either side of Lake Burley Griffin.[173]

Based on its review, and advice from Wilson Cook, the AER considers that ActewAGL has demonstrated a genuine need for the investment, supported by sufficient documentation and analysis. Sound policies and practices have been observed in determining the need and timing for this project, as well as in determining the most efficient investment solution. The AER considers the project is necessary during the next regulatory control period to meet expected demand and is satisfied that this aspect of ActewAGL's forecast capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives under clause 6.5.7(a) of the transitional chapter 6 rules.

***Other augmentation and customer-driven capex***

ActewAGL's remaining augmentation capex is largely attributable to:

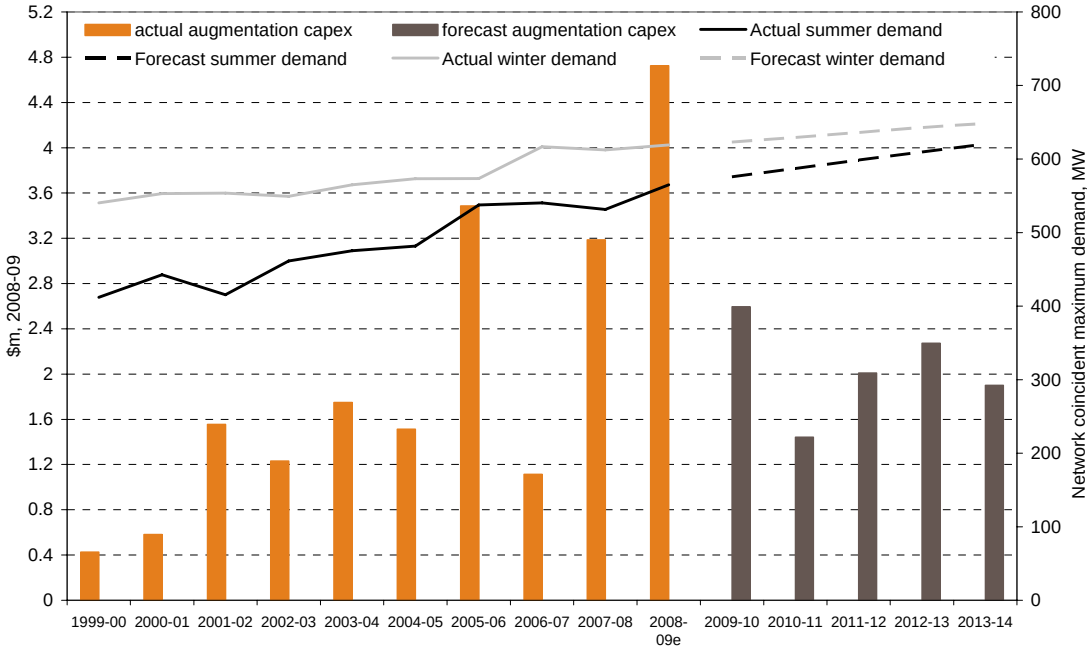
- cable and feeder upgrades in response to increased demand
- augmentation of the low voltage distribution network to accommodate customer growth in urban and commercial developments
- customer initiated replacements and relocations
- community and associated developments and
- new service wires.

The customer initiated category of expenditure is forecast to total $94 million during the next regulatory control period. ActewAGL has estimated it will recover approximately 31 per cent of this through customer contributions in accordance with the Electricity Networks Capital Contributions Code (ACT).

In the context of the data presented by the EMRF, the AER has compared ActewAGL's augmentation capex (less the major projects noted in the growth capex section) with peak demand growth, as illustrated in figure 8.2.

[173] ActewAGL, *Regulatory proposal*, p. 140.

**Figure 8.2: ActewAGL's other augmentation capex and peak demand**




Source: ActewAGL, RIN templates 2.2.1 and 2.3.8.

Such a comparison indicates that there is no discernable correlation between augmentation capex and peak demand growth. The variability in historical expenditures is likely to reflect the impact of specific projects which have not been identified in ActewAGL's data.

Based on its review of ActewAGL's proposal, and advice from Wilson Cook, the AER considers that ActewAGL has applied an appropriate methodology for estimating customer initiated expenditures which is likely to result in an efficient expenditure allowance. Specifically, the AER considers ActewAGL has:

- made reasonable assumptions in developing its customer initiated capital investment program
- demonstrated detailed consideration of expected new developments and customer connections
- appropriately not included forecast allowances or contingency factors for projects which are uncertain.

Based on these considerations regarding other elements of ActewAGL's augmentation expenditure, the AER considers the proposed expenditure reasonably reflects the efficient costs a prudent operator, in the circumstances of ActewAGL, would require to achieve the capex objectives under clause 6.5.7(a) of the transitional chapter 6 rules.

### Replacement capex

ActewAGL proposed renewal and replacement capex of $99 million ($ 2008–09) representing around 35 per cent of the total forecast capex program. This category of expenditure is forecast to increase by around 31 per cent from the current period.

Major drivers of ActewAGL's replacement and renewal capex include continued expenditure on replacement and reinforcement of poles ($51 million), and ground substation replacement ($8 million). Table 8.3 sets out the main replacement projects and programs forecast for the next regulatory control period. These represent around 78 per cent of the total forecast replacement program.

**Table 8.3: Major replacement and renewal programs ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Pole replacement and reinforcement | 9.8 | 10.1 | 10.3 | 10.3 | 10.4 | 51.1 |
| Ground substation replacements | 1.6 | 1.9 | 1.4 | 1.6 | 1.7 | 8.1 |
| Reactive and planned zone substation equipment replacement | 0.7 | 0.9 | 0.3 | 0.3 | 0.6 | 2.8 |
| Zone fence upgrades | 0.7 | 0.7 | 0.7 | 0.7 | 0.4 | 3.3 |
| Underground network replacement | 1.1 | 0.9 | 0.9 | 0.9 | 0.9 | 4.8 |
| Civic zone substation switchboard replacement | 1.4 | 2.2 | 0.0 | 0.0 | 0.0 | 3.6 |
| Over current and distance protection relay replacements | 0.5 | 0.6 | 0.6 | 0.7 | 0.4 | 2.8 |
| Total | 16.0 | 17.3 | 14.2 | 14.5 | 14.5 | 76.5 |

Source: ActewAGL, *Regulatory proposal*, p. 148

Wilson Cook considered that the scope of the replacement capex program is prudent and efficient, concluding that no adjustments are required. Wilson Cook has concluded that the proposed projects and programs appear reasonable, as is their proposed timing. Wilson Cook has considered all forecast renewal and replacement capex to be consistent with ActewAGL's overall network development strategy.[174]

***Pole replacement and reinforcement program***

The pole replacement and reinforcement program represents the largest component (at around 67 per cent of the total) of ActewAGL's forecast replacement works. ActewAGL submitted that it expects to replace 5492 poles during the next regulatory control period, noting that pole reinforcement is also a significant expense and a prudent method of extending pole life and deferring capex.[175]

ActewAGL and SKM developed a pole replacement and reinforcement model to forecast management requirements for different types of poles during the next regulatory control period.

[174] Wilson Cook, Volume 5, p. 21.
[175] ActewAGL, *Regulatory proposal*, p. 148.

ActewAGL submitted that approximately 39 000 of its 53 000 poles are wooden, and almost half of the poles in its network are untreated natural round wood poles, which are susceptible to deterioration over time.[176] ActewAGL noted that failure of its power poles has lead to a significant number of incidents, including damage to property and injury to people.[177]

Wilson Cook and the AER have reviewed ActewAGL's proposed pole replacement and reinforcement program and are satisfied that the work is necessary during the next regulatory control period to manage safety risks associated with deteriorated wooden poles. ActewAGL's pole replacement and reinforcement model was examined by the AER and Wilson Cook and represents a reasonable approach to estimating condemnation rates and replacement expenditures for different pole types in ActewAGL's network, based on its planned inspection regime.

The AER considers ActewAGL's forecast pole replacement and reinforcement program is necessary and has been developed in accordance with sound policies and procedures. The AER is satisfied that this aspect of ActewAGL's forecast capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives under clause 6.5.7(a) of the transitional chapter 6 rules.

**Other replacement programs**

ActewAGL's other key forecast replacement programs include:[178]

- replacement of ground mounted substations and switching station components to ensure compliance with technical regulatory obligations
- replacement of the Civic zone substation switchboard due to deteriorated insulation and upgrading of fencing, protection relays, cable sealing ends, instrument transformers, isolators, battery chargers and other components, also due to deterioration
- replacement of underground network components.

The AER requested supporting information from ActewAGL to justify its additional expenditure, particularly relating to replacement needs for ground mounted substations and underground network components (for example, minipillars). ActewAGL provided a number of documents from the ACT Planning and Land Authority (the ACT technical regulator) which provide results of condition inspections it conducted on a sample of ActewAGL's ground mounted substations and minipillars.[179] In these documents, the ACT technical regulator expressed a number of concerns with the general condition of these installations, identifying defects requiring repairs and examples of units deemed to be in an unacceptable condition. The ACT technical regulator indicated that ActewAGL's maintenance plan for minipillar assets is not in accordance with the principles of the *Management of*

176 ActewAGL, *Regulatory proposal*, p. 148.
177 ActewAGL, *Regulatory proposal*, p. 149.
178 ActewAGL, *Regulatory proposal*, pp. 148–151.
179 ACT Planning and Land Authority, email to ActewAGL, 11 July 2007.

*Electricity Assets Code*.[180] ActewAGL submitted that this finding will result in a requirement for additional capex and opex to address problems and implement ongoing planned maintenance cycles.

The AER has reviewed ActewAGL's other replacement capex plans, taking into account additional supporting information, and the advice of Wilson Cook. Based on this review the AER considers that ActewAGL's other proposed replacement programs are necessary to comply with jurisdictional safety and reliability obligations. The AER is satisfied that this aspect of ActewAGL's forecast capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives under clause 6.5.7(a) of the transitional chapter 6 rules.

### Non-system capex

ActewAGL proposed a non-system capex allowance of $36 million ($2008–09) for the next regulatory control period, representing around 13 per cent of the total forecast capex program. This category of expenditure is forecast to increase by around 94 per cent from the current regulatory control period. Table 8.4 sets out ActewAGL's proposed non-system capex by category.

**Table 8.4: Major non-system capex projects and programs ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Network IT systems | 4.3 | 4.1 | 3.5 | 3.5 | 5.1 | 20.5 |
| Corporate services business support | 7.4 | 1.5 | 1.6 | 1.4 | 1.5 | 13.3 |
| Other non-system | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 2.6 |
| Total | 12.2 | 6.1 | 5.6 | 5.4 | 7.1 | 36.4 |

Source: ActewAGL, *Regulatory proposal*, p. 153, 155.
Note: Totals may not add up due to rounding.

Wilson Cook assessed ActewAGL's non-system capex against the other NSW DNSPs forecasts and the regulatory allowances of Ergon Energy and Energex from the 2005 Queensland network determination made by the Queensland Competition Authority. These comparisons were made on a 'cost-per-size' basis which Wilson Cook considers takes into account the main parameters which drive non-system capex.[181]

Wilson Cook's comparison revealed that ActewAGL's non-system capex is lower than the other NSW DNSPs based on expenditure by size.[182] Wilson Cook took account of the one-off expenditure attributable to the corporate headquarters relocation (discussed below) and the fact that some typically system-related expenditure items have been included in the non-system forecast. From its review Wilson Cook concluded that the overall level of non-system capex is reasonable from

[180] ACT Government, *Management of Electricity Network Assets Code,* section 6, p. 15. The code requires that 'electricity networks shall be maintained in a manner that ensures the safety of persons while taking into account reliability of supply and the associated risks'.

[181] Wilson Cook, Volume 1, section 3.

[182] This is to be expected given ActewAGL leases many of its non-system assets including vehicles and computers.

a 'top-down' perspective. Based on its review, Wilson Cook concluded that no adjustment to ActewAGL's forecast non-system capex is required.[183]

**Network IT expenditure**

ActewAGL's forecast network IT capex program is comprised of the following key projects and programs of work:[184]

- replacement of intertrip and SCADA[185] communications pilot cables
- major IT system replacements including assets and works management, geographic information systems, and preliminary work on a replacement SCADA system
- replacement of zone substation remote terminal unit due to failures and lack of replacement parts for ageing units currently in service
- three network automation programs — enhancement of high-voltage switchgear to allow remote operation, upgrading of key distribution substations for remote operability and improvements to fault location capabilities linked to SCADA systems to reduce unplanned outage durations.

At the request of the AER, ActewAGL provided additional information in support of these proposed projects. Wilson Cook and the AER have reviewed ActewAGL's project overviews and justifications and are satisfied that ActewAGL has demonstrated a need for the investment, supported by sufficient analysis and consideration of options. Wilson Cook has advised that it found nothing unusual or excessive in ActewAGL's proposed network IT expenditure program, and that benchmarking analysis showed the proposed allowance was not out of line with that of other DNSPs sampled.[186]

Based on these considerations the proposed investment is required and is satisfied that this aspect of ActewAGL's forecast capex is necessary and reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives under clause 6.5.7(a) of the transitional chapter 6 rules.

**Corporate capex—relocation of headquarters**

ActewAGL's major proposed corporate capex project during the next regulatory control period is the relocation of its corporate headquarters from an owned premised to a leased premises. The capex amount associated with this relocation (allocated to the electricity networks division) is forecast to be $4.8 million ($2008–09), and is largely attributable to fit-out of the new premises.[187] ActewAGL's other proposed corporate capex is attributable to ongoing refurbishments of existing buildings, security enhancements and IT and telecommunications enhancements.

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183 Wilson Cook, Volume 5, pp. 26, 28.
184 ActewAGL, *Regulatory proposal*, pp. 153–154
185 Supervisory Control and Data Acquisition.
186 Wilson Cook, Volume 5, pp. 26–28
187 The total capex associated with the relocation is apportioned across ActewAGL's multiple business units in accordance with its cost allocation method approved by the AER. Under this cost allocation method, ActewAGL attributes 54.75 per cent of corporate expenditure to its electricity networks division.

ActewAGL has provided a business case for the headquarters relocation project setting out the reasons for the relocation, as well as risks and benefits of the project.[188] Wilson Cook and the AER have reviewed this analysis and consider that ActewAGL has developed a sound justification for the proposed corporate relocation. The AER considers the proposed relocation will:

- avoid potentially significant future expenditures to maintain and refurbish ActewAGL House
- result in lower ongoing operating expenditures related to corporate accommodation
- give rise to other potential efficiencies in ActewAGL's corporate operations.

Based on its review of ActewAGL's business case, and advice from Wilson Cook, the AER considers ActewAGL's proposed relocation of its corporate headquarters is reasonable and has been appropriately justified. Based on this, the AER is satisfied that this aspect of ActewAGL's forecast capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives under clause 6.5.7(a) of the transitional chapter 6 rules.

#### Other corporate and non-system capex

Wilson Cook noted that ActewAGL's other forecast corporate and non-system capex are at a similar level to prior years and are at a relatively low level.[189] The AER is satisfied that ActewAGL's forecast other non-system capex allowance reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives under clause 6.5.7(a) of the transitional chapter 6 rules.

### Other issues

#### Undergrounding and backyard reticulation issues

ActewAGL submitted it is considering a program to underground the existing overhead network over a long-term investment horizon. It has drawn on its willingness to pay study to inform the preliminary cost benefit analysis of the project. The early results from this review indicate a potential net economic benefit from an underground conversion program in the ACT, but ActewAGL submits its results would need to be tested further.[190]

Wilson Cook provided comment in its report suggesting that it may be a better long-term solution to replace backyard reticulation with street front underground reticulation, as the existing configuration unnecessarily adds to maintenance and replacement costs due to access difficulties. It has suggested that if the AER is able to address this issue, it should consider doing so.[191]

The AER notes that, while investment in front yard or underground reticulation may provide more efficient long-term reliability and maintenance expenditure outcomes,

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188 ActewAGL, response to request for information date 6 August 2008, 15 August 2008.
189 Wilson Cook, Volume 5, p. 28.
190 ActewAGL, *Regulatory proposal*, p. 42.
191 Wilson Cook, Volume 5, p. 20.

these options have not been fully explored or costed by ActewAGL or Wilson Cook. Any undergrounding program, or street placement of existing backyard reticulation, is likely to represent a very significant capital works and investment program. ActewAGL has not included such a program in its capex proposal, therefore, addressing this issue is beyond the scope of the AER's considerations in making this draft decision.

**Service target performance incentive scheme (STPIS) preparations**

ActewAGL proposed an allowance of $0.5 million during the next regulatory control period to establish additional systems and processes to ensure compliance with the requirements of the AER's national distribution service target performance incentive scheme (national distribution STPIS). The national distribution STPIS will apply to ActewAGL from 1 July 2014.

ActewAGL submitted that due to timing constraints, and uncertainties in the nature and scope of the AER's final national distribution STPIS, it has not been able to develop a detailed plan of the nature of the capex required.[192] ActewAGL noted that any additional expenditure requirements may be quantified following further clarification of the AER's specific information requirements to apply during the next regulatory control period.[193]

The AER reviewed ActewAGL's proposed capex requirement and subsequently sought additional information on the nature of the expected investment. Based on a review of this information, and advice of Wilson Cook, the AER accepts that ActewAGL's forecast capex allowance is necessary to prepare systems and processes for the introduction of the national distribution STPIS from 1 July 2014. The AER considers it important for ActewAGL to establish capabilities to comply with the requirements of the AER's national distribution STPIS, as soon as possible.[194]

The AER notes ActewAGL's submission that it may need to incur further expenditures to achieve full compliance with the national distribution STPIS, following initial works and testing of new capabilities. It is the AER's expectation that any proposal by ActewAGL to recover such expenditures would be made in accordance with the transitional chapter 6 rules, and would be assessed by the AER on its merits at the time.

**Deliverability of the forecast capex program**

ActewAGL submitted it is aware that it will be competing with other Australian distribution businesses, as well as in the broader international market, for resources and expertise to deliver its proposed capex and opex programs.[195] It is proposing to put in place a range of measures to ensure it is sufficiently resourced to deliver its infrastructure program.[196] ActewAGL submitted it has:

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192 ActewAGL, response to request for additional information, 7 August 2008, p. 5.
193 ActewAGL, letter to AER, 26 September 2008, p. 1.
194 The AER's decision on service performance data reporting requirements to apply to ActewAGL during the next regulatory control period is set out at chapter 13 of this draft decision.
195 ActewAGL, *Regulatory proposal*, pp. 111–112.
196 ActewAGL, *Regulatory proposal*, p. 112.

- undertaken a strategic restructuring to focus organisational attention on the delivery of major projects, and has increased its project management and planning staff numbers

- undertaken a resource matching exercise to ensure it has sufficient resources to deliver the expected projects, with ongoing assessment of resource needs during the next regulatory control period

- increased the scope of its apprenticeship program in anticipation of the ongoing escalation of the capex program, and anticipated staff attrition due to retirements

- assumed the use of a combination of in-house and contract-based project delivery measures during the next regulatory control period, and will utilise existing relationships with a number of potential suppliers.[197]

Wilson Cook reviewed ActewAGL's implementation plans and considered there are no reasons to conclude that the necessary resources could not be mobilised to implement the program.[198] It concluded that ActewAGL had put forward a reasonable implementation strategy.

The AER notes that ActewAGL's forecast capex program represents a significant increase compared to current period levels, however, it notes that this increase is driven predominantly by four major projects. The AER considers that ActewAGL has identified the resourcing requirements associated with these projects and has implemented appropriate strategies to meet them, which aligns with Wilson Cook's conclusions.

Having considered ActewAGL's proposed implementation strategy, and the advice of Wilson Cook, the AER is satisfied that the deliverability of the forecast capex program will not be constrained by resource availability. This conclusion is subject to the proviso that ActewAGL can adequately finance its proposed capex program. The AER will monitor ActewAGL's performance on an annual basis to assess the delivery of its capital program.

The AER is also satisfied that the deliverability of ActewAGL's forecast capex program is consistent with the capex objectives generally, and in so far as this aspect is concerned, is satisfied it reasonably reflects the capex criteria.

## 8.7 AER conclusion

The AER considered ActewAGL's proposed forecast capex allowance and, for the reasons set out in this chapter, considers that the proposed capital projects and programs reviewed are consistent with the capex objectives at clause 6.5.7(a) of the transitional chapter 6 rules. However, the AER does not consider ActewAGL's forecast capex allowance satisfies the capex criterion at clause 6.5.7(c)(3) of the transitional chapter 6 rules.

197 ActewAGL, *Regulatory proposal*, p. 112.
198 Wilson Cook, email from Jeffrey Wilson to Mike Buckley, 17 October 2008.

The AER has reviewed ActewAGL's overall proposed forecast capex allowance and, for the reasons set out in this chapter, is not satisfied that the scope of the proposed capital projects and programs reasonably reflects the efficient costs, or a realistic expectation of the demand forecast and cost inputs, a prudent operator in the circumstances of ActewAGL, would require to achieve capex objectives as provided for in the capex criteria at clause 6.5.7(c) of the transitional chapter 6 rules.

While the AER is satisfied that the scope of the forecast system capex program is appropriate and necessary, it considers ActewAGL's application of input cost escalators does not reflect a realistic expectation of the efficient cost inputs required to achieve the capex objectives, as required by clause 6.5.7(c). Following its review of the SKM cost escalation methodology the AER has modified the input cost escalators used by ActewAGL in its regulatory proposal. Specifically, the AER's amended real input cost escalators:

- remove the effect of SKM's assumed 12 month lag in prices for aluminium, copper, steel and oil
- reflect movements in real forecast steel prices
- reflect updated source data where appropriate.

The AER requested ActewAGL to remodel its forecast capex program using these amended input cost escalators, resulting in a reduction of $8.5 million to ActewAGL's capex forecast.[199] After applying the amended input cost escalators, the AER considers that a forecast capex allowance that reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to satisfy the capex objectives at clause 6.5.7(a) and capex criteria at 6.5.7(c) is $278 million.

**Table 8.5: AER's conclusion on ActewAGL's capex allowance ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL's proposed net capex[a] | 79.9 | 59.8 | 53.5 | 53.0 | 40.3 | 286.6 |
| AER's adjustments to cost escalators | –2.2 | –1.6 | –1.6 | –1.8 | –1.5 | –8.5 |
| AER's capex allowance | 77.7 | 58.2 | 51.9 | 51.2 | 38.9 | 277.9 |

(a) These amounts reflect an increase of $8.9 million from ActewAGL's published proposal due to a correction of its cost escalation calculations.

[199] The AER has not fully verified ActewAGL's calculations for the purposes of this draft decision. As such this adjustment is indicative and will be confirmed for the AER's final distribution determination.

## 8.8 AER draft decision

In accordance with clause 6.12.1(3)(ii) of the transitional chapter 6 rules the AER does not accept ActewAGL's forecast capex for the next regulatory control period. The AER is not satisfied that ActewAGL's forecast capex, taking into account the capex factors reasonably reflects the capex criteria in clause 6.5.7 of the transitional chapter 6 rules. The AER's reasons for this decision are set out in section 8.6 of the draft decision. The AER's estimate of the total capex required by ActewAGL in the next regulatory control period, that reflects the capex criteria taking into account the capex factors, is set out in table 8.5 of the draft decision.

# 9 Forecast operating expenditure

## 9.1 Introduction

This chapter sets out ActewAGL's opex proposal, submissions from interested parties, a summary of consultants' reviews and the AER's conclusion on ActewAGL's opex allowance for the next regulatory control period.

The opex forecasts in ActewAGL's proposal refer to its requirements for the provision of standard control services during the next regulatory control period. The AER has reviewed ActewAGL's opex proposal against the requirements of the transitional chapter 6 rules.

## 9.2 Regulatory requirements

Under clause 6.12.1(4) of the transitional chapter 6 rules, the AER must make a decision to accept or not accept the forecast opex included in a building block proposal. If the AER does not accept the proposal it must form its own estimate in accordance with the opex criteria and factors outlined in clause 6.5.6 of the transitional chapter 6 rules.

### 9.2.1 Opex objectives

Clause 6.5.6(a) of the transitional chapter 6 rules provides that a distribution network service provider (DNSP) must include the total forecast opex for the regulatory control period in order to achieve the following opex objectives:

> (1) meet or manage the expected demand for standard control services over that period;
>
> (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
>
> (3) maintain the quality, reliability and security of supply of standard control services; and
>
> (4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

### 9.2.2 Opex criteria and factors

Clause 6.5.6(c) of the transitional chapter 6 rules also provides that the AER must accept the opex forecast included in a regulatory proposal if it is satisfied that the total of the forecast opex for the regulatory control period reasonably reflects:

> (1) the efficient costs of achieving the opex objectives; and
>
> (2) the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

In making this assessment the AER must have regard to the following opex factors:

(1) the information included in or accompanying the building block proposal;

(2) submissions received in the course of consulting on the building block proposal;

(3) any analysis undertaken by or for the AER and published before the distribution determination is made in its final form;

(4) benchmark opex that would be incurred by an efficient DNSP over the regulatory control period;

(5) the actual and expected opex of the DNSP during any preceding regulatory control periods;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between opex and capex;

(8) whether the total labour costs included in the capex and opex forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;

(9) the extent to which the forecast of required opex of the DNSP is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms; and

(10) the extent the DNSP has considered, and made provision for, efficient non–network alternatives.

Clause 6.5.6(d) of the transitional chapter 6 rules states that, if the AER is not satisfied that a DNSP's forecast opex reasonably reflects the opex criteria, then the AER must not accept the forecast opex in a building block proposal. If the AER does not accept the total forecast opex proposed by a DNSP, clause 6.12.1(4)(ii) of the transitional chapter 6 rules requires the AER to include in its draft decision:

> …an estimate of the total of the DNSP's required opex for the regulatory control period that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

## 9.3 ActewAGL proposal

ActewAGL's forecast opex for the next regulatory control period is $306 million ($2008–09), which is $81 million greater than its expected opex in the current regulatory control period. ActewAGL's opex costs have been split into the following major categories:[200]

- network opex
- network maintenance expenditures
- other expenditures

[200] ActewAGL, *Regulatory proposal*, p. 199.

- debt raising costs
- utilities network facilities tax (UNFT).

ActewAGL identified the following significant cost drivers:[201]

- increases in real wages and cost of raw materials
- asset base growth
- introduction of an enhanced pole inspection program
- additional activities associated with the vegetation and bushfire mitigation inspection and management program.

Table 9.1 sets out ActewAGL's forecast opex by cost category and year for the next regulatory control period. Figure 9.1 shows ActewAGL's actual and expected opex in the current regulatory control period, and its forecast opex for the next regulatory control period.

**Table 9.1: ActewAGL's opex proposal by category and year ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Network opex | | | | | | |
| Network operations | 13.4 | 13.9 | 14.3 | 15.4 | 15.8 | 72.8 |
| Maintenance expenditure | 16.8 | 16.9 | 16.8 | 17.1 | 16.3 | 83.9 |
| Other expenditures | 22.7 | 23.1 | 23.9 | 24.3 | 24.7 | 118.6 |
| Total network opex | 52.9 | 53.9 | 55.0 | 56.8 | 56.8 | 275.3 |
| Non-controllable opex | | | | | | |
| Debt raising costs | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 1.8 |
| Self insurance costs | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 7.5 |
| UNFT | 4.0 | 4.1 | 4.2 | 4.3 | 4.4 | 20.9 |
| Total opex | 58.7 | 59.9 | 61.1 | 63.0 | 63.1 | 305.5 |

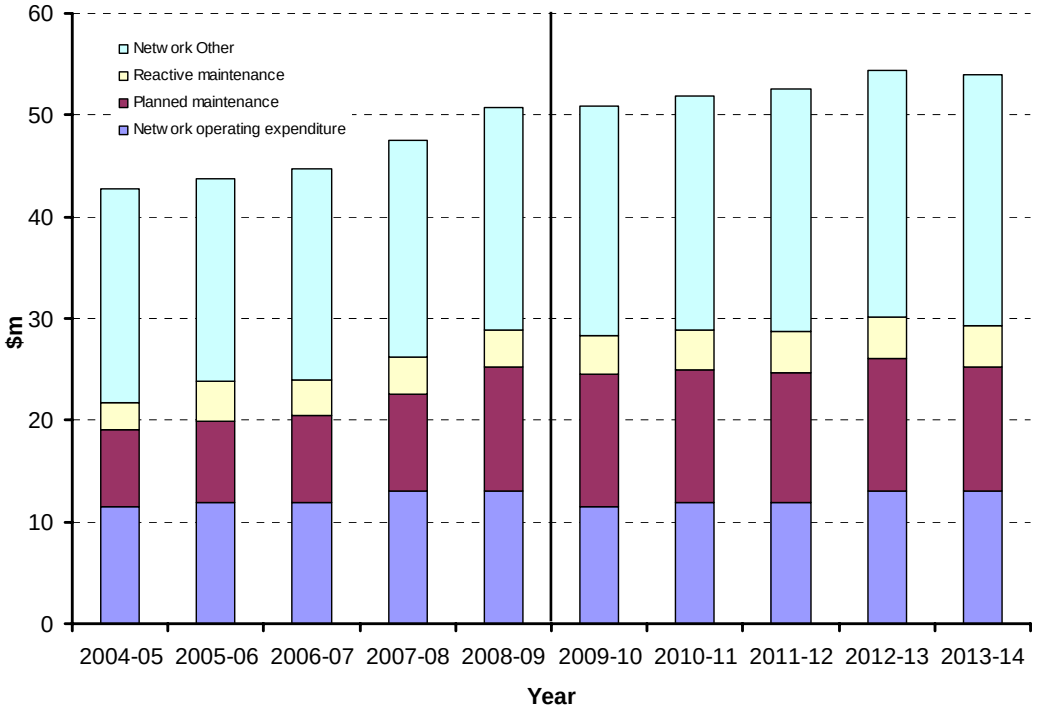
Source: ActewAGL, *Regulatory proposal*, table 8.19, p. 199.
Note: Totals may not add up due to rounding.

ActewAGL has used both base year and zero base methodologies in forecasting its opex for the next regulatory control period.[202] The base year method involves defining an efficient base year for its opex and modelling the impact of future cost drivers and efficiency factors on all components of its base year expenditure. The zero based approach to forecasting has been used where it considered the base year did not

[201] ActewAGL, *Regulatory proposal*, pp. 164–165.
[202] ActewAGL, *Regulatory proposal*, pp. 167–168.

accurately reflect the future expenditure requirements due to lack of historical information. Zero based forecasts are derived from bottom up estimates of annual costs for the expenditure category.

**Figure 9.1: ActewAGL's actual and forecast opex 2004–2014 ($m, 2008–09)**




Source: ActewAGL, RIN, profroma 2.2.2.

## 9.4 Submissions

The EMRF stated that ActewAGL seems to be seeking opex well in excess of its historical trend, and this is not in keeping with its need to prove that there has been a real step change or a need to match the growth in demand. The EMRF also noted that ActewAGL's expected opex was close to the ICRC allowance in the current regulatory control period.[203]

## 9.5 Consultant review

Wilson Cook reviewed ActewAGL's regulatory proposal, including ActewAGL's forecasting methodology for opex (including base year extrapolation and zero base estimates). Wilson Cook did not review debt raising costs.

Wilson Cook examined the base year and zero based forecasting methodology used by ActewAGL using a top down approach as well as a bottom up review of the appropriateness of forecast opex requirements.[204]

[203] EMRF, p. 29.
[204] Wilson Cook, Volume 5, pp. 33–39.

Wilson Cook tested the prudence and efficiency of the proposed overall opex expenditure, and stated that it:[205]

- reviewed the policies and procedures by which ActewAGL makes its operational and investment decisions
- reviewed cost allocations by category including network operational expenditure, planned and reactive maintenance expenditure and other operating costs
- tested the magnitude of the opex forecasts submitted by ActewAGL by examining the application of the submitted policies, procedures and unit costs to ActewAGL's networks for the next regulatory control period
- tested the effectiveness of ActewAGL's operating practices and procedures and asset management system in ensuring only necessary and efficient opex occurs
- examined the appropriateness of any trade–off between capex and opex.

Wilson Cook has not recommended any adjustment to ActewAGL's controllable opex.[206] Wilson Cook's review of specific opex components is discussed in sections 9.6.2 to 9.6.6 of this chapter.

## 9.6 Issues and AER considerations

### 9.6.1 Forecast methodology

**ActewAGL proposal**

ActewAGL has forecast its opex by escalating its base year estimates for its reactive maintenance, network operations and other opex costs and using zero based estimates for planned network maintenance, debt raising, self insurance and UNFT.[207]

To escalate base year expenditures ActewAGL has used forecast CPI for non–labour costs, and Econtech labour cost growth forecasts for the Australian utilities sector for labour costs. Base year expenditures are adjusted to add costs that would be required in the future but are not already included.[208]

ActewAGL has increased its base year estimates to take account of changes in expenditure patterns for:[209]

- network operations – quality, environmental and safety systems ($0.22 million) and network systems obligations ($0.11 million)
- other opex expenditure – training apprenticeship and engineers ($0.75 million).

[205] Wilson Cook, Volume 5, pp. 32–39.
[206] Wilson Cook, Volume 5, p. 44.
[207] ActewAGL, *Regulatory proposal*, pp. 167–168.
[208] ActewAGL, *Regulatory proposal*, pp. 168–173.
[209] ActewAGL, *Regulatory proposal*, p. 168.

ActewAGL's zero based forecasts for planned maintenance costs are derived using historical opex. The bottom up approach also takes into account the detailed requirements of the asset management plan (AMP).[210]

ActewAGL stated its proposed self insurance costs were estimated by SAHA International (SAHA), taking into account risk mitigation strategies. Its debt raising costs were derived using the post tax revenue model (PTRM) and its UNFT obligations were estimated by reference to the ACT government UNFT revenue projections.[211]

***Efficiency assumptions***

In preparing its opex forecasts for the next regulatory control period, ActewAGL stated it did not directly adjust for growth in customer numbers or the size of its network.[212]

**Consultant review**

Wilson Cook did not provide a specific assessment of ActewAGL's forecasting methodology. Instead it reviewed ActewAGL's forecast opex from both a top down and bottom up perspective. In its bottom up review of specific forecasts Wilson Cook did not note any methodological deficiencies in ActewAGL's forecasting model.[213]

**AER considerations**

ActewAGL's methodology is similar to opex forecasting methodologies used by other NSPs in Australia. The AER accepts the use of zero based estimates for some opex components, as well as extrapolation of base year opex for the remaining opex categories. Specific issues regarding the methodology and forecasts are considered in the sections 9.6.2 – 9.6.9 of this chapter.

### 9.6.2 Efficient base year

**ActewAGL's proposal**

ActewAGL used 2006–07 as the base year for forecasting opex in the next regulatory control period, noting that it is the most recent year for which audited financial accounts are available.[214] However, it used 2008–09 as the base year for corporate services expenditure, because the corporate services cost structure changed due to the sale of the corporate headquarters.

ActewAGL did not make any deductions from the base year opex, stating it expected all activities included in the base year to continue throughout the next regulatory control period.[215]

ActewAGL increased the following elements of its network operating costs in the base year so that the starting point for the forecasts reflected the expected cost base for future years:[216]

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210 ActewAGL, *Regulatory proposal*, p. 167.
211 ActewAGL, *Regulatory proposal*, pp. 193–194.
212 ActewAGL, *Regulatory proposal*, p. 168.
213 Wilson Cook, Volume 5, pp. 33–39.
214 ActewAGL, *Regulatory proposal*, p. 168.
215 ActewAGL, *Regulatory proposal*, p. 168.

- network systems operations arising from new obligations
- quality, environmental and safety measures
- executive and financial management

These adjustments increase the base year by $0.6 million ($2006–07). Other base year adjustments are applied to forecasts for specific years for IT support services ($45 000 in 2010–11 to 2013–14) and other network operating costs ($0.6 million in 2012–13 and 2013–14).

ActewAGL noted that corporate services opex has been escalated based on 2008–09 cost levels, to take account of the new cost structure arising from the sale of ActewAGL's corporate headquarters.[217]

ActewAGL stated its distribution business should not be benchmarked against energy supplied or system demand. Furthermore, its small electricity network business with its unique attributes should not be compared with larger DNSPs. It stated its overhead costs in terms of support systems, covering financial, billing, asset management and geographical information systems, customer contact centres, control centres and corporate functions are expected to represent a larger proportion of operating costs for smaller businesses when compared to larger entities.[218]

**Consultant review**

Wilson Cook stated it did not consider that ActewAGL has demonstrated its base year is an efficient starting point for forecasting opex. Wilson Cook noted its benchmarking comparisons suggest that ActewAGL's proposed base year opex was around 20 per cent above the industry norm.[219] It formed this view by considering:[220]

- ActewAGL's opex performance during the current regulatory control period
- ActewAGL's performance compared to the performance of other DNSPs
- the cost drivers unique to ActewAGL's operating and maintenance activities.

Wilson Cook compared all businesses based on the relationship of total opex versus a composite size variable. It determined that the composite size variable was a valid measure on which to make a high–level comparison of businesses with different network characteristics.[221]

Wilson Cook also considered factors that could contribute to ActewAGL's higher opex in comparison to other DNSPs:[222]

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216 ActewAGL, *Regulatory proposal*, p. 167–168 and 173.
217 ActewAGL, Site presentation, July 10–11, 2008.
218 ActewAGL, *Regulatory proposal*, pp. 184–185.
219 Wilson Cook, Volume 5, p. 33.
220 Wilson Cook, Volume 1, section 3.
221 Wilson Cook, Volume 1, p. 18.
222 Wilson Cook, Volume 5, pp. 33–35.

- ActewAGL has a relatively low level of allocation of overhead to direct maintenance and capital costs compared to the other DNSPs

- ActewAGL leases its motor vehicles and computer equipment, resulting in higher corporate overheads compared to companies that own these assets

- ActewAGL had submitted that it is a small distributor in terms of customer numbers and network size but still bears fixed costs such as compliance and billing and thus is not able to achieve the same economies of scale as bigger distributors.

While acknowledging these factors, Wilson Cook stated it had not been provided with evidence that they account for a cost structure that is around 20 per cent above the industry norm.[223] However, Wilson Cook noted improvements in ActewAGL's relative opex per size over the next regulatory control period, and did not recommend any adjustment to the proposed base year.

**AER considerations**

The base year from which opex is forecast should be representative of efficient expenditure by a DNSP.

ActewAGL's proposed base year is 2006–07. In this year its actual opex was equal to its regulatory allowance. ActewAGL has also estimated that its total opex in the current regulatory control period will be equal to its allowance, as determined by the ICRC, in its 2004 determination.[224]

However, the AER considers that as the base year is only used to forecast some components of total opex, the efficiency of the base year excluding zero based components and abnormal expenditures also needs to be established. The AER has compared ActewAGL's base year expenditure to the opex allowance provided by the ICRC in its 2004 revenue determination. The AER has estimated that the adjusted base year expenditure by ActewAGL (excluding zero based components) was $1.5 million less than the adjusted opex allowance included in the ICRC 2004 pricing decision (excluding zero based components).[225]

The AER notes Wilson Cook's conclusion on the overall efficiency of ActewAGL's opex in 2006–07. The implication of Wilson Cook's finding is that the efficient opex allowance provided by the ICRC is on the high side of a range of opex allowances that could be considered efficient. The ICRC recognised that the opex proposed by ActewAGL was high and applied a productivity improvement factor to its allowance.[226] The ICRC is likely to have been cautious in setting a productivity target and ActewAGL's underspend is consistent with a conservative target.

However, Wilson Cook has not recommended a specific base year adjustment and noted ActewAGL's efficiency improvement (in comparison to the NSW DNSPs) by the end of the next regulatory control period. The AER has therefore decided not to

223 Wilson Cook, Volume 5, p. 34.
224 ActewAGL, *Regulatory proposal*, p. 161.
225 ActewAGL, email response to questions, 15 October 2008; ActewAGL, RIN proforma 2.2.2.
226 ICRC, *Final decision*, pp. 84–85.

adjust the base year expenditure. The need to apply an overall productivity improvement is discussed in section 9.7 of this chapter.

Given ActewAGL's actual opex in the base year has been verified by an audit of the regulatory information provided to the AER and is around 4 per cent less than the adjusted opex allowance provided by the ICRC, the AER considers it represents an efficient amount from which to forecast opex in the next regulatory control period.

### 9.6.3 Network operations

Network operations opex includes costs associated with network management, network systems operations and control, network support systems and planning and control. ActewAGL's network operations opex was around $61 million in the current regulatory control period, increasing from $11 million in 2004–05 to $13 million in 2008–09 ($2008–09).

**ActewAGL proposal**

ActewAGL forecast its networks operations opex using base year extrapolation, for all components of network operations expenditures. It used weighted utilities sector labour cost growth forecasts and CPI forecasts to extrapolate the network operations opex component, except for executive and financial management. The labour costs for executive and financial management were escalated by a corporate services escalator.[227] As noted in section 9.6.2, ActewAGL increased the base year opex for the following components: network systems operations; IT support, quality environmental and safety systems; executive and financial management; and other network operating costs.

The network operations component, other network operations, includes ActewAGL's annual licence fee from the ICRC, the new energy industry levy, and regulatory review costs.[228] The annual licence fee from the ICRC and the energy industry levy is now combined into one levy, the Energy industry levy.

Table 9.2 sets out ActewAGL's proposed network operations expenditure.

[227] ActewAGL, *Regulatory proposal*, p. 167–173.
[228] ActewAGL, *Regulatory proposal*, p. 173.

**Table 9.2: ActewAGL's proposed network operations expenditure ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Network control | 3.8 | 3.9 | 4.0 | 4.1 | 4.2 | 20.0 |
| IT planning and operations | 0.8 | 0.9 | 0.9 | 0.9 | 0.9 | 4.4 |
| Network systems operations | 3.0 | 3.1 | 3.1 | 3.2 | 3.3 | 15.6 |
| Quality environmental and safety systems | 1.3 | 1.3 | 1.3 | 1.4 | 1.4 | 6.6 |
| Executive and financial management | 1.8 | 1.8 | 1.9 | 2.0 | 2.0 | 9.5 |
| Other network operations costs | 2.9 | 3.0 | 3.0 | 3.8 | 3.9 | 16.6 |
| Total network operations expenditures | 13.4 | 13.9 | 14.3 | 15.4 | 15.8 | 72.8 |

Source: ActewAGL, *Regulatory proposal*, table 8.6, p. 174.

**Consultant review**

Wilson Cook noted the cost drivers impacting on network operations opex include increased customer enquiries relating to network connection and modification advice, increased system switching costs due to customer initiated works and the asset replacement program, the implementation of full retail contestability, increase in the ICRC licence fee and the introduction of an industry levy by the ACT government.[229]

Wilson Cook also noted step increases in costs due to new regulatory obligations and an allowance for the next regulatory price review in 2012–13 and 2013–14.[230]

Wilson Cook found the estimates to be consistent with ActewAGL's methodology, except for executive and financial management component. Wilson Cook noted the increase between the base year and 2009–10 was greater than that resulting from the standard cost escalations, but noted ActewAGL had provided information stating the difference arose from the creation of a team to oversee the capex program.[231]

**AER considerations**

***Base year adjustments***

Base year adjustments to network operations opex (network systems operations, quality environmental and safety systems, and executive and financial management) increase the base year by $0.6 million. The adjustments relate to new obligations associated with the *Planning and Development Act 2007(ACT)* and occupational health and safety obligations.

