Final decision

# Australian Capital Territory distribution determination

## 2009–10 to 2013–14

28 April 2009

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# 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 |
| draft decision | AER, *Draft decision, Australian Capital Territory distribution determination 2009–10 to 2013–14*, 7 November 2008 |
| draft distribution determination | AER, *ActewAGL Distribution draft distribution determination 2009–10 to 2013–14*, 7 November 2008 |
| final decision | AER, *Final decision, Australian Capital Territory distribution determination 2009–10 to 2013–14*, 28 April 2009 |
| 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 |
| NSW DNSPs | Country Energy, EnergyAustralia and Integral Energy |
| opex | operating expenditure |
| regulatory proposal | ActewAGL, *Distribution determination 2009–14, Regulatory proposal to the AER*, June 2008 |
| revised regulatory proposal | ActewAGL, *Distribution determination 2009–14, Revised regulatory proposal to the AER*, January 2009 |
| transitional chapter 6 rules | transitional provisions set out in appendix 1 of the NER |
| Wilson Cook | Wilson Cook & Co Limited |

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# 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 in the national electricity market (NEM).

The AER's distribution determination for ActewAGL for the 2009–14 regulatory control period is made under transitional provisions set out in appendix 1 of the NER (the transitional chapter 6 rules) which incorporate key aspects of the new general chapter 6 rules, but also locks in certain aspects of the current determination made by the ACT regulator, the Independent Competition and Regulatory Commission (ICRC).

## Review process

In making its determination, the AER assessed ActewAGL's regulatory proposal to determine if it was in accordance with the requirements of the transitional chapter 6 rules. Expert engineering consultants, as well as financial and economic experts, assisted the AER in making its assessment.

The AER released its draft decision and draft distribution determination for ActewAGL in November 2008. ActewAGL submitted a revised regulatory proposal in January 2009 indicating where it did not agree with the draft decision.

The AER received three submissions on its draft decision and ActewAGL's revised regulatory proposal. The AER's consideration of these submissions forms part of this determination.

In this final decision the AER specifically addresses those aspects of the draft decision that ActewAGL did not accept, or were raised in a submission by another party. Where an aspect of the draft decision was not addressed in the revised regulatory proposal or submissions then the determination made in the draft decision is confirmed in this final decision.

This final decision approves a capex allowance of $275 million. Specifically, this final decision takes account of the need for an additional $3.7 million in capex to meet the AER's future service standards reporting requirements, and $0.3 million to prepare IT systems for the ACT Government's new feed–in tariff scheme. It also provides a further $2.7 million to install new specialised metering equipment which will be needed under the feed–in tariff scheme. The need for these expenditures was considered in the draft decision. Updated material and labour cost escalators, to reflect the latest available information, are also included in this final decision. Reflecting the revisions to labour and materials cost escalators, the capex allowance is 0.7 per cent lower than that approved in the draft decision.

In the draft decision, the AER reduced ActewAGL's forecast opex proposal to $296 million ($2008–09). In its revised regulatory proposal ActewAGL sought reconsideration of aspects of its operating expenditure allowance and proposed a revised forecast opex allowance proposal of $359 million.

After assessing ActewAGL's revised regulatory proposal against the operating expenditure criteria in the transitional chapter 6 rules, the AER has determined that the operating expenditure allowance proposed is greater than the amount needed to meet the operating expenditure criteria in the transitional chapter 6 rules. For this final decision, the AER has determined an operating expenditure allowance of $341 million for ActewAGL for the next regulatory control period. The increase to the forecast opex allowance from the draft decision is largely driven by the inclusion of direct tariff payments under the feed–in tariff scheme.

## Outcome of regulatory process

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.

Higher prices will be largely driven by significant investment in four major capital projects. These projects include construction of two new zone substations, which are the first to be built in the ACT since 1994, augmentation of a third substation and construction of new assets to improve the security of electricity supply to the ACT. In addition, ActewAGL has already undertaken significant capital works to reinforce and replace a large number of unsafe poles, and these costs will now flow through to consumers. While consumers within the ACT will face higher charges as a result of this investment, they will also benefit from a more reliable and secure network.

In this final decision the AER estimates that retail charges will need to increase by 4.15 per cent in real terms in 2009–10. In addition to higher capital investment, increases in network charges are also being driven by the introduction of the feed–in tariff scheme, which imposes a cost on ActewAGL.

# Summary

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 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.

This final decision on the distribution determination for ActewAGL should be read in conjunction with the draft decision on the distribution determination for ActewAGL, together with the consultants' reports. Except as specified in this final decision, the AER maintains its conclusions set out in the draft decision.

The key components of this final decision are:

- the classification of services that will apply to ActewAGL for the next regulatory control period
- the arrangements for negotiation including those components of direct control services which are to be classified as negotiable components, the negotiable component criteria (NCC) and ActewAGL's negotiating framework
- the control mechanism for standard control services provided by ActewAGL
- confirmation of the prudence of capex undertaken by ActewAGL during the current regulatory control period
- the opening regulatory asset base (RAB) value for ActewAGL
- an assessment of ActewAGL's demand forecasts for the next regulatory control period
- an allowance for forecast capex for ActewAGL over the next regulatory control period
- an allowance for forecast opex for ActewAGL over the next regulatory control period
- an assessment of ActewAGL's estimated corporate income tax and updated tax asset base
- a decision on ActewAGL's depreciation schedules
- an estimate of the efficient benchmark weighted average cost of capital (WACC) for ActewAGL
- a decision on the service target performance incentive arrangements to apply to ActewAGL for the next regulatory control period
- a decision on the application of the efficiency benefit sharing scheme (EBSS) to ActewAGL for the next regulatory control period
- a decision on the demand management incentive scheme (DMIS) to apply to ActewAGL for the next regulatory control period

- the nominated pass through events that may apply to ActewAGL for the next regulatory control period
- the annual revenue requirement and X factors for ActewAGL for each regulatory year of the next regulatory control period
- the control mechanism for alternative control services provided by ActewAGL.

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

## Classification of services

### AER draft decision

The AER accepted ActewAGL's proposed classification of services as it aligns with that deemed under the transitional chapter 6 rules, and is based on the existing classification of services applied by the ICRC. The AER proposed procedures for ActewAGL to follow when assigning or reassigning customers to tariff classes.

### Revised regulatory proposal

ActewAGL sought confirmation from the AER that its decision on procedures for assigning or reassigning customers to tariff classes does not require ActewAGL to assign customers. ActewAGL was concerned that this would remove the freedom consumers and retailers currently have to select the most appropriate network charge.

### AER conclusion

In accordance with clause 6.12.1(1) of the transitional chapter 6 rules 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.

## Arrangements for Negotiation

### AER draft decision

The AER 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) in certain circumstances.

The AER's NCC for ActewAGL was set out in appendix B of the draft decision.

The AER approved ActewAGL's negotiating framework to apply for the next regulatory control period.

### Revised regulatory proposal

ActewAGL submitted that the AER rejected its proposed criteria for identifying negotiable components of direct control services, and replaced it with an alternative (as proposed by another DNSP) without establishing that ActewAGL's proposal is unreasonable and without establishing that the alternative would deliver better outcomes.

ActewAGL considered that its original proposed approach is consistent with the requirements of the transitional chapter 6 rules. ActewAGL stated that its original proposed approach is flexible, accommodates a wide range of possible circumstances and provides guidance for customers on services which are likely to be negotiable.

### AER conclusion

The AER has defined a negotiable component of a direct control service as any component of a direct control service (including the terms and conditions on which that direct control service or component is provided) where:

(a) the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation;

(b) 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

(c) 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,

but excludes, in relation to any component of a direct control service, requirements imposed under a regulatory instrument (other than this final decision and distribution determination).

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

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

The AER approves ActewAGL's proposed negotiating framework to apply for the next regulatory control period. The negotiating framework is in appendix C of this final decision.

## Control mechanism for standard control services

### AER draft decision

In the draft decision, the AER considered ActewAGL's proposed form of control mechanism for direct control services was compliant with the requirements of the transitional chapter 6 rules and the AER's standard control services guideline.

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

### Revised regulatory proposal

ActewAGL noted that the AER's example shown in appendix E of the draft decision incorporates interest that could be earned for regulatory years 1 (actual) and 3 (forecast). However, this formula omits year 2 and in doing so, ActewAGL was concerned that it may omit the interest that should be paid or earned in this year.

ActewAGL stated that the AER's formula for the side constraint draws upon the actual load in the previous financial year. ActewAGL considered that it would be more appropriate to apply the load for the previous calendar year to pricing and to calculate the side constraint.

ActewAGL submitted that the feed–in tariff payments it is liable to pay to retailers should be included in its forecast opex allowance. Related to this, it proposed that an annual pricing adjustment mechanism (with respect to standard control services) should be introduced to reconcile discrepancies between any forecast and actual feed–in tariff payments in a financial year.

### AER conclusion

The control mechanism for ActewAGL's standard control services is a maximum allowable average revenue cap to ActewAGL's standard control services.

In monitoring compliance with the control mechanism, side constraints and TUOS recoveries the AER will apply the requirements as set out in appendices D, E and F of this final decision.

## Past capital expenditure

### AER draft decision

The AER considered 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.

### Revised regulatory proposal

ActewAGL did not raise any issues regarding the AER's draft decision on its past capex. ActewAGL provided its actual capex for 2007–08 and an updated capex forecast for 2008–09.

### AER conclusion

The AER considers the total amount of $156.2 million in past capex is prudent and should be included in the opening RAB. The AER confirms its draft decision that all of ActewAGL's capex in the current regulatory control period was prudent and that the projects and programs undertaken were required, efficient and consistent with ActewAGL's policies and good industry practice. ActewAGL's updated capex incurred for the current regulatory control period 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 | 35.6 | 46.0 | 156.2 |

## Opening regulatory asset base

### AER draft decision

The AER determined ActewAGL's opening RAB to be $588 million for the next regulatory control period (as at 1 July 2009). The draft decision proposed to use actual depreciation to establish the opening RAB for the 2014–19 regulatory control period.

### Revised regulatory proposal

ActewAGL did not raise any issues regarding the draft decision on its opening RAB. ActewAGL's revised regulatory proposal referred to an opening RAB for the next regulatory control period of $592 million. While this amount incorporated an updated capex forecast for 2008–09 it did not include an update for actual 2007–08 capex as required by the draft decision.

### AER conclusion

To take into account the updated capex and consumer price index (CPI) data, the AER amends its draft decision and determines ActewAGL's opening RAB for the next regulatory control period to be $599 million (as at 1 July 2009). The RAB roll forward calculations are set out in table 2.

**Table 2: AER conclusion on 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 | 574.4 |
| Actual net capex[c] | 21.7 | 23.4 | 29.5 | 35.6 | 33.4 |
| CPI adjustment on opening RAB | 12.2 | 14.2 | 19.4 | 13.4 | 25.7 |
| Straight-line depreciation (adjusted for actual CPI) | –24.3 | –25.5 | –27.1 | –28.6 | –30.5 |
| Closing RAB | 520.2 | 532.3 | 554.1 | 574.4 | 603.1 |
| Adjustment for difference between actual and forecast capex for 2003–04 | | | | | –2.7 |
| Adjustment for return on difference[d] | | | | | –1.7 |
| Opening RAB at 1 July 2009 | | | | | 598.7 |

(a) Updated for actual 2007–08 capex.
(b) Updated for actual CPI for 2008–09 (sum of four quarters to December). Based on updated net capex forecast.
(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.

The AER will use actual depreciation for establishing the regulatory asset base for the commencement of the 2014–19 regulatory control period.

## Demand forecast

### AER draft decision

The AER stated that ActewAGL's maximum demand forecast methodology and forecasts set out in its regulatory proposal provided a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the transitional chapter 6 rules.

The AER also stated that ActewAGL's energy forecast methodology was reasonable, but rejected ActewAGL's energy forecast on the basis that the forecast should be updated to take into account the most recent energy sales data, for the financial year 2007–08.

### Revised regulatory proposal

ActewAGL provided revised maximum demand forecasts, accounting for revisions to economic growth forecasts as a result of the global financial crisis and changes to the Australian Government's climate change policies, including the release of the Carbon Pollution Reduction Scheme (CPRS) White Paper in December 2008. Aside from these changes, ActewAGL maintained the forecasting methodology it used to generate its original (June 2008) maximum demand forecasts, including the spatial forecasts at the zone substation level.

ActewAGL also provided a revised energy forecast for the next regulatory control period, incorporating energy sales data for 2007–08 and updated inputs relating to economic growth and the CPRS.

### AER conclusion

The AER considers that ActewAGL's revised maximum demand forecast provided in its revised regulatory proposal provides a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the transitional chapter 6 rules.

The AER considers the revised energy forecast provided to the AER on 25 March 2009, generated according to the AER's conclusions on the assumed price elasticity of demand, is an appropriate input to the post–tax revenue model (PTRM) under clause 6.12.1(10) of the transitional chapter 6 rules.

The AER's final decision on ActewAGL's energy forecast inputs to the PTRM are provided in table 3.

**Table 3: AER conclusion on ActewAGL's energy sales forecasts 2009–14 (GWh)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average annual growth 2009–14[a] |
|---|---|---|---|---|---|---|
| Energy forecast | 2933 | 2916 | 2908 | 2898 | 2889 | –0.1% |

(a) The average annual growth rate includes a 1.2 per cent forecast growth rate in year 2009–10.

## Forecast capital expenditure

### AER draft decision

The AER did not accept ActewAGL's proposed capex allowance of $286 million ($2008–09). It accepted the scope of the forecast program and the proposed investment decisions, however, it did not consider the forecast costs reasonably reflected the capex criteria. The AER made adjustments to ActewAGL's cost estimation methodology which resulted in a real net reduction of $8.6 million or around 3 per cent of its proposed capex.

### Revised regulatory proposal

ActewAGL's revised regulatory proposal sought a capex allowance of $298 million ($2008–09) for the next regulatory control period. ActewAGL's revised regulatory proposal has implemented the draft decision in respect of forecast capex, except in relation to cost escalation. In addition, it made the following adjustments:

- deferred some key projects due to revised peak demand forecasts (demand driven adjustments)

- included additional capex requirements to prepare for the AER's national distribution service target performance incentive scheme (STPIS)
- included additional capex requirements arising from feed–in tariff (FiT) scheme obligations.

### AER conclusion

The AER considers that the scope of the revised capex program, including demand driven adjustments, additional FiT and STPIS related expenditure, is reasonable. However, the AER is not satisfied that total forecast capex allowance 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 the capex objectives as provided for in the capex criteria at clause 6.5.7(c) of the transitional chapter 6 rules.

The AER does not accept the total capex allowance proposed by ActewAGL. The AER is therefore required to provide an estimate of the capex for ActewAGL over the next regulatory control period that it is satisfied reasonably reflects the capex criteria, including the capex objectives.

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 $275 million.

The AER's conclusion for ActewAGL's capex for the next regulatory control period is set out in table 4.

**Table 4: AER conclusion on ActewAGL's capex allowance for standard control services ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL's revised proposed capex (including demand driven adjustment) | 69.0 | 63.4 | 60.9 | 53.4 | 50.9 | 297.6 |
| Adjustments to cost escalators | –5.9 | –5.7 | –4.5 | –3.3 | –2.9 | –22.4 |
| Capex allowance | 63.1 | 57.7 | 56.4 | 50.1 | 47.9 | 275.2 |

Note: Totals may not add up due to rounding.