The AER has reviewed the base year data and considers the adjustments proposed by ActewAGL are necessary to ensure the forecast opex reflects the efficient costs a

229 Wilson Cook, Volume 5, pp. 35–36.
230 Wilson Cook, Volume 5, pp. 35–36.
231 Wilson Cook, Volume 5, pp. 35–36.

prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

***IT support***

ActewAGL noted that costs associated with implementing the national service target performance incentive scheme (STPIS) have been included in this cost category.[232] ActewAGL proposed that $45 000 per annum, would be required for on going opex associated with STPIS activities.[233] STPIS related costs account for about half of the opex associated with IT planning and operations for the years 2010–11 onwards. Specific issues regarding the STPIS are considered in chapter 13 of this draft decision.

The AER has reviewed the base year data and considers the adjustments proposed by ActewAGL are necessary to ensure the forecast opex reflects the efficient costs a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

***Regulatory price review***

ActewAGL's base year costs for the regulatory price review are zero, but the forecasting methodology increases the base year by $0.6 million when forecasting the opex for 2012–13 and 2013–14. Regulatory price review costs are only included in those two years of the next regulatory control period.

The AER considers that costs for the regulatory review are a valid inclusion in opex forecasts. It notes ActewAGL has forecast its requirement based on budget projections for the current regulatory review process. The AER considers the proposed opex for this cost component represents the efficient costs a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

***Conclusion***

The AER considers that base year escalation is an appropriate methodology to forecast network operations expenditures. It has reviewed the escalators in section 9.6.7 and considers the revised escalators are appropriate for this opex component. Overall the AER considers that ActewAGL's proposed network operations opex (adjusted to reflect the revised escalators) reflects the efficient costs a prudent operator in the circumstances of ActewAGL would require to meet the opex objectives, as required by clause 6.5.6(c).

### 9.6.4 Network maintenance

**ActewAGL proposal**

ActewAGL stated its maintenance strategy is based on its AMP. Its AMP is used for planning and analysis of maintenance requirements and for ensuring compliance with applicable legislation. ActewAGL divided network maintenance into two categories: planned and reactive. Each of these categories is further disaggregated into five

[232] ActewAGL, *Regulatory proposal*, p. 322.
[233] ActewAGL, *Regulatory proposal*, pp. 70, 322.

specific maintenance categories: zone substations; sub–transmission; underground; overhead; and distribution station.[234]

Network maintenance accounts for around 28 per cent of total opex in the current and next regulatory control periods. Table 9.3 compares ActewAGL's maintenance opex in the current and next regulatory control periods.

**Table 9.3: ActewAGL's total maintenance opex, ($m, 2008–09)**

| | 2004–09 | 2009–14 |
|---|---|---|
| Planned maintenance | | |
| Zone substation | 8.2 | 10.4 |
| Sub–transmission | 1.2 | 1.9 |
| Underground | 0.6 | 1.8 |
| Overhead | 30.6 | 39.5 |
| Distribution station | 5.1 | 10.5 |
| Total planned | 49.0 | 64.1 |
| Reactive maintenance | | |
| Zone substation | 0.7 | 0.9 |
| Sub–transmission | 0.1 | 0.1 |
| Underground | 6.4 | 6.6 |
| Overhead | 9.3 | 11.1 |
| Distribution station | 0.9 | 1.1 |
| Total reactive | 17.4 | 19.8 |
| Total maintenance | 63.0 | 83.9 |

Source: ActewAGL, *Regulatory proposal*, table 8.7 and table 8.8.
Note: ActewAGL's data has been converted to $2008–09 using the CPI data provided by ActewAGL.

ActewAGL stated the increase in total maintenance opex is due to increased planned maintenance in the next regulatory control period. However, it noted that both planned and reactive maintenance are stable across all years in the next regulatory control period, with the bulk of the increase in planned maintenance opex occurring in the final two years of the current regulatory control period.[235] These costs are increasing relative to the base year due to:[236]

- a new condition monitoring approach based around a five-yearly inspection and maintenance cycle
- increased pole inspections and a program for restoring access tracks to a reusable condition after being damaged during the major bushfires in 2001 and 2003
- changes in employee safety obligations resulting in modifications to work methods, access procedures and engineering controls.

[234] ActewAGL, *Regulatory proposal*, p. 175.
[235] ActewAGL, *Regulatory proposal*, pp. 175–179.
[236] ActewAGL, *Regulatory proposal*, p. 176.

#### 9.6.4.1 Planned maintenance

Planned maintenance includes inspection of assets, scheduled preventative maintenance, vegetation management and scheduled repair of identified defects.

**ActewAGL proposal**

ActewAGL stated planned maintenance accounted for 72 per cent of total maintenance costs in the current regulatory control period, and is forecast to increase to 76 per cent in the next regulatory control period. It noted planned maintenance costs have been forecast using historical rates and other non–material unit rates.[237] ActewAGL's proposed planned maintenance expenditure is shown in table 9.4.

**Table 9.4: ActewAGL's proposed planned maintenance expenditure ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Zone substation | 2.0 | 2.1 | 2.1 | 2.2 | 2.1 | 10.4 |
| Sub–transmission | 0.6 | 0.5 | 0.3 | 0.2 | 0.2 | 1.8 |
| Underground | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 1.8 |
| Overhead | 8.1 | 8.0 | 7.9 | 8.0 | 7.5 | 39.5 |
| Distribution station | 2.0 | 2.1 | 2.1 | 2.2 | 2.1 | 10.5 |
| Total planned maintenance | 13.0 | 13.0 | 12.8 | 13.0 | 12.2 | 64.1 |

Source: ActewAGL, *Regulatory proposal*, p. 177.

ActewAGL stated that overhead planned maintenance has increased throughout the current regulatory control period due to costs associated with pole inspections and a program for restoring access tracks to a reusable condition after being damaged during the major bushfires in December 2001 and January 2003.[238]

Planned maintenance for distribution and zone substations is forecast to increase in 2008–09 as ActewAGL must comply with a wide range of obligations to ensure employee safety. It stated developments in OHS standards are such that previously acceptable work methods or installation arrangements are no longer considered to provide a safe work environment.[239]

After the benefits of the step increase in planned overhead maintenance are realised, these costs are forecast to stabilise and decrease towards the end of the next regulatory control period. The maintenance expenditures for sub–transmission assets are expected to decrease after the completion of major track maintenance works. Planned maintenance costs for zone substations, distribution substations and underground assets are forecast to be stable throughout the next regulatory control period.[240]

[237] ActewAGL, *Regulatory proposal*, pp. 175 and 168.
[238] ActewAGL, *Regulatory proposal*, p. 176.
[239] ActewAGL, *Regulatory proposal*, p. 177.
[240] ActewAGL, *Regulatory proposal*, p. 177.

**Consultant review**

Wilson Cook reviewed the maintenance plans included in the AMP, including ActewAGL's budgeted costs. It found that the proposed work programs were consistent with ActewAGL's policies and that the expenditure proposed was consistent with the schedule of works in the AMP. Wilson Cook noted the step changes in the maintenance program, and the resulting requirement to use zero based estimates for planned maintenance. It also stated that labour cost escalators have been applied to derive the planned maintenance forecasts but that other cost have been held constant in real terms. Further, the time allowances for the various tasks were reviewed by Wilson Cook and considered reasonable.[241]

Overall Wilson Cook considered that the increases in planned maintenance are justified and based on prudent network management practice.[242]

**AER considerations**

ActewAGL has justified its proposal to forecast planned maintenance using a zero based approach because of significant changes in planned maintenance activities between the base year and the next regulatory control period. These changes impact on all categories of planned maintenance and have been driven by a change to the maintenance cycle as well as regulatory changes. The AER notes Wilson Cook's review of the planned maintenance forecasts and is satisfied that these changes have had a real impact on planned maintenance costs and that a zero based forecasting methodology is appropriate.

The AER also notes Wilson Cook's assessment that the maintenance plans were consistent with ActewAGL's policies, and the schedule of works in its AMP. The forecasts of planned maintenance costs were derived using labour cost escalators and CPI escalators for non-labour components. These escalators are subject to adjustment, as noted in section 9.6.7 of this draft decision, and hence the forecasts for planned maintenance will vary from that proposed by ActewAGL.

Based on Wilson Cook's advice the AER considers ActewAGL's planned maintenance proposal demonstrates that ActewAGL's proposed planned maintenance opex (with adjustments to the cost escalators) represents the efficient costs a prudent operator in the circumstances of ActewAGL would require to meet the opex objectives, as required by clause 6.5.6(c).

#### 9.6.4.2 Reactive maintenance

**ActewAGL proposal**

ActewAGL has forecast reactive maintenance by extrapolating the 2006–07 base year expenditure, using Econtech labour cost growth forecasts and CPI for labour and non-labour costs, respectively.[243] ActewAGL's forecast reactive maintenance costs are shown in table 9.5.

241 Wilson Cook, Volume 5, pp. 37-38.
242 Wilson Cook, Volume 5, p. 38.
243 ActewAGL, *Regulatory proposal*, pp. 168–173.

**Table 9.5: ActewAGL's proposed reactive maintenance expenditure ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Zone substation | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.9 |
| Sub–transmission | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |
| Underground | 1.3 | 1.3 | 1.3 | 1.4 | 1.4 | 6.6 |
| Overhead | 2.1 | 2.2 | 2.2 | 2.3 | 2.3 | 11.1 |
| Distribution station | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 1.1 |
| Total reactive maintenance | 3.8 | 3.9 | 4.0 | 4.1 | 4.1 | 19.8 |

Source: ActewAGL, *Regulatory proposal*, table 8.8, p. 177.

ActewAGL stated that reactive maintenance expenditures increased by $1 million during the current regulatory control period as a result of ageing assets. In the next regulatory control period, ActewAGL stated that expenditure would only increase by $0.3 million as reactive maintenance is replaced by less costly planned maintenance.[244]

**Consultant review**

Wilson Cook reviewed ActewAGL's reactive maintenance forecasts and found the estimates for reactive maintenance were consistent with ActewAGL's methodology and historical expenditure levels. It concluded that the forecast reactive maintenance opex was reasonable.[245]

**AER considerations**

The AER has reviewed ActewAGL's proposed reactive maintenance expenditure estimates and the methodology used to derive them. It considers that the methodology is robust but notes that the conclusions on labour cost escalators noted in section 9.6.7 will impact on these forecasts.

The AER has also considered Wilson Cook's findings. Based on Wilson Cook's advice the AER considers ActewAGL's reactive maintenance proposal demonstrates that ActewAGL's proposed reactive maintenance opex (with adjustments to the cost escalators) represents the efficient costs a prudent operator in the circumstances of ActewAGL would require to meet the opex objectives, as required by clause 6.5.6(c).

### 9.6.5 Other operating costs

**ActewAGL proposal**

ActewAGL has described its other operating costs as including:[246]

- advertising and marketing

[244] ActewAGL, *Regulatory proposal*, pp. 176 and 178.
[245] Wilson Cook, Volume 5, p. 38.
[246] ActewAGL, *Regulatory proposal*, pp. 179–180.

- corporate management fee
- business services provided by ActewAGL Retail
- apprentice training program
- business overheads
- regulated miscellaneous charges
- external business expenditure.

ActewAGL stated that to forecast this expenditure it reviewed historical costs and trends, applied labour and CPI escalators and assessed the regulatory requirements.[247]

ActewAGL stated it made a specific adjustment to the apprenticeship training program to account for both the increased scope of the program during the current regulatory control period, and its intention to maintain the program throughout the next regulatory control period. It noted that it will maintain the number of trainees in the program throughout the next regulatory control period to counter the need for increased staff to deal with increasing maintenance and capital activity, and increases in planned retirement of existing staff.[248]

ActewAGL's proposed opex for other operating costs is set out in table 9.6. ActewAGL noted other opex will increase by $0.9 million in 2009–10, compared to 2008–09, and stated the increase is due to higher operating costs in relation to leasing corporate headquarters, rather than owning the building.[249]

**Table 9.6: ActewAGL's proposed other operating costs ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Advertising and marketing | 1.1 | 1.1 | 1.1 | 1.1 | 1.2 | 5.6 |
| Corporate management fee | 10.8 | 11.0 | 11.5 | 11.8 | 12.0 | 57.0 |
| Business services provided by ActewAGL Retail | 2.2 | 2.2 | 2.2 | 2.3 | 2.3 | 11.2 |
| Apprentice training program | 5.0 | 5.2 | 5.3 | 5.4 | 5.5 | 26.4 |
| Business overheads | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 11.8 |
| Regulated miscellaneous charges | 1.3 | 1.3 | 1.3 | 1.3 | 1.4 | 6.6 |
| External business expenditure (net) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total other expenditure | 22.7 | 23.1 | 23.9 | 24.3 | 24.7 | 118.6 |

Source: ActewAGL, *Regulatory proposal*, p. 182.

247 ActewAGL, *Regulatory proposal*, pp. 167–173.
248 ActewAGL, *Regulatory proposal*, p. 168.
249 ActewAGL, *Regulatory proposal*, p. 165.

**Consultant review**

Wilson Cook reviewed ActewAGL's other opex forecasts and noted that there are two step changes between the base year and the first year of the next regulatory control period. The corporate management fee increases due to the lease costs of the new corporate headquarters and there is a further increase in apprenticeship costs.

Wilson Cook found the step changes applied to the base year opex small and reasonable, and overall found the forecast associated with this cost category consistent with the methodology outlined by ActewAGL.[250]

**AER considerations**

The AER notes ActewAGL's other opex has been forecast using base year extrapolation. The inclusion of marketing costs and costs of customer services provided by ActewAGL Retail has been permitted under ActewAGL's cost allocation method. The cost allocation method approved by the AER reflects the NER requirement to adopt the cost allocation method approved by the ICRC in the current regulatory control period.[251]

The AER reviewed the base year data adjustments for the apprenticeship and training program, and the corporate management fee.

The AER notes ActewAGL has incorporated a step increase in its apprentice training program costs to reflect the cost of additional apprentices and trainees in the next regulatory control period. ActewAGL stated that apprentice numbers will be maintained at the higher level throughout the next regulatory control period and hence the step change to the base year costs is required.[252]

The AER considers that training and apprenticeship programs are a valid tool in addressing staff shortages facing NSPs in Australia. The increase in numbers participating in ActewAGL's apprenticeship and training program should help ease the labour shortage facing ActewAGL in the next regulatory control period.

The AER considers that the costs included in the apprentice and training program cost estimates do not double count retention benefits and are appropriately extrapolated. The step change has been estimated as the cost of additional apprentices required to increase the number of participants in the apprenticeship and trainee program in 2006–07 to 72. ActewAGL proposes to maintain participant numbers in the program at 72 in each year of the next regulatory control period.[253] The AER considers the adjustment to the base year opex provides an adequate basis from which to forecast apprenticeship and training program costs.

ActewAGL has also adjusted its base year for the corporate management cost forecasts to take into account the cost impact of the sale of its existing corporate headquarters and the leasing of its new corporate headquarters. The AER considers this adjustment provides an adequate basis from which to forecast corporate and management costs.

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250 Wilson Cook, Volume 5, p. 39.
251 AER, *ActewAGL cost allocation method – Final decision*, March 2008, p. 6.
252 ActewAGL, email response to AER, 15 October 2008.
253 ActewAGL, email response to AER, 15 October 2008.

The adjusted base year data for each component of other opex expenditure is extrapolated using the corporate services labour cost growth index for labour costs and CPI escalator for non–labour costs. The adjustments to ActewAGL's cost escalators, discussed in section 9.6.7, will impact on the forecasts of other opex costs. The AER considers that ActewAGL's proposed other opex forecast (as adjusted for revised escalation rates) reflects the efficient costs a prudent operator in the circumstances of ActewAGL would require to meet the opex objectives, as required by clause 6.5.6(c).

### 9.6.6 Capex/opex trade off

**ActewAGL proposal**

ActewAGL stated that the level of opex will increase, other things being equal, as an electricity distribution system ages. It engaged SKM to construct a model which reflects the profile of increasing opex with increasing asset age, for each different class of assets (for example, distribution overhead, distribution underground, substations).[254]

It stated the model demonstrated the relationship between opex and age which would provide insight into the potential trade off between capex and opex. For specific projects where a trade off between capex and opex exists, such as for asset maintenance and replacement, various options are considered with respect to achieving the lowest life cycle cost. This process is undertaken as part of the AMP and results in maintenance savings where the trade off between capex and opex is applicable.[255]

ActewAGL also stated it can be demonstrated that as a system ages, it will require increasing corrective and emergency maintenance.[256] In ActewAGL's case, the modelling suggests that this additional opex amounts to about $1.4 million ($2007–08) on average per annum from 2007–08 to 2013–14. As older assets are replaced, the required opex declines.

**Consultant review**

Wilson Cook reviewed the modelling presented by ActewAGL and had the following comments:[257]

- The relationship derived from the analysis is or ought to be restricted principally to maintenance costs and should not to be applied more widely, e.g. to opex as a whole or to opex categories unrelated to network condition.
- Quantitatively, the analysis begs the questions:
  - whether the present maintenance costs are efficient
  - whether the costs of maintaining new assets are comparable with those of maintaining old ones

254 ActewAGL, *Regulatory proposal*, pp. 113 and 168.
255 ActewAGL, *Regulatory proposal*, p. 116.
256 ActewAGL, *Regulatory proposal*, p. 113.
257 Wilson Cook, Volume 5, pp. 32–33.

- why the curve should be exponential?

Wilson Cook stated the answers to the preceding questions are not clear. It stated that although intuitively a relationship would appear to exist, evidence available from New Zealand suggests that direct costs may not increase exponentially with the average age of the network components.[258]

**AER considerations**

The AER notes the expectation that an increase in replacement (non–load driven) capex will result in a fall in opex, as the maintenance effort required for new assets is less than that required for old assets. However, when reviewing the capex and opex in total it must also be remembered that augmentation capex will over time, all other things being equal, increase the total opex, as it results in a bigger network needing to be maintained.

The AER considers that the issue of the capex/opex trade off principally relates to how any efficiencies resulting from the capex program can be incorporated into the opex forecasts. In ActewAGL's case this has been done by:

- not increasing opex to reflect the growth in the network expected in the next regulatory control period

- using the AMP, and the trade off model it had developed to assess cost impacts of different options for managing specific assets.

The AER is satisfied that the efficiencies implicit in the opex modelling adequately address the capex/opex trade off and are appropriate for developing the efficient costs a prudent operator in the circumstances of ActewAGL would require to meet the opex objectives, as required by clause 6.5.6(c).

## 9.6.7 Cost escalators

### 9.6.7.1 Labour costs

**ActewAGL proposal**

***EGW wage escalator***

ActewAGL obtained advice from SKM on annual labour cost escalators for the electricity, gas and water (EGW) or utility sector in the ACT.[259] SKM compared labour forecasts produced by Access Economics, BIS Shrapnel and Econtech for the Australian utility sector. SKM recommended that ActewAGL adopt the national forecast produced by Econtech for the Australian utility sector as an appropriate estimate of labour cost growth in the utility sector in the ACT.[260] ActewAGL stated that the proportion of labour costs in total opex is approximately 70 per cent.[261] The labour escalators adopted by ActewAGL as a measure of wage growth in the utility sector in the ACT are set out in table 9.7.

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258 Wilson Cook, Volume 5, p. 33.
259 SKM, *Capital works project cost escalation factors for the period 2007/8 – 2013/4*, 23 May 2008.
260 SKM, *Cost escalation factors*, p. 47.
261 ActewAGL, *Regulatory proposal*, p. 168.

**Table 9.7: SKM's real wage growth rate for the EGW sector in the ACT (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| EGW labour | 2.1 | 2.9 | 5.1 | 4.4 | 3.6 | 3.3 | 3.0 |

Source: ActewAGL, *Regulatory proposal*, p. 170.
Note: The AER has calculated the real escalator using the CPI forecasts provided by SKM on 12 September 2008.

***General wage escalator***

ActewAGL advised that labour costs associated with contracts for pole inspection, vegetation management and plant operator programs have been escalated by CPI. However, during the AER's review of ActewAGL's regulatory proposal, ActewAGL advised that it considered a general wage escalator to be a more appropriate reflection of labour costs associated with these outsourced services.[262] Accordingly, it proposed to apply the general wage escalator as recommended by SKM to labour associated with pole inspection, vegetation management and plant operator programs which are outsourced. ActewAGL advised that applying this escalator results in an increase of $1.6 million ($2008–09) to its forecast opex.[263]

SKM used a general wage forecast from Econtech's report prepared for the AER for the SP AusNet revenue reset in August 2007.[264] SKM's proposed general wage forecasts are outlined in table 9.8.

**Table 9.8: SKM's real wage growth rate for general labour (per cent)**

| | 2007–08 | 2008−09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| General labour | 1.8 | 2.1 | 2.8 | 2.6 | 2.4 | 2.3 | 1.9 |

Source: Sinclair Knight Merz, *Capital works project cost escalation factors for the period 2007/8–2013/14*, 23 May 2008, p. 63.
Note: The AER has derived this real escalator using the CPI forecasts provided by SKM on 12 September 2008.

***Corporate services escalator***

ActewAGL has applied a 5.5 per cent (nominal) wage escalator for corporate services labour in each year of the next regulatory control period.[265] This escalator is based on the Mercer 2007 Quality Review Report (Mercer report). ActewAGL has developed this corporate service wage escalator by taking an average of salary increases expected across a number of occupations in the business/professional services industry for the 2009–10 year.[266] The real corporate services escalators are outlined in table 9.9.

[262] ActewAGL, response to AER request for information, 26 August 2008.
[263] ActewAGL, response to request for information, 12 September 2008.
[264] Econtech, *Labour cost growth forecasts*, 13 August 2007.
[265] ActewAGL, *Regulatory proposal*, p. 181.
[266] ActewAGL, response to AER request for information, confidential, 7 August 2008.

**Table 9.9: ActewAGL's real corporate services labour escalator (per cent)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Corporate services | 3.0 | 2.9 | 2.8 | 2.8 | 2.9 |

Source: ActewAGL, *Regulatory proposal*, p. 181.
Note: The AER has derived the real escalator using CPI forecasts provided by SKM to the AER on 12 September 2008.

**Consultant review**

The AER engaged Econtech to provide advice on wage forecasts for the EGW sector in ACT. In preparing its labour cost forecasts, Econtech took account of the latest available wage data.

Econtech's forecasts for labour cost growth rates in the EGW sector in the ACT for the next regulatory control period is shown in table 9.10 and outlined in further detail in appendix G.

**Table 9.10: Econtech's real labour escalation rates for the ACT EGW sector (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| ACT | 9.4 | 2.0 | 3.7 | 3.6 | 3.3 | 3.1 | 2.4 |

Source: Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, 19, appendix D, September 2008, p. 12.

**AER considerations**

***EGW wage escalator***

The AER has examined the forecasts of real wages growth for the EGW sector in the ACT put forward by SKM against the latest Econtech EGW forecasts for the ACT.

The details of the AER's assessment of the labour cost forecasts proposed by ActewAGL for the EGW sector are set out in appendix G of this draft decision.

The AER does not consider that the SKM proposed labour cost growth rates provide an accurate reflection of the likely future labour wage trends in the ACT, as it does not take into account recent economic forecasts. In particular, the AER notes Econtech's advice that since it provided forecasts of labour cost growth rates to the AER in August 2007, the economic climate has changed considerably, resulting in some pressure being taken off wages growth.[267]

For these reasons the AER does not consider SKM's proposed labour cost growth rates for the EGW sector in the ACT provide reasonable inputs to deriving the efficient costs a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

From 2008–09 the AER will adopt Econtech's forecasts for wages growth in the EGW sector in ACT for the next regulatory control period. The AER considers that the application of the Econtech forecasts for wages growth in the EGW sector for

[267] Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, 19 September 2008, p. 24.

ACT reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c). Given that the actual wage data is available for 2007–08, the AER will apply the actual wage increase provided for under ActewAGL's enterprise bargaining agreement.

The AER is also of the view that the ACT specific forecast should be used as it is likely to be a better predictor of future trends in wages growth in the utility sector in the ACT.

The EGW labour cost growth forecasts the AER will apply to ActewAGL's opex for the next regulatory control period are shown in table 9.11.

**Table 9.11: AER's conclusion on the ACT EGW real labour growth rates (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| AER's EGW labour | –0.5 | 2.0 | 3.7 | 3.6 | 3.3 | 3.1 | 2.4 |

Source: Econtech, *Labour cost growth forecasts*, appendix D, p. 12.
Note: The AER derived the real EBA rate by using actual CPI for 2007–08.

***General wage escalator***

The AER accepts the application of labour cost growth rates which reflect the specific circumstance of the service which is being provided. For example, the AER would expect a general wage escalator to be applied to the provision of services which are not unique to the EGW sector.

The AER considers that the application of a general wage escalator to ActewAGL's outsourced services is reasonable given that it is applied to labour which is not subject to the same wage pressures as labour in the EGW sector. The AER therefore accepts ActewAGL's proposal to apply the general wage escalator to its outsourced services.

Given the change in economic conditions since 2007, the AER does not consider that the general wage forecasts proposed by ActewAGL are reasonable for the purposes of forecasting labour market wage trends for the next regulatory control period. The AER will apply the updated Econtech general wage escalator to labour associated with ActewAGL's outsourced services.

The wage growth forecasts for general labour cost that the AER will apply to ActewAGL's opex for the next regulatory control period are shown in table 9.12.

**Table 9.12: AER's conclusion on real general wage growth (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| AER's general labour | 0.6 | 1.0 | 1.1 | 0.7 | 0.7 | 0.8 | 0.6 |

Source: Econtech, *Labour cost growth forecasts*, p. 25.

Further detail of the AER's consideration of the issues associated with the forecast escalators for general labour cost is included in appendix G of this draft decision.

***Corporate services escalator***

The AER does not consider that the corporate services escalator proposed by ActewAGL is an appropriate measure of labour market wage trends for this type of labour.

ActewAGL has developed the corporate service escalator by taking an average of salary increases expected across a number of occupations in the business/professional services industry from the Mercer report. This data is based on responses by participants to Mercer's Market Issues Survey.[268] Therefore, the data upon which ActewAGL has drawn to develop its escalator is based on what respondents to the survey consider will happen to labour costs, rather than any data or specific information.

The AER notes that ActewAGL has applied the corporate services wage forecast for the 2009–10 to each year in the next regulatory control period. The AER considers it unlikely that a wage forecast for 2009–10 will persist until the end of the next regulatory control period.

The AER also notes other NSW DNSPs have applied a general wage escalator to labour associated with corporate services and this is considered appropriate for ActewAGL.[269]

The AER considers that the corporate services escalator proposed by ActewAGL does not reasonably reflect the likely future labour costs associated with ActewAGL's corporate services. The AER will therefore apply Econtech's general wage forecasts as it considers this better reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c). The general wage forecasts which the AER will apply are outlined in table 9.13.

***Conclusion***

The AER has reviewed the proposed labour cost escalators and considers the revised escalators are appropriate. Overall, the AER considers that the application of these revised labour cost escalators to estimate ActewAGL's forecast opex results in the efficient costs a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

#### 9.6.7.2 Non–labour costs

***ActewAGL proposal***

ActewAGL proposed the use of CPI to escalate the non–labour component of its opex forecasts.

***AER considerations***

The AER considers that ActewAGL's proposed use of CPI to escalate the non–labour components of its opex forecasts—that is, no real increase—is reasonable and the approach is consistent with past regulatory practice, and is therefore accepted.[270]

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268 Mercer, *Quarterly Salary Review*, September 2007, p. 4.9.

269 AER, *NSW distribution determination 2009–10 to 2013–14*, Draft decision, November 2008, appendix N, section N.3.2.

### 9.6.8 Non–controllable opex

Non–controllable opex includes costs associated with benchmark debt raising requirements, self insurance and UNFT liabilities.

**Debt raising costs**

To raise debt, a company incurs debt financing costs or transaction costs. Such costs are likely to vary between each debt issue and the AER assumes a benchmark cost, which varies with size and depends on market conditions.

According to the Allen Consulting Group (ACG) the debt raising cost being considered should be the transaction cost of re-financing fixed rate bonds to the value of the notional gearing component of the regulated firm's regulatory asset base (RAB). The allowed debt benchmark does not relate to:

- acquisitions by the regulated firm
- non-core construction or investment activities that are being undertaken.

Therefore, the transaction costs associated with the benchmark cost of debt should not relate to activities outside of the re-financing of bonds for the regulated firm's core activities.[271]

***ActewAGL proposal***

ActewAGL has proposed an allowance for benchmark debt raising costs based on the methodology developed by the ACG and accepted in previous AER decisions. The allowance was estimated by ActewAGL using the PTRM and applying the benchmark debt raising costs in basis points to the notional debt component of the RAB for each year of the next regulatory control period. It then took the mean of these values to derive an average benchmark debt raising allowance of 9.36 basis points per annum (bppa) over the next regulatory control period. The resulting total debt raising cost allowance proposed by ActewAGL for the next regulatory control period is $1.8 million.[272]

**AER considerations**

The 2004 ACG report concluded that debt raising costs are a legitimate expense that should be recovered through the revenues of the regulated entity.[273] The ACG based its benchmark on debt raising costs applicable to Australian international bond issues and joint Australian market/international issues and found that the benchmark decreases as the number of bond issues increase.

In developing the benchmark, the ACG calculated a gross underwriting fee benchmark of 5.5 bppa based on a five–year term. To this, it added allowances for legal and roadshow expenses; credit rating fees for the firm and for each issue of

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270 AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, Final decision, 14 June 2007
AER, *ElectraNet transmission determination 2008–09 to 2012–13*, Final decision, 11 April 2008.

271 ACG, *Debt and equity raising transaction costs: final report to the ACCC*, December 2004, p. 5.

272 ActewAGL, *Regulatory proposal*, p. 192.

273 ACG, *Debt and equity raising transaction costs*, p. 5.

bonds; and registry and paying charges. The median bond issue size was determined to be $175 million.[274]

In accordance with the ACG methodology, the AER updated the gross underwriting fee and bond issue size benchmarks using recent publicly available data. This resulted in the gross underwriting fee increasing from 5.5 bppa to 6.0 bppa and the median bond issue size increasing from $175 million to $200 million.[275] Table 9.13 shows the updated build up of debt raising costs and the total benchmark for various bond issues, based on the ACG's methodology.

The AER broadly accepts ActewAGL's proposal to calculate an allowance for benchmark debt raising costs based on the ACG methodology. The AER does not, however, consider it appropriate to apply an average benchmark debt raising cost in basis points to the notional debt component of the opening RAB to derive the associated debt raising cost for each year of the next regulatory control period. This method is inconsistent with the AER's approach, which is to derive the debt raising allowance for the regulatory control period based on the benchmark debt raising cost in basis points corresponding to the notional debt share of the opening RAB at the commencement of the regulatory control period. ActewAGL's proposed approach is not appropriate as it implies debt refinancing would occur at the end of each year of the regulatory control period, rather than at the end of a regulatory control period. For this draft determination the AER has recalculated the debt raising cost allowance based on this methodology.

**Table 9.13: Benchmark debt raising costs for corporate bond issues (bppa)**

| Fee | Explanation/source | 1 issue | 2 issues | 3 issues | 4 issues |
|---|---|---|---|---|---|
| Amount raised | Multiples of median bond issue size | $200m | $400m | $600m | $800m |
| Gross underwriting fees | Bloomberg for Australian internal issues, term adjusted | 6.0 | 6.0 | 6.0 | 6.0 |
| Legal and roadshow | $75k–$100k: industry sources | 1.0 | 1.0 | 1.0 | 1.0 |
| Company credit rating | $30k–$50k (once off): S&P ratings | 2.5 | 1.3 | 0.8 | 0.6 |
| Issue credit rating | 3.5 (2.5) basis points up front: S&P ratings | 0.7 | 0.7 | 0.7 | 0.7 |
| Registry fees | $3k/issue: Osborne Associates | 0.2 | 0.2 | 0.2 | 0.2 |
| Paying fees[a] | $1/$1m quarterly: Osborne Associates | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | Basis points per annum | 10.4 | 9.2 | 8.7 | 8.5 |

Source: ACG, *Debt and equity raising transaction costs*, AER updated.
(a) Rounded to one decimal place.

[274] ACG, *Debt and equity raising transaction costs*, p. 5.
[275] The latest update by the AER indicates that the gross underwriting fee and median bond issue size have not changed.

ActewAGL has an opening RAB of $588 million and an assumed benchmark gearing ratio of 60:40. The notional debt component of ActewAGL's opening RAB is therefore around $353 million. Based on the ACG methodology which assumes refinancing of debt with each regulatory determination, this debt size would require around two bond issues. As such, the AER considers that an allowance of 9.2 bppa for debt raising costs is a reasonable benchmark for ActewAGL. Using the PTRM, this benchmark is multiplied by the debt component of ActewAGL's opening RAB to provide an average allowance of less than $0.4 million per annum ($2008–09). Table 9.14 shows the AER's conclusion on the debt raising cost allowance for ActewAGL.

**Table 9.14: AER's conclusion on debt raising costs ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Debt raising allowance | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 1.8 |

The AER considers this revised debt raising forecast represents the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives in the next regulatory control period.

**Equity raising costs—forecast capital expenditure**

An entity incurs equity raising costs when it raises new equity capital. These costs may include legal and brokerage fees, and marketing costs. For initial equity raising costs, the fundamental question is whether the RAB has already been determined. For utilities, costs for raising subsequent equity capital have generally been for acquisition activities outside the regulated business. The need for access to external equity funds would generally not be expected if the entity were financed in a manner consistent with regulatory benchmark assumptions.

According to the 2004 ACG report, firms finance subsequent capex in the least-cost manner.[276] That is, financing is sourced from retained earnings when possible and that debt financing is preferred to equity financing (this relates to the 'pecking order theory' of capital structure). External equity financing for subsequent capex should be considered only when a case is made that the retained earnings and additional borrowings are insufficient provided that the gearing ratio and other assumptions about financing decisions are consistent with regulatory benchmarks.

***ActewAGL proposal***

ActewAGL has not sought to be compensated for equity raising costs associated with its forecast capex program. ActewAGL submitted that the level of the forecast expenditure will not exceed the AER's threshold for triggering an allowance for such costs.[277]

[276] ACG, *Debt and equity raising transaction costs*, pp. ix–xii.
[277] ActewAGL, *Regulatory proposal*, p. 192.

**AER consideration**

The AER has undertaken an analysis of ActewAGL's benchmark cash flows to assess the requirement for equity raising costs associated with the equity component of its forecast capex over the next regulatory control period.

Based on the capex allowance in this draft decision, the benchmark cash flow analysis supports ActewAGL's proposal that it will be able to fund its capex program over the next regulatory control period with retained cash flows and therefore not require additional equity finance. Accordingly, the AER accepts ActewAGL's proposal and has not included an allowance for benchmark equity raising costs for the next regulatory control period.

**Self insurance**

***ActewAGL proposal***

ActewAGL proposed an allowance for self insurance for the next regulatory control period. ActewAGL engaged SAHA International Limited (SAHA)[278] to undertake an assessment of the self insurance risks, and the corresponding self insurance premium associated with these risks.[279] The risks identified by SAHA and estimated annual self insurance costs of those risks for ActewAGL are outlined in table 9.15.

**Table 9.15: ActewAGL's proposed self insurance risk premium for the next regulatory control period ($m, 2008−09)[280]**

| Type of risk | Description of risk | Risk premium |
|---|---|---|
| Theft of assets | Assets owned by ActewAGL are subject to the risk of theft by third parties. | 0.07 |
| Earthquakes (for earthquakes with a magnitude of less than 6) | Risk to assets from earthquakes. | 0.05 |
| Counterparty credit | Probability that one or more ActewAGL's customers default on a payment. | 0.07 |
| Bushfire | Exposure to liability and damage to assets from bushfires. | 0.91 |
| Towers/poles and lines | Risk that an exogenous incident could cause damage to ActewAGL's network. | 5.39 |
| Key assets | Risks associated with failure of key assets (transformers and circuit breakers). | 1.44 |
| General public liability | Risk of injuries/losses suffered by the general public as a result ActewAGL negligence or fault. | 0.01 |
| Total self insurance risk premium | | 7.94 |

Source: ActewAGL, *Regulatory proposal*, table 8.15, p. 194.

278 SAHA provides strategic, commercial, economic, corporate finance and financial consulting services. See SAHA website http://www.sahainternational.com/SAHA/SERVICES/pc=PC_90006

279 SAHA, *ActewAGL Electricity Networks – Self Insurance Risk Quantification*, Final Report, confidential, 20 May 2008.

280 ActewAGL's self insurance premiums in its regulatory proposal were provided in 2007–08 dollar terms. The AER converted these to 2008–09 dollar terms using ActewAGL's proposed 2.7 per cent escalation.

***AER considerations***

Since self insurance is not specifically addressed in the NER, ActewAGL's self insurance claims have been assessed by the AER against the opex objectives and criteria in clauses 6.5.6 of the transitional chapter 6 rules. Specifically, the AER has assessed ActewAGL's self insurance claims to determine whether the proposed allowances reasonably reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

The self insurance premiums proposed by SAHA have been derived by estimating the annual probability of each proposed self insurance event occurring and the costs associated with each of those events occurring.

The AER has assessed the efficiency and prudence of the proposed self insurance allowance by considering whether the probability of an event occurring and the costs associated with the event (and therefore the associated insurance premium) have been reasonably determined.

Having reviewed the analysis by SAHA the AER is satisfied that ActewAGL's proposed allowances for self insurance for theft of assets risk and counterparty credit risk reasonably reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

However, the AER does not consider that all of the proposed self insurance premiums reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c). Specifically it is concerned that in several areas they do not represent a realistic expectation of the costs of self insurance premiums in the next regulatory control period.

*Earthquakes*[281]

The SAHA analysis focused on the probability and consequence associated with an earthquake of magnitude 5 impacting ActewAGL's network. SAHA examined the number of earthquakes impacting each Australian state over the last 166 years to determine the future probability of an event for ActewAGL.

SAHA indicated that no magnitude 5 earthquakes were recorded in the ACT over the 166 year period. However, SAHA assumed that there was a potential for at least one magnitude 5 earthquake to occur in the ACT over this period and therefore adopted a probability of 1 in 166 years for ActewAGL.

The AER notes that even with significant historical observations earthquake forecasting can be regarded, at best, as imprecise. Where there are no historical observations, as is the case for magnitude 5 earthquakes in the ACT, earthquake prediction could be considered virtually impossible. The AER considers that SAHA has provided no reasonable rational basis for the adoption of a 1 in 166 year probability of a magnitude 5 earthquake in the ACT.

281 SAHA, *ActewAGL Self Insurance Risk Quantification*, confidential, pp. 15–22.

Based on the information provided, the AER rejects the self insurance premium for magnitude 5 earthquakes on the basis that the probability of occurrence has not been reasonably determined and therefore the proposed allowance does not reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

*Bushfires*[282]

SAHA suggested that ActewAGL was exposed to bushfire related risks. SAHA's assessment of bushfire risk was separated into two types of bushfires—those ignited by ActewAGL's own assets, and those ignited by a third party. Each of these scenarios is examined below.

*Bushfires ignited by ActewAGL's own assets*[283]

In terms of "very minor" bushfires—that is, bushfires causing less than one acre of property damage—SAHA assumed that the average value of ActewAGL's past third party bushfire claims provided a reasonable proxy for future incidents and costs. The AER considers this approach to be appropriate based on the timeframe of historical observations and the significant number of events over that period. Therefore, the AER accepts the proposed self insurance premium for very minor bushfires of $10 000 per annum.

SAHA indicated that ActewAGL had no historical records of minor bushfires ignited by its assets. SAHA used NSW bushfire data (from the NSW Rural Fire Service) to determine the number of bushfires ignited by electricity assets in NSW per annum. SAHA then derived the proportion of power lines in the ActewAGL network relative to the NSW network and applied this proportion to the number of NSW bushfires ignited by electricity assets to determine the number of minor bushfires caused by ActewAGL's electricity assets per annum.

The AER considers that the process for determining the probability of a minor bushfire in ActewAGL's network is not sufficiently robust. In particular, the data upon which the ActewAGL probability is determined is not appropriate:

- the data relates to NSW and reflects bushfire incidents in only one year (2002−03)—one of the worst bushfire seasons in NSW history[284]
- the data does not distinguish between bushfires caused by distribution and transmission power lines
- no information is provided with regards to the reporting criteria used (for example, the size of the bushfire or the extent of damage). As such, the incidence of bushfires may include very minor bushfires.

The AER therefore rejects the associated self insurance premium on the basis that the estimate of the probability of occurrence is not sufficiently robust to be used to determine a self insurance allowance.

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282 SAHA, *ActewAGL Self Insurance Risk Quantification*, confidential, pp. 30–40.
283 SAHA, *ActewAGL Self Insurance Risk Quantification*, confidential, pp. 33–38.
284 NSW Rural Fire Service, *Annual Report 2003*.

In relation to a major bushfire[285] ignited by ActewAGL's assets, SAHA noted that since ActewAGL's inception in 1997, it has never started a major bushfire.[286] Notwithstanding this, SAHA noted that fires in 1978−79 were said to be caused by a drop-out fuse from a high tension power line.

In calculating the costs associated with a major bushfire ignited by ActewAGL's own assets, SAHA relied on information related to the 2003 Canberra bushfires. SAHA indicated that since ActewAGL's operating region covers a small area of land, and not much of that is rural. SAHA therefore considered it reasonable to adopt a conservative 1 in 300 year probability for the risk of ActewAGL starting a major bushfire.

The AER considers that there is no basis for the adoption of the probability proposed by SAHA. There is no reason to believe that a 1 in 300 year probability is any more reasonable than a 1 in 100 year or 1 in 500 year probability. As a result, based on the information provided, the AER rejects the associated self insurance premium on the basis that the probability of occurrence has not been reasonably determined.

*Bushfire ignited by third party*[287]

ActewAGL made no claim in relation to very minor bushfires ignited by a third party.

In relation to minor bushfires ignited by third parties, SAHA indicated that ActewAGL has had 4 incidents of minor bushfire ignited by third party impacting its business since its inception. Thus, SAHA suggested that ActewAGL has been affected by 4 minor bushfire incidents caused by a third party in 11 years, and adopted a probability of 4 in 11.

The AER is unclear the inception date that SAHA is referring to (ActewAGL was founded in October 2000).[288] Notwithstanding this, the AER notes that there is no rationale for the application of an 11 year historical period—that is, there is nothing inherently important about the inception date of ActewAGL.

In calculating the costs associated with a minor bushfire ignited by a third party, SAHA relied on information from the Centre for International Economics (CIE).[289] In particular, SAHA relied upon a functional relationship between damage costs and area burnt by bushfires proposed by CIE.[290] In addition, SAHA calculated the proportion of power lines in the ActewAGL network in relation to lines in NSW and applied this to the CIE outputs to derive an estimate of land burnt in the ACT.

The AER considers that the functional relationship between damage costs and area burnt proposed by CIE cannot be relied upon. In particular, based on an examination of the historical data underpinning the CIE modelling, the AER is unable to comprehensively match the values provided in the CIE report with those in the base

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285 Defined by SAHA as a bushfire similar to the 2003 Canberra bushfire.
286 The AER notes that ActewAGL was formed in October 2000 (ActewAGL, *Annual Report and Sustainability Report 2007*).
287 SAHA, *ActewAGL Self Insurance Risk Quantification*, confidential, pp. 38–40.
288 ActewAGL, *Annual Report and Sustainability Report 2007*.
289 CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, November 2000.
290 CIE, pp. 112–113.

data. [291] In addition, for those values that can be identified, it appears that the damage costs used by CIE to forecast the relationship have not been converted to constant dollars. As such, the observations are not comparable over time.

Notwithstanding the data issues set out above, the explanatory power of the proposed CIE functional relationship is poor. The coefficient of determination is reported as 0.39, implying that only 39 per cent of the variance in bushfire damage cost can be explained by the amount of hectares burnt.[292]

Based on the information provided to the AER therefore rejects the associated self insurance premium on the basis that the estimate of the probability of occurrence and associated cost are not sufficiently robust to be used to determine a self insurance allowance.

Based on the information provided to the AER therefore rejects the associated self insurance premium on the basis that the estimate of the probability of occurrence is not sufficiently robust to be used to determine a self insurance allowance.

In relation to major bushfires ignited by third parties, SAHA noted that the ACT has only ever experienced one major bushfire in its history, which was the Canberra bushfires of January 2003.

Given the long return period associated with such events, SAHA suggested that it was very difficult to determine to a reasonable level of accuracy the return period for such an event. Notwithstanding this, SAHA believed that it was reasonable to assume that the return period for such an event would be lower (that is, a higher probability) than that associated with ActewAGL igniting a major bushfire, mainly due to the sheer number of bushfires started by third parties as compared with ActewAGL.

As such, SAHA considered it reasonable to assume a probability of 1 in 100 years of a third party starting a major bushfire impacting on ActewAGL's assets. The AER notes that SAHA has provided no evidence in support of the proposed 1 in 100 year probability.

In calculating the costs associated with a major bushfire ignited by a third party, SAHA relied on information relating to the 2003 Canberra bushfires.

Based on the information provided, the AER rejects the total self insurance premiums in relation to third party bushfires on the basis that the probabilities of occurrence have not been reasonably determined.

*Bushfires–conclusion*

In summary the AER has accepted ActewAGL's proposed self insurance premium of $10,000 per annum for very minor bushfires ignited by ActewAGL's own assets. Based on the information provided, it has rejected all other proposed self insurance

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[291] See: http://www.ema.gov.au/ema/emadisasters.nsf/webEventsByCategory?OpenView&Start=1&Count=30&Expand=1#1. While this assessment is based on an examination of the data source in its current format, given the historical nature of the data, the AER would not expect any deviation between this data set and that used by CIE over the observed timeframe.

[292] CIE, pp. 113.

costs relating to bushfires. The AER does not consider that the proposed self insurance premiums for these components of bushfire risks reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

*Poles and lines*[293]

SAHA suggested that there was an inherent risk that an exogenous incident could cause damage to ActewAGL's distribution network. Such an incident would incur costs to repair any damage to ActewAGL's own assets and costs incurred to repair any subsequent damage to third party property. Power poles and lines are currently self insured for third party property damage.

SAHA divided its analysis into three key categories of risk to poles and lines namely:

- storm–type natural disaster—damage to ActewAGL's electricity distribution assets caused by hail, lightning, wind and storms
- unrecoverable third party damage—all damage to ActewAGL's electricity distribution assets for which the costs cannot be recovered, including vehicle collisions, vandalism, etc
- third party liability resulting from the failure of a power line—consequential damage to third party assets resulting from damage to electricity assets caused by the events described above. For example, a pole which falls due to strong wind, rot or termite infestation can cause damage to a third party property.

SAHA proposed that the probability of a catastrophic storm impacting ActewAGL was 1 in 30 years. This probability was based on a media statement from the NSW Fire Brigades which indicated that the storms that hit the Lower Hunter area of New South Wales in June 2007 resulted in the region's "worst natural disaster in 30 years".[294]

The AER considers that the media statement relied upon by SAHA does not constitute a robust assessment of the probability of a catastrophic storm impacting ActewAGL's network and therefore does not accept the adoption of a 1 in 30 year probability of such an event.

ActewAGL also claimed a self insurance premium in relation to unrecoverable third party liability.[295] ActewAGL provided a summary of the number of third party damage claims on its network over the period April 2007 to March 2008. SAHA used this information as the basis for the probability of future claims.

SAHA suggested that it was logical to assume that every incident involves only one pole. ActewAGL provided an estimate of the replacement and repair cost for its poles. SAHA calculated the risk premium for third party damage as the probability of third

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293 SAHA, *ActewAGL Self Insurance Risk Quantification*, confidential, pp. 41–49.

294 NSW Fire Brigade, "*Firefighters go above and beyond during Newcastle, Central Coast and Hunter Valley storms and floods*" http://www.fire.nsw.gov.au/page.php?id=724, October 2007.

295 Unrecoverable third party damage includes all damage to ActewAGL's electricity distribution assets for which the costs cannot be recovered, including vehicle collisions, vandalism, excavation, farm animals, termite infestation and fungal decay.

party damage multiplied by the financing costs (associated with the replacement assets) and repair costs associated with damaged assets.[296]

ActewAGL indicated that a portion of this premium was included in its regulatory proposal.[297] SAHA subtracted this amount from its original estimate to derive an adjusted risk premium.

The AER considers that the claims history provided by ActewAGL (April 2007 to March 2008) is too short to provide a robust indication of historical claims. In addition, the amount already included in ActewAGL's baseline opex for the next regulatory control period to accommodate these events is substantially below the amount proposed by SAHA. The AER notes that the amount included by ActewAGL in its baseline opex appeared to be based on previous experience with these events.

Based on the above, the AER is not satisfied that the self insurance premium proposed by SAHA reasonably reflects the efficient costs of self insurance and therefore rejects the additional allowance related to self insurance for third party damage.

ActewAGL also sought a self insurance risk premium for consequential damage to third parties leading to claims (general liability insurance scheme claims).[298] ActewAGL provided historical data pertaining to third party liability claims paid by it and claims above the deductible. Based on this historical information, SAHA derived the annual value of below deductible claims and the probability of claims above the deductible.

Accordingly, SAHA calculated the self insurance risk premium for consequential damage to a third party leading to claims as the annualised cost for below deductible claims plus the probability of above deductible incidents multiplied by the insurance deductible.

The AER is satisfied with the assumptions used by SAHA to calculate the self insurance premium for consequential damage to third parties. Therefore, the AER accepts the self insurance premium of $35 000 per annum.

*Poles and lines–conclusion*

In summary the AER has only accepted ActewAGL's proposed self insurance premium for consequential damage to third parties of $35 000 per annum. Based on the information provided, it has rejected all other proposed self insurance costs relating to poles and lines. The AER does not consider that the proposed self insurance premiums for these components of risks for poles and lines reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

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296 SAHA assumed costs would be divided evenly between repair (operating) and replacement (capital) costs.

297 ActewAGL included an amount associated with these events in its baseline opex for the next regulatory control period. However, this amount was lower than that calculated by SAHA as part of its self insurance report.

298 This relates to consequential damage/liability to a third party's property as a result of damage to ActewAGL's assets.

*Key assets*[299]

ActewAGL sought self insurance for costs associated with the failure of power transformers and circuit breakers, including third party claims.

The AER is satisfied with the assumptions used by SAHA to calculate the self insurance premium for costs associated with the failure of power transformers and circuit breakers. Therefore, the AER accepts the self insurance premium of $286 000 per annum.

ActewAGL also sought self insurance to cover consequential damage/liability to a third party's property as a result of failure of the above assets.

While ActewAGL indicated that there had been no previous third party claims, SAHA suggested that it was reasonable to assume that one such event was likely to occur. SAHA assumed one event was likely between ActewAGL's inception and the end of next regulatory control period—that is, 1 in 24 years.

The AER considers that SAHA has not provided a robust rationale for the application of a 24 year period—there is nothing inherently important about the inception date of ActewAGL. The AER also notes that ActewAGL was founded in October 2000 (that is, 15 years ago in the context of the SAHA analysis).[300]

The AER therefore rejects the self insurance premium in relation to third party damage on the basis that the probability of occurrence has not been reasonably determined and the proposed allowance does not reflect the efficient costs of self insurance that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

In total, the AER has reduced ActewAGL's proposed self insurance allowance for key assets from $287 000 per annum to $286 000 per annum.

*Key assets–conclusion*

In summary the AER has accepted ActewAGL's proposed self insurance premium of $286 000 per annum for costs associated with the failure of power transformers and circuit breakers. However, based on the information provided, it has rejected the self insurance premium for consequential damage or third party liability arising from such a failure. The AER does not consider that the proposed self insurance premiums for this component of key asset risks reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

*General public liability risk*[301]

General public liability risk covers incidents where ActewAGL is liable for injuries or other losses suffered by member(s) of the general public as a result of its (or its

299 SAHA, *ActewAGL Self Insurance Risk Quantification*, confidential, pp. 50–59.
300 ActewAGL, *Annual Report and Sustainability Report 2007*.
301 SAHA, *ActewAGL Self Insurance Risk Quantification*, confidential, pp. 27–29.

employees') negligence or fault. ActewAGL sought self insurance costs in relation to general public liability for claims above the existing external insurance deductible.[302]

Whilst SAHA indicated that ActewAGL had not experienced any such claims, SAHA suggested that, based on the experience of Integral Energy, there was a possibility of claims above the deductible.[303] SAHA calculated that probability as 1 in 24 years for ActewAGL. SAHA chose this probability on the basis that it was 24 years since the inception of ActewAGL to the end of the next regulatory control period.

The AER considers that the basis for determining the probability of these events is not robust, in particular:

- Integral Energy's experience with above deductible claims is not relevant to ActewAGL, given the inherent differences between Integral Energy and ActewAGL's businesses and network environment

- SAHA has provided no robust rationale for the application of a 24 year period as the base for the probability calculation—there is nothing inherently important about the inception date of ActewAGL. The AER also notes that ActewAGL was founded in October 2000 (that is, 15 years ago in the context of the SAHA analysis).[304]

As a result, based on the information provided, the AER rejects the associated self insurance premium on the basis that the probability of occurrence has not been reasonably determined and therefore the self insurance premium does not reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

*General public liability risk– conclusion*

Based on the information provided, the AER has rejected the total proposed self insurance costs for general public liability risk.

*Self insurance–Conclusion*

For the reasons set out above, the AER is not satisfied that SAHA has provided robust analysis which supports the probability of certain events occurring or that the costs of those events are reasonable. Accordingly, it has not accepted the proposed self insurance premiums.

The AER considers that ActewAGL's proposed total self insurance allowance does not reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would incur to meet the opex objectives, as required by clause 6.5.6(c).

As a result of its analysis of the information provided, the AER is satisfied that the revised estimate of the total self insurance allowance shown in table 9.16, based on the above accepted self insurance premiums, reflects the efficient costs that a prudent

302 ActewAGL indicated that costs associated with below deductible claims are included in the baseline opex.
303 Integral Energy experienced two such claims in the last regulatory control period.
304 ActewAGL, *Annual Report and Sustainability Report 2007*.

operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

The total self insurance allowance covers direct control services, and hence is apportioned between standard control services and alternative control services.

**Table 9.16: AER's conclusion on total self insurance costs ($m, 2008−09)**

| Type of risk | ActewAGL proposal | AER adjustment | AER conclusion |
|---|---|---|---|
| Total self insurance premium | 7.9 | –6.1 | 1.8 |

Note: Totals may not add up due to rounding.

**Utilities network facilities tax**

***ActewAGL proposal***

ActewAGL has included forecasts of its UNFT obligations in its proposed opex, as shown in table 9.17. It has forecast its future liability by escalating its current liability using the ACT government's expected increase in UNFT revenues (4 per cent), plus an amount for network growth (1 per cent).[305]

It has also proposed a pricing unders and overs mechanism to adjust for differences between forecast and actual tax liability during the next regulatory control period.[306]

**Table 9.17: ActewAGL's proposed opex for UNFT ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| UNFT | 4.0 | 4.1 | 4.2 | 4.3 | 4.4 | 20.9 |

Source: ActewAGL, *Regulatory proposal*, p. 195.

***AER considerations***

The AER has reviewed ActewAGL's forecast of its UNFT liability and its proposed treatment of variations between forecast and actual tax liability.

The AER considers ActewAGL's forecast of UNFT obligations is overstated. The forecast relies on the ACT government forecast of expected revenues from this tax, which shows a growth in revenue of 4 per cent per annum. The tax is levied on line length for ActewAGL and the revenue calculation therefore implicitly includes a measure of network growth. The AER considers that network growth escalation is implicit in the ACT government's forecast of revenue growth and does not need to be separately applied by ActewAGL. The AER is not satisfied that ActewAGL's proposed UNFT reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to meet the opex objectives, or a realistic expectation of those costs, and has made adjustments accordingly. The AER is satisfied that the revised estimate of the UNFT allowance, set out in table 9.18, reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c).

[305] ActewAGL, *Regulatory proposal*, p. 195.
[306] ActewAGL, *Regulatory proposal*, p. 28.

**Table 9.18: AER's conclusion on ActewAGL's UNFT liability ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| UNFT | 3.9 | 4.0 | 4.1 | 4.2 | 4.3 | 20.7 |

The AER has considered ActewAGL's proposed treatment of differences between forecast tax and actual tax payable. Clause 6.18.2(6) of the transitional chapter 6 rules requires a pricing proposal to:

> …set out how charges incurred by the Distribution Network Service Provider for transmission use of system services are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous regulatory year;

However, this clause does not set out that other charges can be adjusted in a similar manner. In the absence of the rules allowing such an adjustment the AER considers that ActewAGL's proposed treatment of variations in its UNFT forecasts and actual liability should not be subject to adjustment through the pricing proposal—that is, the unders and overs mechanism.[307]

The AER notes that an adjustment of the UNFT rate by the ACT government could appropriately be described as a 'change in a relevant tax' or else a 'change… in the rate of a relevant tax'.[308] Accordingly, a change in the actual tax rate set by the ACT government would constitute a tax change event, which is a pass through event. In such circumstances ActewAGL can apply to the AER to pass through the difference between the forecast cost of the UNFT approved by the AER and the actual cost of the UNFT set by the ACT government. Any such application would be assessed by the AER against the requirements of the pass through provisions of the NER.

## 9.7 AER conclusion

The AER has considered ActewAGL's forecast total opex of $306 million ($2008–09) and for the reasons outlined in this chapter is not satisfied that this total opex forecast proposed by ActewAGL reasonably reflects the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules.

In drawing this conclusion the AER has had regard to the opex factors set out in clause 6.5.6(e) of the transitional chapter 6 rules.

As the AER is not satisfied that ActewAGL's total forecast opex reasonably reflects the opex criteria, under clause 6.5.6(d), the AER must not accept the forecast opex in ActewAGL's regulatory proposal. Therefore, the AER is required under clause 6.12.1(4)(ii) to provide an estimate of the total opex that ActewAGL will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

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307 This is consistent with the treatment of the easement tax in Victoria. See AER, *SP Ausnet transmission determination 2008–09 to 2013–14, January 2008*, pp. 161–163.

308 NER, Chapter 10 glossary: tax change event.

After considering the advice of Wilson Cook, and undertaking its own analysis of ActewAGL's proposed opex, the AER has applied a reduction of $9.5 million to ActewAGL's proposed opex. This represents a reduction of around 3 per cent of ActewAGL's proposed opex of $306 million and results in a revised forecast opex allowance of $296 million.

This revised estimate represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c). The AER is satisfied that the revised total forecast opex of $296 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. The revised opex allowance is shown by opex category in table 9.19.

**Table 9.19: AER's conclusion on ActewAGL's total opex allowance ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL proposed opex | | | | | | |
| Controllable opex | 52.9 | 53.9 | 55.0 | 56.8 | 56.8 | 275.3 |
| UNFT | 4.0 | 4.1 | 4.2 | 4.3 | 4.4 | 20.9 |
| Debt raising | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 1.8 |
| Self insurance[a] | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 7.5 |
| Total opex | 58.7 | 59.9 | 61.0 | 63.0 | 63.0 | 305.5 |
| AER revised opex | | | | | | |
| Controllable opex | 52.7 | 53.4 | 54.3 | 55.9 | 55.6 | 271.9 |
| UNFT | 3.9 | 4.0 | 4.1 | 4.2 | 4.3 | 20.7 |
| Debt raising | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 1.8 |
| Self insurance[a] | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 1.7 |
| Total opex | 57.3 | 58.2 | 59.1 | 60.8 | 60.6 | 296.0 |

Note: Totals may not add up due to rounding.
(a) Based on allocation for standard control services.

Table 9.20 sets out the AER's adjustments to ActewAGL's forecast controllable opex allowance. These adjustments are derived from the opex model and reflect the AER's conclusion on an efficient controllable opex allowance.

**Table 9.20: AER's conclusion on ActewAGL's controllable opex ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL's proposed controllable opex | 52.9 | 53.9 | 55.0 | 56.8 | 56.8 | 275.3 |
| Adjustments to labour escalators | –0.2 | –0.5 | –0.7 | –0.9 | –1.2 | –3.5 |
| AER's adjusted controllable opex | 52.7 | 53.4 | 54.3 | 55.9 | 55.6 | 271.9 |

## 9.8 AER draft decision

In accordance with clause 6.12.1(4)(ii) of the transitional chapter 6 rules the AER does not accept ActewAGL's proposed opex for the next regulatory control period. The AER is not satisfied that ActewAGL's forecast opex, taking into account the opex factors reasonably reflects the opex criteria in clause 6.5.6 of the transitional chapter 6 rules. The AER's reasons for this decision are set out in section 9.6 of the draft decision. The AER's estimate of the total opex required by ActewAGL in the next regulatory control period, that reflects the opex criteria taking into account the opex factors, is set out in table 9.19 of the draft decision.

# 10 Estimated corporate income tax

## 10.1 Introduction

This chapter sets out the AER's assessment of ActewAGL's estimated corporate income tax liabilities for the next regulatory control period.

## 10.2 Regulatory requirements

The AER must make a decision on the estimated costs of corporate income tax to a DNSP in accordance with clause 6.5.3 of the transitional chapter 6 rules. Clause 6.5.3 of the transitional chapter 6 rules provides the following formula for the calculation of the estimated cost of corporate income tax of a DNSP for each regulatory year ($ETC_t$):

$$ETC_t = (ETI_t \times r_t)(1 - \gamma)$$

Where:

- $ETI_t$ is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than the DNSP, operated the business of the DNSP, such estimate being determined in accordance with the Post–Tax Revenue Model (PTRM)
- $r_t$ is the expected statutory income tax rate for that regulatory year as determined by the AER
- $\gamma$ is the assumed utilisation of imputation credits and is deemed to be 0.5.

For these purposes:

- the cost of debt must be based on that of a benchmark efficient DNSP (this is done by applying a benchmark cost of debt to a benchmark debt equity ratio)
- the estimate must take into account the estimated depreciation for that regulatory year for tax purposes, for a benchmark efficient DNSP, of assets where the value of those assets is included in the regulatory asset base for the relevant distribution system for that regulatory year.

### 10.2.1 Transition from pre–tax to post–tax

The ICRC has previously applied a pre–tax cost of capital in its determinations for ActewAGL. Under the pre–tax approach applied by the ICRC, an allowance for tax was built into the cost of capital. However the AER must determine a nominal post–tax WACC pursuant to clause 6.5.2(b) of the transitional chapter 6 rules. This is discussed in chapter 12 of this draft decision.

Under the post–tax cost of capital required by the NER, an explicit allowance for tax is made on the basis of cashflow analysis rather than including an implicit allowance for tax within the cost of capital (as previously done by the ICRC). To enable the cashflow modelling required to estimate the cost of income tax, the remaining tax

value of ActewAGL's assets (the tax asset base) is required. This information was not required for the pre–tax approach applied by the ICRC. Accordingly, the tax asset base must be established on transition to the post–tax approach. In this regard, the AER provided an issues paper on the matter to the DNSPs in June 2007. The issues paper noted that:

> Setting the tax base at commencement of post–tax regulation is important and will have an impact on the calculation of the tax allowance (tax building block). The AER proposes to establish appropriate values for the tax base in light of the specific circumstances of each business. One of the most notable influences concerns business ownership. The proposed approach involves taking the value of a firm's assets for tax purposes when it first became subject to tax, and rolling these values forward to the date when a post–tax approach is to apply, taking account of relevant tax depreciation rules and actual capex and disposals. In the case of government owned businesses, the proposed approach is similar, but utilises the date and tax base when the business became subject to the NTER [National Tax Equivalence Regime]. A key issue for all businesses will be to distinguish RAB assets from non-RAB assets. However, with inflation and the depreciation of existing assets that comes with passing time, the tax base used in the regulatory accounts will become increasingly reflective of the actual tax base of RAB assets.[309]

## 10.3 ActewAGL proposal

ActewAGL proposed an allowance for tax that was calculated by the PTRM, which calculates a tax allowance in accordance with the methodology set out in clause 6.5.3 of the transitional chapter 6 rules. It should be noted that the allowance for tax is an output of the PTRM rather than an input to be specified or proposed by the regulated business.

### 10.3.1 ActewAGL's proposed tax asset base

ActewAGL proposed an opening tax asset base derived in a manner consistent with the AER's preferred approach set out in its issues paper on the transition from pre–tax to post–tax.

## 10.4 Consultant review

The AER sought the assistance of McGrathNicol to assess ActewAGL's proposal with respect to establishing the opening tax asset base for ActewAGL. McGrathNicol supported ActewAGL's methodology for determining its tax asset base.[310]

## 10.5 Issues and AER considerations

ActewAGL's estimate of corporate income tax expense comes from the PTRM which performs the calculations required by clause 6.5.3 of the transitional chapter 6 rules. The AER's assessment of the relevant inputs to the PTRM including the tax asset base is set out below.

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309 AER, *Issues Paper*: *Transition of energy businesses from pre–tax to post–tax regulation*', 14 June 2007, p. 69.

310 McGrathNicol, letter to AER, 14 July 2008, confidential.

### 10.5.1 Asset classes, standard tax lives and remaining tax lives

**ActewAGL proposal**

Tax depreciation has been calculated by the PTRM on the basis of ActewAGL's tax remaining and tax standard life inputs and the proposed remaining tax asset values/tax asset base (discussed below). ActewAGL aggregated its asset classes into a single asset category in the PTRM and applied an average remaining life and standard life input derived from its detailed tax asset register.[311]

**Consultant review**

McGrathNicol has observed that ActewAGL maintains a tax asset register which contains commissioning dates for individual assets by asset class. McGrathNicol also noted that ActewAGL has used this tax asset register to derive its aggregate tax remaining and tax standard life which formed part of ActewAGL's regulatory proposal.[312]

**AER considerations**

Clause 6.5.5(b) of the transitional chapter 6 rules sets out certain requirements with respect to depreciation profiles. These requirements include:

- depreciation profile must reflect the nature of the asset (or asset class) and be applied over the economic life of the asset
- the sum of real depreciation for an asset (or asset class) over the economic life of the asset must be equal to the value at which the asset first entered the RAB.

While the ICRC accepted the use of a single aggregated asset category, the AER considers it appropriate to include a more detailed breakdown of ActewAGL's forecast capital expenditure (capex) to be allocated into relevant asset classes to enable verification that ActewAGL's depreciation profiles meet the requirements of the NER. In response to the AER's request to disaggregate its asset category into various classes, ActewAGL provided the asset classes and standard lives set out in table 10.1. Accordingly, these disaggregated asset classes will apply to forecast capex from the next regulatory control period onwards. The calculation of tax depreciation in the PTRM will also be done using the disaggregated asset classes.

The AER has reviewed ActewAGL's proposed asset classes and standard lives and considers them to be reasonable. The AER considers it appropriate that ActewAGL's tax remaining and tax standard lives are consistent with its detailed tax register as observed by McGrathNicol. Section 11.4 of this draft decision sets out the AER's assessment of the proposed standard lives for regulatory depreciation purposes.

311 ActewAGL, *PTRM*.
312 McGrathNicol, letter to AER, 14 July 2008, p 2.

**Table 10.1: ActewAGL's proposed asset classes and standard lives (years)**

| Asset classes for forecast capex | Standard life | Tax standard life |
|---|---|---|
| Sub–transmission Overhead | 40.0 | 47.5 |
| Sub–transmission Underground | 60.0 | 47.5 |
| Zone Substation | 40.0 | 40.0 |
| Distribution Substations | 40.0 | 40.0 |
| Distribution Overhead Lines | 50.0 | 45.0 |
| Distribution Underground Lines | 60.0 | 50.0 |
| IT & Communication Systems (Networks) | 10.0 | 10.0 |
| Motor Vehicles | 7.0 | 8.0 |
| Other Non–System Assets (Networks) | 5.0 | 5.8 |
| IT Systems (Corporate) | 5.0 | 4.1 |
| Telecommunications (Corporate) | 5.0 | 6.7 |
| Other Non-System Assets (Corporate) | 5.0 | 5.7 |
| Land | n/a | n/a |
| Buildings | 60.0 | 100.0 |

Source: ActewAGL, response to AER, 25 August 2008.

### 10.5.2 Establishing the tax asset base—transition from pre–tax to post–tax regulation

**ActewAGL proposal**

ActewAGL proposed an opening tax asset base derived in a manner consistent with the AER's preferred approach set out in its issues paper on the transition from pre–tax to post–tax. In summary, the AER requested that each of the DNSPs (including ActewAGL) present their tax asset base for each year since becoming subject to the National Tax Equivalence Regime (NTER). The AER also requested that ActewAGL allocate the total tax asset base between RAB assets and non–RAB assets. Non–RAB assets include assets relating to ActewAGL's alternative control services.

ActewAGL stated that ACTEW Corporation and its subsidiary entities were first recorded on the NTER entity register on 1 July 2001.[313] ActewAGL has presented the tax value of assets in the relevant divisional tax asset register as well as an allocation of central corporate assets. ActewAGL stated that the allocation of corporate assets

[313] ActewAGL, *Regulatory proposal*, p. 213.

has been made in accordance with the approach adopted by the ICRC in the distribution determination for the current regulatory control period.[314]

ActewAGL noted that the treatment of combined meter and connection assets involved judgement as metering assets are excluded from the tax asset base for standard control services while connection assets are included. ActewAGL excluded metering assets on the basis of the ratio of capex on meters to capex on connection assets during the current regulatory control period (50:50).[315]

ActewAGL rolled forward its tax asset base from 1 July 2001 to 30 June 2009 using standard tax lives[316] and the relevant worksheet in the NSW roll forward model.[317] ActewAGL has proposed a tax asset base of $473 million for the start of the next regulatory control period.[318]

**Consultant review**

The AER sought the assistance of McGrathNicol to assess ActewAGL's proposal to establish the opening tax asset base. McGrathNicol identified a number of issues for further investigation with ActewAGL. Some of these issues are confidential in nature, relating to assumptions made by ActewAGL in its forecasting and modelling process. The non-confidential issues raised are discussed below. Notwithstanding the issues identified by McGrathNicol, it concluded that ActewAGL's methodology for determining its tax asset base:[319]

- has a sound basis and demonstrates an understanding of the NER and the movement to a post–tax regime
- reflects the relevant taxation requirements of the NTER, Australian Tax Law and the Australian Accounting Standards
- results in the determination of tax asset values that are generally able to be verified by supporting registers.

**AER considerations**

As noted above, the AER requested each of the DNSPs to present their respective tax asset bases for RAB and non–RAB assets for each year since the commencement of the NTER. The assessment of the tax asset base over the period (as opposed to a single point in time) was intended to ensure that:

- the proposed tax asset base was reflective of the underlying regulatory assets and consistent with regulatory determinations over the period
- there were no transfers of tax assets to other non–regulated business units or related entities.

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314 ActewAGL, *Regulatory proposal*, p. 213.
315 ActewAGL, *Regulatory proposal*, p. 213.
316 ActewAGL, *Regulatory proposal*, p. 214.
317 The ACT roll forward model is based on the model applied by the ICRC and does not contain a tax roll forward worksheet.
318 ActewAGL, *Regulatory proposal*, p. 214.
319 McGrathNicol, letter to AER, 14 July 2008, p. 2.

The AER considers that ActewAGL's proposal demonstrates that its tax asset base is reflective of its RAB assets and there are no tax asset transfers that would require an adjustment to the opening tax asset base. There are however a range of technical issues which were considered by the AER and its consultant in assessing ActewAGL's proposed tax asset base.

***Allocation of corporate assets***

ActewAGL's proposed tax asset base includes assets in its divisional tax register and an allocation of central corporate assets. This allocation has been made in accordance with the approach applied by the ICRC in its current determination and is therefore considered by the AER to be appropriate.

***Allocation of combined metering and connection assets***

The AER understands that ActewAGL's tax asset register contains assets that have been treated as combined metering and connection assets. In order to allocate the assets into meters (alternative control services) and connections (standard control services), ActewAGL has applied a 50:50 ratio. The ratio of total metering capex and total connection capex over 2004−05 to 2006−07 is approximately 50:50. Accordingly, the AER considers ActewAGL's proposal to be reasonable in the circumstances.

***Exclusion of historical capital contributions***

The PTRM to apply to the DNSPs for the next regulatory control period explicitly accounts for forecast capital contributions. That is, the forecast value of capital contributions is added to the tax value of assets to be depreciated (for tax purposes) and is also used to calculate forecast total tax expense. Capital contributions do not form part of the RAB.

The ICRC did not include capital contributions in its estimates of tax payable as its tax allowance was embedded in the WACC allowed for ActewAGL in the current distribution determination. In the current and previous regulatory control periods, ActewAGL has been taxed on capital contributions received as if it was revenue. Tax paid on capital contributions created a tax asset to be depreciated and thereby offset future income tax payments. Accordingly, the AER considers it appropriate to exclude historical capital contributions from the opening tax asset base. The inclusion of capital contributions in the tax asset base without any recognition of the tax paid when the capital contributions were received could lead to an inappropriately low regulatory tax allowance. ActewAGL has excluded capital contributions from the opening tax asset base which is considered appropriate by the AER.

***Inclusion of work in progress***

Under the *Income Tax Assessment Act*, capex translates to a tax asset upon commissioning of the asset. In the PTRM to apply to the DNSPs for the next regulatory control period, capex is recognised on an as-incurred basis. This means that capex creates a notional tax asset in the PTRM when the expenditure is incurred. ActewAGL did not propose any work in progress to be added to its tax asset base. Accordingly, the AER requested ActewAGL to make an adjustment to the 1 July 2009 opening tax asset base to include work in progress amounts.

ActewAGL noted in response that the amount of work in progress at 1 July 2009 is forecast to be approximately 3.6 per cent of the total tax asset base.[320] However it also noted that work in progress should not be included in the opening tax asset base as a matter of principle. The AER notes this would reduce regulatory revenue by less than 0.1 per cent in the next regulatory control period. The AER considers that while inclusion of work in progress is technically correct when transferring from an as-commissioned to as-incurred approach for recognising capex, it will not require inclusion of work in progress in the opening tax asset base given its immateriality.

## 10.6 AER conclusion

The AER has assessed each of the inputs to the PTRM that are used to calculate the expected cost of corporate income tax in accordance with clause 6.5.3 of the transitional chapter 6 rules. The AER considers that ActewAGL's proposed tax remaining and tax standard lives are appropriate. The AER also considers ActewAGL's proposed tax asset base of $473 million appropriate and reasonable. On the basis of these inputs, the PTRM has calculated the allowance for corporate income tax presented in table 10.2.

**Table 10.2: AER's conclusion on ActewAGL's corporate income tax allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Tax allowance | 5.1 | 6.0 | 6.2 | 5.9 | 6.1 | 29.1 |

## 10.7 AER draft decision

In accordance with clause 6.12.1(7) of the transitional chapter 6 rules the AER has decided the estimated cost of corporate tax to ActewAGL for each regulatory year of the regulatory control period is specified in table 10.2 of the draft decision.

[320] ActewAGL, email response to AER, 7 August 2008.

# 11 Depreciation

## 11.1 Introduction

This chapter sets out the annual allowances for regulatory depreciation—also referred to as the return of capital—that sum the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB). It also sets out the AER's assessment of ActewAGL's proposed asset lives used to calculate its depreciation schedules for the next regulatory control period.

Regulatory depreciation is used to model the nominal asset values over the regulatory control period and provides the depreciation allowance in the annual revenue requirement. The annual regulatory depreciation allowance is an amortised value of the efficient cost of the capital included in the RAB, derived using a specified depreciation schedule that reflects the nature of the assets over their economic life. Regulatory practice has been to assign a regulatory life (standard or remaining) to each category of assets that equals its expected economic or technical life. Generally, the regulatory, economic and technical lives of an asset coincide.

## 11.2 Regulatory requirements

Under clause 6.12.1(8) of the transitional chapter 6 rules the AER must make a decision on whether or not to approve the depreciation schedules submitted by a DNSP, in accordance with clause 6.5.5 of the transitional chapter 6 rules. Clause 6.5.5(a) of the transitional chapter 6 rules provides that depreciation must be calculated on the value of the assets included in the RAB at the beginning of the regulatory year.

A building block proposal must contain depreciation schedules that conform to the following requirements set out in clause 6.5.5(b) of the transitional chapter 6 rules:

> (1) the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets;
>
> (2) the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of that asset or category of assets was first included in the regulatory asset base for the relevant distribution system) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant distribution system; and
>
> (3) the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.

To the extent that a DNSP's building block proposal does not comply with the above requirements then the AER must determine the depreciation schedules, in accordance with clause 6.5.5(a)(2)(ii) of the transitional chapter 6 rules.

## 11.3 ActewAGL proposal

In the interest of maintaining consistency with its current distribution determination, simplicity and transparency, ActewAGL proposed to continue the straight-line approach to calculating depreciation in the post tax revenue model (PTRM).[321] It proposed the regulatory depreciation allowance set out in table 11.1.

**Table 11.1: ActewAGL's proposed depreciation allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Regulatory depreciation | 14.8 | 16.0 | 17.3 | 18.6 | 20.0 |

Source: ActewAGL, *Regulatory proposal*, p.218.

ActewAGL aggregated its RAB value into a single asset category in the PTRM and applied a single remaining and standard asset life. It noted this is consistent with the approach applied at the last review by the ICRC.[322] ActewAGL adopted an average remaining life of 20.45 years and a standard life of 40 years for this aggregated asset class as at 1 July 2009.[323] Under this approach, ActewAGL's forecast capital expenditure (capex) incurred over the next regulatory control period is also included in the RAB within the single asset category.

ActewAGL stated that splitting the RAB into asset classes in the PTRM and assigning them remaining lives that were not used when the assets were first included in the RAB, would be inconsistent with clauses 6.5.5(b)(1) and 6.5.5(b)(2) of the transitional chapter 6 rules.[324]

## 11.4 Issues and AER considerations

The allowance for regulatory depreciation is an output of the PTRM rather than an input to be specified or proposed by the DNSP. The relevant inputs to the PTRM's calculation of an allowance for regulatory depreciation include:[325]

- remaining life for each asset class
- standard life for each asset class
- existing assets (opening RAB) and new asset values (forecast capex) for each asset class.

### 11.4.1 Asset classes, standard asset lives and remaining asset lives

Regulatory depreciation has been calculated by the PTRM on the basis of ActewAGL's proposed remaining and standard asset life inputs, the opening RAB (discussed in chapter 7) and forecast capex values (discussed in chapter 8) .

321 ActewAGL, *Regulatory proposal*, pp. 217–218.
322 ActewAGL, *Regulatory proposal*, p. 218.
323 ActewAGL, *Regulatory proposal*, p. 218.
324 ActewAGL, *Regulatory proposal*, pp. 218–219.
325 Forecast inflation is also a relevant input and is discussed in chapter 12.

**ActewAGL proposal**

ActewAGL aggregated its RAB value into a single asset category in the PTRM and applied a single remaining asset life of 20.2 years rolled forward from the start of the current regulatory control period and a single standard asset life of 40 years.[326]

**AER considerations**

The AER accepts ActewAGL's approach to depreciate its opening RAB (existing assets) within the single asset category based on the proposed remaining life. This maintains consistency with the ICRC's treatment of the RAB in previous distribution determinations and ensures that the assets are depreciated using a consistent approach over their economic lives. The AER also reviewed the remaining asset life and found that it has been appropriately rolled forward during the current regulatory control period.

While the ICRC accepted the use of a single aggregated asset category, the AER considers it appropriate to include a more detailed breakdown of ActewAGL's forecast capex (new assets). Allocating new assets into relevant asset classes will enable verification that ActewAGL's depreciation profiles meet the requirements of the NER. In response to the AER's request to disaggregate its asset category into various classes, ActewAGL provided the asset classes and standard lives set out in table 11.2. The AER considers that these disaggregated asset classes should apply to ActewAGL's forecast capex from the next regulatory control period onwards. Accordingly, regulatory depreciation for new assets in the PTRM will be calculated using the disaggregated asset classes and standard asset lives.

**Table 11.2: ActewAGL proposed asset classes and standard lives (years)**

| Asset classes for forecast capex | Standard asset life | Tax standard asset life |
|---|---|---|
| Sub-transmission overhead | 40.0 | 47.5 |
| Sub-transmission underground | 60.0 | 47.5 |
| Zone substation | 40.0 | 40.0 |
| Distribution substations | 40.0 | 40.0 |
| Distribution overhead lines | 50.0 | 45.0 |
| Distribution underground lines | 60.0 | 50.0 |
| IT & communication systems (networks) | 10.0 | 10.0 |
| Motor vehicles | 7.0 | 8.0 |
| Other non-system assets (networks) | 5.0 | 5.8 |
| IT systems (corporate) | 5.0 | 4.1 |
| Telecommunications (corporate) | 5.0 | 6.7 |
| Other non-system assets (corporate) | 5.0 | 5.7 |
| Land | n/a | n/a |
| Buildings | 60.0 | 100.0 |

Source: ActewAGL, response to AER, 25 August 2008.

[326] ActewAGL, *Regulatory proposal*, p. 218.

With the assistance of EMS, the AER has reviewed ActewAGL's proposed asset classes and standard lives and considers them to be reasonable.[327] ActewAGL's proposed standard asset lives compare closely with those proposed by the NSW DNSPs, which have been accepted by the AER. Chapter 10 of this draft decision sets out the AER's assessment of the proposed tax asset lives for tax depreciation purposes.

## 11.5 AER conclusion

The AER has assessed each of the proposed asset life inputs to the PTRM that were used to calculate the regulatory depreciation allowance in accordance with clause 6.5.5 of the transitional chapter 6 rules. It does not consider ActewAGL's proposed depreciation schedules comply with the NER requirements and therefore has not approved the schedules under clause 6.12.1(8) of the transitional chapter 6 rules.

While the AER accepts ActewAGL's approach to depreciate its opening RAB (existing assets) within the single asset category based on the proposed remaining life, the AER considers it appropriate to include a more detailed breakdown of ActewAGL's forecast capex (new assets). ActewAGL has provided the asset classes and standard lives which will apply to its forecast capex from the next regulatory control period onwards. The AER has reviewed these asset classes and standard lives and considers them to be reasonable.

On the basis of these approved asset lives, opening RAB and forecast capex allowance, the AER has determined ActewAGL's regulatory depreciation allowance for the next regulatory control period in accordance with clause 6.5.5(a)(2)(ii) of the transitional chapter 6 rules, as set out in table 11.3.

**Table 11.3: AER's conclusion on regulatory depreciation allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Regulatory depreciation allowance | 14.5 | 16.2 | 17.7 | 19.3 | 21.1 | 88.8 |

## 11.6 AER draft decision

In accordance with clause 6.12.1(8) of the transitional chapter 6 rules the AER decides not to approve the depreciation schedules submitted by ActewAGL. The AER has determined the depreciation schedule for ActewAGL is set out in table 11.3 of the draft decision.

[327] EMS, advice, 27 August 2008.

# 12 Cost of capital

This chapter sets out the AER's estimate of an efficient (market-based) benchmark weighted average cost of capital (WACC) or the rate of return for ActewAGL over the next regulatory control period. The key issues considered include the WACC parameters specified in the transitional chapter 6 rules, and the determination of the risk-free rate, debt risk premium and inflation forecast.

The AER's consideration of debt and equity raising costs, and corporate tax allowances is not set out in this chapter because they are not compensated for through the WACC. Accordingly, the analysis of debt and equity raising costs is found in chapter 9 and the analysis of corporate tax is found in chapter 10 of this draft decision.

## 12.1 Regulatory requirements

Clause 6.5.2 of the transitional chapter 6 rules requires that the return on capital be calculated by applying the rate of return to the value of the regulatory asset base (RAB) as determined in chapter 7 of this draft decision.

The AER must determine the rate of return in accordance with clause 6.5.2 of the transitional chapter 6 rules. Clause 6.5.2(b) provides that the rate of return for a DNSP is a nominal post–tax WACC calculated in accordance with the following formula:

$$\text{WACC} = k_e \frac{E}{V} + k_d \frac{D}{V}$$

where:

$k_e$ = the return on equity

$k_d$ = the return on debt

E/V = the market value of equity as a proportion of the market value of equity and debt, which is 1 – D/V

D/V = the market value of debt as a proportion of the market value of equity and debt, which is deemed to be 0.6.

It also states that the return on equity ($k_e$) is determined by using the capital asset pricing model (CAPM):

$$k_e = r_f + \beta_e \times \text{MRP}$$

where:

$r_f$ = the nominal risk-free rate of return for the regulatory control period determined in accordance with clause 6.5.2(c)

MRP = the market risk premium, which is deemed to be 6 per cent

$\beta_e$ = the equity beta which is deemed to be 1.

It also states that the return on debt ($k_d$) is calculated as:

$$k_d = r_f + DRP$$

where:

DRP = the debt risk premium for the regulatory control period is determined in accordance with clause 6.5.2(e).

## 12.2 ActewAGL proposal

In estimating the WACC for its revenue proposal, ActewAGL stated it used the values for the WACC parameters set out in the transitional chapter 6 rules.[328] For the purposes of its revenue proposal ActewAGL has calculated a nominal vanilla WACC of 10.70 per cent. The parameters underlying ActewAGL's calculation of the WACC are presented in table 12.1.

**Table 12.1: ActewAGL's proposed WACC parameters**

| Parameter | ActewAGL's proposal |
|---|---|
| Risk-free rate (nominal) | 6.27% |
| Risk-free rate (real) | 3.67% |
| Expected inflation rate | 2.51% |
| Debt risk premium | 3.38% |
| Market risk premium | 6.00% |
| Gearing | 60% |
| Equity beta | 1.00 |
| Nominal pre–tax return on debt | 9.65% |
| Nominal post–tax return on equity | 12.27% |
| Nominal vanilla WACC | 10.70% |

Source: ActewAGL, *Regulatory proposal*, p.208.