## Forecast operating expenditure

### AER draft decision

The AER did not accept ActewAGL's proposed opex allowance of $306 million ($2008–09). The AER made the following adjustments to ActewAGL's proposed opex allowance:

- reduced the labour cost escalators

- reduced the self insurance costs by $5.8 million
- reduced the proposed Utilities Network Facilities Tax (UNFT) allowance by $0.2 million.

### Revised regulatory proposal

ActewAGL did not accept the AER's conclusion on controllable opex and substituted an amount of $275 million ($2008–09). ActewAGL also provided revised opex estimates for non-controllable opex elements including: debt raising costs, equity raising costs, self insurance, and FiT scheme direct tariff payments.

### AER conclusion

The AER has considered ActewAGL's revised forecast total opex of $359 million ($2008–09) and is not satisfied that the total opex forecast proposed by ActewAGL reasonably reflects the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules, including the opex objectives.

The AER has applied a reduction of $18 million to ActewAGL's proposed opex. This represents a reduction of around 5 per cent of ActewAGL's proposed opex of $359 million and results in an amended forecast opex allowance of $341 million. This amended forecast opex allowance is higher than the amount approved in the draft decision because of the inclusion of the FiT scheme direct tariff payments. This amended 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) of the transitional chapter 6 rules.

The AER's adjustments to ActewAGL's forecast controllable opex allowance are set out in table 5. These adjustments reflect the AER's conclusion on an efficient controllable opex allowance.

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

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL's revised controllable opex | 53.0 | 54.0 | 54.9 | 56.6 | 56.3 | 274.8 |
| Adjustments to labour escalators | –1.5 | –1.9 | –1.7 | –1.6 | –1.6 | –8.3 |
| Controllable opex | 51.4 | 52.1 | 53.2 | 55.0 | 54.7 | 266.4 |

The amended total opex allowance is set out in table 6.

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

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL's revised proposed opex | | | | | | |
| Controllable opex | 53.0 | 54.0 | 54.9 | 56.6 | 56.3 | 274.8 |
| UNFT | 3.9 | 4.0 | 4.1 | 4.3 | 4.3 | 20.6 |
| Debt raising | 0.5 | 0.6 | 0.6 | 0.6 | 0.7 | 3.0 |
| Equity raising | 1.1 | 1.1 | 1.0 | 0.7 | 0.5 | 4.4 |
| Self insurance[a] | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 7.5 |
| FiT scheme direct tariff payments | 3.4 | 6.8 | 10.0 | 12.7 | 15.3 | 48.2 |
| ActewAGL's revised proposed total opex | 63.5 | 68.0 | 72.1 | 76.3 | 78.6 | 358.5 |
| AER total opex | | | | | | |
| Controllable opex | 51.4 | 52.1 | 53.2 | 55.0 | 54.7 | 266.4 |
| UNFT | 3.9 | 4.0 | 4.1 | 4.3 | 4.3 | 20.6 |
| Debt raising | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 1.8 |
| Equity raising[b] | – | – | – | – | – | – |
| Self insurance[a] | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 4.1 |
| FiT scheme direct tariff payments | 3.1 | 6.8 | 10.0 | 12.7 | 15.3 | 47.9 |
| Demand management innovation allowance[c] | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.5 |
| AER total opex | 59.7 | 64.2 | 68.6 | 73.3 | 75.7 | 341.4 |

Note: Totals may not add up due to rounding.
(a) Based on allocation for standard control services.
(b) The AER will allow ActewAGL to amortise a total of $0.3 million ($2008–09) for benchmark equity raising costs associated with forecast capex for the next regulatory control period.
(c) Refer to chapter 15 for details on this allowance.

# Estimated corporate income tax

## AER draft decision

The AER determined that each of the inputs proposed by ActewAGL that have been used in the PTRM to calculate the expected cost of corporate income tax is in accordance with the transitional chapter 6 rules. The AER considered that ActewAGL's proposed tax remaining and tax standard lives were appropriate. The AER also considered ActewAGL's proposed tax asset base of $473 million as appropriate and reasonable.

## Revised regulatory proposal

ActewAGL submitted a revised allowance for corporate income tax in its revised regulatory proposal. The method used by ActewAGL to calculate the income tax allowance was consistent with the draft decision. However, the proposed tax asset base was revised to $476 million as a result of a higher estimate of capex in 2008–09. The tax estimate for 2008–09 has been updated to reflect minor escalation changes to the 2008–09 forecast capex. On 4 March 2009 ActewAGL provided a further revised estimate of its proposed tax asset base of $475 million. This figure includes 2007–08 actuals for capex and tax depreciation rather than estimates.

## AER conclusion

The AER considers that ActewAGL's proposed tax remaining and tax standard lives are appropriate. The AER also considers the updated tax asset base of $475 million appropriate and reasonable. On the basis of these inputs, the AER has used the PTRM to calculate the allowance for corporate income tax as set out in table 7.

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

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Tax allowance | 4.7 | 5.5 | 5.7 | 5.4 | 5.6 | 26.9 |

# Depreciation

## AER draft decision

As a result of adjustments to include a more detailed breakdown of asset classes for ActewAGL's forecast capex, the AER did not accept ActewAGL's proposed depreciation schedule as it did not consider that the schedule complied with the transitional chapter 6 rules.

## Revised regulatory proposal

ActewAGL proposed a revised regulatory depreciation schedule in response to the draft decision, that reflected changes to its opening RAB and forecast capex.

### AER conclusion

As a result of required adjustments to asset life inputs, changes to the opening RAB and changes to the capex allowance, the AER has not approved the depreciation schedule proposed by ActewAGL in its revised regulatory proposal.

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER has determined ActewAGL's depreciation schedule. The depreciation schedule has resulted in a regulatory depreciation allowance for ActewAGL for the next regulatory control period as set out in table 8.

**Table 8: AER conclusion on ActewAGL's regulatory depreciation allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Regulatory depreciation allowance | 15.2 | 17.0 | 18.8 | 20.5 | 22.3 | 93.9 |

## Cost of capital

### AER draft decision

The AER determined a nominal vanilla WACC of 9.82 per cent for ActewAGL. The AER stated it would update the WACC to reflect movements in 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 decision.

### Revised regulatory proposal

In estimating the WACC for its revised regulatory proposal, ActewAGL proposed that the averaging period used to calculate the risk–free rate and debt risk premium be changed to eliminate the impacts of the global financial crisis. Consistent with this approach, ActewAGL adopted a new averaging period and revised the risk–free rate, debt risk premium and nominal vanilla WACC. ActewAGL rejected the use of just Bloomberg data to estimate the debt risk premium. ActewAGL also proposed a geometric average of the annual inflation rate over a 10–year period for calculating expected inflation.

### AER conclusion

The AER has determined a nominal vanilla WACC of 8.79 per cent for ActewAGL using an updated risk–free rate and debt risk premium, and other parameters prescribed under the transitional chapter 6 rules. Table 9 lists the WACC parameter values used for this final decision. The AER's WACC is lower than ActewAGL's revised regulatory proposal WACC because of a lower nominal risk–free rate—commensurate with monetary policy and softening in economic growth—adopted for this final decision.

**Table 9: AER conclusion on ActewAGL's WACC parameters**

| Parameter | AER's conclusion |
|---|---|
| Risk–free rate (nominal) | 4.29% |
| Risk–free rate (real)[a] | 1.77% |
| Expected inflation rate | 2.47% |
| Debt risk premium | 3.49% |
| Market risk premium | 6.00% |
| Gearing | 60% |
| Equity beta | 1.00 |
| Nominal pre–tax return on debt | 7.78% |
| Nominal post–tax return on equity | 10.29% |
| Nominal vanilla WACC | 8.79% |

(a) The real risk–free rate was calculated using the Fisher equation.

The AER considers that its decision to withhold agreement to the averaging period in ActewAGL's regulatory proposal is reasonable and that the agreed averaging period is consistent with finance theory, regulatory practice, the NER and NEL. The AER considers that the material provided by ActewAGL in support of its revised regulatory proposal does not justify that an averaging period prior to September 2008 is better than a period that is as close as practically possible to the start of the next regulatory control period.

The AER considers that only Bloomberg data should be used to estimate the debt risk premium based on its analysis of the fair yields reported by Bloomberg and CBASpectrum, observed yields of BBB+ corporate bonds and the methodologies adopted by these two data providers.

Having assessed ActewAGL's revised regulatory proposal, the AER agreed that a geometric average may provide for a more accurate estimate of expected inflation during the forecast period. The AER noted that the difference between applying a simple average and a geometric average is marginal.

The AER has maintained its draft decision to apply a methodology to determine a forecast inflation rate over a 10–year period using the RBA's inflation forecasts for the first two years and the mid–point of the RBA's target inflation range for the remaining eight years. The AER considered that, consistent with the draft decision, this methodology provides the best estimate of a 10–year inflation forecast to be applied in the post–tax revenue model for this final decision.

## Service target performance incentive arrangements

### AER draft decision

The AER decided it would collect and monitor ActewAGL's service performance data during the next regulatory control period. It also decided that revenue would not be placed at risk under the data collection process during this period.

As foreshadowed in the AER's final decision on the service target performance incentive scheme (STPIS) arrangements for the ACT and NSW determinations, the draft decision aligned data reporting requirements with the requirements of the national distribution STPIS, published on 26 June 2008.

The AER stated it expects ActewAGL to implement measures to achieve full compliance with the national distribution STPIS as soon as practical, but no later than December 2009.

### Revised regulatory proposal

In response to the draft decision data collection requirements, ActewAGL proposed to implement a 'network connectivity solution' to establish the ability to record interruptions at the individual customer level. However, it stated that the development of the network connectivity solution is a complex and lengthy project, and is not expected to be completed until 2013. Given this, it noted that full compliance with the data reporting requirements would not be achievable within the timeframe set in the draft decision.

### AER conclusion

The AER maintains its draft decision to collect and monitor ActewAGL's service performance data during the next regulatory control period. Revenue will not be placed at risk during this period.

The AER acknowledges that full compliance with the data reporting requirements will not be realised before December 2009. However, the AER expects ActewAGL to implement measures to achieve full compliance with the national distribution STPIS as soon as practical.

In implementing the data reporting requirements, the AER expects to accumulate a reliable data series to allow the application of the national distribution STPIS to ActewAGL from 1 July 2014.

## Efficiency benefit sharing scheme

### AER draft decision

The AER stated it will apply the EBSS released in February 2008 to ActewAGL for the next regulatory control period and outlined the opex cost categories to be excluded from the operation of the EBSS for the next regulatory control period.

## Revised regulatory proposal

In its revised regulatory proposal, ActewAGL stated that, in addition to the excluded cost categories listed in the draft decision, direct feed–in tariff payment costs and equity raising costs should also be excluded from the EBSS.

## AER conclusion

The AER will apply the EBSS released in February 2008 to 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 relating to defined benefit and retirement schemes
- the UNFT payments
- direct FiT scheme payments
- non–network alternatives costs.

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 10 will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.

**Table 10: AER conclusion on ActewAGL's forecast controllable opex for EBSS purposes ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Total forecast opex | 59.7 | 64.2 | 68.6 | 73.3 | 75.6 | 341.4 |
| Adjustment for debt raising costs | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 1.8 |
| Adjustment for self insurance | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 4.1 |
| Adjustment for insurance | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 3.8 |
| Adjustment for superannuation | 3.2 | 3.3 | 3.4 | 3.5 | 3.6 | 16.9 |
| Adjustment for UNFT payments | 3.9 | 4.0 | 4.1 | 4.3 | 4.3 | 20.6 |
| Adjustment for direct feed–in tariff payments | 3.1 | 6.8 | 10.0 | 12.7 | 15.3 | 47.9 |
| Adjustment for non–network alternatives | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.5 |
| Forecast opex for EBSS purposes | 47.5 | 48.1 | 49.0 | 50.7 | 50.3 | 245.7 |

Note: Numbers may not add up due to rounding.

# Demand management incentive schemes

## AER draft decision

The draft decision, subject to the agreement of ActewAGL (as the affected DNSP), was to amend the demand management innovation allowance (DMIA) published on 29 February 2008 by replacing it with the DMIA specified in the AER's *Demand management incentive scheme for the ACT and NSW distribution determinations,* (the replacement DMIA). The replacement DMIA was published concurrently with the draft decision.

## Revised regulatory proposal

ActewAGL provided its agreement that the original DMIA be replaced by the replacement DMIA for application to ActewAGL in the next regulatory control period. However, ActewAGL raised a number of issues with both the original and replacement DMIA schemes in its revised regulatory proposal.

## AER conclusion

The AER has maintained its draft decision to apply the replacement DMIA to ActewAGL in the next regulatory control period.

# Pass through arrangements

## AER draft decision

In the draft decision the AER accepted the proposed major natural disaster event as a nominated pass through event for ActewAGL but amended the proposed definition. The AER determined that ActewAGL's other proposed pass through events did not meet the AER's assessment criteria.

## Revised regulatory proposal

In its revised regulatory proposal ActewAGL rejected the draft decision not to accept the transitional period event as a nominated pass through event and submitted a revised definition of the major natural disaster event. ActewAGL also proposed the inclusion of a force majeure event. ActewAGL considered that this event captures some events not included in the major natural disaster event.

## AER conclusion

The AER has decided to nominate two types of nominated pass through events in ActewAGL's distribution determination:

- specific nominated pass through events to cover certain foreseeable events that can easily be defined
- general nominated pass through event to cover unforeseeable changes in circumstances falling outside of the normal operations of ActewAGL's business.

The AER has decided to nominate for ActewAGL a feed–in tariff direct payment event, a smart meter event, an emissions trading scheme event, and a general pass through event as defined in section 16.6 of this final decision:

The AER has decided not to nominate the other events proposed by ActewAGL as specific nominated pass through events.

## Building block revenue requirement

### AER draft decision

The draft decision resulted in a total revenue requirement over the next regulatory control period of $779 million, compared with $823 million proposed by ActewAGL.

In setting X factors to adjust revenues, the AER maintained ActewAGL's approach of achieving real annual increases of the MAAR of two per cent for years two to five of the next regulatory control period. The effect of the draft decision was therefore a reduction in the size of the X factor in year one.

### Revised regulatory proposal

ActewAGL's revised regulatory proposal was for a nominal total revenue requirement of $868 million over the next regulatory control period.

ActewAGL proposed X factors of –28.69 per cent (i.e. a real increase) for the first year of the regulatory control period and –2.00 per cent for subsequent years. This results in the NPVs of the revenue requirements and expected revenues being equal over the regulatory control period as shown in table 12. ActewAGL's approach to setting X factors appears to be similar to that adopted in its initial proposal, that is, real average price increases of 2.00 per cent for years 2 to 5 for the next regulatory control period, with a corresponding value for year 1 which equates expected and required revenues in NPV terms.

### 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 11.

The AER's final decision results in a total revenue requirement for ActewAGL of $793 million ($nominal) for the next regulatory control period. This is $75 million lower than the $868 million proposed by ActewAGL. This difference mainly reflects the AER's decision to apply a WACC of 8.79 per cent, which contributes $56.4 million to this difference, and its decision on ActewAGL's forecast opex, which contributes a further reduction of $19.7 million.