## 12.3 Issues and AER considerations

Businesses are typically funded by a combination of equity and debt. Therefore, a weighted average cost of equity and debt must be established to derive the rate of return. This is usually referred to as the WACC. The derivation of the WACC requires several parameters. Many of these parameters have values specified in the transitional chapter 6 rules. Where the transitional chapter 6 rules do not specify a value, it specifies a method for determining the value.

[328] ActewAGL, *Regulatory proposal*, p. 206.

### 12.3.1 The WACC parameters specified in the NER

The transitional chapter 6 rules specify values for the equity beta and the market risk premium to be used to calculate the return on equity using the CAPM. The transitional chapter 6 rules also specify the value of debt as a proportion of the value of equity and debt (or gearing) to be used when calculating the WACC.[329]

**ActewAGL proposal**

ActewAGL stated it estimated the return on equity using the CAPM and adopted the parameter values specified in the transitional chapter 6 rules for the equity beta, market risk premium (MRP), and proportion of debt funding (gearing).[330]

**AER considerations**

Based on the transitional chapter 6 rules requirements, the parameters and values as outlined in section 12.2 of this draft decision have been applied by the AER for the purposes of determining the WACC for ActewAGL.

### 12.3.2 The risk free rate

The risk-free rate measures the return an investor would expect from an asset with zero volatility and zero default risk. The yield on long-term Commonwealth Government Securities (CGS) is often used as a proxy for the risk-free rate because the risk of government default on interest and debt repayments is considered to be low.

In the capital asset pricing model (CAPM) framework, all information used for deriving the rate of return should be as current as possible. While it may be theoretically correct to use the on-the-day rate as it represents the latest available information, this can expose the DNSP to day-to-day volatility. For this reason, an averaging method is used to minimise volatility in observed bond yields.

**Regulatory requirements**

Clause 6.5.2(c) of the transitional chapter 6 rules states that the nominal risk-free rate is to be determined by the AER:

> … on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years using:
>
> (1) the indicative mid rates published by the Reserve Bank of Australia; and
>
> (2) a period of time which is either:
>
> (i) a period ('the agreed period') proposed by the relevant Distribution Network Service Provider, and agreed by the AER (such agreement is not to be unreasonably withheld); or
>
> (ii) a period specified by the AER, and notified to the provider within a reasonable time prior to the commencement of that period, if the period proposed by the provider is not agreed by the AER under subparagraph (i),

329 Transitional chapter 6 rules, clause 6.5.2(6).
330 ActewAGL, *Regulatory proposal*, p. 206.

and, for the purposes of subparagraph (i):

(iii) the start date and end date for the agreed period may be kept confidential, but only until the expiration of the agreed period; and

(iv) the AER must notify the Distribution Network Service Provider whether or not it agrees with the proposed period within 30 business days of the date of submission of the building block proposal.

Clause 6.5.2(d) of the transitional chapter 6 rules states that if there are no CGS with a maturity of 10 years on any day in the averaging period, the AER must determine the nominal risk-free rate by:

> … interpolating on a straight line basis from the two Commonwealth Government bonds closest to the 10 year term and which also straddle the 10 year expiry date.

**ActewAGL proposal**

ActewAGL has nominated an averaging period of 20 days to calculate the risk-free rate. It proposed an indicative risk-free rate of 6.27 per cent based on annualised CGS yields with a maturity of 10 years for the purposes of its proposal, recognising that the AER will determine the applicable risk-free rate at the time of its final distribution determination.[331]

**AER considerations**

Clause 6.5.2(c) of the transitional chapter 6 rules requires the AER to determine the nominal risk-free rate using annualised CGS yields with a maturity of 10 years.

In accordance with clause 6.5.2(c) of the transitional chapter 6 rules, ActewAGL proposed an averaging period to estimate the risk-free rate. The AER did not agree with the period proposed on the basis that it considered the proposed dates of the period were too far removed from the final determination date and the commencement of the next regulatory control period. A period that is too far removed from the final determination date may not provide the most relevant information. This is consistent with past practice by the AER and other state regulators, and supported by CAPM theory.[332]

The AER specified a period that is closer to the final determination date and ActewAGL responded with a new proposed starting and ending date for the averaging period (based on an averaging period of 20 business days). The AER has accepted ActewAGL's revised proposal as it considers the 20 day averaging period and revised dates address its earlier concerns. The AER has agreed to keep the start and end dates of the averaging period confidential until the expiration of the period as requested by ActewAGL.

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331 ActewAGL, *Regulatory proposal*, p. 207.

332 Martin Lally, *The cost of capital for regulated entities*, report prepared for the Queensland Competition Authority, 26 February 2004, p. 63.
Kevin Davis, *Report on risk free interest rate and equity and debt beta determination in the WACC*, report prepared for the ACCC, 28 August 2003, p. 16.

For this draft decision, the 20 day moving average for CGS yields with a 10-year maturity for the period ending 17 October 2008 results in a proxy nominal risk-free rate of 5.46 per cent (effective annual compounding rate). The AER will update the risk-free rate, based on the AER specified averaging period, at a time closer to its final distribution determination.

### 12.3.3 The debt risk premium

The debt risk premium (or debt margin) is added to the nominal risk-free rate to calculate the return on debt, which is an input for calculating the WACC. The debt risk premium is the margin above the risk-free rate that investors in a benchmark efficient DNSP are likely to demand as a result of issuing debt to fund the business operations. It is intended to equate to a commercial cost of debt.

The debt risk premium varies depending on the entity's operational and financial risk as well as the term of the debt. This can be characterised as a credit rating. Applying the return on debt (as a percentage) to the RAB, adjusted for the assumed gearing, will generate the interest expense for regulatory purposes (also referred to as the cost of debt).

**Regulatory requirements**

Clause 6.5.2(b) of the transitional chapter 6 rules states that the return on debt ($k_d$) is calculated as:

$$k_d = r_f + DRP$$

Where:

$r_f$ = the nominal risk-free rate

DRP = the debt risk premium for the regulatory control period determined in accordance with clause 6.5.2(e).

Clause 6.5.2(e) of the transitional chapter 6 rules states that the debt risk premium is:

> … the margin between the 10 year Commonwealth annualised bond rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity of 10 years and a credit rating of BBB+ from Standard and Poors.

**ActewAGL proposal**

Based on the transitional chapter 6 rules requirements for setting the debt risk premium and using Bloomberg data, ActewAGL has proposed a debt risk premium of 3.38 per cent.[333] ActewAGL has recognised that the AER will determine the debt risk premium using updated market data at a date closer to its final distribution determination.

ActewAGL has proposed that the debt risk premium be calculated by reference to Bloomberg's 10-year BBB predicted yield.[334] In the event that the Bloomberg 10-year

[333] ActewAGL, *Regulatory proposal*, p. 208.
[334] ActewAGL, *Regulatory proposal*, p. 208.

BBB predicted yield is unavailable during the sample period ActewAGL has proposed the use of the highest value from either the:

- 10-year CBASpectrum BBB+ predicted yield
- 8-year Bloomberg BBB predicted yield plus the spread between an 8-year and 10-year A rated Bloomberg predicted yields.

**AER considerations**

In previous revenue determinations the AER conducted a review which compared the estimated average daily fair yields for corporate bonds with BBB+ credit rating and maturity of up to 10 years from the Bloomberg and CBASpectrum databases over a period.[335] Differences when comparing the average yields for actual bonds with the estimated average fair yields from the two databases were observed. The review indicated that Bloomberg provides estimates of BBB+ rated, long-term fair yields which are more consistent with the observed yields of similarly rated actual bonds. The AER has therefore decided to use the fair yields estimated by Bloomberg, rather than CBASpectrum, to determine the benchmark debt risk premium margin for ActewAGL.

The AER has previously used BBB 10-year corporate bond fair yields sourced from Bloomberg for the purposes of establishing a 10-year benchmark debt risk premium with a BBB+ credit rating.[336] In late October 2007, Bloomberg ceased publication of its BBB fair yields for bonds with 9 or 10-year maturities. The AER understands that the decision to cease publication was based on a lack of data for these long-dated corporate bonds (within the BBB credit rating category) from which Bloomberg could produce a fair yield. The longest maturity BBB bond fair yield now published by Bloomberg is 8 years.

Due to the unavailability of the Bloomberg fair yields for BBB rated 10-year corporate bonds, it is necessary to adopt an alternative proxy for deriving a 10-year BBB+ benchmark debt risk premium, as required by the NER.[337] The AER recently considered this issue and the details are set out in its SP AusNet final transmission determination.[338] Specifically, the methodology applied by the AER is to take the Bloomberg fair yield for BBB rated 8-year corporate bonds and add the Bloomberg fair yield spread between A rated 8 and 10-year corporate bonds, in order to derive a proxy 10-year BBB+ corporate bond yield. The AER considers that this methodology remains appropriate for the purposes of determining the benchmark debt risk premium.

Consistent with previous regulatory practice, the AER considers that the debt risk premium should be determined with reference to the same averaging period that was

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335 AER, *Powerlink Queensland*, Draft Decision, 14 June 2007.
AER, *Directlink Joint Venturers' application for conversion and revenue cap*, Decision, 3 March 2006.

336 Bloomberg's BBB fair yields are assumed to approximate BBB+ fair yields due to the estimation technique employed and the market being disproportionately weighted with longer term BBB+ rated bonds.

337 The proxy corporate bond yield less the nominal risk-free rate produces the debt risk premium.

338 AER, *SP AusNet transmission determination, 2008–09 to 2013–14: Final decision*, January 2008, pp. 94–98.

adopted for determining the risk-free rate. For this draft decision, the 20-day moving average benchmark debt risk premium for the period ending 17 October 2007, based on BBB+ rated corporate bonds with a maturity of 10 years, is 3.27 per cent (effective annual compounding rate).[339] Adding this debt risk premium to the nominal risk-free rate of 5.46 per cent provides a nominal return on debt of 8.73 per cent. The AER is satisfied that the debt risk premium is consistent, under clause 6.5.2(e) of the transitional chapter 6 rules, with the required margin between the 10-year CGS yield and observed Australian benchmark corporate bond yields corresponding to BBB+ credit rating and maturity of 10 years.

The debt risk premium will be updated by the AER based on this methodology at a time closer to its final distribution determination. As outlined above in relation to the risk-free rate, the AER did not agree with the averaging period originally nominated by ActewAGL and has substituted an alternative averaging period to use in its calculations for the final decision.

### 12.3.4 Expected inflation

The expected inflation rate is not an explicit parameter within the WACC calculation. However, it is used in the post tax revenue model (PTRM) to forecast nominal allowed revenues. It is an implicit component of the nominal risk-free rate, with implications for the return on both equity and debt. The PTRM framework essentially provides a real rate of return to the business, which means that the expected inflation rate included in the nominal WACC must be appropriately measured.

**Regulatory requirements**

Clause 6.4.2(b)(1) of the transitional chapter 6 rules states that the PTRM must specify:

> … a method that the AER determines is likely to result in the best estimates of expected inflation.

Historically, the AER has used an objective market-based approach to forecast the expected inflation rate—calculated as the difference between the CGS (nominal) and the indexed CGS yields. However, since late 2006 a downward bias in the indexed CGS has become evident due to the limited supply of these securities. Consequently, using this method potentially yields an overestimate of expected inflation. This limitation was recognised in the AER's PTRM guideline for DNSPs published in January 2008.[340] The PTRM guideline states that:

> …the AER considers the appropriate methodology for deriving forecast inflation would incorporate the forecasts and target inflation range of the Reserve Bank of Australia.[341]

In its recent final determinations for ElectraNet and SP AusNet, the AER applied the RBA's short-term inflation forecasts for the first two years of the next regulatory

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339 Bloomberg's BBB fair yields are assumed to approximate BBB+ fair yields due to the estimation technique employed and the market being disproportionately weighted with longer term BBB+ rated bonds.

340 AER, *Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–14: PTRM: final decision,* 1 January 2008, p. 10.

341 AER, *PTRM*, p. 10.

control period and adopted the mid-point of its target inflation band (that is, 2.5 per cent) for the remaining eight years.[342] An implied 10-year forecast is derived by averaging these individual forecasts. This aligns the inflation forecast to the term of risk-free rate.

**ActewAGL proposal**

ActewAGL proposed a ten year forecast of annual inflation of 2.51 per cent per annum.[343] This forecast is the average of forecast inflation for the regulatory control period in table 12.2 and the mid-point of the RBA target inflation band for the following five years. The forecast inflation figures were based on a report by the Competition Economists Group (CEG).[344] CEG's inflation forecasts were obtained from a weighted average mean of professional economic forecasters' inflation expectations.

**Table 12.2: ActewAGL's proposed inflation forecasts for 2008–09 to 2013–14 (per cent)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Inflation | 2.4 | 2.5 | 2.6 | 2.6 | 2.5 |

Source: ActewAGL, *Regulatory proposal*, p. 210.

**AER considerations**

The AER has determined in previous transmission determinations that a method that is likely to result in the best estimate of inflation over a 10-year period is to apply the RBA's short-term inflation forecasts—currently extending out to two years—and adopt the mid-point of its target inflation band beyond that period (i.e. 2.5 per cent) for the remaining eight years. An implied 10-year forecast is derived by averaging these individual forecasts.

The inflation forecasting methodology proposed by ActewAGL in its revenue proposals is broadly similar to that applied by the AER for its previous transmission determinations.[345] The difference between the two approaches, however, is the range of sources used to establish the 10-year average inflation estimate. ActewAGL's proposed methodology draws on forecasts from a number of independent economic forecasters,[346] while the AER's approach in previous transmission determinations relies on the RBA's inflation forecasts and the mid-point of its target band.

The AER notes the RBA's responsibility for monetary policy in Australia means it is an independent authority on inflation expectations. The AER considers that the RBA's inflation forecasts are objective and represent the best estimates of forecast inflation for the purpose of this draft decision. The RBA's statement on monetary policy examines a wide variety of objective data influencing inflation in both the

342 AER, *ElectraNet transmission determination Final Decision*, p. 69.
AER, *SP AusNet transmission determination Final decision*, pp. 99–106.
343 ActewAGL, *Regulatory proposal*, p. 210.
344 CEG, *A methodology for estimating expected inflation*, 17 January 2008.
345 AER, *ElectraNet transmission determination Final Decision*, p. 69.
AER, *SP AusNet transmission determination Final decision*, pp. 99–106.
346 CEG, *Escalation factors affecting expenditure forecasts: a report for NSW electricity businesses,* April 2008, p. 6.

domestic and international financial markets to develop its inflation forecast. The forecast is produced on a regular basis and is publicly available, including supporting analysis and reasoning. The AER's approach uses the RBA report. This provides consistency and transparency in the AER process for deriving an inflation forecast.

In the absence of an objective market-based approach, the AER considers that its methodology remains appropriate for the purposes of determining an inflation forecast in its determinations. The AER has updated the inflation forecast for the first two years of the regulatory control period using the latest published RBA inflation expectations as shown in table 12.3. The AER considers that, based on a simple average, an inflation forecast of 2.55 per cent per annum produces the best estimate for a 10-year period to be applied in the PTRM for this draft decision.

**Table 12.3: AER's conclusion on inflation forecast (per cent)**

| | June 2010 | June 2011 | June 2012 | June 2013 | June 2014 | June 2015 | June 2016 | June 2017 | June 2018 | June 2019 | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast inflation | 3.00 | 2.50[a] | 2.50 | 2.50 | 2.50 | 2.50 | 2.50 | 2.50 | 2.50 | 2.50 | 2.55 |

Source: RBA, *Statement on monetary policy*, 11 August 2008, p. 62.
(a) The RBA has not yet released a forecast for the year ending June 2011. This forecast will be available and adopted by the AER (including any updated forecasts) at the time of the final decision. The mid-point of its target inflation band has been assumed for the purposes of this draft decision.

The AER recognises that inflation forecasts will change in line with market sensitive data. Regulatory practice in Australia has been to update these parameter values at a time closer to the making of the final determination to take account of most recent information. Accordingly, the AER will update the inflation forecast to be used in the PTRM based on this methodology at the time of its final determination.

## 12.4 AER conclusion

The transitional chapter 6 rules prescribe a number of the WACC parameter values to be adopted by the AER for the purposes of setting a rate of return for DNSPs. For the parameters where the values have not been prescribed—nominal risk-free rate and the debt risk premium—the transitional chapter 6 rules sets out the methodology to be used by the AER for determining the values.

For this draft decision, the AER has determined a nominal vanilla WACC of 9.82 per cent for ActewAGL. The WACC is less than that proposed by ActewAGL due to the declines in the risk-free rate and debt risk premium since ActewAGL submitted its regulatory proposal.

Table 12.4 outlines the WACC parameter values for this draft decision. The AER will update the nominal risk-free rate and debt risk premium, based on the agreed averaging period, and the expected inflation rate at a time closer to its final determination.

**Table 12.4: AER's conclusion on ActewAGL's WACC parameters**

| Parameter | ActewAGL's proposal | AER's conclusion |
|---|---|---|
| Risk–free rate (nominal) | 6.27% | 5.46% |
| Risk–free rate (real) | 3.67% | 2.84% |
| Expected inflation rate | 2.51% | 2.55% |
| Debt risk premium | 3.38% | 3.27% |
| Market risk premium | 6.00% | 6.00% |
| Gearing | 60% | 60% |
| Equity beta | 1.00 | 1.00 |
| Nominal pre–tax return on debt | 9.65% | 8.73% |
| Nominal post–tax return on equity | 12.27% | 11.46% |
| Nominal vanilla WACC | 10.70% | 9.82% |

## 12.5 AER draft decision

In accordance with clause 6.12.1(5) of the transitional chapter 6 rules the AER decides the rate of return to apply to ActewAGL is 9.82 per cent.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the AER decides the other appropriate amounts, values or inputs to apply to ActewAGL are as specified in table 12.4 of the draft decision.

# 13 Service target performance incentive arrangements

## 13.1 Introduction

Clause 6.6.2(a) of the transitional chapter 6 rules provides that the AER may develop and publish a service target performance incentive scheme (STPIS) to provide incentives for DNSPs to maintain and improve the performance of their networks.

Under clause 6.6.2(k) of the transitional chapter 6 rules, the AER cannot apply a STPIS to ActewAGL which places revenue at risk during the next regulatory control period, without agreement from ActewAGL.

The AER is required to collect service performance data during the next regulatory control period under clause 6.6.2(h) of the transitional chapter 6 rules, which states:

> The AER must monitor and collect information from any or all of the NSW and ACT DNSPs on matters relevant to be included in a service target performance incentive scheme for the purpose of developing, amending or applying a service target performance incentive scheme for the regulatory control period commencing on 1 July 2014…

In late 2007, the AER undertook public consultation on service performance incentives for the ACT and NSW DNSPs for the next regulatory control period and decided not to introduce a STPIS with financial impact at this distribution determination due to concerns with data availability. The AER's decision was to implement a data collection process in accordance with 6.6.2(h) of the transitional chapter 6 rules, with a view to applying a national STPIS to ActewAGL for the regulatory control period commencing 1 July 2014.[347]

To facilitate the transition of ActewAGL to a national STPIS from 2014 it was decided that information reporting requirements for the next regulatory control period would be based on the AER's national STPIS for electricity DNSPs (the national distribution STPIS) and determined in consultation with ActewAGL prior to commencement of the next regulatory control period.

The AER published its national distribution STPIS on 26 June 2008.[348] Following this, the AER wrote to the ActewAGL setting out how it proposed to conduct the data collection exercise based on the national distribution STPIS framework.[349]

## 13.2 ActewAGL proposal

ActewAGL has acknowledged that the details of the service performance data collection process would be settled following the publication of the AER's national distribution STPIS. At the time of lodgement of ActewAGL's regulatory proposal on 2 June 2008, the national STPIS had not been published. ActewAGL submitted that,

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347 AER, *Final Decision, Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations*, February 2008, p15.

348 AER, *Electricity distribution service providers service target performance incentive scheme*, 26 June 2008.

349 AER, letter to ActewAGL, 1 August 2008.

in developing its regulatory proposal, it assumed that the information requirements of the final national STPIS would be similar to those set out in the proposed STPIS published in April 2008. ActewAGL proposed that any significant changes to the national distribution STPIS occurring after the date of its regulatory submission, which have cost impacts, could be addressed in response to the AER's draft decision, or through ActewAGL's proposed 'transitional period' pass through event mechanism.[350]

ActewAGL submitted that it expects to incur additional costs to establish new systems and processes, during the next regulatory control period, to prepare for the introduction of the national STPIS from 2014. ActewAGL included forecast capex and opex amounts in its regulatory proposal to establish these systems and processes.[351]

## 13.3 Submissions

The Energy Market Reform Forum (EMRF) made a submission to the AER expressing concern that no service performance incentive targets have been set for the next regulatory control period for the ACT and NSW DNSPs. It submitted that this would not be in the long-term interests of consumers.[352]

On 26 September 2008, ActewAGL wrote to the AER setting out its views on the details of the AER's proposed data collection process. In this letter, ActewAGL sought clarification of some issues before being able to confirm its ability to comply with the AER's data collection requirements. ActewAGL also identified some aspects of the data collection process that may require additional expenditure to collect and manage the data under the AER's requirements.[353] The issues about which ActewAGL has sought clarification are addressed below.

## 13.4 Issues and AER considerations

**Service performance incentive targets during the next regulatory control period**

The AER acknowledges the submission of the EMRF and notes that arrangements for service performance incentives were established in consultation with interested parties in February 2008.[354] In determining the service target performance incentive arrangements to apply to ActewAGL during the next regulatory control period, the AER was required to observe clause 6.6.2(k) of the transitional chapter 6 rules which states:

> A service target performance incentive scheme applying to the ACT distribution network service provider must not, without the agreement of the provider, confer financial rewards or impose financial penalties on the provider for the regulatory control period 2009–2014, but this paragraph does not affect the operation of paragraph (h)

350 ActewAGL, *Regulatory proposal*, pp. 44–47. The issue of recovery of efficient costs associated with complying with the data collection process is set out at chapters 8 and 9 of this draft decision.
351 ActewAGL, *Regulatory proposal*, pp. 45–46.
352 EMRF, p. 33.
353 ActewAGL, letter to AER, 26 September 2008.
354 AER, *STPIS ACT and NSW*, February 2008, p. 1.

During consultation, ActewAGL stated that it would not agree to the application of financial penalties or rewards under a STPIS for the next regulatory control period. Given this, the AER is not able to apply financial incentives to ActewAGL for the next regulatory control period under the transitional chapter 6 rules.

From 1 July 2014, ActewAGL will be subject to the provisions of the general chapter 6 rules which will not preclude the application of financial incentives in the ACT. The AER expects that financial rewards and penalties will be linked to ActewAGL's service performance under the AER's national distribution STPIS during the 2014–19 regulatory control period.

**Network segmentation**

ActewAGL proposed to retain its current approach to network segmentation for performance reporting. The AER notes that the existing feeder definitions observed by ActewAGL in its reporting to the ICRC are consistent with the requirements of the national distribution STPIS. No reassignment of ActewAGL's existing network segments will be required under the AER's data collection process during the next regulatory control period.

**Data resolution and inactive accounts**

ActewAGL noted that it does not currently have the capacity to record interruptions at the individual customer level and additional expenditure would be required to deliver this capacity.[355] Expenditure forecasts to deliver this specific capability were not included by ActewAGL in its regulatory proposal, rather, it proposed to use a pass through mechanism to recover associated costs, should the AER require data resolution to the individual customer level.

ActewAGL also noted the AER's national distribution STPIS requires the exclusion of inactive accounts when reporting SAIDI, SAIFI and MAIFI,[356] and sought clarification on the definition of an inactive account. ActewAGL submitted that it does not currently have the capacity to accurately identify the number of inactive accounts, as it cannot record data at the individual customer level.[357]

The AER's national distribution STPIS adopted the definitions established by the Steering Committee on National Regulatory Reporting Requirements (SCNRRR).[358] These definitions require the exclusion of inactive accounts. While the SCNRRR reliability measures do not define an inactive account, the term is defined in the AER's national distribution STPIS as:

> A connection to the DNSPs network that is inactive, that is, it does not have an active account with a retailer or is otherwise ineligible to take a supply of electricity. [359]

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355 ActewAGL, *Regulatory proposal*, p. 46.

356 SAIDI: system average interruption duration index, SAIFI: system average interruption frequency index, MAIFI: momentary average interruption frequency index.

357 ActewAGL, *Regulatory proposal*, p. 46.

358 Utility Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses, Discussion paper,* March 2002, p. 6. The AER understands that the existing reliability reporting requirements imposed by the ICRC are consistent with the SCNRRR parameter definitions, which require the exclusion of inactive accounts when calculating performance.

359 AER, *DNSP STPIS*, p. 31.

The AER acknowledges that ActewAGL is not presently able to report data net of inactive accounts. In the absence of observable data, the AER considers the use of a best estimate of the number of inactive accounts is acceptable in the short term, when reporting reliability for the data collection process. However, the AER expects ActewAGL to establish capabilities to record outages at the individual customer level and observe the number of actual inactive accounts on its network, as soon as practical. This will ensure compliance with the requirements of the national distribution STPIS.

**Momentary average interruption frequency index (MAIFI)**

ActewAGL commented on the appropriateness of the MAIFI parameter used in the national distribution STPIS. It submitted a more appropriate measure of MAIFI would capture only the first momentary interruption, and not subsequent unsuccessful attempts by automatic reclosers to clear a fault.[360]

The AER's national distribution STPIS adopted the definition of MAIFI established by SCNRRR. The national distribution STPIS prescribes that:

> In calculating MAIFI, each operation of an automatic reclose device is counted as a separate interruption. Sustained interruptions which occur when a recloser locks out after several attempts to reclose should deleted from MAIFI calculations.[361]

The AER developed and published its national distribution STPIS following stakeholder consultation. During consultations the AER did not receive any comments on its proposed definition for the MAIFI parameter.

The AER does not accept ActewAGL's proposal to record only initial momentary interruptions under the MAIFI parameter for the data collection process, as it is inconsistent with the national distribution STPIS. The AER considers the national distribution STPIS should apply. To accommodate ActewAGL's proposed alternative definition, the AER would be required to amend the national distribution STPIS in accordance with the distribution consultation procedures. The AER is not able to make such amendments through the distribution determination process. Any amendment to the national distribution STPIS should be proposed to the AER in accordance with section 1.8 of the national distribution STPIS.[362]

ActewAGL undertook testing of the data capabilities of its current communications-enabled reclosers. It advised that it is able to record multiple recloser events from all its communications-enabled reclosers.[363] However, ActewAGL indicated that its future ability to record this data will depend on communications coverage in areas where the recloser population is to be expanded.[364] For the purposes of the data collection process, the AER will require ActewAGL to report MAIFI data under the national distribution STPIS definition.

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360 ActewAGL, letter to AER, 26 September 2008, p.6

361 AER, *DNSP STPIS,* p. 22.

362 Should the national distribution STPIS be amended following the establishment of data reporting requirements set out in this draft decision, the AER will formally notify ActewAGL of any resulting changes to data reporting requirements to apply for the next regulatory control period.

363 ActewAGL, email to AER, 15 October 2008.

364 ActewAGL, letter to AER, 26 September 2008. p.7

**Exclusions**

ActewAGL submitted it expects to have capacity to report exclusions on a daily basis under the beta 2.5 methodology required by the national distribution STPIS from 2010–11.[365] ActewAGL noted that compliance with this requirement is dependent upon the AER approving its proposed expenditures to establish the necessary systems.

The AER acknowledges that ActewAGL has not previously been required to report reliability data under the beta 2.5 methodology and that it may need to establish systems and processes to achieve this. The AER expects ActewAGL to work towards achieving this capability as soon as practical during the next regulatory control period.

## 13.5 AER conclusion

In accordance with clause 6.6.2(h) of the transitional chapter 6 rules, the AER will collect and monitor ActewAGL's service performance data during the next regulatory control period. Revenue will not be placed at risk under the data collection process during this period.

In consultation with ActewAGL, the AER has developed service performance data reporting requirements for the next regulatory control. The data reporting requirements have been aligned with the requirements of the national distribution STPIS, published on 26 June 2008. Collection of data consistent with the national distribution STPIS is important to ensure that a reliable data series is available for setting robust performance targets once the national distribution STPIS is applied.

The AER acknowledges that ActewAGL will need to implement additional systems and processes to achieve full compliance with the AER's national distribution STPIS by 2014, and that that full compliance may not be realised before the commencement of the next regulatory control period. To ensure that the data collection process is effective in establishing a useable data set for future target setting, the AER expects ActewAGL to implement measures to achieve full compliance with the national distribution STPIS as soon as practical, but no later than December 2009.

In implementing the data reporting requirement, the AER expects to accumulate a sufficient data series to allow the application of the national distribution STPIS to ActewAGL from 1 July 2014. The application of the national STPIS for the 2014–19 regulatory control period for ActewAGL will be the subject of consultation under the framework and approach process, prior to the 2014 distribution determination.

Table 13.1 sets out the application of the national STPIS framework for service performance data collection under clause 6.6.2(h) of the transitional chapter 6 rules during the next regulatory control period for ActewAGL. These arrangements should be read in conjunction with the AER's national distribution STPIS for electricity distribution businesses.[366]

[365] ActewAGL notes that it will have manual processes in place to calculate exclusions under the beta 2.5 methodology in the near future.

[366] AER, *DNSP STPIS*.

**Table 13.1 Service performance data collection arrangements for ActewAGL: 2009–14**

| Element | Relevant provision – national distribution STPIS | Requirements for the 2009–14 regulatory control period |
|---|---|---|
| Timing of performance measure | 2.4 | ActewAGL must measure performance in accordance with the data collection process for each financial year starting on that same year within the regulatory control period, from 1 July until 30 June inclusive. |
| Revenue at risk | 2.5 | No revenue will be placed at risk under the data collection process during the 1 July 2009 to 30 June 2014 regulatory control period.<br>Performance outcomes reported during the 2009–14 regulatory control period may be used in determining performance targets for the 2014–19 regulatory control period. |
| Reliability of supply component | 3.1 | Section 3.1 of the national distribution STPIS must be observed during the 2009–14 data collection process, with the exception of clause 3.1(e).<br>For the 2009–14 data collection process, ActewAGL is to report annual performance against the following parameters, consistent with section 3.1 of the national distribution STPIS:<br>• Unplanned SAIDI<br>• Unplanned SAIFI<br>• MAIFI.<br>ActewAGL is to divide its electricity network into segments by feeder type as specified in clause 3.1(c) of the national distribution STPIS for the purposes of reporting this information. The AER accepts ActewAGL's existing network segmentation is consistent with the requirements of national distribution STPIS |
| Exclusions – reliability of supply component | 3.3 | Events to be excluded for the purposes of reporting data under the 2009–14 data collection process are limited to those set out at section 3.3 of the national distribution STPIS. |
| Customer service component | 5.1 | ActewAGL is to report performance against the customer service parameter 'telephone answering' and may propose additional parameters subject to clauses 5.1(c) – 5.1(e) of the national distribution STPIS.<br>No revenue will be placed at risk under section 5.2 of the national distribution STPIS, for the 2009–14 data collection process. |
| Exclusions – customer service component | 5.4 | Section 5.4 of the national distribution STPIS must be observed in determining events to be excluded for the purposes of reporting performance under the 2009–14 data collection process. |
| Guaranteed service level component | 6 | A GSL scheme currently applies to ActewAGL under existing jurisdictional legislation. Consistent with clause 6.1(b) of the national STPIS, should these obligations be removed during the next regulatory control period, the AER may require reporting of performance under clauses 6.2-6.4 of the national distribution |

| | | |
|---|---|---|
| | | STPIS, with the exception of clauses 6.3.1, 6.3.2 and 6.3.3. |
| Information and reporting requirements | 7 | Section 7 of the national distribution STPIS must be observed during the 2009–14 data collection process, with the exception of clause 7.2(b)(3).<br><br>The AER will request information for the data collection process through an annual regulatory reporting process. The AER expects to initiate the first request for such data following the conclusion of the first year of the next regulatory control period. This information request is expected to cover performance during the period 1 July 2009 to 30 June 2010.<br><br>Where possible, the AER will seek to draw on performance data reported to jurisdictional authorities as part of the existing reporting process against existing jurisdictional obligations. It is anticipated that ActewAGL will provide the AER with a copy of the relevant information when it provides this to the relevant jurisdictional authorities. |
| Format of data | n/a | Where the AER's data collection requirements differ from those currently in place, the AER will determine appropriate reporting formats in consultation with ActewAGL, prior to the first request for information. |

## 13.6 AER draft decision

In accordance with clause 6.3.2(a)(3) of the transitional chapter 6 rules the AER decides that the application of the service target performance incentive scheme to apply to ActewAGL is as specified in section 13.5 of the draft decision.

# 14 Efficiency benefit sharing scheme

## 14.1 Introduction

This chapter sets out how the AER intends to apply its efficiency benefit sharing scheme (EBSS) to ActewAGL. An EBSS shares between DNSPs and distribution network users the efficiency gains or losses derived from the difference between a DNSP's actual operating expenditure (opex) and the forecast opex allowance for a regulatory control period.

The AER has published a guideline under clause 6.5.8(a) of the transitional chapter 6 rules which establishes an EBSS that will apply to ActewAGL from 1 July 2014 (the EBSS scheme).[367] During the next regulatory control period, the AER will collect opex data from ActewAGL to allow the application of the scheme during the 2014–19 regulatory control period.

## 14.2 Regulatory requirements

Clause 6.5.8(a) of the transitional chapter 6 rules provides that the AER may develop and publish an EBSS. Under clause 6.12.1(9) of the transitional chapter 6 rules, the AER must specify how this EBSS will apply to ActewAGL as part of its distribution determination.

**First year formula**

The EBSS guideline states that the AER will calculate an efficiency gain or loss in the first year of the regulatory control period using the following formula:

$$E_1 = F_1 - A_1$$

where:

$E_1$ = the efficiency gain/loss in year 1

$A_1$ = actual opex incurred by the DNSP for year 1 of the regulatory control period

$F_1$ = forecast opex accepted or substituted by the AER in the distribution determination for year 1 of the regulatory control period.

**Subsequent years' formula**

Gains or losses that arise in the second and subsequent years of the regulatory control period will be calculated as:

$$E_t = (F_t - A_t) - (F_{t-1} - A_{t-1})$$

where:

$E_t$ = the efficiency gain/loss in year t

[367] AER, *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008.

$A_t$, $A_{t-1}$ = the actual, or adjusted actual, opex incurred in years t and t–1 respectively

$F_t$, $F_{t-1}$ = the forecast, or adjusted forecast, opex accepted or substituted by the AER for years t and t–1 respectively.

**Final year formula**

As the distribution determination for the 2014–19 regulatory control period will be made prior to the completion of the next regulatory control period, the AER will estimate the actual opex required to calculate gains or losses for the final year of the next regulatory control period as follows:

$$A_5 = F_5 – (F_4 – A_4)$$

Where differences arise between this estimate and the actual expenditure amount of the final year, the efficiency gain or loss in the first year of the 2014–19 regulatory control period ($E_6$) will be adjusted as follows:

$$E_6 = (F_6 – A_6) – (F_5 – A_5) + (F_4 – A_4)$$

**Other provisions**

The EBSS also makes provision for:

- adjustments to forecast opex allowances for the purpose of calculating carryover amounts to account for variations between forecast and outturn demand growth
- DNSPs to propose cost categories to be excluded from the operation of the EBSS
- the review or amendment of the EBSS with the agreement of each affected DNSP under clause 6.5.8(d) of the transitional chapter 6 rules.

## 14.3 ActewAGL proposal

ActewAGL has proposed the following cost categories for exclusion from the operation of the EBSS:[368]

- self insurance costs
- debt raising costs
- costs of approved pass throughs
- utilities network facilities tax (UNFT) payable to the ACT Government.

ActewAGL did not propose a method for adjusting forecast opex for EBSS purposes to account for any difference between forecast demand growth and actual demand growth during the next regulatory control period.

[368] ActewAGL, *Regulatory proposal*, p. 198.

## 14.4 Consultant review

As part of its review of ActewAGL's regulatory proposal Wilson Cook assessed the reasonableness of the opex cost categories proposed by ActewAGL to be uncontrollable for the purposes of the EBSS.

Wilson Cook suggested that proposals for exclusions from the EBSS:[369]

> … ought to meet a high threshold in the sense of being uncontrollable, as the pressure on the DNSPs to minimise costs efficiently in any reasonable changing circumstance ought not to be diluted.

Wilson Cook considered ActewAGL's proposed cost categories solely from the standpoint of whether the costs were uncontrollable. On that basis, Wilson Cook considered that the UNFT payments should be excluded as it considered those costs to be completely outside the control of ActewAGL. Wilson Cook also considered that pass through events proposed by ActewAGL should be exempted from the EBSS if those events are accepted by the AER for pass through.[370]

In principle, Wilson Cook did not consider self insurance or debt raising costs to be uncontrollable. However, it noted that it may be appropriate to exclude these cost categories from the EBSS for reasons other than controllability, such as if the allowance for these costs was determined externally.[371]

## 14.5 Issues and AER considerations

### 14.5.1 Demand growth adjustment

In developing the EBSS the AER recognised that a DNSP's opex will, to some degree, be affected by the level of demand growth experienced in the network. The EBSS provides that forecast opex is to be adjusted for variances between actual and forecast demand growth. This is intended to prevent DNSPs being penalised/rewarded for changes in opex that are directly attributable to demand growth which is beyond the control of the DNSP. However, as the AER may make a decision about how to apply the EBSS to a particular DNSP, it may decide not to make such an adjustment.[372]

**ActewAGL proposal**

ActewAGL noted in its proposal that the relationship between demand growth and opex is complicated and that to form a relationship between them would be a complex task. ActewAGL argued that to develop such a relationship would have required it to recast its forecasting methodology as well as to revise its forecasts and regulatory proposal content for the next regulatory control period. It stated that the time available between the release of the EBSS final decision (on 29 February 2008) and the

369 Wilson Cook, Volume 1, p. 12.
370 Wilson Cook, Volume 5, p. 41.
371 Wilson Cook, Volume 5, p. 41.
372 Transitional chapter 6 rules, clause 6.12.1(9).

submission of the regulatory proposal (on 2 June 2008) was not sufficient to undertake such a task.[373]

Consequently, ActewAGL has not proposed a method for adjusting forecast opex for EBSS purposes to account for any difference between forecast demand growth and actual demand growth during the next regulatory control period.

**AER considerations**

The AER recognises ActewAGL's view that to form a relationship between demand growth and opex would be a complex task. The AER does not consider a demand growth adjustment is necessary for the EBSS to provide DNSPs a continuous incentive to pursue efficiency gains. The demand growth adjustment was incorporated into the EBSS to prevent DNSPs from being penalised or rewarded by the EBSS for changes in demand growth over which the DNSP has no control. The risk to DNSPs of being rewarded or penalised by the EBSS for changes in demand growth is a symmetrical one. The AER considers it reasonable for the EBSS to not be adjusted for changes in demand growth if a DNSP does not regard this necessary. Accordingly, the AER will not adjust the EBSS for the consequences of changes in demand growth for ActewAGL for the next regulatory control period.

### 14.5.2 Excluded cost categories

By default the EBSS excludes the costs of pass through events from the calculation of carryover amounts. In addition, the EBSS allows DNSPs to propose a range of additional cost categories to be excluded from the operation of the EBSS. The scheme requires that these cost categories must be proposed by a DNSP in their regulatory proposal for the next regulatory control period.

**ActewAGL proposal**

ActewAGL has proposed the following cost categories for exclusion from the operation of the EBSS:

- self insurance costs
- debt raising costs
- costs of agreed pass throughs
- UNFT payable to the ACT government.

ActewAGL has proposed the exclusion of these cost categories because it considered them to be uncorrelated with the underlying efficiency of its business processes and service provision.[374]

**AER considerations**

There are two factors that should be considered when assessing whether an opex category should be excluded from the EBSS. The first factor is whether or not the opex is controllable. The AER does not consider it appropriate for DNSPs to receive

[373] ActewAGL, *Regulatory proposal*, pp. 197–198.
[374] ActewAGL, *Regulatory proposal*, p. 198.

benefits or penalties through the EBSS for variances in its opex for cost categories over which it has no control.

The second factor is how actual expenditure for that cost category is used in setting opex forecasts for the following regulatory control period. The EBSS assumes that actual opex is used as a basis for setting future opex allowances. If this is not the case, for instance if opex forecasts for a given cost category were based on an external benchmark, the EBSS would not provide a continuous incentive to reduce opex.

Applying these factors the AER considers it appropriate to exclude from the operation of the EBSS for the next regulatory control period the following opex cost categories:

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs
- UNFT payable to the ACT Government
- non–network alternatives.

These are in addition to the costs of pass through events which are directly excluded by the EBSS.

The AER considers it appropriate that debt raising costs be excluded from the operation of the EBSS on the basis that forecast costs are based on a benchmark efficient firm rather than the historical costs of ActewAGL. Similarly self insurance and insurance cost forecasts are based on independent expert analysis rather than historical costs. Consequently, the AER considers it reasonable that they be excluded from the operation of the EBSS.

The AER notes that many DNSP employees are members of defined benefit superannuation schemes. Consequently, a DNSP's superannuation liabilities relating to these employees are impacted, among other things, by the number of these employees that retire in a given year and the performance of the superannuation fund. Given that both of these factors are broadly beyond the control of the DNSP, the AER considers it reasonable that superannuation costs be excluded from the operation of the EBSS.

In 2006, the ACT Government introduced a UNFT, which ActewAGL is required to pay.[375] The tax rate to apply to ActewAGL is determined each year by the ACT Government for the coming year. Consequently, the AER considers that ActewAGL's UNFT liability is uncontrollable and should be excluded from the EBSS as proposed by ActewAGL.

[375] ACT Treasury, *Utilities (Network Facilities) Tax,* http://www.revenue.act.gov.au/utilities_network_facilities_tax

The AER also considers that to meet the requirements of the transitional chapter 6 rules, non–network alternatives should be excluded from the operation of the EBSS. This ensures that the EBSS does not impact on the incentives for DNSPs to implement non–network alternatives.

## 14.6 AER conclusion

The AER will apply the EBSS released in February 2008 to ActewAGL for the next regulatory control period. Recognising ActewAGL's view that to form a relationship between demand growth and opex would be a complex task, the AER will not adjust the EBSS for the consequences of changes in demand growth for ActewAGL for the next regulatory control period.

The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs
- the UNFT
- non–network alternatives.

These are in addition to the costs of pass through events which are directly excluded by the EBSS.

The forecast controllable opex outlined in table 14.1 will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.[376]

**Table 14.1: Forecast controllable opex for EBSS purposes ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Total forecast opex | 57.3 | 58.2 | 59.1 | 60.8 | 60.6 |
| Adjustment for debt raising costs | –0.3 | –0.3 | –0.4 | –0.4 | –0.4 |
| Adjustment for self insurance costs | –0.3 | –0.3 | –0.3 | –0.3 | –0.3 |
| Adjustment for insurance costs | –6.5 | –6.5 | –6.5 | –6.5 | –6.5 |
| Adjustment for superannuation costs | –3.1 | –3.2 | –3.3 | –3.4 | –3.5 |
| Adjustment for UNFT | –3.9 | –4.0 | –4.1 | –4.2 | –4.3 |
| Forecast opex for EBSS purposes | 43.1 | 43.7 | 44.4 | 45.9 | 45.5 |

[376] AER, *ACT and NSW EBSS*, pp. 5–6.

## 14.7 AER draft decision

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the AER decides the efficiency benefit sharing scheme to apply to ActewAGL is as defined in the AER's *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, published in February 2008. The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs
- the utilities network facilities tax
- non–network alternatives.

These are in addition to the costs of pass through events which are excluded by the EBSS.

In accordance with clause 6.3.2(a)(3) of the transitional chapter 6 rules the AER decides that the application of the efficiency benefit sharing scheme to apply to ActewAGL is as specified in section 14.6 of the draft decision.

# 15 Demand management incentive schemes

## 15.1 Introduction

This chapter sets out the AER's demand management incentive scheme (DMIS) to apply to ActewAGL for the next regulatory control period.

The DMIS to apply to ActewAGL is in the form of an innovation allowance scheme. In February 2008 the AER published the demand management innovation allowance scheme (DMIA) to apply to ActewAGL and the NSW DNSPs in the next regulatory control period.[377] The DMIA will provide incentives for ActewAGL to pursue innovative, broad–based non–network solutions to growing demand and constraints on its network.

This chapter also sets out the AER's considerations and conclusions on how the DMIA should apply to ActewAGL during the next regulatory control period. It provides a brief description of demand management projects carried out during the current regulatory control period, and demand management projects proposed by ActewAGL for the next regulatory control period.

## 15.2 Regulatory requirements

Clause 6.6.3 of the transitional chapter 6 rules provides that:

> the AER may develop and publish a DMIS to provide incentives for DNSPs to implement efficient non–network alternatives or to manage the expected demand for standard control services in some other way.

On 29 February 2008, the AER published a DMIS to apply to ActewAGL, Country Energy, EnergyAustralia and Integral Energy during the next regulatory control period.[378] This included a DMIA to apply to ActewAGL (the original DMIA). The AER can determine how its DMIS will apply to a DNSP as part of its distribution determination under clause 6.12.1(9) of the transitional chapter 6 rules.

## 15.3 Demand management innovation allowance

In accordance with clause 6.6.3(c) of the transitional chapter 6 rules the AER may, from time to time, and with the agreement of each affected DNSP, amend or replace any published DMIS.

As part of its draft determination, and dependent upon the agreement of ActewAGL, the AER proposes to amend the DMIS published on 29 February 2008 by replacing the original DMIA with the DMIA set out in the AER's *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations*, published concurrently with this draft decision in November 2008 (the replacement DMIA).

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377 AER, *Final Decision: Demand management incentives schemes for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008.

378 AER, *DMIS*, February 2008, pp. 28–29.

The replacement DMIA takes account of the AER's current considerations in developing a DMIS to apply to DNSPs in Queensland and South Australia. It also addresses a number of issues raised in the NSW DNSPs' regulatory proposals and stakeholders' submissions on these proposals.

The replacement DMIA provides ActewAGL with an allowance of $100 000 per annum for expenditure on demand management projects during the next regulatory control period. The allowance is identical to that provided to ActewAGL in the original DMIA.

The replacement DMIA varies the original scheme by modifying the way the allowance is provided and the criteria for assessment. The replacement DMIA provides an ex ante allowance for demand management projects in ActewAGL's opex forecasts for the next regulatory control period. It also allows for a one–off adjustment at the end of the next regulatory control period for any amount of the allowance unspent or unapproved over the regulatory control period, and the time value of money lost or accrued as a result of the expenditure profile selected by the DNSP.[379]

To be eligible for the allowance under the replacement DMIA, demand management programs must meet the criteria established in the replacement DMIA.[380] By setting criteria, the replacement DMIA provides certainty as to which demand management programs are eligible for the allowance, and negates the need for the case–by–case ex ante approval process as provided for in the original DMIA.

For DNSPs subject to a form of control where revenue is dependent on the quantity of electricity sold (including an average revenue cap), the replacement DMIA allows for the recovery of forgone revenues resulting from a reduction in the quantity of electricity sold due to approved demand management projects carried out under the scheme, independently of the allowance provided.[381] Recovery of forgone revenue under the replacement DMIA does not have a specified cap. However, the actual amount that can be recovered is limited to approved forgone revenue resulting from a successful project carried out under the DMIA.

## 15.4 ActewAGL regulatory proposal

### 15.4.1 Application of the DMIA

ActewAGL did not comment on the application of the original DMIA in its regulatory proposal. It stated that it would provide its proposal in relation to the application of a DMIA in its annual pricing submission, in accordance with the requirements set out in the AER's final decision on the DMIS.[382]

The AER notes that the replacement DMIA does not require DNSPs to apply for prior approval of demand management programs. Instead, the scheme contains a set of general criteria which demand management programs must meet to be eligible for the

379 AER, *Demand management innovation allowance to apply to ActewAGL, Country Energy, EnergyAustralia and Integral Energy in the 2009–14 regulatory control period, November 2008,* p. 6-7.
380 AER, *DMIA*, p. 4–5.
381 AER, *DMIA*, p. 7–11.
382 ActewAGL, *Regulatory proposal*, p 105.

allowance. The criteria enable a DNSP to assess internally whether planned demand management projects are likely to be approved for cost recovery under the DMIA, without the AER assessing each project prior to its implementation.

### 15.4.2 Demand management initiatives

ActewAGL stated that its approach to demand–side management has focused on developing and offering tariff incentive structures, such as time–of–use tariffs which signal to customers the higher cost of consumption during periods of high demand. It also stated that in its experience, project–specific demand management opportunities are not as cost effective as system–wide initiatives.[383] It noted this may be the result of the small industrial base in the ACT, which only provides limited scope for embedded generation as an alternative to network augmentation.

ActewAGL outlined the following demand management measures that it has introduced or continued during the current regulatory control period:[384]

- kVA based maximum demand tariffs, which provide incentives for customers to improve their power factor
- adjusting the balance between the energy and demand components of tariffs to provide stronger demand related price signals
- capacity tariffs
- off–peak tariff options
- time–of–use residential distribution use of system charges to complement the introduction of interval meters for all new and replacement installations[385]
- establishing business processes and tariffs to facilitate the connection of small–scale photovoltaic generation to the network
- developing technical guidelines and business processes to facilitate embedded generation
- amending the requirements of the ActewAGL service and installation rules for connection to the electricity distribution network, to require customers to ensure an appropriate power factor is maintained (in 2003)[386]
- undertaking network loss management through planning and design of the network.

383 ActewAGL, *Regulatory proposal*, pp. 103–104.
384 ActewAGL, *Regulatory proposal*, pp. 104–105.
385 ActewAGL stated that approximately 80 per cent of its commercial customer load is now billed using time–of–use tariffs. ActewAGL, *Regulatory proposal*, p. 16.
386 ActewAGL, *Service and Installation Rules for Connection to the electricity distribution network*, 13 March 2007, as at 18 September 2008, <http://www.actewagl.com.au/Publications/Electricity/ServiceInstallationRules1.pdf>

ActewAGL's regulatory proposal also detailed its tariff based demand management program, which it intends to continue developing over the next regulatory control period.[387]

## 15.5 NSW DNSPs regulatory proposals

The NSW DNSPs raised issues concerning the design and application of the DMIA within their regulatory proposals to the AER. The issues relevant to the DMIA are set out and considered in this section and section 15.6.

### 15.5.1 Country Energy regulatory proposal

Country Energy stated its support for the implementation of the AER's DMIA for the next regulatory control period.[388] However, it submitted that the $0.6 million per annum allowance for Country Energy proposed within the AER's DMIA is unlikely to cover the cost of undertaking 'intelligent network pilots and trials' and thus Country Energy proposed that the DMIA be increased.[389]

### 15.5.2 EnergyAustralia regulatory proposal

EnergyAustralia stated that it supports the AER's proposed DMIA, however, maintains its preference for a more generous incentive scheme. EnergyAustralia proposed that the AER make a number of changes to the DMIA:[390]

- any unspent amount of the DMIA in a regulatory year should be rolled forward into the DMIA cap for the next regulatory year
- any unspent amount of the DMIA at the end of the next regulatory control period should be rolled forward and made available to DNSPs over the subsequent regulatory control period
- the DMIA should include a recognition for the time value of money invested in innovation projects, consistent with the timing of investments within the post tax revenue model (PTRM). EnergyAustralia proposes that capital investments undertaken within the DMIA be multiplied by one plus the nominal vanilla weighted average cost of capital (WACC)
- the DMIA should also recognise the timing gap between the real value of opex under the DMIA and the real value of recovery for those projects. EnergyAustralia proposes that opex undertaken within the DMIA be multiplied by one plus the nominal vanilla WACC (effectively allowing opex and capex under the DMIA to earn the same return)
- that the pre–approval assessment and notification stage within the DMIA be not mandatory for a project to be considered for the final ex post review

387 ActewAGL, *Regulatory proposal*, chapter 13.
388 Country Energy, *Country Energy's Electricity Network Regulatory Proposal 2009–2014*, Port Macquarie, June 2008, p. 172.
389 Country Energy, *Regulatory proposal*, p. 169.
390 EnergyAustralia, *Regulatory proposal*, June 2008, pp. 104–105.

- that the AER clarify that demand management initiative milestones that occur in a regulatory year will be calculated as part of the DMIA for that regulatory year, even though completion of the demand management initiative may be in a subsequent year (to ensure that a demand management initiative which spans a number of years is eligible for cost recovery up to the annual cap across each of the regulatory years, rather than the total costs for an initiative being recoverable under the DMIA for the year in which the initiative is completed)

- the AER ensure that the administration of the next regulatory control period DMIA be carried over into the subsequent regulatory control period until such time that all initiatives commenced within the next regulatory control period have been completed or the total funding allowance under the DMIA has been exhausted.

### 15.5.3 Integral Energy regulatory proposal

Integral Energy stated that it acknowledges that the AER's introduction of the DMIA is a positive move to encourage demand management innovation, and that it intends to undertake innovative tariff and non–tariff based demand management programs during the next regulatory control period.[391] However, Integral Energy submitted that it seeks an increase in the annual allowance from $0.6 million per annum to $1 million per annum to support a higher level of innovative demand management activity for the benefit of consumers.[392] Integral Energy submitted that the proposed increase in the allowance aligns its allowance with that of EnergyAustralia, and reflects Integral Energy's view that the relative sizes of the DNSPs' should not reduce the amount of funding for demand management.

## 15.6 Issues and AER considerations

As noted above, neither ActewAGL's regulatory proposal, nor stakeholders' submissions on the ACT and NSW regulatory proposals raised any issues relating to the application of the DMIA to DNSPs in the next regulatory control period. Accordingly, in considering how the DMIA is to apply to ActewAGL over the next regulatory control period, the AER considered the issues raised in NSW DNSPs' regulatory proposals.

***Issues raised by EnergyAustralia***

The AER notes EnergyAustralia's submission that any unspent amount of the DMIA in a regulatory year should be rolled forward into the DMIA cap for the subsequent regulatory year. The replacement DMIA allows unspent allowance from a regulatory year to be available for expenditure in any other regulatory year, up to the end of the regulatory control period.

EnergyAustralia submitted that any unspent amount of the DMIA at the end of the next regulatory control period should be rolled forward and made available to DNSPs over the 2014–19 regulatory control period. It also submitted that the AER should ensure that the administration of the 2009–14 DMIA be carried over into the 2014–19 regulatory control period, until such time that all initiatives commenced in the next

391 Integral Energy, *Regulatory proposal to the Australian Energy Regulator 2009 to 2014*, Sydney, 2 June 2008, p. 196.

392 Integral Energy, *Regulatory proposal*, p. 196.

regulatory control period have been completed, or the total funding under the DMIA be exhausted. The AER considers that these recommendations are not consistent with the objective of the scheme, which is to provide a modest level of financial support to defray some of the start-up costs of demand management in the next regulatory control period. The DMIA is not intended to be the sole source of funding for demand management projects in the next regulatory control period, rather it is to support the requirements for DNSPs to consider demand management where it is an efficient response to network constraints. The AER also considers that EnergyAustralia's suggestions may result in fewer demand management projects being undertaken in the next regulatory control period, as DNSPs would be able to delay planned projects into the 2014–19 regulatory control period.

The AER notes EnergyAustralia's submission that the DMIA should include recognition for the time value of money invested in innovation projects that is consistent with the timing of investments within the post tax revenue model, such that capex undertaken under the DMIA should be multiplied by one plus the nominal vanilla WACC. EnergyAustralia also submitted that opex undertaken under the DMIA should be multiplied by one plus the nominal vanilla WACC. These suggestions would result in a significant increase in the demand management incentive generated by the DMIA. It would result in the effective double recovery of costs under the scheme, as DNSPs would receive the principle costs within the allowance, as well as having expenditure rolled into the regulatory asset base (RAB) in the subsequent regulatory control period.

The AER considers that capex payments made under the replacement DMIA should be treated as capital contributions under clause 6.2.1.1 of the transitional chapter 6 rules, and therefore not rolled into the RAB at the start of the next regulatory control period. However, the AER's decision in that regard will only be made as part of its distribution determination for the 2014–19 regulatory control period. The AER considers that the replacement DMIA offers a sufficient incentive to meet the objective of the scheme, which is to provide a modest level of financial support to defray some of the start-up costs of demand management over the next regulatory control period.

EnergyAustralia submitted that the DMIA should recognise the timing gap between the real value of opex under the DMIA and the real value of recovery for those projects. The end of period adjustment under the replacement DMIA takes into account the time value of money accrued or lost as a result of the expenditure profile selected by the DNSP, and accordingly addresses EnergyAustralia's concern.

EnergyAustralia submitted that the pre–approval and notification stage within the DMIA should not be mandatory for a project to be considered for the ex post review under the scheme. The replacement DMIA does not include a pre–approval and notification stage, and is therefore administratively simpler than the original DMIA proposed by the AER.

The AER notes EnergyAustralia's submission that the requirement for demand management project milestones should be clearer under the DMIA, and should ensure that a project that spans several years is eligible for cost recovery up to the annual cap across each of the regulatory years. The replacement DMIA applies clearer criteria for

cost recovery, and does not require demand management project milestones for each year.

EnergyAustralia suggested that the administration of the next regulatory control period DMIA be carried over into the subsequent regulatory control period until such time that all initiatives commenced within the next regulatory control period have been completed or the total funding allowance under the DMIA has been exhausted. The AER considers that this recommendation is not consistent with the replacement DMIA, which provides a modest allowance to defray some of the start up costs of demand management in the next regulatory control period. The AER considers it important that the DMIA ensures DNSPs are indifferent in deciding which year to carry out demand management solutions, such that DNSPs will elect to undertake demand management when it is an efficient response to network constraints in any regulatory year. The administration of the replacement DMIA is guaranteed only up to the end of the next regulatory control period, at which time the AER will reconsider the DMIA and demand management incentives present in the broader regulatory framework at that time.

The DMIA is a relatively modest financial reward for a DNSP. It is not intended to replace or substitute for demand management initiatives currently being carried out, and is additional to the obligations on DNSPs to consider non–network alternatives to capex or opex imposed by the transitional chapter 6 rules. The DMIA can, however, be used to finance set up costs associated with larger demand management projects. Given the modest size of the allowance provided, any underspend will not be rolled forward into the subsequent regulatory control period.

***Issues raised within other proposals and submissions***

The AER notes Integral Energy's statement that the relative sizes of the DNSPs' should not reduce their allowances. The AER considers that it is appropriate to base the DMIA allowances on the relative sizes of the ACT and NSW DNSPs' revenues, as it considers each DNSP's efficient level of demand management will vary relative to network size and the potential for deferral of network augmentation.

The AER notes Country Energy's submission that its allowance should be increased. The AER considers the magnitude of the allowance provided under the original DMIA provides a sufficient incentive to meet the objectives of the scheme. DNSPs have an obligation to undertake demand management where efficient, as part of normal business operations. The allowance is modest, recognising that it is provided in addition to demand management expenditures undertaken where they are efficient responses to network constraints. The DMIA is not a substitute for current expenditure on demand management.[393]

***The replacement DMIA***

The replacement DMIA reflects the suggestions made in the NSW DNSPs' regulatory proposals, as well as the AER's current thinking on the appropriate design and application of a DMIS to DNSPs in Queensland and South Australia. The replacement DMIA aims to provide incentives for the same types of demand management projects

[393] Further recommendations made in the NSW DNSPs' regulatory proposals and stakeholders' submissions on those regulatory proposals are available in AER, *NSW distribution determination 2009–10 to 2013–14*, draft decision, chapter 14.

as the original scheme, being broad–based and/or innovative initiatives, however, it provides simpler, clearer guidelines for DNSPs seeking cost recovery under the scheme. The replacement DMIA also provides DNSPs with an ex ante opex allowance for demand management project implementation costs over the next regulatory control period, with the recovery of any unspent or inefficiently spent allowance in the subsequent regulatory control period.

The AER's replacement DMIA will provide ActewAGL with an allowance of the same magnitude as the original DMIA, however, it removes administrative complexities and provides for a fairer allocation of the allowance. The replacement DMIA allows ActewAGL to recoup approved forgone revenues, in addition to the allowance provided under the DMIA, and provides clear guidelines as to the process by which forgone revenues will be assessed by the AER. This will result in more demand management projects being supported by the DMIA, as the allowance will not be eroded by the recovery of forgone revenues. Overall, the AER considers that the replacement DMIA creates a more constant incentive for DNSPs to conduct demand management over the course of the regulatory control period.

## 15.7 AER conclusion

The AER's draft decision, subject to the agreement of ActewAGL (as the affected DNSP), is to replace the original DMIA with a replacement DMIA. Under the replacement DMIA ActewAGL will have its forecast opex increased by $100 000 in each year of the next regulatory control period.

The AER seeks a submission from ActewAGL on the replacement DMIA. If ActewAGL agrees that the original DMIA is to be replaced by the replacement DMIA, the AER seeks written confirmation of its agreement for the purposes of clause 6.6.3(c) of transitional chapter 6 rules.

## 15.8 AER draft decision

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the AER decides that, with the agreement of ActewAGL the demand management incentive scheme to apply to ActewAGL is the DMIA set out in the AER's *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations*, November 2008.

In accordance with clause 6.3.2(a)(3) of the transitional chapter 6 rules the AER decides that the application of the demand management incentive scheme to apply to ActewAGL is as specified in section 15.7 of the draft decision.

# 16 Pass through arrangements

## 16.1 Introduction

This chapter sets out the AER's assessment of ActewAGL's proposed pass through events to apply during the next regulatory control period.

An objective of the incentive framework is to ensure that risks are appropriately managed. If a DNSP fails to manage risks properly and incurs additional costs it would be expected to bear those costs. However, the NER recognises that the DNSPs are exposed to risks beyond their control which may have a material impact on their costs. In some cases the risk may be symmetrical in which case costs could potentially increase or decrease.

One means of dealing with such outcomes is the pass through provisions contained in the NER. These provisions allow material changes (both increases and decreases) in the costs of providing direct control services to be passed through to distribution network users during a regulatory control period if certain events occur. This pass through of costs is achieved through an amendment to the price or revenue determination.

## 16.2 Regulatory requirements

### Types of pass through events

The transitional chapter 6 rules allow for two categories of pass through events in electricity distribution:

- Defined events—the following four events are set out in chapter 10 of the NER as pass through events:
  - a regulatory change event
  - a service standard event
  - a tax change event
  - a terrorism event.
- Nominated pass through events—other events that the DNSPs may propose to the AER to include as 'nominated pass through events' in its determination.

Pass through events can be both positive and negative. A positive change event is a pass through event that materially increases the costs of providing direct control services. If this occurs a DNSP may seek the approval of the AER to pass through to distribution network users a positive pass through amount under clause 6.6.1(a) of the transitional chapter 6 rules.

A negative change event is a pass through event that materially reduces the costs of providing direct control services. If this occurs a DNSP must notify the AER of the details of the event and the negative pass through amount. After becoming aware that

a negative change event has occurred, the AER must determine a negative pass through amount under clause 6.6.1(g) of the transitional chapter 6 rules.

### Pass through adjustments within the regulatory control period

Clause 6.6.1 of the transitional chapter 6 rules outlines the procedure for making pass through adjustments after the making of a determination.

If the AER determines that a pass through event has occurred, the AER must determine the pass through amount and how that amount is to be recovered over the remainder of the regulatory control period (clause 6.6.1(d) of the transitional chapter 6 rules for positive change events and clause 6.6.1(g) for negative change events). The factors that the AER is required to take into account in determining the pass through amount are contained in clause 6.6.1(j) of the transitional chapter 6 rules. These include an efficiency test, including whether the DNSP could have taken any reasonable measures to minimise cost increases.

## 16.3 ActewAGL proposal

ActewAGL proposed that, in addition to the four defined events in the NER, the following five events be included as pass through events:[394]

- a major natural disaster event
- a transitional period event
- a smart meter event
- an input price event
- a supply curtailment event.

These are discussed in more detail below.

### A major natural disaster

ActewAGL defined a major natural disaster event as:

> Any major natural disaster (but excluding bushfire or an earthquake which registers less than or equal to 6 on the Richter Scale[395]) which results in costs incurred by ActewAGL Distribution which are materially different to those incorporated into the AER's determination for the 2009-2014 regulatory period and which would not have been incurred but for the occurrence of the event.[396]

### A transitional period event

ActewAGL defined a transitional period event as:

> Any event that falls within the definition of a cost pass through event set out in the NER or which is approved as a cost pass through event by the AER in

394 ActewAGL, *Regulatory proposal*, pp. 104–5.
395 ActewAGL has proposed self insurance for these events.
396 ActewAGL, *Regulatory proposal*, p. 270.

> its final determination for ActewAGL Distribution for the 2009-2014 period, and which occurs during the period 2 June 2008 to 30 June 2009.[397]

### Smart meter event

ActewAGL defined a smart meter event as:

> The imposition of a requirement on ActewAGL Distribution to replace existing meters used to measure the consumption of electricity by distribution customers with meters that measure the consumption of electricity at specific time intervals and which are capable of being remotely read (commonly referred to as 'smart meters'), either on a pilot basis or as part of a wider roll out, which has a material impact on the cost of providing direct control services by ActewAGL Distribution which would not have occurred in the absence of the mandatory roll out.[398]

### Input price event

ActewAGL defined an input price event as:

> Any variation in input prices which results in costs incurred by ActewAGL Distribution being materially different to those incorporated into the AER's determination for the 2009-2014 regulatory period and which would not have been incurred but for the occurrence of the event.[399]

### Supply curtailment event

ActewAGL defined a supply curtailment event as:

> When power is not transmitted to the ACT or is rationed to or within the ACT and cannot be supplied to meet normal requirements, as represented by ActewAGL Distribution forecasts supplied in this regulatory proposal for the 2009-2014 regulatory control period, and the event is outside of the control of ActewAGL Distribution.[400]

## 16.4 Submissions

While the EUAA did not comment specifically on ActewAGL's proposal, in response to the NSW DNSPs' proposals it submitted that pass through events need to be tightly defined so that risks are appropriately shared between DNSPs and consumers and that DNSPs should not use pass through events to remove all risk.[401]

## 16.5 Consultant review

Wilson Cook considered that only exceptional events should be included as pass through events. Wilson Cook stated:

> We suggest that additional pass-through proposals are not to be recommended unless they are of a type that a prudent DNSP would not normally provide for in its expenditure estimates. We suggest such proposals should meet a high threshold in that respect. In essence, we suggest that the potential events

397 ActewAGL, *Regulatory proposal*, p. 272.
398 ActewAGL, *Regulatory proposal*, p. 274.
399 ActewAGL, *Regulatory proposal*, p. 275.
400 ActewAGL, *Regulatory proposal*, p. 276.
401 EUAA, *Submission to AER's review of the regulatory proposals by the NSW electricity distributors*, 15 August 2008, p. 5.

> ought to be exceptional in nature. Normal or foreseeable business risks, including risks that an owner of the business ought to bear, should be excluded.[402]

Of the pass through events proposed by ActewAGL and the NSW DNSPs Wilson Cook only commented on the introduction of smart meters. Wilson Cook expressed concern that the inclusion of the costs of smart meters as a pass through event may remove the incentive for ActewAGL to argue against the introduction of smart meters if it does not consider the expenditure to be beneficial. However, Wilson Cook noted that ActewAGL would have no choice if the introduction of smart meters was legislated, in which case it would be a defined event.[403]

## 16.6 Issues and AER considerations

### 16.6.1 Criteria for assessing the pass through events proposed by ActewAGL

The AER must decide whether the events proposed by ActewAGL in its regulatory proposal should be included in the AER's distribution determination as nominated events. In deciding whether or not to include an event proposed by ActewAGL as a nominated event the AER will consider whether:

- the event is already captured by the defined event definitions
- the event is clearly identified
- the event is uncontrollable (that is, a prudent service provider through its actions could not have reasonably prevented or substantially mitigated the event)
- despite the event being foreseeable, the timing and/or cost impact of the event could not be reasonably forecast by ActewAGL at the time of submitting its regulatory proposal
- the event is not already insured for (either external or self insured)
- the event cannot be self insured because a self insurance premium cannot be calculated or the potential loss to ActewAGL is catastrophic
- the party who is in the best position to manage the risk is bearing the risk
- if passing through the costs associated with the event would undermine the incentive arrangements within the regulatory regime.

### 16.6.2 Nominated pass through events proposed by ActewAGL

The AER accepts a major natural disaster event as a nominated pass through event, but rejects the other nominated events proposed by ActewAGL.

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402 Wilson Cook, Volume 1, p. 43.
403 Wilson Cook, Volume 5, p. 42.

**A major natural disaster event**

A major natural disaster is an uncontrollable event and often difficult to cover with insurance (either externally or through self insurance). The AER considers passing through the costs of a major natural disaster event meets the AER's assessment criteria and therefore it accepts ActewAGL's major natural disaster event as a pass through event.

As provided for in the transitional chapter 6 rules,[404] in any application for a pass through amount for a major natural disaster event, ActewAGL must demonstrate that it has taken all reasonable measures to reduce the magnitude of the pass through amount.

**Smart meters**

Although ActewAGL acknowledges that the introduction of smart meters is likely to fall within the definition of a regulatory change event, ActewAGL has proposed it as a nominated event to avoid any doubt. The AER agrees with ActewAGL that this is likely to be a regulatory change event and considers that a separate nominated event is therefore unnecessary. The AER considers that the policy intent was that this type of event would be a regulatory change event.

Wilson Cook also has concerns that inclusion of this event as a nominated pass through event may undermine incentives for ActewAGL to argue against the introduction of smart meters if it did not consider it cost effective. However, Wilson Cook noted that ActewAGL would have no choice if the introduction of smart meters was legislated, in which case it would be a defined event.

The AER considers that ActewAGL's proposal that a smart meter event be included as a nominated event does not meet the AER's assessment criteria. Accordingly, the AER does not accept ActewAGL's proposed smart meter event as a pass through event.

**Transitional period event**

ActewAGL has proposed this event to cover any pass through events that occur in the period between the date that it lodged its regulatory proposal and the date that the proposal comes into effect.

The AER considers that no provision is made in the NER to cover the circumstances described by ActewAGL. The only occasion on which the AER could accept an application for a pass through amount for an event that occurs prior to the next regulatory control period is the occurrence of a defined event within 90 business day of 1 July 2009 (the commencement date for the next regulatory control period). Given that under the NER a DNSP is allowed 90 business days to submit an application for a pass through amount, ActewAGL could delay submission of its application until the next regulatory control period.

The AER does not accept ActewAGL's proposed transitional period event as a nominated event because it is inconsistent with the NER.

[404] Clause 6.6.1(j)(3).

**Input price event**

ActewAGL has proposed that any variations to input prices that result in material changes to its costs be included as a nominated pass through event.

The AER does not accept ActewAGL's proposed input price event on the grounds that it may act to undermine the incentive framework. A basic tenet of an incentive framework is that forecasts represent best estimates and the business will bear the risk of actuals varying from forecasts. While the business will sustain the loss if actuals fall below forecasts, similarly the business will retain the additional profit if actuals exceed forecasts. Incentives to produce robust estimates and minimise costs may be undermined if variations to normal business costs are included as pass through events.

The AER has previously indicated that there may be scope for DNSPs to nominate significant input cost variations as pass through events.[405] However, because of the broad nature of the proposed input costs event and the potential for the incentive framework to be undermined, the AER does not accept the pass through event as proposed by ActewAGL. Nevertheless, the AER will consider any specific events provided that ActewAGL can demonstrate the criteria set out in section 16.6.1 of this draft decision have been met.[406]

**Supply curtailment**

ActewAGL has submitted that the ACT has no substantive electricity generation capacity, relying instead on its power from interstate. As a consequence ActewAGL is at risk of supply being rationed or curtailed in the event of supply shortfalls interstate. ActewAGL stated:

> The ACT Government is party to power sharing arrangements at times of supply shortfalls. In agreed circumstances, the ACT [sic] is required to manage and ration supply in the ACT in accordance with an agreed protocol. In addition, Regulations under the *Utilities Act 2000* allow the responsible Minister to approve an Electricity restriction scheme if satisfied that the scheme is necessary to facilitate, as far as practicable, the provision of efficient, reliable and sustainable electricity services to consumers; to protect the interests of consumers; manage the safety and security of the electricity network; or protect public safety.[407]

ActewAGL is seeking the costs of customer claims and forgone revenue resulting from any supply curtailment that is beyond its control.

The AER asked ActewAGL whether it could seek compensation from TransGrid (the owner of the transmission network to which ActewAGL is connected) under the terms of its connection agreement. In response ActewAGL informed the AER that under section 120(1) of the NEL a registered participant is not liable for failure to supply

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405 AER, *ACT and NSW EBSS*, p. 13.

406 In the ACCC's assessment of GasNet's proposed revisions to its access arrangement for the Victorian gas transmission system the ACCC decided that variations to GasNet's estimates of fuel gas costs would be treated as a pass through event. In that instance volatility of gas prices made it difficult to estimate fuel gas costs. To ensure incentives to GasNet to seek the most efficient costs were not undermined GasNet was required to continue its current practice of tendering for its fuel gas needs. ACCC, *Final Decision – Revised access arrangement by GasNet Australia (Operations) Pty Ltd for the Principal Transmission System*, 30 April 2008, p. 92.

407 ActewAGL, *Regulatory proposal*, p. 276.

unless the failure is due to bad faith or negligence. While section 120(2) allows the parties to contract away from this position, ActewAGL considers that TransGrid is unlikely to assume this liability.

ActewAGL stated that it does not have in place a current connection agreement with TransGrid. It stated that a draft agreement is being negotiated, but it does not include any compensation for supply curtailment events.[408]

ActewAGL acknowledged that the potential for it being liable for claims against losses due to the actions of third parties is limited. It stated that its current standard electricity connection and distribution contract excludes supply failures due to the actions of third parties. Nevertheless, ActewAGL submitted that there may still be scope for 'strangers to the contract' to sue ActewAGL on tort grounds (that ActewAGL took action that it reasonably should have known would have caused the other party harm).[409]

ActewAGL further stated that it is liable to pay customers compensation under the service level rebate scheme (guaranteed service levels (GSL) payments). However, ActewAGL qualified this statement by stating under the *Consumer Protection Code* ActewAGL does not have to comply with the minimum service standards if the events or conditions outside its control prevent it from complying. Despite these limitations on its liability, ActewAGL submitted that it may still be liable for significant customer rebates under the *Consumer Protection Code* that are beyond those anticipated in forecast operating expenditure.[410]

ActewAGL informed the AER that no events of this nature have occurred to date.[411]

With regards to ActewAGL's proposal to recover the loss of foregone revenue, the AER considers that no provision is made in the NER for DNSPs to recover foregone revenue through a pass through mechanism. The transitional chapter 6 rules specifically confine pass through events to events that materially increase or decrease the costs of providing direct control services.

With respect to third parties claims and GSL payments, from the information provided by ActewAGL it appears that ActewAGL would not be liable if an event outside its control occurs. As ActewAGL is not seeking, as a pass through event, claims due to its own actions (for example, as a result of its negligence or breach of contract), the AER considers that the pass through event proposed by ActewAGL for third party claims and GSL payments is unnecessary.

The AER has a fundamental concern with nominated pass through events of this nature in that incentives to manage the risk may be undermined. In this particular instance, the AER has concerns that, if it accepts ActewAGL's proposed pass through event, incentives to implement measures, or maintain existing measures, to limit ActewAGL's liability may be undermined. This includes measures that ActewAGL has introduced (for example, provisions in its contracts) or measures imposed externally (for example, limitations included in the *Consumer Protection Code*).

408 ActewAGL, *Regulatory proposal*, p. 276.
409 ActewAGL, *Regulatory proposal*, p. 276.
410 ActewAGL, *Regulatory proposal*, p. 276.
411 ActewAGL, *Regulatory proposal*, p. 276.

Moreover, incentives to investigate the validity of any claims may be similarly undermined.

The AER does not consider that ActewAGL's proposal for a supply curtailment event as a pass through event meets its assessment criteria. Accordingly, the AER does not accept ActewAGL's proposal.

### 16.6.3 Applicability to alternative control services

ActewAGL has proposed that the pass through provisions of the transitional chapter 6 rules (section 6.6.1) apply to alternative control services as well as standard control services. In other words, should a defined event or any nominated event accepted by the AER occur that materially changes the costs of alternative control services, ActewAGL could apply to the AER for a pass through of costs. ActewAGL notes that the transitional chapter 6 rules relating to pass through events refer to direct control services, which include both standard services and alternative control services.[412] The AER agrees with ActewAGL that the transitional chapter 6 rules does not preclude pass through provisions applying to alternative control services.

## 16.7 AER conclusions

The AER considers that ActewAGL's proposed major natural disaster event meets the AER's assessment criteria for nominated pass through events and therefore the AER accepts ActewAGL's proposed event. This event is defined as:

> **A major natural disaster event:** Any major natural disaster (but excluding any insurable events – that is, those events for which external insurance or self insurance is feasible) which results in the costs of providing direct control services incurred by ActewAGL that are materially different to those contained in the AER's determination for the next regulatory control period and which would not have been incurred but for the occurrence of the event.

In an application for a pass through amount in relation to a major natural disaster event, ActewAGL must demonstrate that it has taken all reasonable measures to reduce the magnitude of the pass through amount.

The AER considers that the following events do not meet the AER's assessment criteria for nominated pass through events and therefore the AER does not accept the following events:

- a transitional period event
- a smart meter event
- an input price event
- a supply curtailment event.

412 ActewAGL, *Regulatory proposal*, p. 265.

## 16.8 AER draft decision

In accordance with clause 6.12.1(14) of the transitional chapter 6 rules the AER decides that the nominated pass through event to apply to ActewAGL for the next regulatory control period is a major natural disaster event as defined in section 16.7 of the draft decision.

# 17 Building block revenue requirement

## 17.1 Introduction

This chapter sets out the AER's calculation of ActewAGL's annual revenue requirement for the provision of standard control services for each year of the next regulatory control period. This chapter also sets out X factor values which will be applied to calculate the maximum allowable average revenue (MAAR) for ActewAGL's standard control services.

## 17.2 Regulatory requirements

Clause 6.3.2(a) of the transitional chapter 6 rules states that the AER's building block determination must specify:

> (1) the DNSP's annual revenue requirement for each regulatory year of the regulatory control period;
>
> (2) appropriate methods for the indexation of the regulatory asset base (RAB);
>
> (3) how any applicable efficiency benefit sharing scheme (EBSS), service target performance incentive scheme (STPIS) or demand management incentive scheme (DMIS) are to apply to the DNSP;
>
> (4) the commencement and length of the regulatory control period;
>
> (5) any other amounts, value or inputs on which the building block determination is based.

Clause 6.5.9 of the transitional chapter 6 rules requires a building block determination to include the X factor for each year of the regulatory control period. The X factor must be designed to equalise (in net present value terms) the revenue to be earned from the provision of standard control services with the total revenue requirement attributable to those services. The X factor must also minimise variance between expected revenue and the annual revenue requirement for the last year of the regulatory control period.

A DNSP's building block proposal must be prepared in accordance with the AER's post tax revenue model (PTRM) and the requirements of part C and schedule 6.1 of the transitional chapter 6 rules. The building block proposal must also comply with the requirements of any relevant regulatory information instrument, such as a regulatory information notice (RIN) or regulatory information order (RIO).

Clause 6.10.2(3) of the transitional chapter 6 rules requires the AER to publish its reasons for its draft constituent decisions made in accordance with clause 6.12 of the transitional chapter 6 rules. The constituent decisions dealt with in this chapter are:

- a decision to approve or refuse to approve the annual revenue requirement for the DNSP[413]

[413] Transitional chapter 6 rules, clause 6.12.1(2).

- decisions on other appropriate amounts, values or inputs[414]
- a decision on the X factor (as it relates to the control mechanism discussed in chapter 4 of this draft decision).[415]

Under clause 6.12.3(d) of the transitional chapter 6 rules the AER must approve annual revenue requirements if it is satisfied that they have been calculated using the PTRM on the basis of amounts proposed by ActewAGL and accepted by the AER, or otherwise determined by the AER under part C of the transitional chapter 6 rules.

### 17.2.1 Annual building block revenue requirement

Clause 6.4.3(a) of the transitional chapter 6 rules defines building blocks that form the annual revenue requirement as:

- indexation of the RAB
- return on capital
- depreciation
- estimated cost of corporate income tax
- revenue increments or decrements arising from a service target performance incentive scheme (STPIS) or demand management incentive scheme (DMIS)
- other revenue increments or decrements arising from the application of a control mechanism in the previous regulatory control period that are to be carried forward and are apportioned to the relevant year under the distribution determination for the current regulatory control period
- forecast operating expenditure (opex).

### 17.2.2 Post tax revenue model

The PTRM sets out how the annual revenue requirement is to be calculated and includes:

- a method that is likely to result in the best estimates of expected inflation
- the timing assumptions and associated discount rates applicable to the calculation of building blocks in clause 6.4.3 of the transitional chapter 6 rules
- the manner in which working capital is to be treated
- the manner in which the estimate corporate income tax is to be calculated.

The AER published a transitional PTRM[416] and handbook[417] that are applicable to ActewAGL.

414 Transitional chapter 6 rules, clause 6.12.1(10).
415 Transitional chapter 6 rules, clause 6.12.1(11).

## 17.3 ActewAGL proposal

A description of ActewAGL's calculation of annual revenue requirements and X factors is in chapter 12 of its regulatory proposal[418]. The calculations are contained in the completed PTRM submitted as attachment 8 of its regulatory proposal and are summarised in table 17.1.

**Table 17.1: ActewAGL's proposed annual revenue requirements and X factors ($m, nominal)**

| | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|
| Regulatory depreciation | | 14.8 | 16.0 | 17.3 | 18.6 | 20.0 |
| Return on capital | | 63.4 | 70.8 | 75.9 | 80.2 | 84.5 |
| Tax allowance | | 5.5 | 6.4 | 6.7 | 6.4 | 6.7 |
| Operating expenditure | | 60.2 | 62.9 | 65.7 | 69.4 | 71.4 |
| Annual revenue requirements | | 144.0 | 156.1 | 165.5 | 174.7 | 182.5 |
| Energy sales (MWh) | 2 834 932 | 2 878 338 | 2 925 120 | 2 971 701 | 3 018 337 | 3 066 270 |
| Revenue yield (¢/kWh) | 4.09 | 5.05 | 5.28 | 5.52 | 5.77 | 6.03 |
| Expected revenues | 116.0 | 145.3 | 154.4 | 164.0 | 174.2 | 185.1 |
| Forecast CPI (%) | | 2.51 | 2.51 | 2.51 | 2.51 | 2.51 |
| X factors[a] (%) | | –20.37 | –2.00 | –2.00 | –2.00 | –2.00 |

Source: ActewAGL PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

ActewAGL proposed an X factor of –20.37 per cent (i.e. a real increase) for the first year of the regulatory control period to account for the increase in revenue requirements between 2008–09 and 2009–10. It proposed an X factor of –2.00 per cent for the subsequent years, stating that different X factors for year one and for subsequent years of the regulatory control period is consistent with general regulatory practice.[419] This results in the NPV of the revenue requirements and expected revenues being equal over the regulatory control period as shown in table 17.2. The resulting difference between the annual revenue requirement and expected revenue in the final year of the period is $2.5 million or 1.37 per cent.

416 AER, *Final decision, Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–14: Post–tax revenue model*, Canberra, January 2008, Appendix B.
417 AER, Final decision, *Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–14: Post–tax revenue model*, Canberra, January 2008, Appendix B.
418 ActewAGL, *Regulatory proposal*, pp. 217-221.
419 ActewAGL, *Regulatory proposal*, p. 220.

**Table 17.2: ActewAGL's proposed annual revenue requirements and expected revenues ($m, nominal)**

| | NPV | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|
| Annual revenue requirements | 605.6 | 144.0 | 156.8 | 165.5 | 174.7 | 182.6 |
| Expected revenues | 605.6 | 145.3 | 154.4 | 164.0 | 174.2 | 185.1 |
| Difference (%) | 0.00 | 0.95 | –1.06 | –0.89 | –0.26 | 1.37 |

Source: ActewAGL PTRM.

## 17.4 Submissions

The EMRF stated that ActewAGL's proposal represented a massive increase in average tariffs from those set by the ICRC, which is underlined by the corresponding modest increases in consumption and demand.[420]

## 17.5 AER assessment of building blocks

The following sections summarise the AER's assessment of each of the building blocks listed in section 17.2.1 of this draft decision. Further details on the AER's consideration of ActewAGL's proposed opex, corporate income tax and depreciation are respectively contained in chapters 9, 10 and 11 of this draft decision. The return on capital using the WACC determined by the AER in chapter 12 of this draft decision is outlined in this chapter.

Note that ActewAGL did not identify any revenue increments or decrements arising from incentive arrangements or control mechanisms arising out of the current regulatory control period.

### 17.5.1 Asset base roll forward and indexation

The transitional chapter 6 rules require that the roll forward of ActewAGL's RAB, as at the end of each year of the next regulatory control period, be calculated by taking the opening RAB value, adjusting it for inflation, adding any additional capex, and subtracting disposals and depreciation for the year. The closing RAB value for one year then becomes the opening RAB value for the following year.

The AER has determined the opening value of ActewAGL's RAB to be $588 million as at 1 July 2009. Based on this opening value, the AER has modelled ActewAGL's RAB over the next regulatory control period using the PTRM, as shown in table 17.3.

[420] EMRF, p. 6.

**Table 17.3: AER's forecast roll-forward of ActewAGL's regulated asset base ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Opening RAB | 588.4 | 656.4 | 703.6 | 743.8 | 783.0 |
| Net capital expenditure[a] | 82.5 | 63.4 | 57.9 | 58.6 | 45.6 |
| Indexation of opening RAB | 15.0 | 16.7 | 17.9 | 19.0 | 20.0 |
| Straight-line depreciation | 29.5 | 32.9 | 35.6 | 38.3 | 41.1 |
| Closing RAB | 656.4 | 703.6 | 743.8 | 783.0 | 807.5 |

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes.