**Table 11: AER conclusion on ActewAGL's revenue requirements and X factors ($m, nominal)**

| | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|
| Regulatory depreciation | | 15.2 | 17.0 | 18.8 | 20.5 | 22.3 |
| Return on capital | | 52.6 | 57.1 | 61.1 | 65.0 | 68.2 |
| Tax allowance | | 4.7 | 5.5 | 5.7 | 5.4 | 5.6 |
| Operating expenditure | | 61.2 | 67.4 | 73.8 | 80.8 | 85.5 |
| Annual revenue requirements | | 133.7 | 147.1 | 159.4 | 171.7 | 181.6 |
| Energy sales (MWh) | 2 906 274 | 2 932 862 | 2 916 011 | 2 907 581 | 2 898 320 | 2 888 942 |
| Revenue yield (¢/kWh) | 4.09 | 4.77 | 5.08 | 5.42 | 5.77 | 6.15 |
| Expected revenues | 118.9 | 139.9 | 148.2 | 157.5 | 167.3 | 177.8 |
| Forecast CPI (%) | | 2.47 | 2.47 | 2.47 | 2.47 | 2.47 |
| X factors[a] (%) | | –13.82 | –4.00 | –4.00 | –4.00 | –4.00 |

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

The AER considered ActewAGL's proposed approach of having a larger X factor (and implied price increase) in year 1 of the regulatory control period, with X factors of –2.00 per cent in years 2 to 5 of the regulatory control period. The AER considered that maintaining an X factor of –2.00 per cent for years 2 to 5 of the regulatory control period, when combined with the adjustments resulting from this final decision, would have resulted in a difference between expected and required revenues at the end of the regulatory control period that was unreasonably large. The AER considered various values of X factors for years 2 to 5 of the regulatory control period, deciding that –4.00 per cent, with a corresponding X factor for year one of the regulatory control period of –13.82 per cent, resulted in a difference between expected and required revenues in year 5 of the regulatory control period of around 2 per cent.

The impact of this final decision on an average end user, will be an annual electricity cost increase of 4.15 per cent in 2009–10, and 1.36 per cent per year for the remainder of the next regulatory control period

In accordance with clauses 6.3.2(a) and 6.5.9 of the transitional chapter 6 rules, the AER decides the annual revenue requirements and X factors for each year of the regulatory control period for ActewAGL are set out in table 12.

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

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| X factors (%) | –13.82 | –4.00 | –4.00 | –4.00 | –4.00 |
| Annual revenue requirements | 133.7 | 147.1 | 159.4 | 171.7 | 181.6 |

# Alternative control services

## AER draft decision

The AER approved a MAR for ActewAGL of $40 million for alternative control services for the next regulatory control period. This resulted in a revenue increase in 2009–10 of 31.34 per cent, and further revenue adjustments in line with CPI for each remaining year of the regulatory control period.

## Revised regulatory proposal

ActewAGL's revised regulatory proposal incorporated additional expenditures of $3.4 million relating to the implementation and operation of the ACT feed–in tariff scheme. ActewAGL further adjusted its alternative control services opex forecasts to reflect revised or updated elements of the standard control services opex forecasts.

## AER conclusion

In accordance with the control mechanism specified in the draft decision, the AER has decided to approve a MAR for ActewAGL of $39 million for alternative control services for the next regulatory control period. This revenue will be recovered through a revenue adjustment in 2009–10 of 29.30 per cent and allowed revenues adjusted in line with CPI each year for the remainder of the next regulatory control period.

ActewAGL must demonstrate compliance with the control mechanism by submitting its schedule of metering charges to the AER each year, as specified in the draft decision.

ActewAGL's MAR for alternative control services is set out in table 13.

**Table 13: AER conclusion on ActewAGL's maximum allowed revenue—alternative control services ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Unsmoothed revenue requirement | 7.3 | 7.5 | 7.9 | 8.1 | 8.6 | 39.6 |
| Smoothed revenue requirement | 7.5 | 7.7 | 7.9 | 8.` | 8.3 | 39.4 |
| X factors[a] (%) | –29.3 | 0.0 | 0.0 | 0.0 | 0.0 | n/a |

(a) Negative value for the X factor indicates real price increases under the CPI–X formula.

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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 AER makes determinations according to the relevant transitional provisions within chapter 11 of the NER (the transitional chapter 6 rules). The AER's principal regulatory task is to set the annual revenue requirements that a DNSP can recover from the provision of direct control services within a regulatory control period.

ActewAGL Distribution (ActewAGL) is the owner and operator of the electricity distribution network in the Australian Capital Territory. 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 its regulatory obligations for the period 1 July 2009 to 30 June 2014 (the next regulatory control period).

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.

On 2 June 2008 ActewAGL submitted to the AER its regulatory proposal and its proposed negotiating framework for the next regulatory control period.[1] On 27 June 2008 the AER published these and its proposed negotiable component criteria for ActewAGL. On 28 November 2008 the AER published its draft decision and draft distribution determination for ActewAGL.[2] In mid–January 2009 ActewAGL submitted a revised regulatory proposal in response to the draft decision.[3] The revised regulatory proposal was published by the AER on 19 January 2009.

This final decision should be read in conjunction with the draft decision and draft distribution determination for ActewAGL published by the AER on 28 November 2008.

## 1.2 AER draft decision

In the draft decision the AER calculated ActewAGL's revenue requirements and X factors based on its decisions in relation to the building block components. This calculation is summarised in table 1.1.

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[1] ActewAGL, *Distribution determination 2009–14, Regulatory proposal to the AER*, June 2008.

[2] AER, *Draft decision Australian Capital Territory distribution determination 2009–10 to 2013–14,* 7 November 2008; and AER, *ActewAGL Distribution draft distribution determination 2009–10 to 2013–14*, 7 November 2008.

[3] ActewAGL, *Distribution determination 2009–14, Revised regulatory proposal to the AER*, January 2009.

The draft decision resulted in a total (nominal) annual revenue requirement over the next regulatory control period of $779 million, some $44 million lower than the $823 million proposed by ActewAGL. This mainly reflected the AER's updated calculation of ActewAGL's weighted average cost of capital (WACC) (from 10.70 per cent to 9.82 per cent) which contributed $33 million to the difference, as well as its decision on ActewAGL's forecast operating expenditure (opex), which contributed a further reduction of $9.5 million.

**Table 1.1: AER draft decision on ActewAGL's annual revenue requirements and X factors ($m, nominal)**

| | 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 | 137.5 | 146.1 | 155.3 | 165.0 | 172.8 |
| 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: AER, *Draft decision*, p. 179.
(a) Negative values for X indicate real price increases under the CPI-X formula.

The AER determined ActewAGL's opening regulatory asset base (RAB) to be $588 million for the next regulatory control period (as at 1 July 2009). This includes the capital expenditure (capex) that ActewAGL incurred in the current regulatory control period.

The draft decision approved a capex allowance of $278 million ($2008–09). A total opex allowance of $296 million ($2008–09) for ActewAGL was also approved.

The AER also approved ActewAGL's negotiating framework to apply for the next regulatory control period.

The AER specified the negotiated distribution service criteria to apply to ActewAGL.

## 1.3 Revised regulatory proposal

ActewAGL submitted its revised regulatory proposal to the AER on 16 January 2009.

ActewAGL's revised regulatory proposal sets out an annual revenue requirement that increased from $146 million in 2009–10 to $199 million in 2013–14 (nominal), and a total annual revenue requirement of $868 million for the next regulatory control period.

ActewAGL's revised opening RAB was $592 million (as at 1 July 2009). This amount incorporates an updated capex forecast for 2008–09. ActewAGL accepted all aspects of the draft decision on the opening RAB and, following a request from the AER, revised its 2007–08 actual capex.

ActewAGL's revised capex forecast for the next regulatory control period was $298 million ($2008–09). This forecast included additional capex relating to revised peak demand forecasts and new capex required to implement the service target performance incentive scheme (STPIS) reporting requirements. ActewAGL implemented most aspects of the draft decision relating to forecast capex, except those relating to the determination of cost escalators.

ActewAGL's revised forecast opex for the next regulatory control period was $358 million ($2008–09). This forecast included additional opex relating to the ACT Government Feed-in Tariff (FiT) scheme. ActewAGL implemented most aspects of the draft decision relating to opex, except those related to:

- self insurance costs
- debt raising costs
- equity raising costs
- labour cost escalation.

ActewAGL accepted most other elements of the draft decision relating to the classification of services, arrangements for negotiation, control mechanisms, efficiency benefit sharing scheme, STPIS, demand management incentive scheme and depreciation. ActewAGL did not accept some aspects of the draft decision relating to pass through definitions and self insuance.

ActewAGL provided revised forecasts of maximum demand and energy, which took into account the reduced economic growth forecasts arising from the global financial crisis.

## 1.4 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 transitional 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 submissions. The AER also held a roundtable discussion on ActewAGL's proposal on 29 July 2008, where ActewAGL and interested parties made presentations.
- Submissions—The AER received one submission, from EnergyAustralia.
- Assessment by technical experts—The AER engaged Wilson Cook & Co Limited (Wilson Cook) to advise it on a number of aspects of ActewAGL's regulatory proposal.
- 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 cost growth relevant to electricity distribution businesses.
- Draft decision—The draft decision and draft distribution determination were released on 28 November 2008 and the AER requested submissions from interested parties.
- Public consultation—The AER held a predetermination conference on its draft decision on 8 December 2008 to explain its draft decision and receive oral submissions from interested parties.
- Revised regulatory proposal—ActewAGL submitted its revised regulatory proposal on 16 January 2009. The AER has assessed ActewAGL's revised regulatory proposal against the transitional chapter 6 rules and the AER's transitional guidelines.
- Submissions—The AER received three submissions on its draft decision and draft distribution determination and ActewAGL's revised regulatory proposal, from ActewAGL, EnergyAustralia and the Total Environment Centre.
- Assessment by technical expert—The AER engaged Associate Professor John Handley from the University of Melbourne to advise on issues relating to the cost of capital, and benchmark debt and equity raising transaction costs.
- Final decision—The AER made its final decision and distribution determination on 28 April 2009.

## 1.5 Structure of final decision

This final decision sets out the AER's consideration of ActewAGL's revised regulatory proposal and proposed negotiating framework, together with the negotiated distribution service criteria to apply to ActewAGL. The final decision includes consideration of substantive issues raised in submissions. Except as specified in this final decision, the AER maintains its conclusions set out in the draft decision. Therefore, this final decision should be read in conjunction with the draft decision published by the AER on 28 November 2008.

The structure of the final decision 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 and 6 confirm the prudence of past capex as determined in the draft decision and establish the opening asset base
- chapters 7 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 addresses the AER's review of alternative control services.

# 2 Classification of services

## 2.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on classification of services for ActewAGL. It also sets out the AER's classification of ActewAGL's distribution services for the next regulatory control period and the arrangements for assigning and reassigning customers to tariff classes.

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.

## 2.2 AER draft decision

The AER accepted ActewAGL's proposed classification of services as it aligns with that deemed under the transitional chapter 6 rules, and is based on the existing classification of services applied by the ICRC.[4]

The AER, having regard to the principles in clause 6.18.4 of the transitional chapter 6 rules, proposed the procedures specified in appendix A of the draft decision, for ActewAGL to follow when assigning or reassigning customers to tariff classes.[5]

## 2.3 Revised regulatory proposal

ActewAGL sought confirmation from the AER that its decision on procedures for assigning or reassigning customers to tariff classes does not require ActewAGL to assign customers to a particular tariff class. ActewAGL was concerned that this would remove the freedom consumers and retailers currently have to select the most appropriate network charge.[6]

## 2.4 Submissions

The AER notes that Origin Energy made a submission in relation to the NSW DNSP draft decision.[7] Origin Energy stated that although it did not specifically refer to the ActewAGL draft decision in its submission, Origin Energy's general comments would apply equally to the ActewAGL draft decision.[8] Origin Energy submitted that meter services should be unbundled from standard network use of system charges.[9]

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4 AER, *Draft decision*, p. 12.

5 AER, *Draft decision*, appendix A, pp. 198–199.

6 ActewAGL, *Distribution determination 2009–14, Revised regulatory proposal to the AER*, January 2009, pp. 75–76.

7 The NSW DNSPs are Country Energy, EnergyAustralia and Integral Energy. See AER, *Final decision, New South Wales distribution determination, 2009–10 to 2013–14*. 28 April 2009.

8 Origin Energy, Letter to AER*, NSW draft distribution determination 2009-10 to 2013-14*, 24 February 2009, p. 1.

9 Origin Energy, Letter to AER, p. 2.

The AER's analysis of Origin Energy's submission is set out in section 2.5.1 of the NSW DNSPs' final decision.[10]

## 2.5 Issues and AER considerations

### 2.5.1 Selection of tariffs by customers and retailers

ActewAGL noted that it does not assign customers to tariff classes and stated that a requirement to do so would remove the existing freedom of consumers and retailers to select the most appropriate network charge.[11]

The AER confirms that the procedures for assigning customers to tariffs do not prevent consumers and retailers from selecting the most appropriate network charge and, therefore, the AER confirms that ActewAGL is not required to assign customers to tariff classes.

### 2.5.2 Revised procedures for assigning and reassigning customers to tariff classes

The AER has prepared a revised set of procedures in relation to assigning and reassigning customers to tariff classes. The revised procedures are set out in appendix A of this final decision and reflect the changes made to the procedures which apply to the NSW DNSPs. The AER's consideration of the revised procedures is set out in chapter 2 of the NSW DNSP final decision. The AER considers that for reasons of consistency, the procedures which apply to the NSW DNSPs should also apply to ActewAGL.

## 2.6 AER conclusions

The AER accepts ActewAGL's proposed classification of services as it aligns with that deemed under the transitional chapter 6 rules, and is based on the existing classification of services applied by the ICRC.

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 final decision. The procedures do not prevent consumers and retailers from selecting the most appropriate network charge.

[10] AER, *Final decision, New South Wales distribution determination,* 28 April 2009, p. 22.
[11] ActewAGL, *Revised regulatory proposal*, p. 76.

## 2.7 AER decision

In accordance with clause 6.12.1(1) of the transitional chapter 6 rules 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 160 MWh 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 procedures for assigning customers to tariff classes or reassigning customers from one tariff class to another are specified in appendix A of this final decision.

# 3 Arrangements for negotiation

## 3.1 Introduction

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. 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 specifies 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. ActewAGL does not have any distribution services classified as negotiated distribution services in the next regulatory control period (see chapter 2).

Clause 6.2.7A of the transitional chapter 6 rules provides, however, 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. Future classification of services will be considered in the AER's framework and approach paper which must be prepared in anticipation of each distribution determination under general chapter 6 of the NER.

This chapter sets out the AER's consideration of issues raised in response to the draft decision. It sets out the AER's decisions regarding the arrangements facilitating negotiation for certain distribution services provided by ActewAGL for the next regulatory control period. It sets out the AER's considerations and conclusions on:

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

## 3.2 AER draft decision

The AER 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:[12]

- 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

[12] AER, *Draft decision*, p. 17.

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 response to a submission on the NCC provided by EnergyAustralia, the AER changed the heading of criterion 1 from 'national electricity market objective' to 'national electricity objective'.[13] The AER's NCC for ActewAGL was set out in appendix B of the draft decision.