### 17.5.2 Return on capital

The AER considers that ActewAGL's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding other inputs to the PTRM, notably the RAB and forecast capex.

The AER has determined the annual return on capital allowance by applying the weighted average cost of capital (WACC) to ActewAGL's opening RAB for each year of the next regulatory control period.

The nominal vanilla WACC of 9.82 per cent is based on a post–tax nominal return on equity of 11.46 per cent and a pre–tax nominal return on debt of 8.73 per cent. These figures are calculated using observed market data as at 20 October 2008, and will be updated closer to the AER's final decision and determination.

### 17.5.3 Depreciation

The AER has not approved ActewAGL's proposed depreciation schedules and required it to disaggregate its RAB into multiple asset classes to reflect the requirements of clause 6.5.5(b) of the transitional chapter 6 rules.

Using a post–tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the regulatory control period and to determine the depreciation allowance. Table 17.5 in section 17.6 of this draft decision shows the resulting figures.

### 17.5.4 Estimated taxes payable

Using the PTRM, the AER has modelled ActewAGL's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this draft decision. The amount of tax payable is

estimated using 60 per cent benchmark gearing, rather than ActewAGL's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6.5.3 of the transitional chapter 6 rules, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Under the post–tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost-reflective revenue outcomes. The effective tax rate is defined as the difference between pre–tax and post–tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the PTRM, the AER has derived an effective tax rate of 30.73 per cent for this draft decision. Table 17.4 shows the AER's estimate of ActewAGL's tax payments.

**Table 17.4: AER's modelling of net tax allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Tax payable | 10.1 | 11.9 | 12.4 | 11.7 | 12.1 |
| Value of imputation credits | –5.1 | –6.0 | –6.2 | –5.9 | –6.1 |
| Net tax allowance | 5.1 | 6.0 | 6.2 | 5.9 | 6.1 |

### 17.5.5 Operating and maintenance expenditure

As discussed in chapter 9 of this draft decision, the AER has determined a forecast opex allowance for ActewAGL of $296 million ($2008–09) during the next regulatory control period. Table 17.5 shows the annual opex allowance, which equals an average amount of $64 million per annum in nominal terms.

## 17.6 AER conclusion

The AER has calculated ActewAGL's revenue requirements and X factors based on its decisions regarding the building block components. This calculation is summarised in table 17.5.

The AER's draft decision results in a total (nominal) revenue requirement over the next regulatory control period of $779 million, which is $44 million lower than the $823 million proposed by ActewAGL. This mainly reflects the AER's updated calculation of ActewAGL's WACC (from 10.70 per cent to 9.82 per cent) which contributes $33 million to this difference, as well as its decision on ActewAGL's forecast opex, which contributes a further reduction of $10 million.

**Table 17.5 :AER's draft decision on ActewAGL's revenue requirements and X factors ($m, nominal)**

| | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|
| Regulatory depreciation | | 14.5 | 16.2 | 17.7 | 19.3 | 21.1 |
| Return on capital | | 57.8 | 64.5 | 69.1 | 73.1 | 76.9 |
| Tax allowance | | 5.1 | 6.0 | 6.2 | 5.9 | 6.1 |
| Operating expenditure | | 58.8 | 61.2 | 63.7 | 67.2 | 68.8 |
| Annual revenue requirements | | 136.2 | 147.8 | 156.7 | 165.5 | 172.8 |
| Energy sales (MWh) | 2 834 932 | 2 878 338 | 2 925 120 | 2 971 701 | 3 018 337 | 3 066 270 |
| Revenue yield (¢/kWh) | 4.09 | 4.78 | 5.00 | 5.23 | 5.47 | 5.72 |
| Expected revenues | 116.0 | 137.5 | 146.1 | 155.3 | 165.0 | 175.3 |
| Forecast CPI (%) | | 2.55 | 2.55 | 2.55 | 2.55 | 2.55 |
| X factors[a] (%) | | –13.82 | –2.00 | –2.00 | –2.00 | –2.00 |

Source: PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

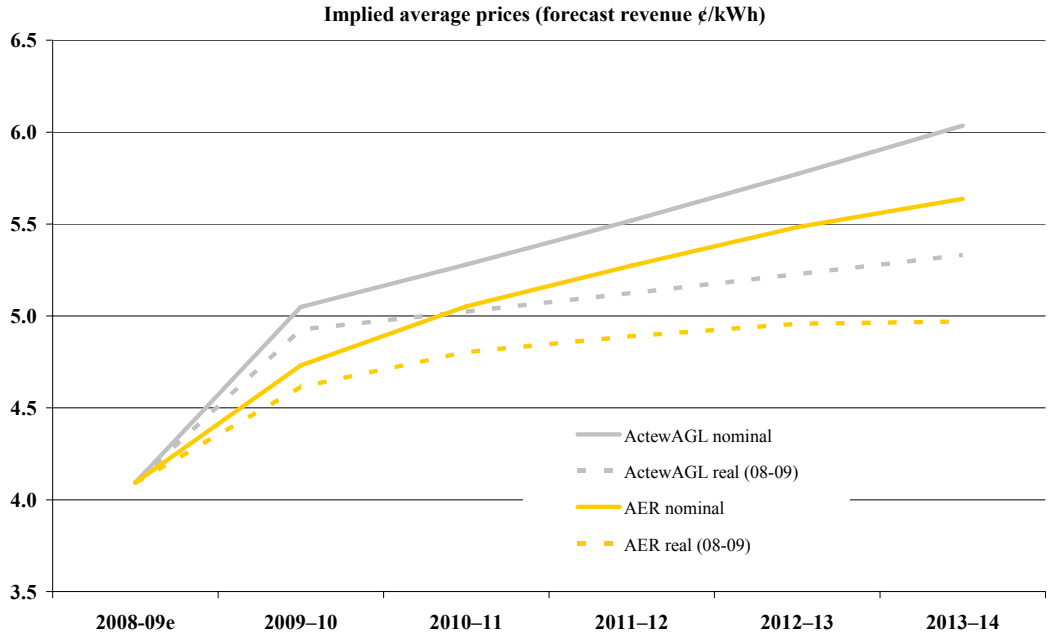
The AER acknowledges the comments made by the EMRF in the context that, under the MAAR, relatively small increases in forecast energy sales imply a higher average revenue constraint. ActewAGL's forecast energy sales (on which its X factor calculation is based) increase at the relatively low annual rate of approximately 1.6 per cent per year over the next regulatory control period. As noted in chapter 6 of this draft decision the AER has examined the methodology used to produce these forecasts and considers it to be reasonable. In response to this draft decision, ActewAGL is required to provide the AER with updated energy data and forecasts for the purposes of calculations that will form part of the AER's final decision and distribution determination.

The AER notes that the MAAR does not incorporate adjustments for under or over-recoveries with respect to the average revenue amount, thus ActewAGL will forego revenue in the case that energy sales are lower than expected and earn additional revenue if they are higher than expected. This is consistent with the mechanism used by the ICRC and clause 6.2.5(c1)(2) of the transitional chapter 6 rules.

The AER notes that ActewAGL's proposed price path appears to have been based on achieving a 2 per cent real increase in average prices in years 2 to 5 of the regulatory control period, which necessitated a larger proposed increase in year 1. In the absence of any stakeholder preferences to do otherwise, the AER has maintained this general approach in this draft decision, which, when combined with the AER's revised annual revenue requirements, results in a reduction in the X factor for 2009–10 from 20.37 per cent to 13.82 per cent. The implied average price paths, in terms of

expected revenues per MWh, of ActewAGL's proposal and the AER's draft decision, are illustrated in figure 17.1.

**Figure 17.1: AER draft decision and ActewAGL proposal – implied average prices**




The AER notes that, in accordance with clause 6.5.9 of the transitional chapter 6 rules, the X factors in this draft decision result in the NPVs of the annual revenue requirement and expected revenues for the regulatory control period being equal, and a difference between these amounts in the final year of the period of 1.44 per cent. These outcomes are illustrated in table 17.6.

**Table 17.6: AER's draft decision on annual revenue requirements and expected revenues ($m, nominal)**

| | NPV | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|
| Annual revenue requirements | 586.80 | 136.2 | 147.8 | 156.7 | 165.5 | 172.8 |
| Expected revenues | 586.80 | 137.5 | 146.1 | 155.3 | 165.0 | 175.3 |
| Difference (%) | – | 0.97 | –1.09 | –0.91 | –0.30 | 1.44 |

For an average end user, this results in a real increase in annual electricity costs of 4.1 per cent in 2009–10, and 0.7 per cent per year for the remainder of the next regulatory control period.[421]

[421] That is, a residential customer with an annual bill of $1200, of which approximately 30 per cent is attributable to distribution prices.

## 17.7 AER draft decision

In accordance with clause 6.12.1(2)(i) of the transitional chapter 6 rules the AER refuses to approve the annual revenue requirement set out in ActewAGL's building block proposal.

In accordance with clause 6.3.2(a)(1) of the transitional chapter 6 rules the AER decides ActewAGL's annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 17.5 of the draft decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the AER decides the X factors to apply to ActewAGL are as set out in table 17.5 of the draft decision.

In accordance with clause 6.3.2(a)(2) of the transitional chapter 6 rules the AER decides an appropriate methodology for indexation of the regulatory asset base is as specified in section 17.5 of the draft decision.

In accordance with clause 6.3.2(a)(5) of the transitional chapter 6 rules the AER decides any other amounts, values or inputs on which ActewAGL's building block determination is based are as specified in sections 17.5 and 17.6 of the draft decision.

# 18 Alternative control services

## 18.1 Introduction

This chapter sets out the AER's considerations of ActewAGL's alternative control services and the control mechanism to apply during the next regulatory control period.

ActewAGL metering services to small customers are deemed to be alternative control services. Alternative control services may be, but need not be, regulated using a building block calculation.

## 18.2 Regulatory requirements

For the next regulatory control period, clause 6.2.3C(b) of the transitional chapter 6 rules deems alternative control services in the ACT to be the same as the ICRC excluded distribution services. The provision of and servicing of meters for customers consuming fewer than 160 megawatt hours per annum including: meter testing, reading and checking; processing of metering data; and provision of non-standard meters were classified as excluded distribution services.

The AER may vary this classification by agreement with ActewAGL as part of its distribution determination under clause 6.2.3C(c) of the transitional chapter 6 rules.

### 18.2.1 Control mechanism

Clause 6.2.5(c2) of the transitional chapter 6 rules sets out the form of control that the AER may apply:

> The control mechanism for alternative control services may consist of:
>
> (1) a schedule of fixed prices;
>
> (2) caps on the prices of individual services;
>
> (3) caps on the revenue to be derived from a particular combination of services;
>
> (4) tariff basket price control;
>
> (5) revenue yield control;
>
> (6) a combination of any of the above.

Clause 6.2.5(d) sets out the matters the AER must have regard to in considering the appropriate control mechanisms for alternative control services:

> (1) the potential for development of competition in the relevant market and how the control mechanism might influence that potential; and
>
> (2) the possible effects of the control mechanism on administrative costs of the AER, the Distribution Network Service Provider and users or potential users; and

(3) the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination; and

(4) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and

(5) any other relevant factor.

### 18.2.2 ICRC approach

In its 2004 determination the ICRC excluded metering services from the revenue cap that applied to ActewAGL's distribution services.[422] The ICRC determined that metering services would be subject to a separate total revenue cap which is escalated annually by CPI.

### 18.2.3 AER statement of approach

In its *Final Decision—Control Mechanisms for Alternative Control Services for the ACT and NSW 2009 distribution determinations*, the AER concluded that it:[423]

> …will maintain the total revenue control mechanism adopted by the ICRC during the current regulatory period. Under this approach, ActewAGL will propose a revenue allowance based on a building block analysis, with maximum allowable revenues to be escalated each year by CPI. The revenue allowance will be established based on the rolled forward value of the relevant metering assets, and an analysis of costs associated with providing the services.

### 18.2.4 Demonstration of proposed approach

Clause 6.8.2 of the transitional chapter 6 rules requires the DNSPs to demonstrate how the AER's proposed control mechanism will apply. The DNSPs must also provide reasons for any departure from the AER's proposed approach.

(c) A regulatory proposal must include (but need not be limited to) the following elements: …

(3A) for direct control services classified as alternative control services:

(i) the proposed control mechanism, a demonstration of the application of the proposed control mechanism, and the necessary supporting information; and

(ii) in the case of a departure from the AER's likely approach to the relevant control mechanisms for alternative control services (as indicated in a statement published under clause 6.2.5(e)) a statement of the reasons justifying the departure; …

422 ICRC, *Final Decision*, p 14.

423 AER, *Final Decision—Control Mechanisms for Alternative Control Services for the ACT and NSW 2009 distribution determinations*, February 2008, p. 20.

## 18.3 ActewAGL proposal

### 18.3.1 Control mechanism

Consistent with the approach applied by the ICRC, ActewAGL has proposed a revenue allowance based on a building block analysis, with maximum allowable revenues (MAR) to be escalated each year by CPI. The revenue allowance for alternative control services will be established based on the rolled forward value of the relevant metering assets and an analysis of costs associated with providing the services.[424]

### 18.3.2 RAB

ActewAGL has used the AER's roll forward model to roll forward its asset base for alternative control services from its closing RAB for the current regulatory control period to its opening RAB for the next regulatory control period. ActewAGL's proposed opening RAB as at 1 July 2009 is $38 million (nominal).[425]

ActewAGL stated its actual capex in 2003–04 was about $0.3 million lower than forecast capex. Under the regulatory framework ActewAGL received a return on the forecast capex amount during the current regulatory control period, approximately $0.2 million greater than it should have received, based on actual capex. ActewAGL has proposed a reduction in the RAB to hand back the extra earnings in the next regulatory control period. Accordingly, ActewAGL has reduced its opening RAB by $0.2 million.[426]

**Table 18.1: Elements of the roll forward calculation ($m, nominal)**

| | 2004–05 | 2005–06 | 2006–07 | 2007–08 | 2008–09 | 2009–10 |
|---|---|---|---|---|---|---|
| Opening RAB | 32.9 | 33.0 | 33.5 | 34.3 | 36.6 | 38.3 |
| Net capital expenditure | 1.1 | 1.3 | 1.9 | 2.8 | 3.1 | – |
| Depreciation | 1.7 | 1.8 | 1.9 | 2.0 | 2.2 | – |
| Indexation | 0.8 | 1.0 | 0.8 | 1.5 | 1.0 | – |
| Closing RAB | 33.0 | 33.5 | 34.3 | 36.6 | 38.5 | – |
| 2003–04 adjustment | – | – | – | – | –0.2 | – |

Source: ActewAGL, *Regulatory proposal*, Table 15.3, 2 June 2008.

### 18.3.3 Capex

ActewAGL stated the methodology for forecasting alternative control services capex utilises the same general methodology and escalators as that utilised for capex for ActewAGL's standard control services. It also noted the extra cost of installing and

424 ActewAGL, *Regulatory proposal*, p. 220.
425 ActewAGL, *Regulatory proposal*, p. 220.
426 ActewAGL, email to AER, 9 October 2008.

replacing interval meters in the next regulatory control period is incorporated in its capex forecasts.[427]

**Installation of upgradeable meters**

ActewAGL has formulated its domestic meter replacement programs and expenditure forecasts based on the NEMMCO approved metering asset management plan (MAMP). ActewAGL stated it plans to replace 3600 meters per annum.[428]

ActewAGL noted its meter replacement program is designed to limit the potential for the stranding of meter assets that may not meet the national smart meters functionality and performance standards. However, it is currently installing interval meters that are capable of being upgraded for remote reading, and which can support an in-house display. This new and replacement policy is undertaken in accordance with the ICRC decision on interval meters. Therefore ActewAGL considered that it should not face stranded asset cost risks, and should be appropriately compensated, if these meters have to be replaced as a result of a smart meter mandate.[429]

**Multi-utility integrated metering infrastructure**

ActewAGL submitted that in 2007, in the context of securing the ACT water supply, the ACT government requested ACTEW Corporation to trial smart metering. The ICRC included funding to support this in its price determination for water and wastewater services in the ACT.[430]

In response to the ACT government request, ActewAGL stated it conducted a full business case review and decided that there would be a net benefit in undertaking a multi-utility integrated metering infrastructure (MIMI) feasibility study. It noted the purpose of this expanded project is to allow investigation of opportunities for multi-utility metering, as well as investigation of some of the organisational, communications and data management issues that may arise in a larger trial of electricity smart metering.[431]

ActewAGL forecast that its electricity distribution business will incur $2.6 million ($2008–09) in capex in 2009–10 attributable to project MIMI. ActewAGL has indicated that the cost recovery for project MIMI is allocated between its businesses on a 40:40:20 basis, that is, 40 per cent electricity, 40 per cent water, and 20 per cent gas. ActewAGL considers that the trial is prudent, given the considerable uncertainties in costs associated with smart metering.[432]

Table 18.2 summarises ActewAGL's proposed capex program for metering services in the ACT.

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427 ActewAGL, *Regulatory proposal*, p. 220.
428 ActewAGL, *Regulatory proposal*, p. 220.
429 ActewAGL, *Regulatory proposal*, p. 220.
430 ICRC, *Water and Wastewater Price Review: Final Report and Price Determination, Report 1 of 2008,* April 2008, p. 15.
431 ActewAGL, *Regulatory proposal*, p. 220.
432 ActewAGL, *Regulatory proposal*, p. 220.

**Table 18.2: Forecast capex for alternative control services 2009–14 ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| New meter installations | 2.1 | 2.0 | 2.1 | 2.2 | 2.0 | 10.3 |
| Meter replacements | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 6.0 |
| MIMI related capex | 2.6 | – | – | – | – | 2.6 |
| Total metering capex | 5.9 | 3.2 | 3.2 | 3.4 | 3.2 | 18.8 |

Source: ActewAGL, *Regulatory proposal*, Table 15.1, 2 June 2008

### 18.3.4 Opex

ActewAGL stated it used the same methodology for forecasting opex for alternative control services as that which it adopted for forecasting opex for standard control services. It noted meter reading and maintenance and repair are the two significant contributors to opex for alternative control services. ActewAGL indicated that meter reading costs have increased in line with CPI. It also stated that commercial metering maintenance costs are forecast to grow faster than CPI as it is required to visually inspect all current transformer (CT) metering sites every 5 years and commence low-voltage CT testing at all sites. It claimed this regulatory obligation drives a cost increase of $0.2 million per annum up until 2013–14.[433]

ActewAGL's opex forecasts are set out at Table 18.3.

**Table 18.3: Forecast opex for alternative control services 2009–14 ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Metering reading | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 4.4 |
| Maintenance and repair | 0.8 | 0.8 | 0.8 | 0.6 | 0.7 | 3.7 |
| MIMI related opex | 0.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 |
| Total opex | 2.1 | 1.7 | 1.7 | 1.5 | 1.6 | 8.5 |

Source: ActewAGL, *Regulatory proposal*, Table 15.2, 2 June 2008.
Note: Total opex excludes self insurance and debt raising costs. These items add approximately $0.2 million to the total opex.

### 18.3.5 Revenue requirement

ActewAGL's estimation of its maximum allowed revenue for the next regulatory control period is set out in Table 18.4.

[433] ActewAGL, *Regulatory proposal*, p. 220.

**Table 18.4: Total revenue requirement for each regulatory year ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Regulatory depreciation | 1.2 | 1.3 | 1.4 | 1.5 | 1.6 |
| Return on capital | 4.1 | 4.6 | 4.9 | 5.1 | 5.3 |
| Tax allowance | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 |
| Operating expenditure | 1.2 | 1.3 | 1.4 | 1.5 | 1.6 |
| Unsmoothed revenue requirement | 8.0 | 8.3 | 8.7 | 8.9 | 9.4 |
| Smoothed revenue requirement | 8.2 | 8.4 | 8.6 | 8.8 | 9.0 |
| X factor (%) | 41.01 | 0.00 | 0.00 | 0.00 | 0.00 |

Source: ActewAGL, *Regulatory proposal*, Table 15.10, 2 June 2008.

### 18.3.6 Pass through—roll out of smart meters

ActewAGL noted that the MCE is currently considering a regulatory impact statement on a mandatory roll out of smart meters. There is considerable uncertainty surrounding timing and costs associated with the roll out of smart meters. As the issues were not resolved at the lodgement of its regulatory proposal, ActewAGL considered that most obligations arising under a smart meter decision should be treated as a regulatory change pass through event.[434]

ActewAGL also noted the potential for a decision and associated obligations with cost implications to occur before the commencement of the next regulatory control period. ActewAGL has sought a transitional period pass through event to address these and other obligations with similar timing issues.[435]

## 18.4 Consultant review

After reviewing ActewAGL's proposal, Wilson Cook noted that:[436]

- the projected expenditure is based primarily on historical expenditure levels with small adjustments for domestic meter installations reflecting the anticipated level of activity in new urban development, urban infill development and commercial and industrial development
- the increase in capex and opex from 2009–10 is largely attributable to meter replacement expenditure and to project MIMI and that the cost allocation is consistent with the ICRC's implicit view
- meter reading costs have been increased in line with the CPI whereas other costs have been increased using the same methods as in the main capex projections.

[434] ActewAGL, *Regulatory proposal*, p. 220.
[435] ActewAGL, *Regulatory proposal*, p. 220.
[436] Wilson Cook, Volume 5, p. 40.

Wilson Cook was satisfied that the level of capex was explained satisfactorily and that the level of opex was found to be similar to prior years. Wilson Cook concluded ActewAGL's proposed expenditure in relation to alternative control services to be a reasonable estimate.[437]

## 18.5 Issues and AER considerations

On 1 October 2008 ActewAGL advised the AER that errors had been identified by SKM in its input cost escalators. The AER requested that ActewAGL resubmit its forecasts of required revenues for alternative control services, which revealed minor amendments to the forecast allowance included in its regulatory proposal of 2 June 2008. The correction of this error has been incorporated into the AER's consideration of ActewAGL's alternative control services proposal.

### 18.5.1 Control mechanism

The AER published a statement indicating its likely approach to the control mechanism for alternative control services in February 2008.[438] ActewAGL is required to demonstrate how the AER's proposed control mechanism will apply to its business. If, in its regulatory proposal, ActewAGL proposes a control mechanism which is inconsistent with that proposed by the AER, ActewAGL is required to provide reasons for any departure from the AER's proposed approach.

The AER considers that ActewAGL has satisfied its obligation to demonstrate how the AER's proposed control mechanism will apply to its business.

The AER considers that ActewAGL's proposal is consistent with the AER's proposed form of control for alternative control services in the ACT. Accordingly, there is no need for ActewAGL to provide justification for any departure from the AER's control mechanism set out in its statement of approach.

### 18.5.2 Building blocks

#### Opening RAB

ActewAGL has used the AER's roll forward model to roll forward its alternative control services RAB to produce its opening RAB for the next regulatory control period. The AER's roll forward model takes account of actual capex, depreciation and indexation and ActewAGL's inputs for actual capex, depreciation and indexation are consistent with the inputs to the roll forward model.

The AER notes that its review of ActewAGL's capex incurred in the current regulatory control period found ActewAGL's past capex to be prudent, see chapter 5. The review included consideration of capex attributable to both standard and alternative control services.

ActewAGL has used straight line depreciation to calculate the regulatory depreciation of its RAB from 2004–05 to the opening RAB for 2009–10. The AER considers that

[437] Wilson Cook, Volume 5, p. 40.

[438] AER, *Statement on control mechanisms for alternative control services for the ACT and NSW 2009 distribution determinations*, February 2008.

the straight line depreciation method is an appropriate method for calculating depreciation.

ActewAGL has not consistently used the same CPI values for indexation of its RAB throughout the current regulatory control period. The allowance of 2.5 per cent for CPI for 2003–04 is the June on June measure. In the 2004 final decision the ICRC used the year to December CPI to measure inflation. The reason for this was to ensure that proposed prices could be considered by March each year.

ActewAGL has adopted the ICRC's methodology to measure actual inflation and has used a June on June measure of actual inflation for 2003–04. As the ABS did not release the June 2008 CPI until 23 July 2008 (after the submission of ActewAGL's Regulatory Proposal in June 2008) ActewAGL used the March on March inflation calculation for 2004–05 to 2007–08. The AER considers this to be an appropriate application of indexation to the RAB.

The AER considers that ActewAGL's proposal to reduce the opening 2009–10 RAB by $0.2 million is consistent with Schedule 6.2.1(c)(2) of the transitional chapter 6 rules. The adjustment will remove the benefit ActewAGL has received associated with the difference between estimated and actual capex for the 2003–04 regulatory year. A further adjustment of $0.3 million is required to reflect the reduced capex in the 2003–04 regulatory year.[439]

For the reasons set out above, the AER considers that ActewAGL's opening RAB for alternative control services for the next regulatory control period is appropriate.

**Capex**

ActewAGL has provided detail of the two categories of capex for alternative control services, meter installations and meter replacements. ActewAGL has adopted the same forecasting and escalation methods as applied to capex for its standard control services. The AER considers it is a prudent and reasonable assumption that forecasts and escalators for alternative control services capex will be in line with ActewAGL's other capex. ActewAGL's forecast capex has increased from $11 million in the current regulatory control period to $19 million in the next regulatory control period, an increase of around 77 per cent (in real terms).

ActewAGL has identified two projects which it is undertaking which will add to its capex, project MIMI and its replacement program with upgradeable meters.

The AER notes that in 2008 the ICRC considered it appropriate to provide funding of $7 million ($2006–07) to ActewAGL for the purposes of project MIMI. Based on the advice of its consultants, Halcrow Pacific, the ICRC suggested that an allocation method for this funding between the electricity, gas and water businesses of ActewAGL.[440] ActewAGL's regulatory proposal reflects the ICRC's allocation method and attributes $2.2 million ($2008–09) of capex and $0.4 million ($2008–09) of opex to project MIMI.

[439] ActewAGL, email to AER, 9 October 2008.
[440] ICRC, *Water and Wastewater Price Review, Report 1 of 2008*, April 2008, pp. 59–60.

The AER notes the benefits of undertaking project MIMI that ActewAGL has identified in its regulatory proposal. In particular, the project will improve ActewAGL's understanding of the costs and potential benefits associated with electricity smart metering. It will report on expected costs and savings in a business case, report on market acceptance and customer behavioural responses, and identify any change management and communication challenges in a full deployment of smart meters across the ACT.

Accordingly, the AER considers that the forecast capex for project MIMI is reasonable and the proposed allocation of costs is appropriate for this project.

ActewAGL is currently installing interval meters that are capable of being upgraded for remote reading, and which can support an in-house display. ActewAGL will be able to install 3600 meters per annum which utilise in-house resourcing and still be able to meet its NEMMCO approved MAMP targets up until 2013–14. ActewAGL has forecast capex of approximately $1.2 million for this project.

The purpose behind this approach is to limit the potential for the stranding of meter assets that may not meet the national smart meters functionality and performance standards. The AER notes that this policy is consistent with the ICRC decision on interval meters.[441] Accordingly, the AER considers that ActewAGL's forecast capex for alternative control services (after adjustments to escalators) of $18 million reflects the efficient costs that a prudent DNSP in the circumstances of ActewAGL would require to meet the capex objectives, as required by clause 6.5.7(c).

**Opex**

ActewAGL has forecast opex for alternative control services for the next regulatory control period of $8.7 million (including self insurance and debt raising costs). Forecast opex is made up of meter reading, maintenance and repair and the opex attributable to project MIMI. The AER notes that ActewAGL's methodology for forecasting alternative control services opex is the same methodology as applied to its opex for standard control services. The AER supports this approach by ActewAGL.

Where ActewAGL's alternative control opex forecasts are estimated using labour cost growth escalators, these escalators will need to be adjusted in line with the adjustments discussed in chapter 9. The AER considers that the same escalators should apply for both standard control services and alternative control services.

The AER has reviewed ActewAGL's meter reading costs and notes they have been increasing with CPI over the current regulatory control period. The AER considers the historical meter reading cost growth is a reasonable basis for forecasting likely future costs and agrees with ActewAGL's proposal to increase meter reading costs by CPI over the next regulatory control period.

ActewAGL stated that in accordance with its MAMP, it has switched to testing Type 6 meters by attributes rather than variables. ActewAGL plans to test 1500 domestic meters per annum at an annual cost of $0.4 million from 2008–09 to 2011–12 inclusive to comply with its MAMP. ActewAGL will then reduce testing to 400 meters per annum at a cost of $0.2 million per annum. The AER considers that

[441] ICRC, *Final Decision—Review of Metrology Procedures*, December 2005, pp. 30–31.

ActewAGL's MAMP has been approved by NEMMCO and forms a reasonable basis for forecasting metering maintenance costs in the next regulatory control period. The AER notes compliance with its MAMP has driven a step increase in ActewAGL's meter maintenance and repair cost forecasts in the next regulatory control period. The AER considers ActewAGL's metering maintenance and repair forecasts to be reasonable.

The AER notes that ActewAGL's commercial metering maintenance costs are forecast to grow faster than CPI. However, the AER accepts that compliance with the NER provisions regarding visual inspection of CT metering sites and low-voltage CT testing at all sites is driving the cost increases.[442] This will result in additional opex of $0.2 million in the next regulatory control period.

The AER notes that self insurance costs are included in the opex forecasts for alternative control services. These costs are estimated for the whole of ActewAGL's direct control services, and allocated to standard control and alternative control services in proportion to the relative contribution to the opening asset base. The AER considers that is an appropriate manner to allocate self insurance costs.

The AER notes that it has made amendments to ActewAGL's allowance for self insurance (the amendments are discussed at 9.6.8). The total self insurance forecast has been pro rated between standard and alternative control services. Accordingly, the AER has adjusted ActewAGL's proposed opex allowance for alternative control services.

Debt raising costs are included in the opex forecasts, and these have been forecast in the same manner as debt raising costs for standard control services. The AER's consideration of this opex component is included in chapter 9.

Consistent with its considerations on opex for standard control services, the AER considers that the opex forecasting methodology for alternative control services (other than self insurance) is appropriate. The AER considers that the step increases to ActewAGL's opex forecasts are attributable to the imposition of additional regulatory requirements. The AER considers ActewAGL's opex forecasts for alternative control services (after adjustments to escalators) of $8.7 million represent the efficient costs that a prudent DNSP in the circumstances of ActewAGL would require to meet the opex objectives, as required by clause 6.5.6(c).[443]

**Revenue requirement**

ActewAGL has forecast a MAR for alternative control services of $43 million ($2008–09) for the next regulatory control period.

The AER notes ActewAGL's proposed price path for alternative control services has been developed in accordance with the requirements of the AER's guideline on alternative control services which states:[444]

> For metering services in the ACT, the AER will maintain the total revenue control mechanism adopted by the ICRC during the current regulatory control

[442] NER, Table S7.3.3.
[443] Adjustments to escalators have negligible impact on the opex forecasts.
[444] AER, *Control Mechanisms for Alternative Control Services ACT and NSW*, appendix B, p. 4.

> period. Under this approach, ActewAGL will propose a revenue allowance based on a building block analysis, with maximum allowable revenues to be escalated each year by the consumer price index (CPI).

ActewAGL has proposed a $P_0$ adjustment of 41.01 per cent in 2009–10, and CPI escalation for each of the remaining years of the next regulatory control period, which is consistent with the requirements of the AER's guideline. The $P_0$ adjustment has been driven by increased expenditure on project MIMI and also reflects increased costs of compliance with changed regulatory arrangements for metering.

The form of control allows revenues to be modelled such that ActewAGL will receive the entire increase in required revenues for the next regulatory control period in the first year (in NPV terms). While this leads to a step change in ActewAGL's revenues in 2009–10, the increase in ActewAGL's revenue for the remaining years of the next regulatory control period is limited to CPI. This reflects the control mechanism applied by the ICRC in the current regulatory control period.

The impact of the increase in MAR for alternative control services is likely to be increased metering charges of $15 per household between 2008–09 and 2009–10, around 43 per cent. Increases for the remainder of the next regulatory control period will be in line with CPI.

The AER has reviewed the PTRM that ActewAGL used for alternative control services. The AER considers that ActewAGL's proposed total revenue requirement has been properly calculated using the PTRM on the basis of amounts calculated, determined or forecast in accordance with part C of the transitional chapter 6 rules.

**Compliance with the maximum allowed revenue**

ActewAGL is required to demonstrate its compliance with the control mechanism. The AER considers that compliance needs to be demonstrated in a manner that does not impose a significant administrative burden on either ActewAGL or the AER. ActewAGL has proposed preparing a schedule of metering charges, showing the revenue from each charge if that charge had applied in the previous year. It has also provided an example of how such a schedule can be used to demonstrate compliance with the revenue cap.[445]

The AER considers ActewAGL's proposal is easy to administer and robust. To demonstrate compliance with its maximum allowed revenue in each regulatory year the AER will require the schedule of metering charges, in the form of table 13.5 of ActewAGL's revenue proposal, to be submitted to the AER as soon as possible after prices for a regulatory year are determined.

**Pass through**

The cost pass through arrangements in chapter 16 apply to ActewAGL's alternative control services.

[445] ActewAGL, *Regulatory proposal*, table 13.5.

## 18.6 AER conclusion

The AER is satisfied that ActewAGL has satisfied its obligation to apply and demonstrate compliance with the control mechanism set out in the AER's statement on control mechanisms for alternative control services.[446]

The AER accepts, for the reasons set out above, that ActewAGL's capex for alternative control services represents efficient expenditure. The AER has reduced ActewAGL's proposed opex allowance to reflect the amended escalators and allowance for self insurance. In all other respects the AER is satisfied that ActewAGL's proposed opex for alternative control services represents efficient expenditure.

The AER is satisfied that ActewAGL's opening RAB and return of capital are appropriate. The AER has adjusted the return on capital and the tax building block in line with changes to the WACC.

The AER is satisfied that the revenue requirements, X factor and the price path have been properly calculated using the PTRM.

The AER has decided to approve a MAR for ActewAGL of $40 million for alternative control services for the next regulatory control period. This revenue will be recovered through a $P_0$ adjustment in 2009–10 of 31.34 per cent and allowed revenues adjusted in line with CPI each year for the remainder of the regulatory control period. ActewAGL's MAR for alternative control services is set out in table 18.5.

**Table 18.5: AER's draft decision on maximum allowed revenue – alternative control services ($m)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Unsmoothed revenue requirement | 7.5 | 7.7 | 8.1 | 8.2 | 8.7 | 40.2 |
| Smoothed revenue requirement | 7.6 | 7.8 | 8.0 | 8.2 | 8.4 | 40.2 |
| X factors[a] (%) | –31.34 | 0.00 | 0.00 | 0.00 | 0.00 | n/a |

(a) Negative values for X indicate real price increases under the CPI–X formula.

446 AER, *Control mechanisms for alternative control services ACT and NSW*.

## 18.7 AER draft decision

In accordance with clause 6.12.1(12) of the transitional chapter 6 rules the AER decides:

- the control mechanism for alternative control services provided by ActewAGL is a revenue cap as specified in the AER's *Statement on control mechanisms for alternative control services for the ACT and NSW 2009 distribution determinations*, published in February 2008
- the maximum allowed revenues for ActewAGL in each year of the next regulatory control period are as set out in table 18.5 (smoothed revenue requirement) of the draft decision
- the X factors to apply in each year of the next regulatory control period is as set out in table 18.5 of the draft decision.

In accordance with clause 6.12.1(13) of the transitional chapter 6 rules the AER decides that ActewAGL must demonstrate compliance with the control mechanism for alternative control services by submitting to the AER a schedule of metering charges, in the form of table 13.5 of ActewAGL's revenue proposal, as soon as practicable after prices for each regulatory year are determined.

# Glossary

| | |
|---|---|
| ABS | Australian Bureau of Statistics |
| ACG | Allen Consulting Group |
| AR | allowed revenue |
| APR | annual planning report |
| CAPM | capital asset pricing model |
| CEG | Competition Economics Group |
| CGS | commonwealth government securities |
| CT | current transformer |
| DMIA | demand management incentive allowance |
| DMIS | demand management incentive scheme |
| DRP | debt risk premium |
| EBSS | efficiency benefit sharing scheme |
| EMRF | Energy Market Reform Group |
| EMS | Energy and Management Services Pty Ltd |
| EUAA | Energy Users Association of Australia |
| GSL | guaranteed service level |
| GWh | gigawatt hour |
| kV | kilovolt, (one thousand volts) |
| MAAR | maximum allowable average revenue |
| MAIFI | momentary average interruption frequency index |
| MAMP | metering asset management plan |
| MCE | Ministerial Council on Energy |
| MMA | McLennan Magasanik Associates |
| MAAR | maximum average allowed revenue |
| MAR | maximum allowed revenue |
| MIMI | multi-utility integrated metering infrastructure |
| MVA | megavolt ampere |
| MW | megawatt, (one thousand kilowatts) |
| MWh | megawatt hour |
| NCC | negotiated component criteria |
| NEMMCO | National Electricity Market Management Company |
| NIEIR | National Institute of Economic and Industry Research |
| NPV | net present value |
| POE | probability of exceedence |

| | |
|---|---|
| PTRM | post tax revenue model |
| RAB | regulatory asset base |
| RBA | Reserve Bank of Australia |
| RFM | roll forward model |
| RIN | regulatory information notice |
| SAIDI | system average interruption duration index |
| SAIFI | system average interruption frequency index |
| SCNRRR | Steering Committee on National Regulatory Reporting Requirements |
| SKM | Sinclair Knight Merz Pty Ltd |
| STPIS | service target performance incentive scheme |
| the NSW DNSPs | collectively: Country Energy, EnergyAustralia and Integral Energy |
| TNSP | transmission network service provider |
| TUOS | transmission use of system |
| UNFT | utilities network facilities tax |
| WACC | weighted average cost of capital |

# Appendix A: Assigning customers to tariff classes

## Procedures for assigning or re-assigning customers to tariff classes

**Assignment of existing customers to tariff classes at the commencement of the next regulatory control period**

1. Each customer who was a customer of ActewAGL immediately prior to1 July 2009, and who continues to be a customer of ActewAGL as at 1 July 2009, will be taken to be assigned to the tariff class which ActewAGL was charging that customer immediately prior to 1 July 2009.

**Assignment of new customers to a tariff class during the next regulatory control period**

2. If, after 1 July 2009, ActewAGL becomes aware that a person will become a customer of ActewAGL, then ActewAGL must determine the tariff class to which the new customer will be assigned.
3. In determining the tariff class to which a customer or potential customer will be assigned, or reassigned, in accordance with section 2 or 5, ActewAGL must take into account one or more of the following factors:
    a. the nature and extent of the customer's usage
    b. the nature of the customer's connection to the network
    c. whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.
4. In addition to the requirements under section 3 ActewAGL, when assigning a customer to a tariff class, must ensure the following:
    a. that customers with similar connection and usage profiles are treated equally
    b. that customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.

**Re-assignment of existing customers to another existing tariff during the next regulatory control period**

5. If ActewAGL believes that an existing customer's load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned or a customer no longer has the same or materially similar load or connection characteristics as other customers on the customer's existing tariff, then ActewAGL may reassign that customer to another tariff class.
6. ActewAGL must notify the customer concerned in writing of the tariff class to which the customer has been re-assigned, prior to the re-assignment occurring. The notice must include advice that the customer may request further information from ActewAGL, may object to the proposed re-assignment and, if the customer objects to the proposed re-assignment and that objection is not resolved to the satisfaction of the customer, the customer or ActewAGL may

request the AER to decide which of ActewAGL's tariff classes the customer should be assigned to.

7. If, in response to a notice issued in accordance with section 6, ActewAGL receives a request for further information from a customer, ActewAGL must provide such information. If any of the information requested by the customer is confidential then ActewAGL is not required to provide that information to the customer.

8. If, in response to a notice issued in accordance with section 6, a customer makes an objection to ActewAGL about the proposed re-assignment, ActewAGL must reconsider the proposed re-assignment, taking into consideration the factors in section 3 above, and notify the customer in writing of its decision and the reasons for that decision.

9. If the AER receives a request in accordance with section 6, then it must decide which of ActewAGL's tariff classes the customer should be assigned to, taking into account one or more of the following factors:

   a. the nature and extent of the customer's usage

   b. the nature of the customer's connection to the network

   c. whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

10. As soon as practicable after being requested to do so by the AER, ActewAGL must provide to the AER a statement setting out which tariff class a particular customer or group of customers has been assigned to and the reasons for ActewAGL's decision.

11. The AER must notify the customer and ActewAGL in writing of its decision and the date from which its decision should be applied.

12. If the AER does not give a written notice under section 11 within 30 business days of receiving the relevant request under section 6 or within such further period that the AER may decide, then the AER is to be regarded as having decided that the customer giving the relevant request under section 6 should not be re-assigned.

13. ActewAGL must comply with a decision by the AER under section 9 and 11 in relation to a customer.

**System of assessment and review of the basis on which a customer is charged**

14. Where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile, ActewAGL must set out in its pricing proposal a method of how it will review and assess the basis on which a customer is charged.

15. If the AER considers that the method provided under section 14 does not provide for an effective system of assessment and review of the basis on which a customer is charged, the AER may request additional information or request that ActewAGL revise and resubmit a revised method.

16. If the AER considers the method provided in accordance with section 14 is reasonable it will approve that method by notice in writing to ActewAGL.

# Appendix B: Negotiable component criteria

## National Electricity Objective

1. The terms and conditions of access for a negotiable component of a direct control service, including the price that is to be charged for the negotiable component and any access charges, should promote the achievement of the national electricity objective.

## Criteria for terms and conditions of access

### Terms and conditions of access

2. The terms and conditions of access for a negotiable component must be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER.
3. The terms and conditions of access for a negotiable component (including, in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between the DNSP and the other party, the price for the negotiable component and the costs to the DNSP of providing the negotiable component.
4. The terms and conditions of access for a negotiable component must take into account the need for the direct control service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

### Price of Services

5. The price for a negotiable component must be the price for that component in the DNSP's approved pricing proposal, unless the terms and conditions sought for the component are so different from those used for the purposes of establishing the approved pricing proposal as to warrant determination of the price without regard to this criterion.
6. Subject to criterion 5, the price for a negotiable component must reflect the costs that the DNSP has incurred or incurs in providing that component, and must be determined in accordance with the principles and policies set out in the Cost Allocation Method.
7. Subject to criteria 5, 8 and 9, the price for a negotiable component must be at least equal to the cost that would be avoided by not providing it but no more than the cost of providing it on a stand alone basis.
8. Subject to criterion 5, if the direct control service of which the negotiable component is a component is the provision of a shared distribution service that:
    i. exceeds any network performance requirements which it is required to meet under any relevant electricity legislation; or
    ii. exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER,

then the difference between the price for that direct control service and the price for the shared distribution service which meets network performance requirements must reflect the DNSP's incremental cost of providing that service (as appropriate).

9. Subject to criterion 5, if the direct control service of which the negotiable component is a component is the provision of a shared distribution service that does not meet or exceed the network performance requirements, the difference between the price for that service and the price for the shared distribution service which meets, but does not exceed, the network performance requirements should reflect the cost the DNSP would avoid by not providing that service (as appropriate).

10. Subject to criterion 5, the price for a negotiable component must be the same for all Distribution Network Users unless there is a material difference in the costs of providing the negotiable component to different Distribution Network Users or classes of Distribution Network Users.

11. Subject to criterion 5, the price for a negotiable component must be subject to adjustment over time to the extent that the assets used to provide the direct control service are subsequently used to provide services to another person, in which case such adjustment must reflect the extent to which the costs of those assets are being recovered through charges to that other person.

12. Subject to criterion 5, the price for a negotiable component must be such as to enable the DNSP to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiable component.

## Criteria for access charges

### Access Charges

13. Any access charges must be based on costs reasonably incurred by the DNSP in providing distribution network user access and, in the case of compensation referred to in clause 5.5(f)(4)(ii) to (iii) of the NER, on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs (as appropriate).

# Appendix C: Negotiating framework

**Proposed Negotiating Framework for Negotiable Components of Direct Control Services**

**2009-14 Regulatory Period**

**ActewAGL Distribution**

Contents

## 1. Background

**1.1.** The National Electricity Rules (NER) provide that:

**1.1.1.** a Distribution Network Service Provider must prepare a document (the 'negotiating framework') setting out the procedure to be followed during negotiations between it and any person who wishes to be provided with a Negotiable Component of a direct control service as to the terms and conditions of access for the provision of the service (NER Part DA Clause 6.7A.5(a));

**1.1.2.** the negotiating framework must comply with and be consistent with the applicable requirements of a distribution determination applying to the provider; and

**1.1.3.** the negotiating framework must comply with and be consistent with the applicable requirements of Part DA clause 6.7A.5(c), which sets out the minimum requirements for a negotiating framework.

**1.2.** This document has been prepared in fulfilment of ActewAGL Distribution's obligations under NER Part DA Clause 6.7A.5(a) to establish a negotiating framework.

**1.3.** This document applies to ActewAGL Distribution and any Service Applicant who applies to receive a Negotiable Component of a direct control service.

**1.4.** A Negotiable Component of a Direct Control Service is a service that is provided by ActewAGL Distribution and that has been deemed by the AER to be a Negotiable Component in accordance with NER Part E 16.12.1 (16A).

## 2. Application of negotiating framework

**2.1.** This negotiating framework applies to ActewAGL Distribution and each Service Applicant who has made an application in writing to ActewAGL Distribution for the provision of a Negotiable Component of a Direct Control Service.

**2.2.** Where a Negotiable Component of a Direct Control Service cannot be separated from a Non Negotiable Component of a Direct Control Service, then the timeframes for the provision of the Negotiable Component shall be in accordance with the timeframes for the provision of the Non Negotiable Component.

2.3. ActewAGL Distribution and any Service Applicant who wishes to receive a Negotiable Component of a Direct Control Service from ActewAGL Distribution should comply with the requirements of this negotiating framework.

2.4. The requirements set out in this negotiating framework are additional to any requirements or obligations contained in Clauses 5.3, 5.4A and 5.5 and Chapter 6 and Chapter 6A of the NER. In the event of any inconsistency between this negotiating framework and any other requirements in the NER, the requirements of the NER will prevail.

2.5. Nothing in this negotiating framework or in the NER will be taken as imposing an obligation on ActewAGL Distribution to provide any service to the Service Applicant.

## 3. Obligation to negotiate in good faith

3.1. ActewAGL Distribution and the Service Applicant must negotiate in good faith the terms and conditions of access for the provision by ActewAGL Distribution of the Negotiable Component of a Direct Control Service sought by the Service Applicant.

## 4. Timeframe for commencing, progressing and finalising negotiations

4.1. Clause 4.4 sets out the target timeframes for commencing, progressing and finalising negotiations in relation to applications for a Negotiable Component of a Direct Control Service.

4.2. The timeframes set out in clause 4.4 may be suspended in accordance with clause 10.

4.3. ActewAGL Distribution and the Service Applicant shall use reasonable endeavours to adhere to the time periods specified in clause 4.4 during the negotiation for the supply of a Negotiable Component of a Direct Control Service.

4.4. Timeframes:

4.4.1. The timeframes for commencing, progressing and finalising negotiations with a Service Applicant are as set out in Table 1. The timeframes can be varied by agreement between the parties.

4.4.2. Unless otherwise agreed, ActewAGL Distribution and the Service Applicant shall use reasonable endeavours to adhere to the time periods set out in Table 1.

**4.4.3.** The agreed program (under C in Table 1) may be modified from time to time by further agreement of the parties, where such agreement must not be unreasonably withheld. Any such amendment to the program shall be taken to be a reasonable period of time for commencing, progressing and finalising negotiations with a Service Applicant for the provision of the Negotiable Component of a Standard Control Service.

**Table 4.1: Timeframes**

| | Event | Timeframe |
|---|---|---|
| A. | Receipt of written application for a Negotiable Component of a Direct Control Service | X |
| B. | Parties meet to discuss a preliminary program with milestones for the supply of the Negotiable Component of a Standard Control service that represents a reasonable period of time for commencing, progressing and finalizing negotiations | X + 10 business days |
| C. | Parties finalise and agree on a program, which may include, without limitation, milestones relating to<br>• the request and provision of commercial information; and<br>• notification and consultation with any affected Distribution Network Users. | X + 20 business days |
| D. | ActewAGL Distribution provides Service Applicant with an offer for the Negotiable Component | In accordance with agreed program |
| E. | Parties finalise negotiations | In accordance with agreed program |

**4.5.** Notwithstanding clause 4.1 or any other provision of this negotiating framework, the timeframes set out in clause 4.4:

**4.5.1.** do not commence until payment of the amount to ActewAGL Distribution pursuant to clause 12;

**4.5.2.** recommence if there is a material change in the nature of the Negotiable Component of a Direct Control Service sought by the Service Applicant, unless ActewAGL Distribution agrees otherwise.

## 5. Provision of initial Commercial Information by Service Applicant

**Obligation to provide Initial Commercial Information**

**5.1.** Within the time agreed by the parties, ActewAGL Distribution must use its reasonable endeavours to request that the Service Applicant provide the Commercial Information that is reasonably required by ActewAGL Distribution to enable it to engage in effective negotiations with the Service Applicant in relation to the application.

**5.2.** Subject to clauses 5.3 and 5.4, the Service Applicant must use its reasonable endeavours to provide ActewAGL Distribution with the

Commercial Information requested by ActewAGL Distribution in accordance with clause 5.1 within the time frame agreed between the parties.

5.3. The obligation under clause 5.1 is suspended as at the date of notification of a dispute if a dispute under this negotiating framework arises until conclusion of the dispute in accordance with clause 10.

**Confidentiality Requirements – Commercial Information**

5.4. For the purposes of this clause 5, Commercial Information does not include:

5.4.1. confidential information provided to the Service Applicant by another person; or

5.4.2. information that the Service Applicant is prohibited, by law, from disclosing to ActewAGL Distribution.

5.5. Commercial Information may be provided by the Service Applicant subject to conditions including the condition that ActewAGL Distribution must not disclose the Commercial Information to any other person unless the Service Applicant consents in writing to the disclosure. The Service Applicant may require ActewAGL Distribution to enter into a confidentiality agreement, on terms reasonably acceptable to both parties, with the Service Applicant in respect of any Commercial Information provided to ActewAGL Distribution.

5.6. A consent provided by the Service Applicant in accordance with clause 5.5 may be subject to the condition that the person to whom ActewAGL Distribution discloses the Commercial Information must enter into a separate confidentiality agreement with the Service Applicant.

## 6. Provision of additional Commercial Information by the Service Applicant

**Obligation to provide additional Commercial Information**

**6.1.** ActewAGL Distribution may give a notice to the Service Applicant requesting the Service Applicant to provide ActewAGL Distribution with any additional Commercial Information that is reasonably required by ActewAGL Distribution to enable it to engage in effective negotiations with the Service Applicant in relation to the provision of the Negotiable Component of a Direct Control Service or to clarify any Commercial Information provided pursuant to clause 5.

**6.2.** The Service Applicant must use its reasonable endeavours to provide ActewAGL Distribution with the Commercial Information requested by ActewAGL Distribution in accordance with clause 6.1 within the time frame agreed between the parties.

**Confidentiality requirements**

**6.3.** For the purposes of this clause 6, Commercial Information does not include:

**6.3.1.** confidential information provided to the Service Applicant by another person; or

**6.3.2.** information that the Service Applicant is prohibited, by law, from disclosing to ActewAGL Distribution; and

**6.4.** Commercial Information may be provided by the Service Applicant subject to conditions including the condition that ActewAGL Distribution must not disclose the Commercial Information to any other person unless the Service Applicant consents in writing to the disclosure. The Service Applicant may require ActewAGL Distribution to enter into a confidentiality agreement, on terms reasonably acceptable to both parties, with the Service Applicant in respect of any Commercial Information provided to ActewAGL Distribution.

6.5. A consent provided by the Service Applicant in accordance with clause 6.4 may be subject to the condition that the person to whom ActewAGL Distribution discloses the Commercial Information must enter into a separate confidentiality agreement with the Service Applicant.

## 7. Provision of Commercial Information by ActewAGL Distribution

**Obligation to provide Commercial Information**

7.1. ActewAGL Distribution shall provide the Service Applicant with all Commercial Information held by ActewAGL Distribution that is reasonably required by a Service Applicant to enable it to engage in effective negotiations with ActewAGL Distribution for the provision of the Negotiable Component of a Direct Control Service within a timeframe agreed by the parties, including the following information:

7.1.1. a description of the nature of the Negotiable Component of a Direct Control Service including what ActewAGL Distribution would provide to the Service Applicant as part of that service;

7.1.2. the terms and conditions on which ActewAGL Distribution would provide the Negotiable Component of a Direct Control Service to the Service Applicant;

7.1.3. the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the Negotiable Component of a Direct Control Service to the Service Applicant which demonstrate to the Service Applicant that the charges for providing the Negotiable Component of a Direct Control Service reflect those costs and/or the cost increment or decrement (as appropriate).

**Confidentiality requirements**

7.2. For the purposes of clause 7.1, Commercial Information does not include:

7.2.1. confidential information provided to ActewAGL Distribution by another person; or

7.2.2. information that ActewAGL Distribution is prohibited, by law, from disclosing to the Service Applicant.

7.3. ActewAGL Distribution may provide the Commercial Information in accordance with clause 7.1 subject to relevant conditions including the condition that the Service Applicant must not disclose the

Commercial Information to any other person unless ActewAGL Distribution consents in writing to the disclosure. ActewAGL Distribution may require the Service Applicant to enter into a confidentiality agreement with ActewAGL Distribution, on terms reasonably acceptable to both parties, in respect of Commercial Information provided to the Service Applicant.

7.4. A consent provided by a Service Applicant in accordance with clause 7.3 may be subject to the condition that the person to whom the Service Applicant discloses the Commercial Information must enter into a separate confidentiality agreement with ActewAGL Distribution.

## 8. Arrangement for assessment and review of charges

8.1. ActewAGL Distribution will assess and review the basis for its charges to a Distribution Network User for any Negotiable Component of a Direct Control Service, following an application by the Distribution Network User for such a review.

8.2. Where a Distribution Network User submits an application for review the Distribution Network User must provide the reason why it considers such a review to be appropriate, plus the supporting information required in order for ActewAGL Distribution to be able to assess the application.

## 9. Determination of impact on other Distribution Network Users and consultation with affected Distribution Network Users

9.1. ActewAGL Distribution must determine the potential impact on Distribution Network Users, other than the Service Applicant, of the provision of the Negotiable Component of a Direct Control Service.

9.2. If applicable, ActewAGL Distribution must notify and consult with any affected Distribution Network Users and ensure that the provision of the Negotiable Component of a Direct Control Service does not result in non-compliance with obligations in relation to other Distribution Network Users under the NER or applicable requirements of the NEL or jurisdictional legislation.

## 10. Suspension of Timeframe for Provision of the Negotiable Component of a Direct Control Service

10.1. The timeframes for negotiation of provision of the Negotiable Component of a Direct Control Service as contained within this

negotiating framework, or as otherwise agreed between the parties, are suspended if:

**10.1.1.** within 15 Business Days of ActewAGL Distribution providing the Commercial Information to the Service Applicant pursuant to clause 7.1, the Service Applicant does not formally accept that Commercial Information and the parties have agreed a date for the undertaking and conclusion of commercial negotiations;

**10.1.2.** a dispute in relation to the Negotiable Component of a Direct Control Service has been notified to the AER under Part L of Chapter 6, from the date of notification of that dispute to the AER until:

(a) the withdrawal of the dispute;

(b) the termination of the dispute by the AER in accordance with clause 6.22.3 of the NER; or

(c) determination of the dispute by the AER under clause 6.22.2;

**10.1.3.** within 15 Business Days of ActewAGL Distribution requesting additional Commercial Information from the Service Applicant pursuant to clause 6 , the Service Applicant has not supplied that Commercial Information;

**10.1.4.** without limiting clauses 10.1.1 to 10.1.3, either of the parties does not promptly conform with any of its obligations as required by this negotiating framework or as otherwise agreed by the parties;

**10.1.5.** ActewAGL Distribution has been required to notify and consult with any affected Distribution Network Users under clause 9.2, from the date of notification to the affected Distribution Network Users until the end of the time limit specified by ActewAGL Distribution for any affected Distribution Network Users, or the receipt of such information from the affected Distribution Network Users whichever is the later regarding the provision of the Negotiable Component of a Direct Control Service.

## 11. Dispute Resolution

**11.1.** All disputes between the parties as to the terms and conditions of access for the provision of the Negotiable Component of a Direct Control Service are to be dealt with in accordance with Part L of

Chapter 6 of the NER.

## 12. Payment of ActewAGL Distribution's reasonable Costs

**12.1.** Prior to commencing negotiations, the Service Applicant shall pay an application fee to ActewAGL Distribution.

**12.2.** The application fee lodged pursuant to clause 12.1 will be deducted from the reasonable Costs incurred in processing the Service Applicant's application to ActewAGL Distribution for the provision of the Negotiable Component of a Direct Control Service.

**12.3.** From time to time, ActewAGL Distribution may give the Relevant Service Applicant a notice setting out the reasonable Costs incurred by ActewAGL Distribution and the off-set of any amount applicable under clause 12.1.

**12.4.** If the aggregate of the Costs exceeds the amount paid by the Service Applicant pursuant to clause 12.1, the Service Applicant must, within 20 Business Days of the receipt of a notice in accordance with clause 12.3, pay ActewAGL Distribution the amount stated in the notice.

**12.5.** ActewAGL Distribution may require the Service Applicant to enter into a binding agreement addressing conditions, guarantees and other matters in relation to the payment of on-going Costs.

## 13. Termination of Negotiations

**13.1.** The Service Applicant may elect not to continue with its application for the Negotiable Component of a Direct Control Service and may terminate the negotiations by giving ActewAGL Distribution written notice of its decision to do so.

**13.2.** ActewAGL Distribution may terminate a negotiation under this framework by giving the Service Applicant written notice of its decision to do so where:

**13.2.1.** ActewAGL Distribution believes on reasonable grounds that the Service Applicant is not conducting the negotiation under this negotiating framework in good faith;

**13.2.2.** the Service Applicant consistently fails to comply with the requirements of the negotiating framework;

**13.2.3.** the Service Applicant fails to comply with an obligation in this negotiating framework to undertake or complete an action within a specified or agreed timeframe, and does not complete the

10

relevant action within 20 Business Days of a written request from ActewAGL Distribution;

**13.2.4.** An act of Solvency Default occurs in relation to the Service Applicant.

## 14. Giving notices

**14.1.** A notice, consent, information, application or request that must or may be given or made to a party under this document is only given or made if it is in writing and delivered or posted to that party at its address set out below.

If a party gives the other party 3 Business Days' notice of a change of its address, a notice, consent, information, application or request is only given or made by that other party if it is delivered or posted to the latest address.

| **ActewAGL Distribution** | |
|---|---|
| Name | ActewAGL Distribution |
| Address | GPO Box 366, Canberra ACT 2601 |
| **Service Applicant** | |
| Name: | Service Applicant |
| Address: | The nominated address of the Service Applicant provided in writing to ActewAGL Distribution as part of the application |

### Time notice is given

**14.2.** A notice, consent, information, application or request is to be treated as given or made at the following time:

**14.2.1.** if it is delivered, when it is left at the relevant address; or

**14.2.2.** if it is sent by post, 2 Business Days after it is posted.

**14.2.3.** If sent by facsimile transmission, on the day the transmission is sent (but only if the sender has a confirmation report specifying a facsimile number of the recipient, the number of pages sent and the date of transmission).

**14.3.** If a notice, consent, information, application or request is delivered after the normal business hours of the party to whom it is sent, it is to be treated as having been given or made at the beginning of the next Business Day.

## 15. Publication of Results of Negotiations on Website

**15.1.** ActewAGL Distribution will publish the outcomes of negotiations for

Negotiable Components of Direct Control Services on its website.

## 16. Definitions and interpretation

### Definitions

**16.1.** In this document the following definitions apply:

**Business Day** means a day on which all banks are open for business generally in Canberra, ACT.

**Commercial Information** shall include at a **minimum**, the following classes of information:

details of corporate structure;

financial details relevant to creditworthiness and commercial risk;

ownership of assets;

technical information relevant to the application for a Negotiable Component of a Direct Control Service;

financial information relevant to the application for a Negotiable Component of a Direct Control Service;

details of an application's compliance with any law, standard, NER or guideline.

**Costs** means any costs or expenses incurred by ActewAGL Distribution in complying with this negotiating framework or otherwise advancing the Service Applicant's request for the provision of a Negotiable Component of a Direct Control Service or such other costs or expenses consistent with the NER, ActewAGL Distribution's Cost Allocation Methodology or any relevant part of a distribution determination applying to ActewAGL Distribution.

**ActewAGL Distribution** means ActewAGL Distribution Pty Limited, ABN 76 670 568 688.

**Solvency Default** means the occurrence of any of the following events in relation to the Service Applicant:

(a) An originating process or application for the winding up of the Service Applicant (other than a frivolous or vexatious application) is filed in a court or a special resolution is passed to wind up the Service Applicant, and is not dismissed before the expiration of 60 days from service on the Service Applicant;

(b) A receiver, receiver and manager or administrator is appointed in respect of all or any part of the assets of the Service Applicant, or a

provisional liquidator is appointed to the Service Applicant;

(c) A mortgagee, chargee or other holder of security, by itself or by or through an agent, enters into possession of all or any part of the assets of the Service Applicant;

(d) A mortgage, charge or other security is enforced by its holder or becomes enforceable or can become enforceable with the giving of notice, lapse of time or fulfilment of a condition;

(e) The Service Applicant stops payment of, or admits in writing its inability to pay, its debts as they fall due;

(f) The Service Applicant applies for, consents to, or acquiesces in the appointment of a trustee or receiver of the Service Applicant or any of its property;

(g) A court appoints a liquidator, provisional liquidator, receiver or trustee, whether permanent or temporary, of all or any part of the Service Applicant's property;

(h) The Service Applicant takes any step to obtain protection or is granted protection from its creditors under any applicable legislation or a meeting is convened or a resolution is passed to appoint an administrator or controller (as defined in the *Corporations Act 2001),* in respect of the Service Applicant;

(i) A controller (as defined in the *Corporations Act 2001)* is appointed in respect of any part of the property of the Service Applicant;

(j) Except to reconstruct or amalgamate while solvent, the Service Applicant enters into or resolves to enter into a scheme of arrangement, compromise or reconstruction proposed with its creditors (or any class of them) or with its members (or any class of them) or proposes re-organisation, re-arrangement moratorium or other administration of the Service Applicant's affairs;

(k) The Service Applicant is the subject of an event described in section 459C(2)(b) of the *Corporations Act 2001;* or

(l) Anything analogous or having a substantially similar effect to any of the events specified above happens in relation to the Service Applicant.

**Interpretation**

**16.2.** In this document, unless the context otherwise requires:

**16.2.1.** terms defined in the NER have the same meaning in this negotiating framework;

**16.2.2.** a reference to any law or legislation or legislative provision includes any statutory modification, amendment or re-enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision;

**16.2.3.** a reference to any agreement or document is to that agreement or document as amended, novated, supplemented or replaced from time to time;

**16.2.4.** a reference to a clause, part, schedule or attachment is a reference to a clause, part, schedule or attachment of or to this document unless otherwise stated;

**16.2.5.** an expression importing a natural person includes any company, trust, partnership, joint venture, association, corporation, body corporate or governmental agency; and

**16.2.6.** a covenant or agreement on the part of two or more persons binds them jointly and severally.

# Appendix D: Miscellaneous standard control services

The following definitions of miscellaneous standard control services will apply to ActewAGL in the next regulatory control period.

## For a visit to re–energise or de–energise a premises

### Business hours — de–energise

A site visit to a customer's premises between the hours of 7.00 am and 5.00 pm on a working weekday or on a Saturday for the purpose of disconnecting (remove fuse) the customer's supply of electricity.

### De–energise premises for non-payment

A site visit to a customer's premises to disconnect the supply of electricity to a customer for breach by the customer of a customer supply contract or a customer connection contract, or where a retail supplier has requested that the supply to the customer be disconnected.

### Business hours – re–energise

A site visit to a customer's premises between the hours of 7.30 am and 4.00 pm on a working day to reconnect (insert fuse) the supply of electricity following the disconnection in paragraphs 1.1.1 and 1.1.2.

### After hours – re–energise

A site visit to a customer's premises outside the hours of paragraph 1.1.3 to reconnect the supply of electricity following the disconnection in paragraphs 1.1.1 and 1.1.2, at the request of a customer.

### Field visit read only (for de–energisation non-payment)

A site visit to a customer's premises to read the customer's meter when the supply of electricity to that customer was scheduled for a de-energise premises for non-payment.

## Temporary connections

### Overhead

Site visits to install, dismantle, connect, disconnect, and inspect mains, lines and apparatus of a single or three phase temporary builders supply where the electricity is supplied by overhead service cables.

### Standard underground

The standard underground supply in a permanent location does not incur a charge unless re-visits are required. Site re-visits to install, dismantle, connect, disconnect, and inspect mains, lines and apparatus of a single or three phase temporary builders

supply where the electricity is supplied by underground service cables. The temporary supply is provided through a meter box installed in the permanent location.

### Free–standing underground

Site visits to install, dismantle, connect, disconnect, and inspect mains, lines and apparatus of a single or three phase temporary builders supply where the electricity is supplied by underground service cables. The temporary supply is provided through a specially erected temporary meter box.

## Modify service connection

### Overhead: remove, reposition or disconnect service

A site visit to a customer’s premises to remove, reposition or disconnect the customer’s supply of electricity where the electricity is supplied by overhead service cables.

### Underground: remove, reposition or disconnect service

A site visit to a customer’s premises to remove, reposition or disconnect the customer’s supply of electricity where the electricity is supplied by underground service cables.

## Upgrade service from single to three phase

### Overhead

A site visit to a customer’s premises to upgrade the service from single to three phase at customer's request where load does not justify three phase (Service and Installation Rules clause 3.10) and where the electricity is supplied by overhead service cables.

### Underground–service cable replacement not required

A site visit to a customer’s premises to upgrade the service from an existing single phase supply to three phase at customer's request where load does not justify three phase supply, but customer requests three phase for other reasons (Service and Installation Rules clause 3.10). The customer is supplied already by the three phase underground service cable connected for a single phase supply and an installation of a new cable is not required to upgrade to three phase supply.

### Underground–service replacement required

A site visit to a customer’s premises to replace the single phase service with the three phase service at customer's request where the electricity is supplied by single phase underground service cables. The customer requests a three phase supply for other reasons, but the load does not justify the three phase supply. The existing single phase cable has to be replaced with a new three phase service cable.

## Other miscellaneous services

### Installation defect

Revisiting a site following obstructed access at previous visit or site visit due to non-compliance with the DNSP's service and installation rules.

### Issue of copies of electrical drawings

Provision of copies of electrical drawings that show existing low and high voltage circuity (geographically and schematically) and adjacent project drawings to enable the preparation of a design drawing and submit it for certification.

### De-energising wires

De-energising wires to allow safe approach, for example, for tree pruning, plant operation, oversize loads, construction activities.

## Operational and maintenance services for small embedded generators other than residential (photovoltaic)

### Connection assets

The service relating to ongoing maintenance and operations of assets connecting an embedded generator to the distribution network. For mixed use connection assets (i.e. assets which connect load as well as embedded generation), only a proportion of the service relating to embedded generation is attributed to the generator.

### Shared network assets

The service relating to ongoing maintenance and operations of shared network assets used by an embedded generator. For mixed use shared assets (i.e. assets which are used for load as well as for embedded generation), only a portion of the service relating to embedded generator is attributed to the generator.

# Appendix E: Transmission overs and unders account

To demonstrate compliance with clause 6.18.7 of the transitional chapter 6 rules and this distribution determination for the next regulatory control period, the AER requires ActewAGL to maintain a Transmission Overs and Unders account. It must provide information on this account to the AER as part of its annual pricing proposal under clause 6.18.2(b)(7).

As part of its pricing proposal for each regulatory year of the next regulatory control period, ActewAGL must provide the amounts for the following entries in its Transmission Overs and Unders account for the most recently completed regulatory year and forecasts for the next regulatory year:

1. opening balance for each year

2. 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. addition for the amount representing the revenue recovered from TUOS charges applied in respect of that year, less the amounts of all transmission related payments made by ActewAGL in respect of that year

4. an adjustment to the net amount in item 3 by 6 months of interest, accrued at the approved nominal rate of return

5. summation of the above amounts to derive the closing balance for each year.

Note that estimates of values for the current regulatory year are not required or relevant to these calculations.

ActewAGL must provide details of their calculations, in the format set out in table E.1.

For the avoidance of doubt, amounts may be either positive or negative and when added to each other, subtracted from each other or multiplied by another number may also yield, as the case maybe, positive or negative amounts.

In proposing variations to the amount and structure of TUOS charges, ActewAGL is to achieve a zero expected balance on their transmission unders and overs account by the end of the next regulatory year.

**Table E.1: Example calculation of Transmission unders and overs account ($m)**

| | Year 1 (actual) | Year 3 (forecast) |
|---|---|---|
| Revenue from TUOS charges | 100.00 | 103.45 |
| Transmission related payments | | |
| Transmission charges paid to TNSPs | 90.00 | 91.00 |
| Avoided TUOS payments approved by the AER | 10.00 | 5.00 |
| Inter-distributor payments to DNSPs | 5.00 | 2.00 |
| Total transmission related payments | 105.00 | 98.00 |
| Over (under) recovery | (5.00) | 5.45 |
| **Unders and Overs account** | | |
| Annual rate of interest (applicable to balances) | 9.00% | 9.00% |
| Semi annual rate of interest (applicable to recoveries) | 4.40% | 4.40% |
| Opening balance of account | 0.00 | (5.22) |
| Interest on opening balance | 0.00 | (0.47) |
| Over (under) recovery for financial year | (5.00) | 5.45 |
| Interest on over/ under recovery | (0.22) | 0.24 |
| Closing balance of account | (5.22) | 0.00 |

# Appendix F: Changes to tariff structures and the maximum allowable average revenue and side constraint formula

The maximum allowable average revenue and side constraint are calculated using historical quantities of consumption. When revisions to tariff classes/components occurs historical quantities for the new tariff classes/components will not be available for two years. This will occur in the following circumstances:

- the introduction of new tariffs
- the introduction of new tariff components for existing tariffs (for example, introducing a step rate for the usage component of the domestic tariff)
- changing the structure of existing tariffs or tariff components (this is essentially introducing a new tariff component, for example, changing the threshold on an inclining block tariff or the time bands associated with time of use tariffs)
- when customers move between existing tariffs (from 'origin' tariffs to 'new' tariffs).

This appendix sets out the adjustment process for incorporating such changes to tariff structures in the maximum allowable average revenue formula when setting prices for Year (*t)*, and for calculating the side constraint for affected tariffs. It provides for estimates for the historical quantities $q_i^{t-1}$, and a substitute value for $p_i^t$ to be used when calculating compliance with the maximum allowable average revenue cap, and for calculating the side constraint.

## F.1 Value of $q_i^{t-1}$ when new tariffs or new tariff components are introduced

When a new tariff or a new tariff component is introduced,[447] there are no historical quantities available. In order to incorporate these tariffs in the maximum allowable average revenue cap and calculate a side constraint, the AER requires reasonable estimates to be submitted by the DNSP, based on the quantities that would have been sold, if the new tariff (or new component) had been introduced in Year (*t*-1). The AER has adopted the following process, which was developed by the Independent Pricing and Regulatory Tribunal of New South Wales, in order for the DNSP to arrive at these estimates.

First, the DNSP must nominate the origin network tariff/s and/or network tariff component/s, which represents the tariff/s and/or component/s that the customer/s who will be moved to the new network tariff/s and/or network tariff component/s, are currently on, or currently being charged at. The DNSP must provide reasonable

[447] This includes when an existing tariff component has undergone a structural change such that the new structure is essentially a new tariff component e.g. changing the threshold value for a step rate, or time bands on a time of use tariff.

estimates for $q_i^{t-1}$ for all applicable units of measure (e.g. kWh, kW) for both, the new network tariff/s and/or network tariff component/s and the origin network tariff/s and/or components.

Second, the DNSP must make the following assumptions when calculating the reasonable estimates:

1. The only customer/s that would have moved to the new network tariff and/or network tariff component in (*t*-1) moved as a result of a direction of the DNSP due to a change in tariff structures (as permitted under the customer's standard network connection contract).[448] This means that no new customer/s are included in the estimate,[449] nor customer/s that request to change tariff/s either voluntarily, or do so through the actions of the retailer.
2. Customer/s have the same consumption and load profile on the new network tariff and/or network tariff component as they did on the origin network tariff and/or network tariff component. This implies that the sum of the reasonable estimates for Year (*t*-1) for each unit of measure on the new network tariff and/or network tariff component plus the reasonable estimates for Year (*t*-1) for each unit of measure on the origin network tariff and/or the network tariff component, equals the actual quantities that occurred for the origin network tariff and/or network tariff component in Year (*t*-1).

In the year after a new network tariff and/or tariff component has been introduced, there is still not a full year of actual historical data available to be used for $q_i^{t-1}$, hence the DNSP will be required to submit reasonable estimates for both the new network tariff and/or the network tariff component and the corresponding origin network tariff and/or network tariff component. The DNSP may base the reasonable estimates on the actual quantities that have occurred to date on the new network tariff and/or network tariff component and the origin network tariff and/or network tariff component. The DNSP must demonstrate how it has arrived at the estimates.

## F.2 Value of $p_i^t$ when new tariffs or new tariff components are introduced

The $p_i^t$ of the corresponding origin network tariff and/or network tariff component/s will be used as the $p_i^t$ for the new network tariff and/or network tariff component/s (or the $d_k^t$ in the side constraint formula). A corresponding origin network tariff and/or network tariff component may be any component that is measured in the same units of measure as the new network tariff and/or network tariff component/s. If there is no corresponding network tariff component/s with the same units of measure, $p_i^t$ will be set to zero.

[448] Each customer has a standard network connection contract with its DNSP and a separate contract with its respective retailer who manages the relationship with the DNSP on the customer's behalf.

[449] New customers have been allowed for in the growth assumption used when setting the X factor.

**Table F.1 Example – introducing a step rate or inclining block tariff component**

| Tariff reform | | $p_i^{t-1}$ | $p_i^t$ | $q_i^{t-1}$ |
|---|---|---|---|---|
| ***Existing tariff – standard domestic*** | | | | |
| Fixed charge | $ pa per customer | $30 | n/a | 25,000 customers |
| Variable rate (all consumption) | c/kWh | 0.04 | n/a | 200,000 MWh |
| ***Proposed tariff with new component*** | | | | |
| Fixed charge | $ pa per customer | $30 | $25 | 25,000 customers |
| Variable rate 1 (consumption up to 5000kWh per customer) | c/kWh | 0.04 (above) | 0.02 | 150,000 MWh |
| Variable rate 2 (consumption over 5000kWh per customer) | c/KWh | 0.04 (above) | 0.05 | (200,000 –150,000) = 50,000 MWh |

## F.3 Value of $q_i^{t-1}$ when customers are transferred by the DNSP to an alternative tariff

If the DNSP proposes to move a number of customers across to an alternative existing network tariff,[450] the rate at which revenue will accrue is different to what was used to calculate the X factor and will be different to what will be calculated under the maximum allowable average revenue formula. In addition, the side constraint calculation will not reflect the actual increase to the customers being transferred. In these circumstances, the AER will require the DNSP to submit reasonable estimates for $q_i^{t-1}$ for each orgin network tariff that the customer is currently on, and the new network tariff that the DNSP will move the customers to, taking the transfer into account.

For compliance purposes, the assumptions the DNSP must make when calculating the reasonable estimates are:

1. The customer movement occurred in Year (*t*-1).
2. The customers only moved as a result of a direction of the DNSP due to a change in tariff structures (as permitted under the standard network connection contract).[451] The estimates are not to include customers that may move at their discretion or due to the retailer discretion (voluntary movement).

[450] The AER does not regulate the re-assignment or transfer of customers to alternative tariffs. The DNSP may decide to transfer customers if a customers' consumption or load profile has changed and the DNSP decides it is no longer be appropriate for them to remain on the same tariff. Alternatively the DNSP may change the structure of an existing tariff to suit the majority of customers.

[451] Each customer has a standard network connection contract with its DNSP and a separate contract with its respective retailer who manages the relationship with the DNSP on the customer's behalf.

3. Customers have the same consumption and load profile under either tariff.

Reasonable estimates will also be required in the year following the movement Year ($t$), given that a full year of actual data will not be available when setting the prices in the next year.

## F.4 Value of $p_i^t$ when customers are transferred by the DNSP to an alternative tariff

As for the introduction of new network tariff/s and/or network tariff component/s, the $p_i^t$ for the corresponding origin network tariff component/s will be used as the $p_i^t$ for the new network tariff component/s for the affected quantities (or the $d_k^t$ in the side constraint formula).[452]

**Table F.2: Example 2 – reasonable estimates for re-assigning some customers from the domestic flat rate tariff to the domestic TOU tariff**

| Network tariff | Customer (number) | Billed consumption (MWh) | | | |
|---|---|---|---|---|---|
| | | Non-TOU | Peak | Shoulder | Off-peak |
| Time of use (existing) | 10,000 | | 25,000 | 20,000 | 25,000 |
| Domestic (existing) | (10,000) | (70,000) | | | |

Assumption: Only some customers from the domestic tariff will be moved to the new TOU tariff (10,000 customers with a consumption of 70,000 MWh). Both tariffs remain in existence and will have remaining customers on the tariffs.

[452] This is only required for movements that occur in Year $t$+1, not for movements in Year $t$.

**Table F.3: Example 2 (cont) – parameters in the MAAR and side constraint formula for re-assigning some customers from the domestic flat rate tariff to the domestic TOU tariff**

| Tariffs | | $p_i^{t-1}$ | $p_i^t$ | $q_i^{t-1}$ |
|---|---|---|---|---|
| ***Domestic*** | | | | |
| Fixed charge | $ pa per customer | $30 | $32 | (25,000 existing - 10,000) =15,000 customers |
| Variable rate | c/kWh | 0.04 | 0.05 | (200,000 existing - 70,000) = 130,000 MWh |
| ***Domestic TOU – existing customers*** | | | | |
| Fixed charge | $ pa per customer | $22 | $25 | 5,000 existing |
| Peak rate | c/kWh | 0.09 | 0.095 | 10,000 MWh existing |
| Shoulder rate | c/kWh | 0.05 | 0.05 | 10,000 MWh existing |
| Off-peak rate | c/kWh | 0.02 | 0.025 | 10,000 MWh existing |
| ***Domestic TOU – customers being transferred*** | | | | |
| Fixed charge | $ pa per customer | $30 (as per domestic) | $25 | 10,000 customers |
| Peak rate | c/kWh | 0.04 (as per domestic) | 0.095 | 25,000 MWh |
| Shoulder rate | c/kWh | 0.04 (as per domestic) | 0.05 | 20,000 MWh |
| Off-peak rate | c/kWh | 0.04 (as per domestic) | 0.025 | 25,000 MWh |

## F.5 The AER's assessment of reasonable estimates

When assessing the reasonableness of quantity estimates provided, the AER will take the following information into account:

1. the actual quantities sold in relevant units under the origin network tariff in previous years

2. a forecast of the number of distribution customers that the DNSP states will move to the new network tariff and/or network tariff component, and the reasons for the move

3. a forecast of the number of distribution customers that the DNSP expects will remain on the origin network tariff

4. a forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that are to be moved to the new network tariff and/or network tariff component

5. a forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that will remain on the origin network tariff

6. a forecast of the distribution tariff, and associated revenue, the DNSP expects will be payable by those distribution customers that will be moved the new network tariff and/or network tariff component

7. a forecast of the distribution tariff, and associated revenue, the distributor expects will be payable by those distribution customers that will remain on the origin network tariff

8. the materiality of the reasonable estimates

9. further information as required by the AER.

# Appendix G: Cost escalators

## G.1 Introduction

In recent decisions for electricity TNSPs (including Powerlink, SP AusNet and ElectraNet) the AER has allowed capex and/or opex allowances to be escalated in real terms for input cost increases.[453] This involves the disaggregation of expenditure allowances into specific inputs (e.g. labour, land and materials) which are priced in terms of a base year. These base year costs are increased or decreased for each year of the regulatory control period relative to changes in the nominal price level, which is taken into account when prices and revenues are adjusted at the aggregated level under the CPI–X control mechanism.

The methodology employed to determine the cost escalators generally combines independent forecast movements in the price of input components with 'weightings' for the relative contribution of each of the components to final equipment/project costs. This in turn generates real capex and opex forecasts for the regulatory control period. The weightings are typically specific to each regulated business given differences in composition of their respective expenditure forecasts.

The underlying objective of real cost escalations was to take account of the commodities boom and skills shortages in the engineering field in Australia. In light of these external factors, it was considered that cost escalation at CPI no longer reasonably reflected a realistic expectation of the movement in some of the equipment and labour costs faced by electricity network service providers (NSPs).[454] It was also communicated by the AER at the time of allowing real cost escalations that the regime should symmetrically allow for real cost decreases.[455] This was to allow end-users to receive the benefit of real cost reductions as well as facing the cost of real increases.

Given that there is no futures market for the procurement and installation of electrical equipment (e.g. transformers, switchgear), in previous decisions cost escalations have been estimated with reference to the expected growth in key input 'cost factors' such as:

- copper
- aluminium
- crude oil
- construction costs
- electricity, gas and water (EGW) sector labour costs
- land/easement costs

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453 AER, *Final Decision – Powerlink revenue cap*, pp. 60–70;
AER, *Draft Decision – SP AusNet transmission determination*, pp. 87–91, 316–331;
AER, *Final Decision – ElectraNet transmission determination*, pp. 29–48.

454 NER, clause 6A.6.7(c)(3).

455 AER, *Final Decision – SP AusNet transmission determination,* p. 80.

- other inputs (such as steel) were escalated at CPI.

During its revenue reset process, ElectraNet engaged the Competition Economists Group (CEG) to develop forecasts for each of the above cost factors for materials and used them to escalate its proposed capex program. In its final decision, the AER accepted its consultant Sinclair Knight Merz's (SKM) recommendation that CEG's proposed real cost escalators for materials are reasonable, subject to a number of adjustments.[456] In particular the AER accepted SKM's recommendations that:

- London Metal Exchange (LME) forward contract prices (i.e. 27 months) provide the best estimate of the price of aluminium and copper for a relevant future date
- monthly average futures prices should be used rather than a single day price
- Consensus Economics' 5−10 year forecasts for aluminium and copper prices represent the best available long-term forecast
- CEG's proposed adjustment to the long-term Consensus Economics aluminium and copper forecasts to reflect the higher LME futures forecast prices is not reasonable
- for the purposes of interpolation, Consensus Economics' 5−10 year forecast for aluminium and copper prices should be interpreted as the mid-point of 7.5 years, rather than 10 years as proposed by CEG.

The AER has been mindful of the arguments presented and conclusions reached in its determination for ElectraNet when assessing ActewAGL's proposal. This appendix presents the AER's assessment of the methodology and data sources for the proposed escalators. Where possible, the values of the escalators presented here will be updated at the time of the AER's final decision and determination.

## G.2 Labour cost escalators

This section discusses the real labour cost escalations proposed by ActewAGL to apply to its forecast capex and opex allowances over the next regulatory control period. The proposed labour cost escalators fall into two categories:

- electricity, gas and water (EGW) or utility sector-specific labour cost forecasts
- general labour cost forecasts.

These two categories of labour costs are discussed separately below.

### G.2.1 Electricity, gas and water (EGW) sector labour escalators

**SKM/ActewAGL**

ActewAGL obtained advice from SKM on annual labour escalators for the utility sector in the ACT.[457] SKM compared labour forecasts produced by Access Economics, BIS Shrapnel and Econtech for the Australian utility sector. SKM

456 AER, *Final Decision – ElectraNet transmission determination*, pp.29–48.
457 SKM, *Cost escalation factors*.

recommended that ActewAGL adopt the national forecast produced by Econtech[458] for the Australian utility sector as an appropriate estimate of labour cost growth in the utility sector in the ACT.

SKM noted that Econtech's report predicted that the ACT's overall labour cost growth rates would track in line with the Australian national average for the 2005–06 to 2015–16 forecast period. SKM therefore considered the national labour cost growth rates for the utility sector could be considered as an appropriate forecast for labour costs in the ACT.[459] The labour escalators adopted by ActewAGL as a measure of wage growth in the utility sector in the ACT are set out in table G.1.

**Table G.1: SKM's real wage growth rate for the EGW sector in the ACT (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| ACT | 2.1 | 2.9 | 5.1 | 4.4 | 3.6 | 3.3 | 3.0 |

Source: ActewAGL proposal, p. 170
Note: The AER has calculated the real escalator using the CPI forecasts provided by SKM on 12 September 2008.

**Econtech**

The AER engaged Econtech to provide advice on wage forecasts for the EGW sectors in NSW, ACT and Tasmania.[460] Econtech's labour cost growth rates for these sectors in NSW, Tasmania, the ACT and nationally are shown in table G.2.

**Table G.2: Econtech's real labour escalation rates for the EGW sector (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| NSW | 1.2 | 2.8 | 3.9 | 3.4 | 3.0 | 2.8 | 2.1 |
| Tasmania | -3.0 | 2.0 | 2.9 | 2.8 | 2.5 | 2.4 | 1.9 |
| ACT | 9.4 | 2.0 | 3.7 | 3.6 | 3.3 | 3.1 | 2.4 |
| Australia | -0.8 | 2.2 | 3.3 | 3.1 | 2.8 | 2.6 | 2.1 |

Source: Econtech, *Forecasts of labour cost growth forecasts 2007/08 to 2016/17*, 19 September 2008, p. 25 and p. 10–12 in appendix D.