The AER approved ActewAGL's negotiating framework to apply for the next regulatory control period.[14]

## 3.3 Revised regulatory proposal

ActewAGL resubmitted in its revised regulatory proposal that the following criteria be adopted to identify negotiable components of direct control services:

> A negotiable component of a direct control service is any component service (including the terms and conditions on which that component is provided) where some variability can be applied without interfering with ActewAGL Distribution's ability to comply with any regulatory obligation or requirement, including those in the NER.[15]

ActewAGL noted that the AER rejected its proposed criteria for identifying negotiable components of direct control services, and replaced it with an alternative, as proposed by another DNSP. ActewAGL submitted that the AER did not establish that ActewAGL's proposal was unreasonable and did not establish that the alternative would deliver better outcomes.[16]

ActewAGL considered that its original proposed approach was consistent with the requirements of the transitional chapter 6 rules. ActewAGL stated that its proposed approach was flexible, accommodated a wide range of possible circumstances and provided guidance for customers on services which are likely to be negotiable.[17]

## 3.4 AER issues and considerations

In the AER's view, the negotiable component definition proposed by ActewAGL does not contain sufficient detail for the criteria to be interpreted and applied by:

- customers when negotiating components of direct control services with ActewAGL
- the AER when resolving access disputes under clause 6.7A.4(a)(2) of the transitional chapter 6 rules.

The AER notes that ActewAGL's proposed definition used very little of the language from the NER. The AER considers that wherever possible, it is important to use the

[13] AER, *Draft decision*, p. 18.
[14] AER, *Draft decision*, p. 22.
[15] ActewAGL, *Revised regulatory proposal*, p. 77.
[16] ActewAGL, *Revised regulatory proposal*, pp. 77–78.
[17] ActewAGL, *Revised regulatory proposal*, p. 78.

language from the NER and limit deviations to providing necessary clarification. The AER's proposed negotiable component definition uses the language from the NER—such as relevant expressions and concepts used in the definition of 'negotiated transmission service' in chapter 10 of the NER. This should enable customers to better identify which components of direct control services are negotiable. Further, using the language of the NER wherever possible should result in more consistent and better outcomes and greater transparency for customers.

The AER notes that ActewAGL did not argue that the AER's proposed definition is inappropriate or unworkable and has not provided the AER with any examples of how the definition is either too broad or narrow in coverage. For the reasons set out above, the AER is of the view that it is appropriate for the same definition to apply to all ACT and NSW DNSPs (with variations to reflect differences in jurisdictional regulation and service classification). As a consequence, the AER has modified the proposed definition in light of the submissions made by EnergyAustralia and Integral Energy. These modifications are discussed further in section 3.5 of the NSW DNSPs' final decision.[18]

The AER considers it is appropriate for there to be one NCC which applies to all NSW and ACT DNSPs. The AER is a national regulator operating under a national regime. The different regulatory regimes which existed in the various states and territories constituted a substantial impediment to the development of a truly national energy market and resulted in significant costs being imposed on industry participants (with those costs typically being passed on to end users).[19] One of the reasons for the establishment of the national regime was to minimise the complexities for DNSPs associated with dealing with more than one regulator and differing interpretations of the rules.[20] Similar reasoning can be applied to the customers of the DNSPs. From the customers' perspective, it would be preferable to only have to assess one set of criteria. If each DNSP had a different set of criteria, the customer would have to compare each criteria to ascertain the differences and then decide on the importance and effect of the differences. The AER considers it is important to maintain a consistent approach wherever possible with the DNSPs especially if it is in relation to customer negotiations.

The AER notes that ActewAGL's annual pricing proposal must include any variations to prices charged for a negotiable component of direct control services which resulted from the application of the NCC.

## 3.5 AER conclusions

### 3.5.1 Negotiable components

The AER has decided to define a negotiable component of a direct control service as any component of a direct control service (including the terms and conditions on which that direct control service or component is provided) where:

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18 AER, *Final decision, New South Wales distribution determination*, pp. 35–42.

19 MCE, *National Framework for electricity and gas distribution and retail regulation, Foreword and issues paper*, August 2004, p. 12 of issues paper prepared by Allens Arthur Robinson.

20 MCE, *Foreword and issues paper*, p. 12 of issues paper prepared by Allens Arthur Robinson.

(a) the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation;

(b) 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

(c) 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,

but excludes, in relation to any component of a direct control service, requirements imposed under a regulatory instrument (other than this final decision and distribution determination).

Therefore, components that fall within the scope of the above definition, are negotiable components. The AER considers that this definition is consistent with the examples of potential negotiable components provided by ActewAGL[21] and provides an appropriate framework under which it can operate.

### 3.5.2 Negotiable component criteria

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

### 3.5.3 Negotiating framework

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

## 3.6 AER decision

In accordance with clauses 6.12.1(15) and 6.7A.3 of the transitional chapter 6 rules the negotiating framework in appendix C of this final decision is to apply to ActewAGL for the next regulatory control period. The preparation of the negotiating framework for 2014–19 regulatory control period must be undertaken in accordance with the framework and approach processes for that regulatory control period.

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21 ActewAGL, *Distribution determination 2009–14, Regulatory proposal to the AER*, June 2008, pp. 246–247.

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

(a) the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation;

(b) 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

(c) 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,

but excludes, in relation to any component of a direct control service, requirements imposed under a regulatory instrument (other than this final decision and distribution determination).

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

The AER published guidelines setting out the control mechanism it proposed to apply to ActewAGL's direct control services for the next regulatory control period.[22] For ActewAGL's standard control services the control mechanism is a maximum average revenue cap.

This chapter sets out the AER's consideration of issues raised by ActewAGL in response to the draft decision. It also discusses how the control mechanism will be applied and sets out how the AER will determine compliance with the control mechanism during the next regulatory control period. No submissions were received on this issue.

## 4.2 AER draft decision

In the draft decision, the AER considered that ActewAGL's proposed form of control mechanism for direct control services was compliant with the requirements of the transitional chapter 6 rules and the AER's standard control services guideline.[23] 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 stated it would apply the approach set out in its standard control services guideline.[24]

## 4.3 Revised regulatory proposal

***Recovery of transmission use of system charges***

ActewAGL stated that it was concerned about the AER's methodology in calculating the transmission use of system (TUOS) unders and overs account required as part of its pricing proposal for each regulatory year of the next regulatory control period.[25]

ActewAGL noted that the AER's example shown in appendix E of the draft decision incorporated interest that could be earned for regulatory years 1 (actual) and 3 (forecast). However, this formula omitted year 2 and, in doing so, ActewAGL was

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

23 AER, *Draft decision*, p. 32.

24 AER, *Guideline on control mechanisms for ACT and NSW.*

25 ActewAGL, *Revised regulatory proposal,* p. 76.

concerned that the draft decision omitted the interest that should be paid or earned in that year.[26]

***Side constraints***

ActewAGL stated that the AER's formula for the side constraint drew upon the actual load in the previous financial year. However, the formula for escalation of the control mechanism used the actual load for the previous calendar year.[27]

ActewAGL considered that it would be more appropriate to apply the load for the previous calendar year to pricing and to calculate the side constraint.[28]

***Feed-in tariff***

ActewAGL stated that the direct tariff payments it is liable to pay to retailers under the recently introduced feed–in tariff scheme should be included in its forecast opex allowance. Related to this, it proposed an annual pricing adjustment mechanism (with respect to standard control services) to reconcile discrepancies between any forecast and actual tariff payments in a financial year.[29]

## 4.4 AER issues and considerations

***Recovery of TUOS***

The AER acknowledges that the calculation of TUOS unders and overs set out in the draft decision did not account for recoveries and interest earned or paid in the current regulatory year. This was in accordance with the AER's guideline on the control mechanism which stated that unders and overs calculations would be based on actual data only (i.e. from the most recently completed regulatory year).[30] The AER also decided to apply the same approach to the NSW DNSPs. The reporting of under and over recoveries, as required under the transitional chapter 6 rules, would be a new arrangement for ActewAGL who had previously relied solely on forecast TUOS costs.

In the final decision for the NSW DNSPs, the AER reconsidered the approach for calculating TUOS unders and overs and decided that it inappropriately departs from that practiced by Independent Pricing and Regulatory Tribunal (IPART). Accordingly, the AER's final decision for the NSW DNSPs was to maintain IPART's approach, which includes estimated data for the current regulatory year.[31] To maintain a consistent regulatory approach across jurisdictions, the AER's final decision is to implement the same approach in the ACT as used by IPART. This addresses ActewAGL's concerns because it provides for interest on the TUOS unders and overs account, and estimated recoveries for the current regulatory year. Appendix E of this final decision sets out an example calculation of this account as well as associated reporting requirements as required by the AER.

26 ActewAGL, *Revised regulatory proposal*, p. 76.
27 ActewAGL, *Revised regulatory proposal*, p. 76.
28 ActewAGL, *Revised regulatory proposal*, p. 76.
29 ActewAGL, *Revised regulatory proposal*, pp. 27–31.
30 In AER, *Guideline on control mechanisms for ACT and NSW*, Appendix B, unders and overs for year 't-1' are not accounted for.
31 AER, *Final decision, New South Wales distribution determination,* p. 60

*Clarification of side constraint formula*

In the draft decision the AER noted that it would calculate the side constraint in accordance with the following formula:

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

where 't' denotes data for regulatory (financial) years.

To maintain consistency between the data used to assess compliance with the maximum allowable average revenue (MAAR) and in the application of side constraints for a particular regulatory year, the AER has amended the side constraint formula to also apply quantity data reported on a calendar year basis. Note that price data, and therefore the weighted average revenue, derived in this calculation would still refer to regulatory (financial) years as required under clause 6.18.6(b) of the transitional chapter 6 rules.

In the draft decision $L_t$ was defined as being the greater of (1 – X)×(1 + 2%) or (1 + 2%), as per clause 6.18.6(c) of the transitional chapter 6 rules. Clause 6.18.6(d) requires that, in applying side constraints, the AER must disregard any changes arising as a result of rule 6.6 (regarding cost pass throughs, service target performance incentive scheme (STPIS) and demand management incentive scheme (DMIS)) and rule 6.13 (regarding the revocation and substitution of a distribution determination). For this final decision the AER has clarified its approach to calculating the permissible percentage in its side constraint formula to recognise the requirements of clause 6.18.6(d) of the transitional chapter 6 rules, as well as to incorporate calendar year quantity data, as follows:

$$\frac{\sum_{k=1}^{m} d_k^t \times q_k^{ct-1}}{\sum_{k=1}^{m} d_k^{t-1} \times q_k^{ct-1}} \leq (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + 2\%) \pm (\text{pass through}_t) \qquad k = 1,...,\text{m.}$$

Where:

- $d_k^t$ is the proposed price for component 'k' for regulatory year 't' (e.g. 2009–10)
- $d_k^{t-1}$ is the current price charged by the DNSP for component 'k' in regulatory year 't–1' (e.g. 2008–09)
- $q_k^{ct-1}$ is the audited/ verifiable quantity of component 'k' of the tariff that was charged by the DNSP in calendar year 'ct–1' (e.g. 2008)
- $X_t$ are the amounts as determined by the AER in table 17.8 of this final decision. If X>0, then X will be set equal to zero for the purposes of the side constraint formula.

- 'pass through$_t$' represent approved pass through amounts (expressed in percentage form) with respect to regulatory year 't' as determined by the AER under rule 6.6 of the transitional chapter 6 rules and chapter 16 of this final decision.
- $\Delta CPI_t$ means the number derived, with respect to regulatory year 't', from the application of the following formula:

$$\Delta CPI_t = \frac{CPI_{March(t-2)} + CPI_{June(t-2)} + CPI_{September(t-1)} + CPI_{December(t-1)}}{CPI_{March(t-3)} + CPI_{June(t-3)} + CPI_{September(t-2)} + CPI_{December(t-2)}} - 1$$

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 of the regulatory year indicated.

***Feed-in tariff***

The AER notes that any adjustments for over and under recoveries of direct tariff payments under the feed–in tariff scheme will be treated as an approved pass through event under this final decision. Therefore no specific pricing adjustment mechanism is required. These adjustments will be accommodated in the 'pass through' term applied when assessing compliance with the MAAR each year. See chapter 16 for further discussion.

***Reasonable estimates associated with changes to tariff structures***

The AER has clarified the approach ActewAGL must apply when it proposes changes to tariffs which require reasonable estimates of quantity data used for compliance purposes. The AER's changes are minor and are made in response to stakeholder comments on similar requirements in its draft decision for the NSW DNSPs.[32] The AER's requirements for this final decision are contained in appendix F.

## 4.5 AER conclusions

### Maximum allowable average revenue

The AER has decided to apply a maximum allowable average revenue cap to ActewAGL's standard control services. This is the same mechanism that was applied by the ICRC and complies with the requirements of the transitional chapter 6 rules.

The miscellaneous standard control services were set out in appendix D of the draft decision and except for minor formatting changes have been reproduced at appendix D of this final decision.

The maximum allowable average revenue is expressed in cents per kilowatt hour for each regulatory year, and is represented by the following formula:

[32] AER, *Final decision, New South Wales distribution determination*, pp. 53–54.

$$MAAR_t = MAAR_{t-1} \times \left(1 + \Delta CPI_t\right) \times \left(1 - X_t\right)$$

Where:

- $MAAR_{t-1}$ is the maximum allowable average revenue for the previous regulatory year
- $X_t$ are the X factor amounts as determined by the AER in table 17.8 of this final decision.
- $\Delta CPI_t$ means the number derived, with respect to regulatory year ‘t’, from the application of the following formula:

$$\Delta CPI_t = \frac{CPI_{March(t-2)} + CPI_{June(t-2)} + CPI_{September(t-1)} + CPI_{December(t-1)}}{CPI_{March(t-3)} + CPI_{June(t-3)} + CPI_{September(t-2)} + CPI_{December(t-2)}} - 1$$

Where:

- CPI means the all groups index number for the weighted average of eight capital cities as published by the 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 regulatory year indicated.

### Compliance with the MAAR

In demonstrating compliance with the control mechanism, ActewAGL must use the following formula:

$$MAAR_t \geq \frac{\sum_{i=1}^{n} p_i^t \times q_i^{ct-1} + MSR_t \pm (\text{pass through}_t)}{\text{kWh transported}_{\text{ct-1}}}$$

Where:

- ‘i’ represent individual tariff components of a total of ‘n’ components across all tariffs for standard control services
- $p_i^t$ are the prices for each tariff component for standard control services (excluding miscellaneous services) proposed for regulatory year ‘t’ (e.g. 2009–10)
- $q_i^{ct-1}$ represent sales quantities for standard control services (excluding miscellaneous services) sold by ActewAGL in the previous calendar year ‘ct-1’ (e.g. 2008) that correspond to the proposed tariff components
- ‘kilowatt hours $\text{transported}_{\text{ct-1}}$’ are the amounts of energy for the previous calendar year delivered by ActewAGL Distribution 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 (e.g. 2008)

- ‘pass through$_t$’ represents approved pass through amounts (in dollars) 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 final decision.

### Side constraints on tariffs for standard control services

For the purposes of determining whether ActewAGL’s annual pricing proposals comply with clause 6.18.6 of the transitional chapter 6 rules, the side constraint formula applicable to ActewAGL is:

$$\frac{\sum_{k=1}^{m} d_k^t \times q_k^{ct-1}}{\sum_{k=1}^{m} d_k^{t-1} \times q_k^{ct-1}} \leq (1+\Delta CPI_t)\times(1-X_t)\times(1+2\%)\pm(\text{pass through}_t) \qquad \mathrm{k}=1,...,\mathrm{m}.$$

where:

The tariff class has up to ‘m’ components:

- $d_k^t$ is the proposed price for component ‘k’ for regulatory year ‘t’ (e.g. 2009–10)
- $d_k^{t-1}$ is the current price charged by the DNSP for component ‘k’ in regulatory year ‘t–1’ (e.g. 2008–09)
- $q_k^{ct-1}$ is the audited/ verifiable quantity of component ‘k’ of the tariff that was charged by the DNSP in calendar year ‘t–1’ (e.g. 2008)
- $X_t$ are the amounts as determined by the AER in table 17.8 of the final decision. If X>0, then X will be set equal to zero for the purposes of the side constraint formula.
- ‘pass through$_t$’ represent approved pass through amounts (expressed in percentage form) with respect to regulatory year ‘t’ as determined by the AER under rule 6.6 of the transitional chapter 6 rules and chapter 16 of this final decision.
- $\Delta CPI_t$ means the number derived, with respect to regulatory year ‘t’, from the application of the following formula:

$$\Delta CPI_t = \frac{CPI_{March(t-2)} + CPI_{June(t-2)} + CPI_{September(t-1)} + CPI_{December(t-1)}}{CPI_{March(t-3)} + CPI_{June(t-3)} + CPI_{September(t-2)} + CPI_{December(t-2)}} - 1$$

Where:

- CPI means the all groups index number for the weighted average of eight capital cities as published by the 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 regulatory year indicated.

Each of the relevant percentage factors noted above (e.g. the X factor, CPI) must be rounded to two decimal places before being applied in the form of control mechanism and side constraint formulae.

In accordance with clause 6.18.2(b)(7) and (8) of the transitional chapter 6 rules ActewAGL must ensure its annual pricing proposals comply with the side constraint formula defined in this section 4.5.

## 4.6 AER decision

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the control mechanism for standard control services is a maximum allowable average revenue cap. It is calculated in accordance with the formula in section 4.5 of this final decision.

In accordance with clause 6.12.1(13) of the transitional chapter 6 rules compliance with the maximum allowable average revenue cap for standard control services must be demonstrated by ActewAGL using the formulae outlined in section 4.5 and in accordance with appendix F of this final decision.

In accordance with clause 6.12.1(19) of the transitional chapter 6 rules 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 this final 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.

No submissions were received on this issue.

## 5.2 AER draft decision

Based on its review and advice from Wilson Cook, the AER considered 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.[33] The draft decision on the past capex to be rolled into ActewAGL's opening RAB for 1 July 2009 is set out in table 5.1.

**Table 5.1: AER draft decision 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 |

Source: AER, *Draft decision*, p. 40.

## 5.3 Revised regulatory proposal

ActewAGL did not raise any issues regarding the draft decision on its past capex. It revised its capex forecast for 2008–09 of $43 million to reflect an updated forecast of $46 million. Based on this update, ActewAGL's total updated capex in the current regulatory control period is $156 million.[34]

## 5.4 AER conclusion

ActewAGL's revised roll forward model did not include an update for actual 2007–08 capex, as required in the draft decision. Following a request from the AER, ActewAGL provided the actual capex for 2007–08 which was $36 million.[35] After including the updates for 2007–08 and 2008–09, ActewAGL's total capex in the current regulatory control period is $156 million.

The AER has reviewed the actual and revised capex data provided by ActewAGL for the years 2007–08 and 2008–09. Based on the information provided, and the assessment made in the draft decision, the AER considers the total amount of $156 million is prudent and should be included in the opening RAB. The AER

33 AER, *Draft decision*, p. 40.
34 ActewAGL, *Revised regulatory proposal*, RFM.
35 ActewAGL, Email response to AER, 18 February 2009.

confirms its draft decision that all of ActewAGL's capex in the current regulatory control period was prudent and that the projects and programs undertaken were required, efficient and consistent with ActewAGL's policies and good industry practice. ActewAGL's updated capex incurred for the current regulatory control period is set out in table 5.2.[36]

**Table 5.2: 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 | 35.6 | 46.0 | 156.2 |

## 5.5 AER decision

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the other appropriate amounts, values or inputs with respect to the past capex to be rolled into ActewAGL's opening RAB for 2009 is set out in table 5.2 of this final decision.

[36] To the extent that actual capex differs from forecast capex for the final year of the current regulatory control period, a reconciliation will be undertaken using the actual values as part of the asset base roll forward process at the next distribution determination, in accordance with the NER.

# 6 Opening regulatory asset base

## 6.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision. It also sets out the method used by the AER to determine the closing regulatory asset base (RAB) for ActewAGL for the current regulatory control period. The closing RAB becomes the opening RAB for the next regulatory control period and is used in the post–tax revenue model as an input for calculating the annual revenue requirement.

No submissions were received on this issue.

## 6.2 AER draft decision

### 6.2.1 Opening RAB for 2009–14 regulatory control period

The AER determined ActewAGL's opening RAB to be $588 million for the next regulatory control period (as at 1 July 2009).[37] The RAB roll forward calculations are set out in table 6.1.

The AER noted it will update the roll forward of ActewAGL's RAB with actual capex for 2007–08, the most recent forecast of capex for 2008–09, and the latest actual CPI data at a time closer to its final distribution determination.[38]

**Table 6.1: AER draft decision on 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 |

Source: AER, *Draft decision*, p. 59.

### 6.2.2 RAB roll forward for the 2014–19 regulatory control period

The draft decision proposed to use actual depreciation to establish the opening RAB for the 2014–19 regulatory control period.[39]

37 AER, *Draft decision*, p. 59.
38 AER, *Draft decision*, p. 59.

## 6.3 Revised regulatory proposal

ActewAGL did not raise any issues regarding the draft decision on its opening RAB. ActewAGL's revised regulatory proposal refers to an opening RAB for the next regulatory control period of $592 million.[40] This amount incorporates an updated forecast capex for 2008–09.

## 6.4 Issues and AER considerations

### 6.4.1 Updated capex

In the draft decision the AER determine that it considered it appropriate to use the most up to date capex estimates to derive the opening RAB.[41] The AER's review of ActewAGL's revised roll forward model did not include an update for actual 2007–08 capex,[42] as required in the draft decision.[43] Following a request from the AER, ActewAGL provided the actual capex for 2007–08.[44] As noted in section 5.4, the AER considers ActewAGL's capex revision for 2007–08 to be reasonable, and has incorporated the revised capex data in the RAB roll forward calculations.

ActewAGL provided an updated capex forecast for 2008–09 in its revised regulatory proposal[45] and the AER has accepted this forecast as an input to the roll forward model.[46]

### 6.4.2 Updated CPI figures

Since the draft decision the roll forward of ActewAGL's RAB has been updated to include the latest CPI data, which was published by the Australian Bureau of Statistics in January 2009, consistent with the method approved in the draft decision.

## 6.5 AER conclusion

To take into account the updated capex and CPI data, the AER amends its draft decision and determines ActewAGL's opening RAB for the next regulatory control period to be $599 million (as at 1 July 2009). The RAB roll forward calculations are set out in table 6.2.

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[39] AER, *Draft decision*, p. 59.
[40] ActewAGL, *Revised regulatory proposal*, p. 68.
[41] AER, *Draft decision*, p. 59.
[42] ActewAGL, *Revised regulatory proposal*, p. 68.
[43] AER, *Draft decision*, pp. 54–55.
[44] ActewAGL, Email response to AER, 18 February 2009.
[45] ActewAGL, *Revised regulatory proposal*, RFM.
[46] To the extent that actual capex differs from forecast capex for the final year of the current regulatory control period, a reconciliation will be undertaken using the actual values as part of the asset base roll forward process at the next distribution determination, in accordance with clause S.6.2.1(e)(3) of the NER.

**Table 6.2: AER conclusion on 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 | 574.4 |
| Actual net capex[c] | 21.7 | 23.4 | 29.5 | 35.6 | 33.4 |
| CPI adjustment on opening RAB | 12.2 | 14.2 | 19.4 | 13.4 | 25.7 |
| Straight-line depreciation (adjusted for actual CPI) | –24.3 | –25.5 | –27.1 | –28.6 | –30.5 |
| Closing RAB | 520.1 | 532.3 | 554.1 | 574.4 | 603.1 |
| Adjustment for difference between actual and forecast capex for 2003–04 | | | | | –2.7 |
| Adjustment for return on difference[d] | | | | | –1.7 |
| Opening RAB at 1 July 2009 | | | | | 598.7 |

(a) Updated for actual 2007–08 capex.
(b) Updated for actual CPI for 2008–09 (sum of four quarters to December). Based on updated net capex forecast.
(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.

## 6.6 AER decision

In accordance with clause 6.12.1(6) of the transitional chapter 6 rules ActewAGL's opening RAB for the next regulatory control period is $598.7 million.

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

# 7 Demand forecast

## 7.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision and the AER's consideration of ActewAGL's maximum demand and energy forecasts. As part of its distribution determination, the AER must assess the extent to which ActewAGL's maximum demand forecast can be relied upon for the purposes of estimating load driven capex. The AER must also make a decision as to whether ActewAGL's energy forecast is an appropriate input into the AER's post–tax revenue model (PTRM).

The AER did not receive any submissions addressing ActewAGL's demand forecasts, or the AER's draft decision on these forecasts.

## 7.2 AER draft decision

The draft decision stated that ActewAGL's maximum demand forecast methodology and forecasts provided a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the transitional chapter 6 rules.[47]

The draft decision also stated that ActewAGL's energy forecast methodology was reasonable, but rejected ActewAGL's energy forecast on the basis that the forecast should be updated to take into account the most recent energy sales data, for financial year 2007–08.[48]

## 7.3 Revised regulatory proposal

### 7.3.1 Maximum demand forecast

ActewAGL's revised regulatory proposal provided revised maximum demand forecasts, accounting for revisions to economic growth forecasts as a result of the global financial crisis and changes to the Australian Government's climate change policies, including the release of the Carbon Pollution Reduction Scheme (CPRS) White Paper in December 2008.[49] Aside from these changes, ActewAGL maintained the forecasting methodology it used to generate its original (June 2008) maximum demand forecasts, including the spatial forecasts at the zone substation level.

ActewAGL's original and revised system maximum demand forecasts are provided in table 7.1.

47 AER, *Draft decision*, p. 51.
48 AER, *Draft decision*, p. 51.
49 ActewAGL, *Revised regulatory proposal*, pp. 41–43.

**Table 7.1: ActewAGL's system maximum demand forecasts (MVA)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average annual growth 2009–14 |
|---|---|---|---|---|---|---|
| Original forecast (June 2008) | 694 | 708 | 721 | 734 | 748 | 1.9% |
| Revised forecast (January 2009) | 689 | 672 | 684 | 697 | 710 | 0.6% |

Source: ActewAGL, *Regulatory proposal*, p. 92; and ActewAGL, *Revised regulatory proposal*, p. 44.
Note: System maximum demand is defined at the 10 per cent probability of exceedence level.

### 7.3.2 Energy forecast

ActewAGL provided a revised energy forecast for the next regulatory control period in response to the draft decision, incorporating actual energy sales data for 2007–08.[50] The revised energy forecast also incorporated updated information and inputs accounting for revisions to economic growth forecasts and the CPRS.

ActewAGL's original and revised energy sales forecasts are provided in table 7.2.

**Table 7.2: ActewAGL's energy sales forecasts 2009–14 (GWh)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average annual growth 2009–14 |
|---|---|---|---|---|---|---|
| Original forecast (June 2008) | 2878 | 2925 | 2972 | 3018 | 3066 | 1.6% |
| Revised forecast (January 2009) | 2936 | 2879 | 2900 | 2920 | 2934 | 0.23%[a] |

Source: ActewAGL, *Regulatory proposal,* p. 94; and ActewAGL, *Revised regulatory proposal*, p. 44.
(a) The average annual growth rate includes a 1.2 per cent forecast growth rate in year 2009–10.

## 7.4 Issues and AER considerations

In reviewing ActewAGL's revised forecasts, the AER focussed on the changes made to the forecasts since the June 2008 forecasts, which were reviewed in the draft decision. Changes made to ActewAGL's forecasts included updated sales data, macroeconomic data, error correction and changes made to account for the CPRS White Paper.

### 7.4.1 Updated data inputs and error correction

The AER notes that in preparing its revised forecasts, ActewAGL substantially used the same methodology it used to generate its original forecasts, but altered its models to incorporate changes in the macroeconomic environment.

50 ActewAGL, *Revised regulatory proposal*, pp. 43–44.

As requested in the draft decision, ActewAGL provided verified 2007–08 energy sales data in its revised regulatory proposal, which was used as an input into its revised energy forecast.[51]

ActewAGL also updated key input data and incorporated the network price impacts of the AER's draft decision, transmission use of system (TUOS) price forecasts and price impacts associated with the CPRS into its forecasts. Updated inputs include:[52]

- Australian Bureau of Statistics (ABS) State Final Demand data for 2007–08
- ACT Government State Final Demand forecasts for 2008–09
- ABS population and household statistics.

ActewAGL also made a further adjustment to its forecast model to correct for a minor error relating to dual fuel arrangements in the ACT.[53]

The AER notes that these changes do not represent a significant variation in the model approved in the draft decision, but update data to incorporate more accurate and relevant information. The AER considers that the changes made to ActewAGL's maximum demand and energy forecasts to incorporate the latest sales data, the changed macroeconomic environment and to correct for minor errors are reasonable.