Econtech determined these forecasts using an updated version of the model it developed for its report to the AER in August 2007. In particular, the forecasts provided by Econtech incorporate:[461]

- a simplified, but enhanced approach to labour cost forecasting

458 Econtech, *Labour cost growth forecasts*, 13 August 2007.
459 SKM, *Cost escalation factors*, p. 47.
460 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, 19 September 2008. Econtech is an economic consulting firm that specialises in economic modelling, forecasting and policy analysis. Econtech merged with KPMG in August 2008.
461 Econtech, *Labour cost growth forecasts*, p. 4.

- national accounts data from December 2007 (which was published by the Australian Bureau of Statistics (ABS) in March 2008)
- average weekly earnings data obtained by request from the ABS in August 2008
- policy measures introduced in the 2008–09 federal budget
- an extension of the forecast period from 2015–16 to 2016–17.[462]

These forecasts are broadly consistent with Econtech's national forecasts. Over the next regulatory control period, Econtech has forecast an average growth rate of 2.8 per cent (real) for the NSW utilities sector, 2.3 per cent (real) for the Tasmanian utilities sector and 3.0 per cent (real) for the ACT utilities sector. In comparison, the forecast average growth rate for the utility industry in Australia is 2.6 per cent (real).

Econtech made the following observations on the utility sectors in NSW, Tasmania and the ACT:[463]

- The forecast annual wage growth for the utility sectors in NSW, Tasmania and the ACT are expected to be higher than the all-industry average over the forecast period.
- The shortage of skilled workers in the utility sectors continues to be a significant driver of labour costs. Electrical and engineering professionals are included in the Department of Education, Employment and Workplace Relations (DEEWR) "Skill Shortage List" for NSW, Tasmania and the ACT.
- A number of initiatives have been introduced to increase the supply of skilled workers. For example, the Australian Government, through its Skilling Australia Policy, will provide 450,000 new training places over the next four years. However, most of these initiatives represent a long-term solution and are therefore not expected to have a material impact in the short-term.
- The Australian Government has put in place a number of initiatives to lift permanent and temporary migration. Such initiatives have the potential to relieve skills shortages in the short-term, however, there are concerns over the ability of this additional labour to meet industry demand.
- An aging workforce in the utility industry may also put further strain on the supply of skilled labour.
- The fact that electricity, gas and water are essential services means that businesses have a greater imperative to attract and maintain skilled workers, and are more likely to absorb wage increases in order to maintain labour supply.
- The utility industry has had difficulty in retaining skilled staff due to demand booms in related industries. The utility industry employs a large proportion of electricians, electrical and other engineers which are occupations also employed extensively by the construction and mining industries.

462 Econtech, *Labour cost growth forecasts* 19 September 2008, p. 4.
463 Econtech, *Labour cost growth forecasts* 19 September 2008, pp. 22–23 and 36–37.

**AER considerations**

The AER has examined the forecasts of real wages growth for the utility sector in the ACT put forward by SKM against the latest Econtech EGW forecasts for the ACT.

The AER does not consider that the SKM proposed labour cost growth rates provide an accurate reflection of the likely future labour wage trends in the ACT. In particular, the AER notes Econtech's advice that since it provided forecasts of labour cost growth rates to the AER in August 2007, the economic climate has changed considerably, resulting in some pressure being taken off labour cost escalation.[464]

The AER notes that SKM concluded that the Australian wage growth rate in the utility sector could be used as a measure of wage movements in the utility sector in the ACT, because there was a correlation in predicted movements between the ACT average wage growth rate and the Australian average wage growth rate.

While there may not be a significant variation between the national and ACT forecast for wages growth in the utility sector, the AER is of the view that where available an ACT specific forecast should be used as it is likely to be a better predictor of future trends in wages growth in the utility sector in the ACT.

For these reasons the AER does not consider SKM's proposed labour cost growth rates for the EGW sector in the ACT provide reasonable inputs to deriving the efficient costs a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, as required by clause 6.5.6(c). Accordingly, the AER will apply Econtech's ACT labour cost forecasts to ActewAGL's opex and capex proposals from 2008–09.

The AER notes that ActewAGL also operates under an EBA which expires in 2008. ActewAGL advised that for 2007–08, the actual wage increase under its EBA was 4 per cent (nominal).[465] Given that the actual wage data is available for 2007–08, the AER will apply the actual wage increase provided for under ActewAGL's EBA.

**AER conclusions**

The AER's conclusion on wage forecasts for the ACT is set out in table G.3. On average, the Econtech labour cost growth forecasts are lower than the SKM forecasts for the ACT during the next regulatory control period. This is largely because the economic climate has changed considerably since the last Econtech forecasts provided to the AER in 2007, resulting in some pressure being taken off wages growth.

[464] Econtech, *Labour cost growth forecasts* 19 September 2008, p. 42.
[465] ActewAGL, response to AER request for information, confidential, submitted 17 September 2008.

**Table G.3: AER's conclusion on the ACT EGW real labour growth rates (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average |
|---|---|---|---|---|---|---|---|---|
| AER/ ActewAGL EBA | –0.5 | 2.0 | 3.7 | 3.6 | 3.3 | 3.1 | 2.4 | 3.2 |

Source: Econtech, *Forecasts of labour cost growth forecasts 2007/08 to 2016/17*, appendix D, 19 September 2008, p. 12.
Note: The AER derived the real EBA rate by using the actual CPI for 2007–08 of 4.5 per cent. The average is calculated for 2009–10 to 2013–14 (the next regulatory control period)

The AER considers that the application of the Econtech forecast for wages growth in the EGW sector for the ACT reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve its capex and opex objectives, as required by clause 6.5.6(c).

## G.2.2 General labour escalators

**SKM/ActewAGL**

SKM has used a general wage forecast from Econtech's report prepared for the AER for the SP AusNet revenue reset in August 2007.[466] SKM's proposed general wage forecasts are outlined in table G.4.

**Table G.4: SKM's real wage growth rate for general labour (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| General wage | 1.8 | 2.1 | 2.8 | 2.6 | 2.4 | 2.3 | 2.0 |

Source: SKM, *Capital works project cost escalation factors for the period 2007/8–2013/14*, 23 May 2008, p. 63.
Note: The AER has derived this real escalator using the CPI forecasts provided by SKM on 12 September 2008.

Similar to the CEG approach applied for other NSPs, ActewAGL has applied SKM's general labour to the indirect labour costs incurred by manufacturers of equipment. ActewAGL has stated:

> General Labour is considered the most appropriate to model the labour component of manufacturing and other off-site labour based activities.[467]

The AER sought more information on the general labour escalator used by ActewAGL. It described this escalator as taking account of:

> …the different escalation rates in general and "site" (electrical field/construction) labour costs, with manufacturing and office based (eg. design) tending to escalate at different rates. SKM considered it was

[466] Econtech, *Labour cost growth forecasts,* 13 August 2007.
[467] ActewAGL, responses to AER cost escalation questions, 26 August 2008, p. 6.

appropriate to build into the analysis and models the capability to differentiate these two labour costs.[468]

**AER considerations—direct labour costs**

The AER accepts that a general labour cost forecast is appropriate to escalate direct labour costs (i.e. other than EGW) incurred by NSPs.

As part of its report to the AER, Econtech also provided advice on general wage forecasts for all industries across Australia. A comparison of Econtech's general wage forecast with the forecasts recommend by SKM is shown in table G.5.

**Table G.5: SKM and Econtech's real labour escalators for general wages (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average |
|---|---|---|---|---|---|---|---|---|
| SKM | 1.8 | 2.1 | 2.8 | 2.6 | 2.4 | 2.3 | 1.9 | 2.44 |
| Econtech | 0.6 | 1.0 | 1.1 | 0.7 | 0.7 | 0.8 | 0.6 | 0.78 |

Source: Econtech, *Labour cost growth forecasts*, p. 25, SKM, Capital works project cost escalation factors for the period 2007/8–2013/14, 23 May 2008, p. 63.
Note: The average is calculated for 2009–10 to 2013–14.

As can be seen from table G.5 there is a material difference between the general wage forecasts provided by SKM and Econtech's general wage forecasts.

The AER notes that the general wage forecasts used by SKM were taken from Econtech reports published in 2007. Econtech stated that, since it provided forecasts of labour cost growth rates to the AER in August 2007, the economic climate has changed considerably.[469]

The AER notes that Econtech's latest ANSIO for June 2008 also predicts a decline in average earnings for general wages.

Given the change in economic conditions since 2007, the AER does not consider that the general wage forecasts proposed by SKM are reasonable for the purposes of forecasting efficient input costs for the next regulatory control period required to meet the capex and opex objectives of the transitional chapter 6 rules.

Accordingly, where applicable the AER will apply Econtech's latest general wage forecasts to ActewAGL's opex and capex proposals.

**AER conclusions—direct labour costs**

The AER's conclusion on a general labour cost escalator is set out in table G.6.

[468] ActewAGL, email *ActewAGL – Followup on General Labour Cost Escalator*, 18 September 2008.
[469] Econtech, *Labour cost growth forecasts,* 19 September 2008, p. 5.

**Table G.6: AER's conclusion on real general wage growth (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average |
|---|---|---|---|---|---|---|---|---|
| AER | 0.6 | 1.0 | 1.1 | 0.7 | 0.7 | 0.8 | 0.6 | 0.8 |

Source: Econtech, *Forecasts of labour cost growth forecasts 2007/08 to 2016/17*, 19 September 2008, p. 25.

**AER considerations—indirect labour costs**

The AER notes that, based on SKM's advice, ActewAGL has applied the Econtech labour cost escalator to equipment cost inputs. This is intended to represent the labour costs incurred by the producers of manufactured equipment that is purchased by NSPs.

SKM stated that it has derived weightings for this component based on:

> …a combination of information generated through strategic procurement study, through consultation with industry, and through an application of SKM's own internal experience.[470]

The AER considers that the introduction of a labour component in equipment costs is inappropriate as it:

- represents a movement beyond the AER's obligation to provide regulated businesses a reasonable opportunity to recover efficient cost towards providing compensation for changes in input costs at a very fine level of detail. The AER considers it sufficient to monitor whether the cost of finished goods, as opposed to the component parts, need to be escalated above or below CPI
- is not supported by robust data.

The AER notes that some amount of producers' labour costs will already be embedded in the NSPs' base cost estimates of equipment (i.e. as at 30 June 2007). However, what is questionable is the extent to which the existing producers' labour costs embedded in base costs are expected to change in real terms over the next regulatory control period, and if a real change is expected, how to reliably measure it.

The data used by SKM assumes that Australian manufacturing conditions (as measured in the ABS input-output tables) and wage growth rates are the same as in those countries where equipment is purchased from. It also assumes that labour and other factor productivity is held constant. These issues have not been addressed by SKM to substantiate its recommended position. The AER also notes that this escalator appears to not be consistently applied across ActewAGL's capex program. No reason was offered by ActewAGL/SKM in its explanation of the methodology.[471]

**AER conclusions—indirect labour costs**

The AER does not accept the producer wage cost escalator proposed by SKM as it does not meet the underlying objective for inclusion in forecast costs under clause 6.5.7(c) of the NER. On the basis of the information presented, the AER is not

[470] ActewAGL, email *ActewAGL – Followup on General Labour Cost Escalator*, 18 September 2008.
[471] ActewAGL, email *ActewAGL – Followup on General Labour Cost Escalator*, 18 September 2008.

satisfied that expenditure associated with a real escalation of indirect labour costs is required to meet the capex and opex criteria.

## G.3 Materials cost escalators

This section discusses the real materials cost escalators proposed by ActewAGL to apply to its forecast expenditure allowances over the next regulatory control period. The proposed materials cost escalators are as follows:

- copper and aluminium
- steel
- crude oil
- exchange rates (used to develop the materials cost escalators)
- producer margins
- construction costs (includes labour and materials costs).

These cost escalators are discussed separately below.

### G.3.1 Aluminium and copper

**ElectraNet transmission determination**

Following the AER's draft decision which rejected ElectraNet's non-labour (materials) cost escalators, ElectraNet engaged CEG to develop forecast materials cost escalators for its capex program.

In determining escalators for aluminium and copper CEG used London Metal Exchange (LME) actual and futures prices of these base metals for the period up to June 2009. From this point CEG determined forecasts through a straight-line interpolation between the latest available LME forecast and Consensus Economics' long-term forecast. The Consensus Economics' long-term forecast used in the calculation was adjusted by CEG to reflect the difference between the price forecast for April 2010 (as implied by the 27-month LME futures price as at January 2008) and the mean Consensus Economics forecast for March 2010—an approach CEG considered to be consistent with the view that futures prices provides the most reliable forecasts of metals prices.[472]

SKM, in its final report for the AER, commented that applying an upward adjustment to Consensus Economics' long-term forecasts detracts from the economic assumptions made by forecasters and that they would have considered the latest market information (such as LME forward contracts) in their forecasts.[473] SKM consequently recommended that the upward adjustments be removed from the calculation of escalators for aluminium and copper.

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[472] In this case, CEG adjusted Consensus Economics' long-term forecasts for aluminium and copper by 9 per cent and 18 per cent respectively.

[473] SKM, *ElectraNet Transmission Network Revised Revenue Proposal 2008-2013*, 24 April 2008.

In its final decision the AER accepted SKM's recommendation to not adjust Consensus Economics' long-term aluminium and copper price forecasts. It also accepted SKM's recommendations that:

- LME forward contract prices provide the best estimate of the price of aluminium and copper for a relevant future date
- a monthly average futures price be used rather than the single day futures price
- the interpolation of the Consensus Economics' long-term price forecast should be to the mid-point of 7.5 years, rather than 10 years.

For further discussion of these issues see chapter 3 of the AER's final decision for ElectraNet.[474]

**SKM/ActewAGL**

ActewAGL engaged SKM to assist it in the development of its aluminium and copper cost escalators.

SKM used two data sources to develop its aluminium and copper price forecasts:

- LME actual prices to March 2008, then forward contracts (3, 15 and 27 months) for short-term price forecasts out to June 2010
- Consensus Economics 'long-term' price forecasts from July 2010 to 2015.

The SKM view that in the short-term LME forward contract prices provide the best estimate of the price of aluminium and copper for a relevant future date is consistent with the approach taken by CEG in developing copper and aluminium escalators for TransGrid, Transend and the NSW DNSPs.[475]

The Consensus Economics report provides a single mean price forecast of long-term aluminium and copper prices (among other commodities), which it developed from a survey of over 20 commodity price forecasters. SKM assumed 'long-term' to represent a period of 7.5 years into the future (the mid-point of the 5 to 10 year period specified as long-term by Consensus Economics).

SKM interpolated the LME forecasts as at June 2010 with Consensus Economics' long-term forecast to create a full data set over the relevant forecasting period. This approach by SKM is consistent with that determined by the AER in its ElectraNet transmission determination.

SKM's/ActewAGL's proposed real copper and aluminium cost escalators for the 2007–14 period are presented in table G.7.

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474 AER, *Final Decision – ElectraNet transmission determination*.

475 CEG, *NSW Electricity Businesses*, April 2008, pp. 11–25;
CEG, *Escalation factors affecting expenditure forecasts — A report for Transend*, April 2008, pp. 11–25.

**Table G.7: SKM's/ActewAGL's proposed real cost escalators for copper and aluminium (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| Copper | 28.81 | –0.83 | –8.19 | –5.91 | –7.78 | –8.35 | –9.03 |
| Aluminium | 10.20 | –6.53 | –2.32 | –1.02 | –2.18 | –2.29 | –2.42 |

Source: ActewAGL email dated 12 September 2008 "Attachment A – weightings from SKM to AER. xls". Converted to real percentage changes using SKM's CPI from *Capital Works Project Cost Escalation Factors for the period 2007/8–2013/14,* 23 May 2008, p. 54.

**AER considerations**

The AER notes that the SKM approach to forecasting copper and aluminium cost escalators is consistent with that accepted in the ElectraNet final decision. This involves a linear interpolation between the LME forecasts and the Consensus Economics' long-term forecast, which the AER considers to be a reasonable approach to merge the short-term LME data with Consensus Economics long-term forecasts. The AER therefore accepts the copper and aluminium cost escalators proposed by SKM but has used updated data for this draft decision.

**AER conclusions**

The AER considers SKM's approach to determining forecast copper and aluminium prices produces forecasts that reflect a realistic expectation of input costs, required to meet the capex and opex objectives of the transitional chapter 6 rules, over the next regulatory control period. This approach involves using LME futures prices up to 2010 and the long-term Consensus Economics forecast (7.5 years), with interpolation between the two data sources.

Based on September/October 2008 data for this draft determination, the AER's conclusions on real copper and aluminium escalators for the 2007–14 period are presented in table G.8. The AER will use updated LME and Consensus Economics data for its final determination.

**Table G.8: AER's conclusions on real copper and aluminium cost escalators (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| Copper | –6.3 | –13.5 | 0.3 | 1.4 | –5.6 | –6.3 | –7.0 |
| Aluminium | –6.3 | –7.0 | 7.5 | 9.3 | –0.8 | –1.3 | –1.6 |

## G.3.2 Steel

**SKM/ActewAGL**

SKM stated that although the LME commenced trading in small quantities of steel futures in 2008, the authority of the prices depicted within the limited futures market remains doubtful for the time being. SKM cited a number of recent global events and conditions which it suggests will place upward pressure on world steel prices. It noted

that it is likely that steel prices will rise in the short-term, with knock-on effects for related materials.[476]

Despite this expectation, SKM has concluded that, given the lack of reliable forward contract prices and the difficulty in accurately forecasting steel prices, the most reasonable approach is to assume a zero real escalation factor for the steel component of its cost escalation model.

**AER considerations**

The AER notes SKM's recommendation of zero real escalation for steel input cost factors is consistent with the approach applied by the AER in its 2008 transmission determination for ElectraNet.[477] This approach was accepted by the AER, based on advice provided by SKM and recognising the limited availability of forecast steel prices at the time.

The AER has since reviewed the Consensus Economics data which presents international market expectations of future HRC steel prices. The AER considers that an average of Consensus Economics' US and European forecasts provides a reasonable approximation for the future price of HRC steel. The AER will, however, reconsider the appropriateness using forecasts for these markets should a more direct and robust source arise in the future.

The HRC steel component has been weighted at 100 per cent in deriving the fabricated steel escalator to apply to the cost estimation process.

In accordance with its preference to use updated data where possible, the AER's final determination will incorporate updated Consensus Economics data when the determination is published in April 2009. Using data published at the time of this draft decision, the AER's conclusion on fabricated steel escalators is set out at table G.9.

**Table G.9: AER's conclusion on real fabricated steel escalators (per cent)**

| | 2007−08 | 2008−09 | 2009−10 | 2010−11 | 2011−12 | 2012−13 | 2013−14 |
|---|---|---|---|---|---|---|---|
| AER | 53.8 | –3.7 | –0.6 | –3.4 | –2.5 | –3.0 | –3.4 |

## G.3.3 Crude oil

**SKM**

SKM proposed using the New York Mercantile Exchange (NYMEX) crude oil light futures price as a reliable predictor of future crude oil prices but stated that the data should be averaged over 20 trading days.[478] SKM's/ActewAGL's proposed crude oil escalators are illustrated in table G.10.

476 SKM, *Cost escalation factors*, p. 26.
477 AER, *Final Decision – ElectraNet transmission determination*, p. 46.
478 SKM, *Cost escalation factors*, p. 30.

**Table G.10: SKM/ActewAGL real crude oil escalators (per cent)**

| | 2007−08 | 2008−09 | 2009−10 | 2010−11 | 2011−12 | 2012−13 | 2013−14 |
|---|---|---|---|---|---|---|---|
| AER | –11.1 | 44.2 | –7.8 | –3.5 | –1.2 | –1.1 | –0.9 |

Source: ActewAGL email 12 September 2008 "Attachment A- weightings from SKM to AER.xls". Converted to real percentage changes using SKM's CPI from, *Capital Works Project Cost Escalation Factors for the period 2007/8 – 2013/14*, 23 May 2008, p. 54.

**AER considerations**

The AER considers that SKM's recommended approach is an appropriate forecasting method and notes that this is consistent with the approach accepted by the AER in its recent transmission determination for ElectraNet. The AER has taken a 20-day average of daily NYMEX crude oil light futures prices using updated data.[479]

The AER converted the NYMEX forecasts into real Australian dollars using:

- Econtech's forecast exchange rate (see section G.3.4 below), and
- The AER's methodology for forecast inflation (see chapter 12 of this draft decision).

**AER conclusions**

The AER accepts SKM's recommended method for forecasting crude oil escalators produces forecasts that reflect a realistic expectation of input costs, required to meet the capex and opex objectives of the transitional chapter 6 rules, over the next regulatory control period.. In accordance with the AER's preference to use the most recent data where possible, the AER's final determination will incorporate updated NYMEX data when the determination is published in April 2009.

Using data published at the time of this draft decision, the AER's conclusion on crude oil escalators is set out in table G.11.

**Table G.11: AER's conclusion on real crude oil (per cent)**

| | 2007−08 | 2008−09 | 2009−10 | 2010−11 | 2011−12 | 2012−13 | 2013−14 |
|---|---|---|---|---|---|---|---|
| AER | 43.5 | –13.4 | 1.5 | 1.7 | 0.1 | –0.6 | –0.1 |

Source: AER analysis.

## G.3.4 Exchange rate

**SKM**

SKM proposed using Econtech's 2007 ANSIO report forecast of AUD/USD exchange rates, as set out in table G.12.

[479] The AER's sample period was between 22 September and 17 October 2008.

**Table G.12: SKM's proposal on AUD/USD exchange rate forecast, as at 1 July**

| | 2007−08 | 2008−09 | 2009−10 | 2010−11 | 2011−12 | 2012−13 | 2013−14 |
|---|---|---|---|---|---|---|---|
| AUD per USD | 0.85 | 0.88 | 0.88 | 0.87 | 0.85 | 0.84 | 0.83 |

Source: SKM, *Capital Works Project Cost Escalation Factors for the period 2007/8–2013/14,* 23 May 2008, p. 63.

**AER considerations**

The AUD/USD exchange rate forecasts are used to convert escalators based on futures/market prices (e.g. crude oil, steel prices etc) which are only quoted in US dollar terms.

Exchange rates are a particularly volatile economic variable, driven by numerous factors and are consequently notoriously difficult to forecast both in the short, medium and long-term. While the AER accepted the use of an Econtech exchange rate forecast in its recent ElectraNet transmission determination, it notes that the potential volatility of exchange rates brings any single source of forecast into question.

Table G.13 sets out Econtech's June 2008 AUD/USD exchange rate forecast.

**Table G.13: Econtech's AUD/USD exchange rate forecast, as at 1 July**

| | 2007−08 | 2008−09 | 2009−10 | 2010−11 | 2011−12 | 2012−13 | 2013−14 |
|---|---|---|---|---|---|---|---|
| AUD per USD | 0.85 | 0.96 | 0.88 | 0.84 | 0.82 | 0.80 | 0.75 |

Source: Econtech, *ANSIO,* 22 June 2008, p. 110.

Events in recent months demonstrate the volatility of exchange rate movements, with the AUD/USD exchange rate peaking at US$0.98 on 16 July 2008 before falling back (by 42 per cent) towards US$0.69 on 17 October 2008. The peak in July was heavily influenced by positive sentiment towards the AUD driven by Australian/US interest rate differentials, strong commodity prices, the downturn in the US economy, housing market and US bank write-downs. The recent reduction resulted from negative sentiment on the AUD stemming from reductions in official interest rates and slowing commodity price growth.

The exchange rate forecasts proposed by SKM from Econtech use forecasts of an exchange rate at five points in time only through the next regulatory control period—that is, the exchange rate on 1 July of each year. However, irrespective of the accuracy of the Econtech's exchange rate forecasting, the very nature of a point in time forecast, particularly in a volatile market, is not necessarily likely to be representative of the AUS/USD exchange rate faced by businesses purchasing equipment throughout the next regulatory control period.

The AER notes that there is little apparent difference between Econtech's latest forecasts and those used as part of ActewAGL's proposal. However the AER considers that the most recent available data in Econtech's latest exchange rate forecast represents a reasonable expectation of the market conditions over the next regulatory control period.

**AER conclusions**

The AER considers that an exchange rate forecast prepared by Econtech at the time of the final decision will represent a realistic expectation of forecast exchange rates over the next regulatory control period. Using more recent data from this source, the AER's conclusion on the AUD/USD exchange rate forecast for this draft decision is set out in table G.14. The AER will obtain updated data from this source for its final determination.

**Table G.14: AER's conclusion on AUD/USD exchange rate forecast, as at 1 July**

| | 2007−08 | 2008−09 | 2009−10 | 2010−11 | 2011−12 | 2012−13 | 2013−14 |
|---|---|---|---|---|---|---|---|
| AUD per USD | 0.85 | 0.96 | 0.88 | 0.84 | 0.82 | 0.80 | 0.75 |

Sources: Econtech, *Australian National State and Industry Outlook,* 22 June 2008, p. 110.

## G.3.5 Producer's margin

**SKM/ActewAGL**

SKM has reviewed the use of a producer's margin in developing ActewAGL's materials cost escalations for the next regulatory period. SKM stated that while it is likely that a producer's margin currently exists, "it is not possible, in this instance, to accurately estimate the quantum of the impact"[480]. On this basis SKM has not recommended the inclusion of a producer's margin escalator over the period 2009-14.

**AER considerations**

As noted in section G.2, the AER considers that the introduction of a new producer's margin escalator is inappropriate as it is:

- inconsistent with the principle of the AER's allowing escalators in general, that being compensation for major cost increases above CPI as a result of the recent commodities boom, and also shortages in the Australian labour market, which have been identified as major cost drivers
- not supported by robust data.

Producers' margins will already be embedded in the NSP's base cost estimates (i.e. as at 31 June 2007). What is in question is the extent to which the existing producers' margins are expected to change in real terms over the forthcoming regulatory control period and, if a real change is expected, how to reliably measure it.

**AER conclusions**

The AER agrees with SKM's conclusion to not incorporate a producer's margin escalator as part of ActewAGL's expenditure proposal.

480 SKM, *Cost escalation factors*, p. 53.

## G.3.6 Construction costs

**SKM/ActewAGL**

ActewAGL obtained advice from SKM to forecast construction cost escalators.[481] SKM recommended that Econtech's engineering construction cost forecasts as an appropriate estimate of construction costs.[482] The SKM construction cost forecasts are outlined in table G.15.

**Table G.15: SKM's proposal on real construction cost escalators (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| SKM engineering | 0.3 | 0.7 | 0.8 | 0.5 | 1.0 | 1.6 | 2.3 |

Source: SKM, *Capital Works Project Cost Escalation Factors for the period 2007/8 – 2013/*, 23 May 2008, p. 50.
Note: The AER has derived the real engineering construction cost escalator using CPI forecasts provided by SKM on 12 September 2008.

**AER considerations**

The Econtech engineering construction cost forecasts used by SKM were obtained from the Construction Forecasting Council's (CFC) website. The AER has obtained updated engineering construction cost forecast from this source and deflated them by CPI in order to provide real forecasts.[483] The AER notes that there is no publicly available updated data on engineering construction costs from Macromonitor. The updated Econtech forecasts for engineering construction costs are shown in table G.16.

**Table G.16: Econtech's real engineering construction cost escalators (per cent, real)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average |
|---|---|---|---|---|---|---|---|---|
| Updated Econtech engineering | –0.3 | –1.9 | 0.4 | 1.2 | 1.1 | 1.0 | 1.0 | 0.9 |

Source: Construction Forecasting Council website http://www.cfc.acif.com.au/.
Note: The average is calculated for 2009–10 to 2013–14 (the next regulatory control period).
The figures provided on CFC's website take into account data and other information available up to 1 May 2008.

There is some difference between the construction cost forecasts provided by SKM and the updated Econtech construction cost forecast. Given the change in economic conditions since 2007, the AER considers that it is reasonable to adopt the updated Econtech construction cost forecasts as they reflect the most recent information and

481 SKM, *Cost escalation factors*, p. 50.
482 The Econtech forecast was obtained from the Construction Council Forecasting website at http://www.cfc.acif.com.au/. SKM did not provide any details of when it obtained the Econtech forecasts from the CFC website.
483 Econtech, *Australian National State and Industry Outlook*, 22 July 2006.

therefore are a reasonable expectation of movements in construction costs into the next regulatory control period.

Accordingly, the AER will apply the updated Econtech construction cost forecasts to ActewAGL's capex proposal.

**AER conclusions**

The AER's conclusion on forecast construction cost escalators is set out in table G.17.

**Table G.17: AER's conclusion on real construction cost escalators (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average |
|---|---|---|---|---|---|---|---|---|
| AER | –0.3 | –1.9 | 0.4 | 1.2 | 1.1 | 1.0 | 1.0 | 0.9 |

## G.4 Lag in application of escalators

In its draft decision for the SP AusNet transmission determination, the AER reviewed a proposal from SKM to recognise a 1−2 year lag effect between base metals prices (i.e. copper, aluminium) and transmission equipment prices (i.e. power transformers, switchgear). Based on an analysis of the movements in base metals prices against relevant producer price indices (PPIs) published by the Australian Bureau of Statistics (ABS), the AER concluded that:

> On the balance of the available information SKM's assumption of a lag between movements in base metals prices and transmission equipment prices appears reasonable, however the AER considers that the lag is not likely to be greater than one year over the forthcoming regulatory control period.[484]

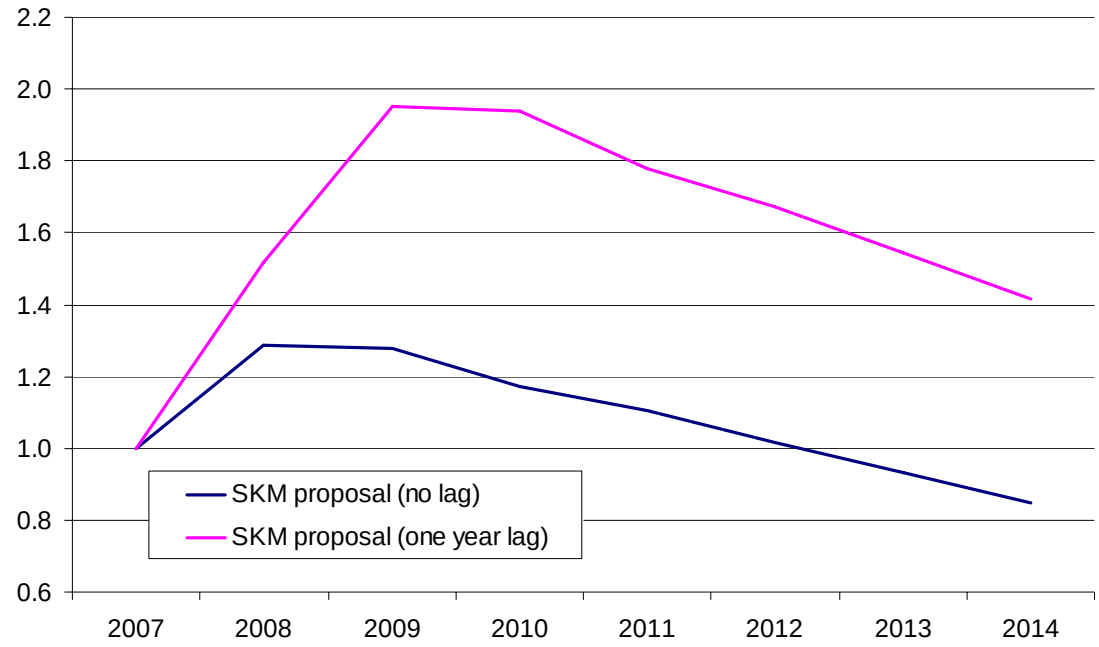
The effect of this was to 'shift' the peak in base metals prices from 2006−07 to 2007−08, on the assumption that movements in transmission equipment prices lag movements in base metals prices by twelve months.

ActewAGL and SKM have assumed a one year lag between commodity prices and the prices of finished products when developing certain cost escalators. SKM presents data which demonstrate a two lag between the prices of aluminium and copper conductor and cables and the prices of the relevant commodities.[485] This information is the same provided to the AER during its review of SP AusNet's transmission determination.

As figures G.2 and G.3 illustrate for copper and aluminium, the effect of the one year lag assumption is to significantly increase the real escalation for these inputs proposed by SKM over the 2007−14 period.

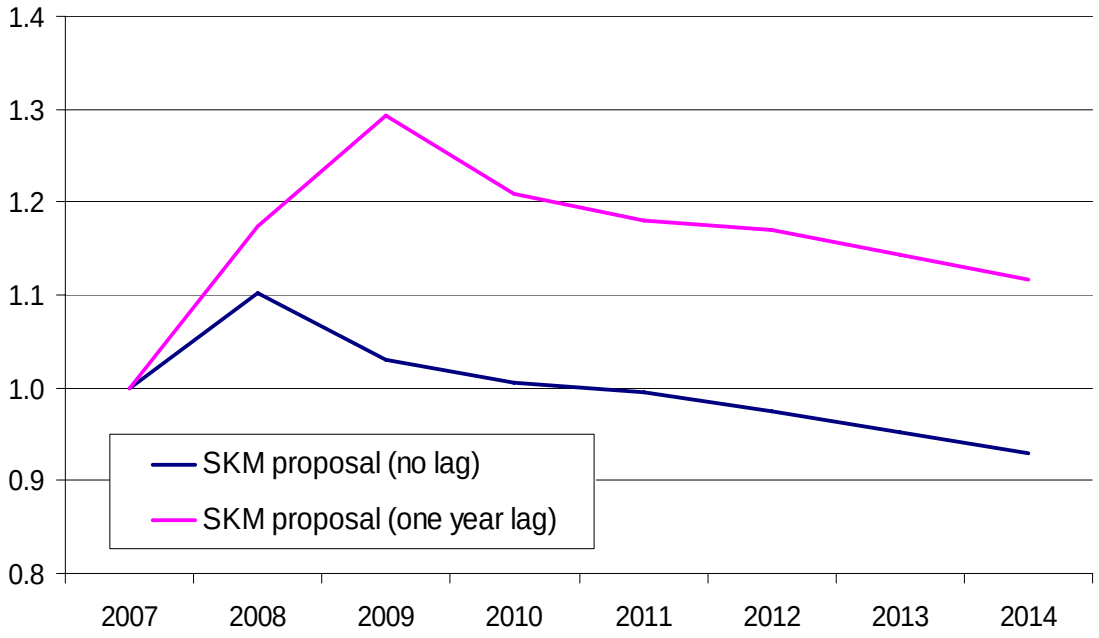
[484] AER, *Draft Decision – SP AusNet transmission determination*, p.90.
[485] SKM, *Cost escalation factors*, p. 39–41.

**Figure G.2: Copper price index (real $AUD, June 2009, base = 2007)**




Source: SKM[486]; AER analysis

**Figure G.3: Aluminium price index (real $AUD, June 2009, base = 2007)**




Source: SKM[487]; AER analysis

It is noted that neither SKM nor ActewAGL have presented any new evidence to justify a lag between movements in base metals and equipment prices. In particular, there has been no evidence presented to support a lag between movements in crude oil prices and electrical equipment prices.

[486] ActewAGL, email *AA Following up on information request dated 28 August regarding cost escalators*, 12 September 2008.
[487] ActewAGL, email, 12 September 2008.

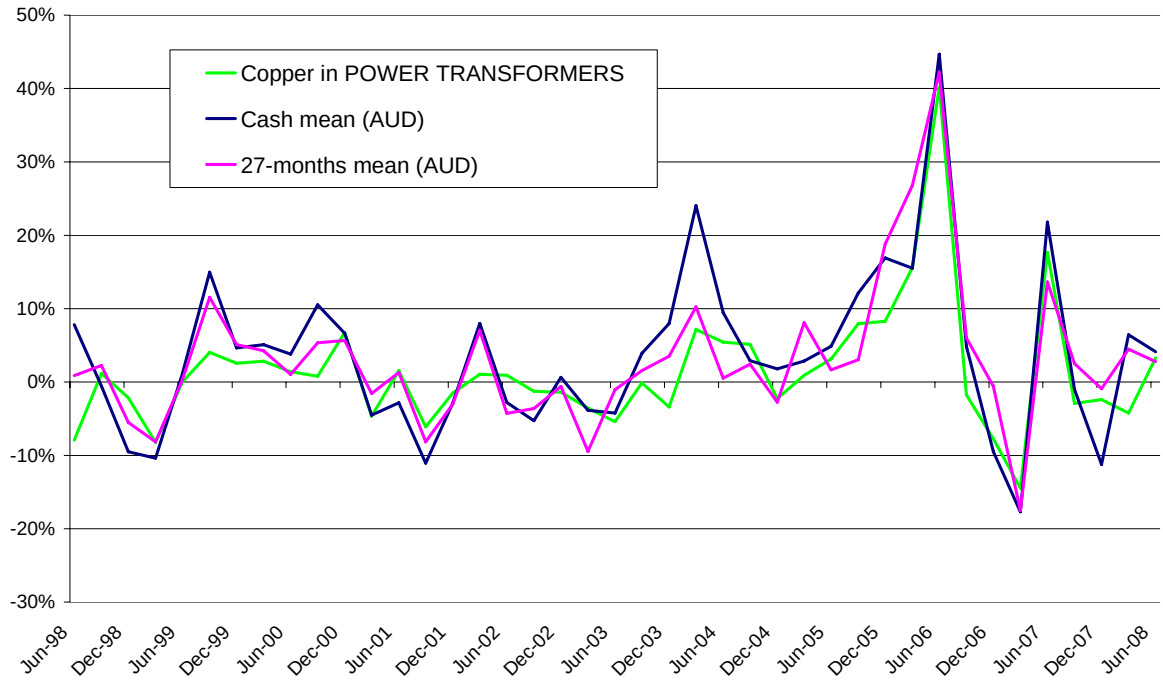
Therefore, given the lack of evidence to support the proposal, the AER is not satisfied that crude oil prices estimated through the application of a lag reflect the cost inputs required to achieve the capex and opex objectives over the next regulatory control period..

The AER has also re-examined the case for a one year lag application of base metals such as copper and aluminium escalators, using similar analysis to that presented in the SP AusNet transmission determination and taking account of further data that is now available. It is noted that at the time of the SP AusNet decision, the extent of a lag in the data was somewhat unclear, as noted by the AER:

> Overall, growth in the PPI appears to track growth in base metals prices quite closely after 2005, possibly indicating a greater flexibility built into contracts after this point in time. The data tends to suggest that any significant lag (i.e. >1 year) persistent over the period 2003-2005 may have been transitory, and has since subsided. Further, given that base metals prices are expected to return to around the long-run average over the period 2006-07 to 2013-14, the two indices may begin to track quite closely again (as in the pre-boom period 1998-2002).[488]

Figures G.4 and G.5 show the quarterly change in LME prices for copper and aluminium against ABS PPIs over the period 1998−2008.

**Figure G.4: LME and PPI copper prices – quarterly % change 1998–2007 (AUD, nominal)**

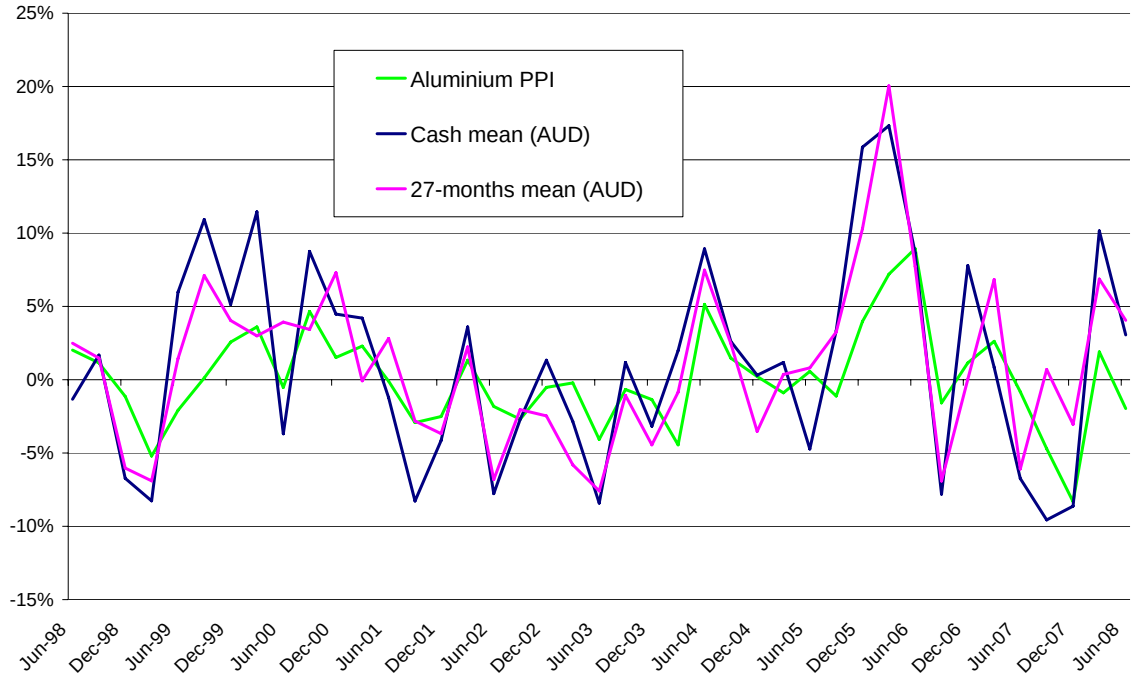



Sources: LME;[489] ABS[490]

[488] AER, *Draft Decision – SP AusNet transmission determination*, p.322

[489] LME, *Average Official and Settlement Prices US$/TONNE – Copper (cash mean, 27-month futures).* The latest data is for the quarter to 30 June 2008. The historical LME data is converted into Australian dollars using actual USD/AUD data from the RBA.

**Figure G.5: LME and PPI aluminium prices – quarterly % change 1998–2007 (AUD, nominal)**




Sources: LME;[491] ABS[492]

Although the PPIs examined are imperfect proxies for the electrical equipment purchased by network businesses, the AER considers that they provide a useful indicator of the relative growth rates at various stages of production.

Based on the data presented in figures G.4 and G.5, the AER does not consider that a lag between movements in base metals and electrical equipment prices is evident. While the two indices clearly do not have a one-to-one relationship, there is a strong correlation—both in the magnitude and timing of price increases. Any lag between movements in base metals and movements in the PPIs selected for analysis appears to be, at most, three to six months, which does not support the one year lags applied by ActewAGL.

On this basis the AER has revised its view from the SP AusNet decision, and now considers that there is no need to recognise a lag between movements in base metals prices and electrical equipment prices. Accordingly, the AER is not satisfied that copper and aluminium prices estimated through the application of a lag reflect the cost inputs required to achieve the capex and opex objectives over the next regulatory control period.

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490 ABS, *Producer Price Indexes, Copper Materials Used in the Manufacture of Electrical Equipment (Power Transformers)*, cat no: 6427.0, Table 47, Australia. The latest data is for the quarter to 30 June 2008.

491 LME, *Average Official and Settlement Prices US$/TONNE – Aluminium (cash mean, 27-month futures)*. The latest data is for the quarter to 30 June 2008. The historical LME data is converted into Australian dollars using actual USD/AUD data from the RBA.

492 ABS, *Producer Price Indexes, Indexes of Metallic Materials used in the Fabricated Metal Products Industry*, cat no: 6427.0, Table 30, Australia. The latest data is for the quarter to 30 June 2008.