### 7.4.2 Impacts of the Carbon Pollution Reduction Scheme on demand

The AER notes ActewAGL's original (June 2008) energy forecasts incorporated an expected small electricity price increase over the next regulatory control period due to Australian and ACT Government climate change policies, based on the information available at the time the forecasts were prepared.[54] In its regulatory proposal, ActewAGL applied these price increases to price elasticity estimates developed by the National Institute of Economic and Industry Research (NIEIR), to determine a likely impact on energy sales.[55]

In December 2008 the Australian Government released the CPRS White Paper, which indicated that significantly greater electricity price rises were likely over the next regulatory control period.[56] As a result, ActewAGL incorporated into its revised forecast an expected 18 per cent increase in residential customers' electricity prices and a 17 per cent increase in commercial electricity prices by 2014.[57]

In its revised regulatory proposal, ActewAGL stated that it considers the elasticity estimates generated by NIEIR may not be appropriate for analysing large price

51 ActewAGL, *Revised regulatory proposal*, p. 40.
52 ActewAGL, *Revised regulatory proposal*, pp. 40–41.
53 ActewAGL, *Revised regulatory proposal*, p. 41.
54 ActewAGL, *Revised regulatory proposal*, p. 41.
55 NIEIR's analysis estimated an elasticity of –0.25 for residential customers and –0.35 for commercial customers. NIEIR, *The own price elasticity of demand for electricity in NEM regions*, June 2007, p. 3.
56 Australian Government, *Carbon Pollution Reduction Scheme–Australia's Low Pollution Future–White paper*, December 2008.
57 ActewAGL, *Revised regulatory proposal*, p. 42.

increases, such as the impacts of the CPRS.[58] It stated that the NIEIR elasticities are point estimates, which are appropriate for analysing small incremental price rises. ActewAGL also stated that NIEIR's elasticities do not properly account for changes in the prices of alternative energy sources such as natural gas, which are anticipated effects of the CPRS that would offset any electricity demand response.[59] Accordingly, ActewAGL amended NIEIR's price elasticities in its revised forecast, applying an elasticity of –0.2 across all customers. This reduced the effect of the price increases on demand as compared to applying NIEIR's derived elasticities. The AER understands that the adjustment to NIEIR's elasticities was made such that the expected CPRS demand response was in line with a forecast developed by McLennon Magasanik Associates (MMA) for the Australian Government's review on the effect of the CPRS on Australia's energy markets.[60]

In reviewing ActewAGL's revised energy forecast, the AER has drawn on the recommendations made by MMA in reviewing EnergyAustralia's revised energy forecasts for the AER.[61] As part of its review, MMA considered the use of NIEIR's elasticities in the context of the large price rises as a result of the CPRS. MMA identified analysis completed by NIEIR in 2004, on behalf of the Electricity Supply Industry Planning Council (ESIPC), assessing the impact of large price rises in South Australia on energy demand.[62] ESIPC's report indicates that the appropriate application of the NIEIR elasticities is that they should be phased in over a number of years following the initial price impact.[63]

Using ESIPC's results and assumptions, MMA estimated that the NIEIR elasticities should be phased in over a period of seven years, as shown in table 7.3.

The AER agrees with ActewAGL that NIEIR's estimates of elasticity may not be suitable for application to large price increases.[64] Accordingly, on 6 March 2009, the AER requested that ActewAGL provide a further revised energy forecast, applying the phased price responses recommended by MMA.[65] ActewAGL provided this revised forecast on 25 March 2009, as outlined in table 7.4.[66]

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58 ActewAGL calculated that the impact of applying NIEIR's elasticities to the anticipated CPRS price increases would result in a reduction in energy consumption of 4.2 per cent. ActewAGL, *Revised regulatory proposal*, p. 42.

59 ActewAGL, *Revised regulatory proposal*, p. 42.

60 MMA forecast that the CPRS would result in a 12 per cent reduction in electricity consumption in 2020. ActewAGL amended its price elasticity to ensure that the resulting effect of the CPRS on demand was equal to MMA's forecast. ActewAGL, *Revised regulatory proposal*, p. 43; and MMA, *Impacts of the carbon pollution reduction scheme on Australia's energy markets*, December 2008, table 3.2.

61 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, 17 March 2009 (updated 17 April 2009).

62 ESIPC, *Sales forecasts by tariff category for South Australia's electricity distribution network for the period 2005–06 to 2009–10*, 14 September 2004, available at www.escosa.sa.gov.au.

63 ESIPC, *Sales forecasts by tariff category for SA electricity distribution network*, pp. 15–17.

64 AER, *Final decision, New South Wales distribution determination*, chapter 6, pp. 110–113.

65 AER, Email to ActewAGL, 6 March 2009.

66 ActewAGL, Email to the AER, 13 March 2009.

**Table 7.3: MMA's estimate of phased price responses**

| Years after price change | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 and subsequent years |
|---|---|---|---|---|---|---|---|---|
| Elasticity impact[a] | 20% | 40% | 60% | 78% | 85% | 91% | 97% | 100% |
| Resulting elasticity - ActewAGL residential customers | –0.05 | –0.10 | –0.15 | –0.19 | –0.21 | –0.23 | –0.24 | –0.25 |
| Resulting elasticity - ActewAGL commercial customers | –0.07 | –0.14 | –0.21 | –0.27 | –0.30 | –0.32 | –0.34 | –0.35 |

Source: MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 35.

(a) This is an average of the assumed impact for residential and commercial customers. ESPIC derived slight differences between customer types as to how the elasticities should be phased, however the AER has averaged the effects to simplify the application of the phasing to ActewAGL's forecasts.

**Table 7.4: AER conclusion on ActewAGL's energy sales forecasts 2009–14 (GWh)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average annual growth 2009–14 |
|---|---|---|---|---|---|---|
| Original forecast (June 2008) | 2878 | 2925 | 2972 | 3018 | 3066 | 1.6% |
| Revised forecast (January 2009) | 2936 | 2879 | 2900 | 2920 | 2934 | 0.23%[a] |
| Revised forecast (March 2009) | 2933 | 2916 | 2908 | 2898 | 2889 | –0.1% |

Source: ActewAGL, *Regulatory proposal*, p. 94; ActewAGL, *Revised regulatory proposal*, p. 44; and ActewAGL, email to the AER, 25 March 2009.

(a) The average annual growth rate includes a 1.2 per cent forecast growth rate in year 2009–10.

The revised forecast provided on 25 March 2009 incorporated the updated data discussed in section 7.4.1, as well as the phased price responses outlined in table 7.3.

The AER considers that the revised energy forecast provided by ActewAGL on 25 March 2009 and shown in table 7.4, reasonably reflects expected energy consumption on its network for the next regulatory control period, and is an appropriate input into the PTRM.

## 7.5 AER conclusion

For the reasons discussed above the AER considers that ActewAGL’s revised maximum demand forecast provided in its revised regulatory proposal provides a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the NER.

For the reasons discussed above the AER considers the revised energy forecast provided to the AER on 25 March 2009, and outlined in table 7.4 above, is an appropriate input into the PTRM under clause 6.12.1(10) of the NER.

## 7.6 AER decision

> In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the other appropriate amounts, values or inputs with respect to energy forecasting for ActewAGL are those that were provided on 25 March 2009, and are set out in table 7.4 of this final decision.

# 8 Forecast capital expenditure

## 8.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision. It sets out the AER's conclusions on forecast capex allowances for ActewAGL for the next regulatory control period and also:

- provides a general overview of ActewAGL's revised regulatory proposal
- sets out the AER's considerations and responses to stakeholder comments.

The AER's conclusions and the estimate of the forecast capex allowance for ActewAGL during the next regulatory control period are set out in section 8.5 of this chapter.

## 8.2 AER draft decision

The AER did not accept ActewAGL's proposed capex allowance of $286 million ($2008–09). It accepted the scope of the forecast program and the proposed investment decisions, however, it did not consider the forecast costs reasonably reflected the capex criteria. The AER made the following adjustments to ActewAGL's cost estimation methodology:

- removed the effect of the 12 month lag in input cost escalators for commodities
- removed the effect of indirect labour cost escalation for manufactured equipment
- updated the source data for real cost escalators, where appropriate.[67]

The result of these adjustments was a real net reduction of $8.5 million or around 3 per cent of ActewAGL's proposed capex. Table 8.1 sets out the draft decision on the capex allowance for ActewAGL.

**Table 8.1: AER draft decision 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 |
| Capex allowance | 77.7 | 58.2 | 51.9 | 51.2 | 38.9 | 277.9 |

Source: AER, *Draft decision*, p. 80.
(a) These amounts reflect an increase of $8.9 million from ActewAGL's published regulatory proposal of 2 June 2008 to correct for errors identified in its cost escalation calculations.
Note: Totals may not add up due to rounding.

[67] AER, *Draft decision*, p. 80.

## 8.3 Revised regulatory proposal

ActewAGL's revised regulatory proposal sought a capex allowance of $298 million ($2008–09) for the next regulatory control period.[68] ActewAGL's revised forecast capex is set out in table 8.2.

ActewAGL's revised regulatory proposal implemented the draft decision in respect of forecast capex, except in relation to cost escalation. In addition, ActewAGL made the following adjustments:[69]

- deferred some key projects due to revised peak demand forecasts (demand driven adjustments)
- included additional capex requirements to prepare for the AER's national distribution service target performance incentive scheme (STPIS)
- included additional capex requirements arising from feed–in tariff (FiT) scheme obligations.

**Table 8.2: ActewAGL's revised capex allowance for standard control services ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Original proposal capex[a] | 79.9 | 59.8 | 53.5 | 53.0 | 40.3 | 286.6 |
| Demand driven adjustments | –13.7 | –0.1 | 5.6 | –1.1 | 9.7 | 0.3[b] |
| New STPIS capex | 1.4 | 1.6 | 0.3 | 0.4 | 0.0 | 3.7 |
| New FiT capex | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 |
| Updated cost escalators | 3.3 | 3.7 | 3.1 | 3.0 | 2.3 | 15.4 |
| Total Revised capex | 69.0 | 63.4 | 60.9 | 53.4 | 50.9 | 297.6 |
| Difference | –10.9 | 3.6 | 7.4 | 0.4 | 10.6 | 11.0 |

Source: ActewAGL, *Revised regulatory proposal*, p. 34.
(a) These amounts reflect an increase of $8.9 million from ActewAGL's published regulatory proposal of 2 June 2008 to correct for errors identified in its cost escalation calculations.
(b) This net increase results from the impact of ActewAGL's cost escalators rather than additional capex.
Note: Totals may not add up due to rounding.

## 8.4 Submissions

The AER received submissions from the Energy Market Reform Forum (EMRF), the Energy Users Association of Australia (EUAA) and Origin Energy on ActewAGL's and the NSW DNSPs' revised regulatory proposals. These submissions did not raise issues specific to ActewAGL's revised regulatory proposal but focussed on issues

[68] ActewAGL, *Revised regulatory proposal*, p. 34.
[69] ActewAGL, *Revised regulatory proposal*, p. 34.

relevant to all DNSPs operating in the NSW and ACT regions. The AER has addressed these concerns in its decision for the NSW DNSPs.[70]

## 8.5 Issues and AER considerations

### 8.5.1 Revised demand forecasts

**AER draft decision**

The draft decision approved a forecast capex allowance of $278 million.[71] In determining this allowance, the AER had regard to ActewAGL's demand forecasts for the next regulatory control period, in accordance with the capex criterion in clause 6.5.7(c)(3) of the transitional chapter 6 rules.

**Revised regulatory proposal**

In response to changes in economic growth forecasts and the implications of the Australian Government's proposed carbon pollution reduction scheme (CPRS), ActewAGL revised its original spatial maximum demand.[72] When compared to its original proposal, ActewAGL's revised system demand growth at the end of the next regulatory control period is 5 per cent lower in summer and 6 per cent lower in winter.[73]

ActewAGL submitted that the combination of the effect of the economic slowdown and the CPRS would result in slightly slower demand growth at the Civic, Fyshwick and Woden zone substations.[74] ActewAGL also submitted that the proposed Eastlake, Civic and Molonglo zone substation projects and associated feeder augmentation works would be deferred by 12 months to reflect the revised demand forecast.[75]

ActewAGL's revised demand forecasts are discussed in more detail in chapter 7 of this final decision.

**AER considerations**

Peak or maximum demand forecasts (MW or MVA) play an important role in the assessment of load driven capex, as DNSPs plan network augmentation to meet expected maximum demand on their networks. In determining the capex allowance, the AER must have regard to whether the total of the forecast capex reasonably reflects a realistic expectation of the demand forecast in accordance with clause 6.5.7(c)(3) of the transitional chapter 6 rules.

ActewAGL updated its forecasts relating to its zone substation peak demand. The updated forecasts included revisions resulting from the change in the economic outlook for the Australian economy since mid–2008, as reflected in official Australia

70 AER, *Final decision, New South Wales distribution determination*, chapter 7.
71 AER, *Draft decision*, p. 80.
72 ActewAGL, *Revised regulatory proposal*, p. 43.
73 ActewAGL, *Revised regulatory proposal*, p .43.
74 ActewAGL, *Revised regulatory proposal*, p .43.
75 ActewAGL, *Revised regulatory proposal*, p. 43.

Treasury forecasts.[76] The rapid change in the economic outlook is closely linked to the global financial crisis which manifest itself in the second half of 2008.

The global financial crisis has been portrayed as being the most serious economic event affecting developed economies since the great depression of the 1930s.[77] Given this extraordinary change in circumstances within the economic environment, the AER has decided to consider the updated forecasts relating to ActewAGL's network peak demand in making its determination.

The AER considered ActewAGL's revised capex and proposed project deferrals, in the context of the revised spatial demand forecasts. Based on the information provided by ActewAGL, the AER considers the deferral of these projects is appropriate given the changes in expected demand growth, which are driven largely by deteriorating economic conditions. The AER also considers the capex deferrals are reasonable and are likely to result in a total capex allowance that:

- more reasonably reflects the demand forecasts than that submitted by ActewAGL in its original regulatory proposal
- results in more efficient deployment of these major network investments by ensuring the assets are commissioned no earlier than reasonably required.

### 8.5.2 Deliverability of capex programs

In the draft decision, the AER was satisfied that the deliverability of the forecast capex program would not be constrained by resource availability. This conclusion was subject to the proviso that ActewAGL could adequately finance its proposed capex program.[78]

On 27 January 2009, the AER sought advice from ActewAGL regarding any matters or circumstances that may affect its ability to obtain finance to deliver the proposed capex program for the next regulatory control period.[79]

On 18 February 2009, ActewAGL advised that it was in a strong position to finance its proposed 2009–14 capex program and that there were no current or pending matters or circumstances of which it was aware that would limit its ability to fund its program.[80]

Based on the information available, including the advice from ActewAGL, the AER considers that ActewAGL will be able to finance and deliver its proposed capex program in the next regulatory control period.

### 8.5.3 Proposed network connectivity project

**AER draft decision**

In the draft decision, the AER decided to implement a data collection process during the next regulatory control period based on the AER's national distribution STPIS.

[76] The Treasury, *Updated Economic and Fiscal Outlook*, February 2009.
[77] IMF, *World Economic Outlook*, October 2008.
[78] AER, *Draft decision,* p. 79.
[79] AER, Letter to ActewAGL, 27 January 2009.
[80] Michael Costello, letter to Steve Edwell, 18 February 2009.

The AER noted ActewAGL's proposal 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. The AER stated that it expected any proposal 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 that time.[81]

**Revised regulatory proposal**

ActewAGL proposed an additional capex allowance of $3.7 million for the next regulatory control period to develop data collection and reporting capabilities required under the AER's national distribution STPIS.[82] Specifically, it proposed to implement a 'network connectivity solution' to enable collection and reporting of the necessary data.

ActewAGL submitted that this project would deliver accurate and timely data that would be compliant with the AER's reporting requirements.[83] It further stated that its proposed network connectivity solution would:[84]

- provide the ability to better plan and manage its network, assets, resources, reporting and fault resolution
- provide customers with improved service.

ActewAGL submitted that its network connectivity solution would be divided into five phases:[85]

- review, design and development of a corporate data model which includes network connectivity data requirements
- review and verification of current data and system availability and capabilities
- field data collection to build a full connectivity data set involving updating and validating information and collecting new information
- development of network connectivity within geographic information systems (GIS)
- GIS viewing and analysis tools and standardised system queries reporting development.

ActewAGL also proposed additional opex to establish and manage its proposed network connectivity solution, which is discussed in chapter 9 of this final decision.

**AER considerations**

In the draft decision, the AER signalled its intent to require service performance data reporting in accordance with the national distribution STPIS. The draft decision also acknowledged that ActewAGL may need to implement additional systems and processes to achieve full compliance with the national distribution STPIS by 2014.[86]

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81 AER, *Draft decision*, p. 78.
82 ActewAGL, *Revised regulatory proposal*, p. 22.
83 ActewAGL, *Revised regulatory proposal*, p. 20.
84 ActewAGL, *Revised regulatory proposal*, p. 20.
85 ActewAGL, *Revised regulatory proposal,* confidential attachment 7.
86 AER, *Draft decision*, p. 78.

It further stated that any claim to recover such expenditures would need to be made in accordance with the transitional chapter 6 rules, and would be assessed by the AER on its merits at the time.[87]

As the AER raised these issues in the draft decision, it is appropriate to consider ActewAGL's proposal for additional forecast capex related to STPIS preparations, consistent with the intent of clause 6.10.3 of the transitional chapter 6 rules.

The AER has reviewed ActewAGL's revised regulatory proposal and accompanying documentation and considers ActewAGL's preferred option is appropriate for inclusion in the capex allowance as:

- implementing the chosen project will ensure ActewAGL can comply with the requirements of the national distribution STPIS
- the project appears to be supported by sound planning and processes, including costings, options and risk assessment and detailed timeframes for various stages of the project
- additional benefits and business efficiencies are likely to be realised through implementation of the project, including improvements to planning and design processes, outage management, network control and customer management.

The AER considers the scope of ActewAGL's proposed network connectivity solution to be appropriate in meeting the data reporting obligations for the next regulatory control period, as set out in the draft decision. The AER also considers ActewAGL has presented a reasonable business case in favour of the option selected and costed, supported by risk assessment and a detailed project implementation timetable.[88]

The AER notes that the draft decision approved a capex allowance of $0.5 million to establish systems to report data for the national distribution STPIS. The AER has reviewed the scope of the additional network connectivity expenditure and accepts that, while these projects are related, this project is distinct from the capex previously approved in the draft decision.

For the reasons discussed above, the AER is therefore satisfied that ActewAGL's additional forecast capex for the proposed network connectivity project reasonably reflects the capex criteria including the capex objectives. In reaching this conclusion the AER has had regard to the capex factors.

### 8.5.4 Feed-in tariff related capex

The introduction of the FiT scheme has impacted on ActewAGL's standard control services capex and opex forecasts (in respect of direct tariff payments, network operations, and IT systems development) and alternative control services capex and opex forecasts (in respect of customer initiated metering installation and inspections). This section considers only the standard control services capex forecasts in respect of the FiT scheme. The AER's consideration of standard control services opex forecasts in respect of the FiT scheme is provided in chapter 9, and alternative control capex

87 AER, *Draft decision*, p. 78.
88 ActewAGL, *Revised regulatory proposal,* confidential attachment 7.

and opex forecasts in respect of the FiT scheme is provided in chapter 18 of this final decision.

**AER draft decision**

ActewAGL did not propose a forecast allowance for the capex associated with the introduction of a FiT scheme in its regulatory proposal. It submitted that uncertainty surrounding the passage and content of the legislation limited its ability to provide a reasonable estimate of the costs to be incurred.[89]

The AER considered the FiT scheme in the context of a nominated pass through (transitional period) event, but rejected ActewAGL's proposed treatment of the FiT scheme because it was inconsistent with the transitional chapter 6 rules.[90]

**Revised regulatory proposal**

ActewAGL noted that the FiT legislation was passed by the ACT Legislative Assembly on 2 July 2008 and that it was now able to provide a forecast of the costs associated with this scheme.[91] It proposed an annual adjustment mechanism to correct for annual over or under recoveries of direct tariff cost opex, however, the mechanism was not proposed to extend to the recovery of other costs associated with the scheme.[92]

ActewAGL's revised regulatory proposal included an additional capex allowance of $0.3 million for standard control services during the next regulatory control period to meet its obligations under the FiT legislation. This expenditure is expected to be incurred during the 2009–10 regulatory year.[93]

The proposed expenditure for standard control services related to the development of a web–based inquiry and application processes to minimise the costs of manual handling of connection applications.[94] ActewAGL submitted that it intended to adapt an existing IT application to manage customer FiT applications, therefore the forecast cost was significantly below the stand–alone cost associated with developing this capability.[95]

**Submissions**

The AER received a submission from ActewAGL relating to FiT expenditures. This submission was made in the context of cost recovery mechanisms for direct tariff components of the FiT scheme and is considered in chapter 9 of this final decision.

**AER considerations**

The AER acknowledges that, at the time of lodging its original proposal, ActewAGL was not in a position to develop a forecast of the capex required to comply with the FiT scheme and that ActewAGL has since prepared forecasts of the expected costs.

89 ActewAGL, *Regulatory proposal*, p. 81.
90 AER, *Draft decision*, p. 168.
91 ActewAGL, *Revised regulatory proposal*, p. 27.
92 ActewAGL, *Revised regulatory proposal*, pp. 29–31.
93 ActewAGL, *Revised regulatory proposal*, p. 28.
94 ActewAGL, *Revised regulatory proposal*, p. 28.
95 ActewAGL, *Revised regulatory proposal*, p. 28.

The AER has reviewed the information provided by ActewAGL on the timing of the introduction of the FiT scheme in the ACT and considers amending ActewAGL's original capex forecast is appropriate for recovering the costs associated with implementing the FiT scheme. The AER has reviewed ActewAGL's forecast capex associated with IT systems required under the FiT scheme, and is satisfied the forecast capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

### 8.5.5 Cost escalators

**Draft decision**

In the draft decision, the AER generally accepted the Sinclair Knight Merz (SKM) methodology for deriving input cost escalators,[96] however, it made the following adjustments to other aspects of the proposed methodology:[97]

- removed the impact of 12 month lags for commodities input prices
- removed the impact of indirect producers labour
- modified the approach to estimating escalators for steel
- updated data to reflect more recent information.

The AER did not consider ActewAGL's cost escalation assumptions reflected a realistic expectation of the cost inputs required to achieve the capex objectives, as required by clause 6.5.7(c). Therefore, it did not consider the resulting allowance fully satisfied the capex criterion at clause 6.5.7(c)(3) of the transitional chapter 6 rules. The AER required ActewAGL to remodel its capex proposal to address the draft decisions on input cost escalators.[98]

**Revised regulatory proposal**

ActewAGL did not accept all aspects of the cost escalators applied by the AER in the draft decision. It noted in its revised regulatory proposal that:[99]

> The framework prescribes a 'presumption of acceptance' with regard to input cost escalation. ActewAGL Distribution's escalators should only be adjusted by the AER where they do not reasonably reflect a realistic expectation of input cost escalation.

ActewAGL relied on the analysis undertaken by SKM[100] in its original and revised regulatory proposal to provide an assessment of the escalation factors to apply to the capital programs and projects for the next regulatory control period.[101]

ActewAGL accepted the AER's updated values for the:[102]

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96 AER, *Draft decision*, p. 66.
97 AER, *Draft decision*, pp. 230–249.
98 AER, *Draft decision*, p. 67.
99 ActewAGL, *Revised regulatory proposal*, p. 9.
100 SKM, *Capital works project cost escalation factors for the period 2007/8 – 2013/4, Final report*, May 2008.
101 ActewAGL, *Revised regulatory proposal*, p. 8.
102 ActewAGL, *Revised regulatory proposal*, p. vii.

- electricity, gas and water (EGW) industry labour escalator
- aluminium, steel, oil and copper escalators.

However, ActewAGL retained the application of a lag on commodity input prices—copper, aluminium and crude oil—and retained its inflation forecast for 2010–11 to 2013–14 proposed in June 2008.[103]

ActewAGL also proposed revised escalators for:[104]

- corporate services labour
- retail labour
- indirect labour.

This section presents the AER's final assessment of the methodology and data sources for the proposed escalators, except corporate services labour and retail labour (chapter 9). The values of the escalators have been updated to reflect the latest available information.

#### 8.5.5.1 Non–labour cost escalators—aluminium, copper, steel and crude oil

**AER draft decision**

Taking into account the methodology it had developed for the ElectraNet decision,[105] the AER generally accepted ActewAGL's materials cost escalators.[106] The AER did, however, make some adjustments to ActewAGL's proposed methodology and considered that more recent data was reflective of the input costs ActewAGL would face during the next regulatory control period. The AER applied the material cost escalators set out in table 8.3 for the next regulatory control period.

**Table 8.3: AER draft decision on real aluminium, copper, crude oil and steel cost escalators (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| Aluminium | –6.3 | –7.0 | 7.5 | 9.3 | –0.8 | –1.3 | –1.6 |
| Copper | –6.3 | –13.5 | 0.3 | 1.4 | –5.6 | –6.3 | –7.0 |
| Steel | 53.8 | –3.7 | 0.6 | –3.4 | –2.5 | –3.0 | –3.4 |
| Crude oil | 43.5 | –13.4 | 1.5 | 1.7 | 0.1 | –0.6 | –0.1 |

Source: AER, *Draft decision*, pp. 240–242.

The AER forecast aluminium and copper prices by using London Metal Exchange (LME) futures prices up to 2010 and then long–term Consensus Economics forecast (7.5 years). It interpolated between the two data sources to obtain a data series that covered the next regulatory control period. Since all aluminium and copper prices

103 ActewAGL, *Revised regulatory proposal*, pp. vii, 9–10.
104 ActewAGL, *Revised regulatory proposal*, p. vii.
105 AER, *Final decision, ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008.
106 AER, *Draft decision*, p. 66.

from the London Metal Exchange (LME) and Consensus Economics were in nominal US dollar (USD) terms, the projections were also converted into nominal Australian dollars (AUD).[107]

The AER used hot rolled coiled steel prices from Bloomberg for historical steel prices from Europe and the United States and then Consensus Economics forecasts for corresponding future prices. These steel prices were then:[108]

- adjusted from short to metric tonnes for US steel prices
- averaged and adjusted to Australian dollar terms using a methodology consistent with that adopted for aluminium and copper prices.

The AER forecast the real cost escalation for oil using historical average world oil prices from the United States Department of Energy and Bloomberg forecast contract prices. The prices were then averaged and adjusted to Australian dollar terms using a methodology consistent with that that adopted for aluminium and copper prices. Due to the volatility of the data, the AER used a centred moving average to account for prices for each month in the process of escalating the materials components of capex.[109]

The AER also considered that it was not appropriate to lag any base metals or crude oil input prices.[110]

**Revised regulatory proposal**

ActewAGL accepted the materials cost escalators applied by the AER in the draft decision for aluminium, steel, oil and copper escalators. However, ActewAGL considered that:[111]

> … the AER's analysis of movements between copper and aluminium prices and equipment does not properly reflect the nature of DNSP operations and is therefore not defensible, and the decision to reject the lag is unreasonable.

ActewAGL also considered that the outcome of the AER's analysis of any existence of a lag between movements in base metals and electrical equipment prices was not unexpected. It noted that since world copper and aluminium prices are set through an open market (the LME), the market price encountered when purchasing these two producer price indices (PPI) components depicted within the ABS measures of PPI, should closely mirror movements in the LME.[112]

ActewAGL therefore retained the application of a lag on commodity input prices in its revised regulatory proposal.[113] Table 8.4 sets out the revised real cost escalators for materials proposed by ActewAGL.

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[107] AER, *Draft decision*, pp. 239–240.
[108] AER, *Draft decision*, p. 241.
[109] AER, *Draft decision*, pp. 241–242.
[110] AER, *Draft decision*, pp. 246–249.
[111] ActewAGL, *Revised regulatory proposal*, p. 15.
[112] ActewAGL, *Revised regulatory proposal*, pp. 15–16.
[113] ActewAGL, *Revised regulatory proposal*, pp. 15–16.

**Table 8.4: ActewAGL's revised real aluminium, copper, steel and crude oil cost escalators (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| Aluminium | –8.6 | –6.3 | –7.0 | 7.5 | 9.3 | –0.8 | –1.3 |
| Copper | 27.0 | –6.3 | –13.5 | 0.3 | 1.4 | –5.6 | –6.3 |
| Steel | –8.3 | 53.8 | –3.7 | –0.6 | –3.4 | –2.5 | –3.0 |
| Crude oil | –12.4 | 43.5 | –13.4 | 1.5 | 1.7 | 0.1 | –0.6 |

Source: ActewAGL, Cost escalation model, 10 February 2009.

**Submissions**

Origin Energy, in a submission to the AER on the NSW DNSP's draft decision, noted that the concerns it raised in its submission equally applied to ActewAGL. Specifically, it noted the economic outlook had changed considerably and that economic data was pointing to reduced materials costs.[114]

**AER considerations**

ActewAGL accepted the approach used by the AER in determining its escalators. However, the AER notes, following receipt of revised regulatory proposals from the NSW DNSPs, Transend and TransGrid it has corrected a number of concerns with its approach to escalators.

***Base period adjustment***

Based on concerns raised by other NSPs, the AER has adopted a 12 month averaging period for materials escalators for each financial year of the next regulatory control period. The AER considers this approach is appropriate and has applied it to ActewAGL (and the other NSPs) as it:[115]

- removes potential price distortions that may occur during any single month
- recognises that not all equipment is costed and purchased over a single month but over each financial year of the period.

The AER considers this approach will permit the development of a more robust forecast that reflects all material cost data for each year.

The AER also considers there is merit in making an adjustment to reflect base period prices, as this allows for more accurate cost escalation to be determined. The AER has adjusted the base period for ActewAGL to reflect the base cost period of December 2006 to each year of the next regulatory control period. The AER notes this change is consistent with the approach that it adopted for the other NSPs.

114 Origin Energy, Letter to AER, p. 5.

115 This averaging period is centred on December as proposed by CEG as it is reflective of price movements over the entire year.

***Adjustment lag***

In the draft decision, the AER examined the material provided by ActewAGL and concluded that no evidence had been provided to support the application of a lag between commodity price changes and changes in equipment costs.[116]

In its revised regulatory proposal, ActewAGL argued that the lag incorporated in its proposal was appropriate and maintained it in its revised regulatory proposal. ActewAGL argued that the analysis conducted by the AER in the draft decision reflected the prices of intermediate goods rather than the equipment being purchased by it. It considered that any lag evident would not reflect the full amount of the time taken for commodity price changes to flow through to final equipment prices.[117]

The AER recognises that the producer price indices used in the draft decision were for intermediate goods and therefore the analysis did not reflect the full time taken for commodity price changes to flow through to the equipment costs incurred by ActewAGL.

The AER also recognises that in the draft decision for SP AusNet, it considered it reasonable to allow a lag of 12 months for commodity prices movements to flow through to the costs of electrical equipment faced by SP AusNet. This conclusion was based on a visual observation of commodity prices and producer price indices.[118] This approach followed the approach adopted by SKM, which conducted the analysis for SP AusNet supporting its proposal for a 24 month lag.[119]

The AER has reconsidered the approach it used to assess lags and concludes that the analysis it has conducted to date was not sufficiently robust. The AER considers that the analysis undertaken did not demonstrate, to a reasonable level, the potential relationship between commodity prices and electrical equipment prices. Furthermore, this analysis did not explore the potential impact of other factors, such as other cost inputs and economic conditions, on electrical equipment prices. More fundamentally, the AER notes that ActewAGL has not provided any new and reasonable evidence in its revised regulatory proposal to support the notion that movements in commodity prices systematically flow through to final goods prices.

In the absence of robust evidence supporting the application of a lag of 12 months, the AER considers that the application of a 12 month lag when calculating materials cost escalators does not provide a realistic expectation of the cost inputs required to achieve the capital expenditure objectives.

***Error correction***

The AER also identified an error in the draft decision model for the calculation of cost escalators for copper and aluminium. In the draft decision, the AER stated that the forecast monthly copper and aluminium prices were determined by interpolating between the LME spot price, the 3 month LME contract price, the 15 month LME contract price, the 27 month LME contract price and the most recent long-term

116 AER, *Draft decision*, p. 249.

117 ActewAGL, *Revised regulatory proposal*, p. 15.

118 AER, *Draft decision, SP AusNet transmission determination 2008–09 to 2013–14*, 31 August 2007, pp. 320–323.

119 SKM, *Escalation factors affecting capital expenditure forecasts*, 21 February 2007, pp. 14–16.

Consensus Economics forecast price. This process was not correctly reflected in the draft model and this error has been addressed.

The AER's conclusion on materials cost escalations is set out in table 8.5.

**Table 8.5: AER conclusion on real aluminium, copper, steel and crude oil cost escalators (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| Aluminium | –16.13 | –17.34 | –14.06 | 9.13 | 10.55 | 10.93 | 9.32 |
| Copper | –6.93 | –27.93 | –10.83 | 2.06 | 2.46 | 2.32 | 1.96 |
| Steel | 5.57 | 16.27 | –15.32 | 7.21 | 5.25 | 1.03 | 0.76 |
| Crude oil | 28.58 | –18.33 | –5.19 | 10.24 | 5.74 | 2.16 | 1.30 |

#### 8.5.5.2 Construction costs

**AER draft decision**

The AER notes ActewAGL's application of Econtech's engineering construction cost forecasts sourced from the Construction Forecasting Council (CFC) website.[120] In the draft decision, the AER applied updated construction cost forecasts sourced from the CFC, which it deflated by CPI,[121] to obtain real numbers. The draft decision on ActewAGL's construction costs is shown in table 8.6.

**Table 8.6: AER draft decision on ActewAGL's construction cost forecasts (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average |
|---|---|---|---|---|---|---|---|---|
| Construction costs | –0.3 | –1.9 | 0.4 | 1.2 | 1.1 | 1.0 | 1.0 | 0.9 |

Source: AER, *Draft decision*, p. 246.

**Revised regulatory proposal**

ActewAGL accepted the construction costs escalator applied by the AER in the draft decision.[122]

**AER considerations**

In its revised regulatory proposal, ActewAGL did not provide any comment on the timing issues pertaining to its cost escalators, as the Competition Economists Group's (CEG) report did for the other NSPs.[123] The AER nonetheless applied the same

[120] Construction Forecasting Council, http://www.cfc.acif.com.au/.

[121] The CPI figures used to deflate the construction cost forecasts from: Econtech, *Australian National State and Industry Outlook*, 22 July 2006.

[122] ActewAGL, *Revised regulatory proposal*, p. 11.

[123] CEG, *Escalators affecting expenditure forecasts, A report for NSW and Tasmanian electricity businesses*, January 2009.

modelling adjustments it applied to address concerns raised by the other NSPs to ActewAGL, to ensure a consistent approach to escalators across all businesses.

The AER has applied updated CFC construction cost forecasts to ActewAGL's capex proposal, received by the CFC on 6 April 2009 The AER has deflated these construction costs with updated inflation forecasts to provide real forecasts.[124] The AER's conclusions on forecast construction cost escalators are set out in table 8.7.

**Table 8.7: AER conclusion on ActewAGL's real construction cost escalators (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| Construction costs | 2.75 | –1.28 | –1.64 | 1.00 | 0.65 | –0.37 | –2.22 |

#### 8.5.5.3 Indirect (producer's) labour

**AER draft decision**

The AER did not accept the producer wage cost escalator proposed by ActewAGL. The AER considered that it did not meet the underlying objective for inclusion in forecast costs under clause 6.5.7(c) of the transitional chapter 6 rules. Based on the information presented, the AER was not satisfied that expenditure associated with a real escalation of indirect labour costs is required to meet the capex and opex criteria.[125]

The AER considered that the introduction of a labour component in equipment costs was inappropriate as it:[126]

- represented a movement beyond the AER's obligation to provide regulated businesses a reasonable opportunity to recover efficient costs towards providing compensation for changes in input costs at a very fine level of detail
- was sufficient to monitor whether the cost of finished goods, as opposed to the component parts, needed to be escalated above or below CPI
- was not supported by robust data.

The AER further noted that some amount of producer's labour costs would have been embedded in ActewAGL's base cost estimates of equipment.[127]

**Revised regulatory proposal**

ActewAGL rejected the draft decision to remove the producer's labour component of its equipment cost escalators. It proposed that a reasonable forecast of equipment costs should be based on an assessment of future key input costs, including labour.[128]

[124] Econtech, *Australian National State and Industry Outlook*, 23 January 2009.
[125] AER, *Draft decision*, p. 244.
[126] AER, *Draft decision*, pp. 237–238.
[127] AER, *Draft decision*, p. 237.
[128] ActewAGL, *Revised regulatory proposal*, p. 14.

ActewAGL retained SKM to update its cost escalation model for its revised regulatory proposal. While it maintained an indirect labour component in its revised regulatory proposal, it proposed the following adjustments:[129]

- for locally produced equipment, the general labour escalator applied to the producer labour component in the original proposal was replaced with CPI
- for imported equipment, the general labour escalator applied to the producer labour component was replaced with the trade weighted index (TWI) adjusted CPI (to proxy the real TWI).

ActewAGL submitted that this approach improved the quality and transparency of the cost escalation model and addressed the AER's concern that the proposal was not supported by robust data.[130]

**AER considerations**

The AER notes ActewAGL's revised approach to indirect labour costs. The AER accepts the revised regulatory proposal to apply zero real cost escalation to the producer's labour components of all domestically sourced equipment. However, the AER does not accept the introduction of a TWI adjusted CPI escalation to skilled labour components of internationally sourced equipment.

The AER is not satisfied that the inclusion of this escalator will produce forecast costs that reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives.

The methodology adopted by ActewAGL and SKM implicitly assumes that manufacturing conditions and wage growth rates are the same across all countries from which equipment is purchased. The AER considers it is reasonable to expect that different countries will exhibit different degrees of capital and labour productivity, as well as growth in wages and the costs of other production inputs. These factors are key determinants of the value of labour as a contributor to final production.

The AER considers that ActewAGL and SKM have not demonstrated that the weightings applied to indirect labour are relevant to production in other countries with different levels of factor productivity, and different costs of production factors.

Based on these considerations, the AER is not satisfied that assumptions of Australian labour contribution will reflect the contribution of labour to production in other countries during the next regulatory control period. The AER also notes that ActewAGL's revised regulatory proposal did not explain the practical application of the TWI, or the rationale for adopting it in its revised methodology.

Given these concerns, the AER considers the proposed methodology gives rise to significant estimation risk. Therefore, the AER considers Australian CPI should be applied to the indirect labour components of ActewAGL's internationally sourced equipment costs.

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129 ActewAGL, *Revised regulatory proposal*, p. 14.
130 ActewAGL, *Revised regulatory proposal*, p. 14.

ActewAGL also submitted that the indirect labour component was included in the SKM escalator model accepted by the AER in the SP AusNet determination.[131] The AER's decision for SP AusNet did not accept real indirect producer's labour escalation for equipment cost escalators. All capex related labour escalations accepted by the AER in that decision related to general and site labour incurred by SP AusNet, in Australia, in the course of installing, commissioning or replacing assets.

**AER conclusions**

For the reasons discussed in the draft decision, and as a result of its analysis of the revised regulatory proposal, the AER is not satisfied that the inclusion of real cost escalation for producer's labour components of equipment costs reasonably reflects the capex criteria, including the capex objectives. The AER does not consider that its inclusion is likely to produce forecast costs that reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives. In coming to this view, the AER has had regard to the capex factors.

Consistent with its draft decision, the AER has applied a zero weighting to the indirect producer's labour components of ActewAGL's base equipment cost escalators. That is, any weighting attributed to producers labour has been reallocated to an alternative 'other' cost factor category which will attract CPI escalation only.

#### 8.5.5.4 Exchange rates

**AER draft decision**

The AER considered that an exchange rate forecast by Econtech updated closer to the time of the final decision would represent a realistic expectation of forecast exchange rates over the next regulatory control period. For the purposes of the draft decision, the AER used the exchange rates set out in table 8.8.

**Table 8.8: AUD/USD exchange rate forecasts**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| AER draft decision | 0.85 | 0.96 | 0.88 | 0.84 | 0.82 | 0.80 | 0.79[a] |

Source: AER, *Draft decision*, pp. 243–244.
(a) In the draft decision this was incorrectly reported as 0.75.

**Revised regulatory proposal**

ActewAGL stated that it supported the AER's intention to use the latest available Econtech exchange rate forecasts for the final decision.[132]

**AER considerations**

Consistent with the draft decision, and ActewAGL's revised regulatory proposal, the AER has used the most recently available exchange rate forecasts from Econtech to calculate the cost escalators. The exchange rates used are set out in table 8.9.

131 ActewAGL, *Revised regulatory proposal*, p. 14.
132 ActewAGL, *Revised regulatory proposal*, pp. 9–10.

**Table 8.9: AUD/USD exchange rate forecasts**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| AER final decision | 0.85 | 0.96 | 0.67 | 0.65 | 0.63 | 0.62 | 0.62 |

Sources: Econtech, *Australian National State and Industry Outlook*, 23 January 2009, p. 110.

#### 8.5.5.5 Calculation of inflation

The AER undertook a review of its calculation of inflation. The AER considers that the approach to handling inflation used by CEG is more accurate than the approach used by the AER in the draft decision, although the difference is relatively minor.

However, the AER also determined that the methodology could be further improved by using the most recent historical monthly inflation figures rather than using yearly inflation figures. The AER therefore amended its methodology to incorporate this change, which also removed the need to amend the calculation of historical inflation as proposed by CEG.[133]

#### 8.5.5.6 Conclusion

The AER's conclusion on cost escalators for ActewAGL is set out in table 8.10.

**Table 8.10: AER conclusion on real escalators (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| Aluminium | –16.13 | –17.34 | –14.06 | 9.13 | 10.55 | 10.93 | 9.32 |
| Copper | –6.93 | –27.93 | –10.83 | 2.06 | 2.46 | 2.32 | 1.96 |
| Steel | 5.57 | 16.27 | –15.32 | 7.21 | 5.25 | 1.03 | 0.76 |
| Crude oil | 28.58 | –18.33 | –5.19 | 10.24 | 5.74 | 2.16 | 1.30 |
| EGW wages | 0.58 | 1.55 | 2.50 | 3.60 | 2.90 | 2.50 | 1.50 |
| General wages | –0.80 | –2.50 | 0.50 | 1.30 | 1.00 | 0.90 | 0.20 |
| Construction costs | 2.75 | –1.28 | –1.64 | 1.00 | 0.65 | –0.37 | –2.22 |

## 8.6 AER conclusion

Based on the information provided by ActewAGL, Wilson Cook and its own analysis, the AER considers that the scope of the revised capex program, including demand driven adjustments, additional FiT and STPIS related project work, is reasonable.

For the reasons set out in this chapter, the AER, however, is not satisfied that ActewAGL's total forecast capex allowance reasonably reflects the efficient costs, or a realistic expectation of the demand forecast and cost inputs a prudent operator in the

[133] CEG, *Escalators affecting expenditure forecasts*, p. 17.

circumstances of ActewAGL would require to achieve the capex objectives as provided for in the capex criteria at clause 6.5.7(c) of the transitional chapter 6 rules. In reaching this conclusion, the AER has had regard to the capex factors.

As the AER is not satisfied that the capex allowance proposed by ActewAGL reasonably reflects the capex criteria, under clause 6.5.7(d) the AER must not accept the proposed capex in its distribution determination. Under clause 6.12.1(3)(ii), the AER is therefore required to provide an estimate of the capex for ActewAGL over the next regulatory control period that it is satisfied reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

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 $275 million. This adjustment reflects the application of modified input cost escalators to ActewAGL's capex program.

The AER's conclusion on ActewAGL's capex for the next regulatory control period is set out in table 8.11.

**Table 8.11: AER conclusion on ActewAGL's capex allowance for standard control services ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| AER's draft decision | 77.7 | 58.2 | 51.9 | 51.2 | 38.9 | 277.9 |
| ActewAGL's revised proposed capex (including demand driven adjustment) | 69.0 | 63.4 | 60.9 | 53.4 | 50.9 | 297.6 |
| Adjustments to cost escalators | –5.9 | –5.7 | –4.5 | –3.3 | –2.9 | –22.4 |
| Capex allowance | 63.1 | 57.7 | 56.4 | 50.1 | 47.9 | 275.2 |

Note: Totals may not add up due to rounding.

## 8.7 AER 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 and 8.5 of this final 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 8.12 of this final decision.

# 9 Forecast operating expenditure

## 9.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision, including ActewAGL's revised opex proposal and the AER's conclusion on the opex allowance for the next regulatory control period.

The opex forecasts in ActewAGL's revised regulatory proposal are based on its requirements for the provision of standard control services during the next regulatory control period. The AER has reviewed the opex proposal against the requirements of the transitional chapter 6 rules.

## 9.2 AER draft decision

The AER did not accept ActewAGL's proposed opex allowance of $306 million ($2008–09).

The AER made the following adjustments to ActewAGL's proposed opex allowance:

- reduced the labour cost escalators
- reduced the self insurance costs by $5.8 million
- reduced the proposed Utilities Network Facilities Tax (UNFT) allowance by $0.2 million.

The result of these adjustments was a reduction of $9.5 million ($2008–09) or around 3 per cent of the proposed opex. Table 9.1 sets out the AER's revised total forecast opex allowance for ActewAGL in the draft decision.

**Table 9.1: AER draft decision on ActewAGL's total opex allowance ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| 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 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 1.7 |
| Total opex | 57.3 | 58.2 | 59.1 | 60.8 | 60.7 | 296.0 |

Source: AER, *Draft decision*, table 9.19, p. 119.
Note: Totals may not add up due to rounding.

## 9.3 Revised regulatory proposal

ActewAGL did not accept the AER's conclusion on controllable opex and substituted an amount of $275 million ($2008–09) that included:

- revised labour cost escalators
- new opex relating to service target performance incentive scheme (STPIS) reporting requirements
- new opex relating to the implementation of the Feed-in Tariff (FiT) scheme.

ActewAGL also provided revised opex estimates for debt raising costs, equity raising costs, self insurance and FiT scheme direct tariff payments. These adjustments increased the total opex forecast by $60 million.

ActewAGL's revised opex forecast is shown in table 9.2.

**Table 9.2: ActewAGL's revised standard control opex forecast ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL opex proposal | 58.7 | 59.8 | 61.0 | 62.9 | 63.1 | 305.5 |
| AER draft decision | 57.3 | 58.2 | 59.1 | 60.8 | 60.6 | 296.0 |
| **Adjustments (to ActewAGL's original proposal)** | | | | | | |
| Revised cost escalators | 0.0 | 0.2 | 0.3 | 0.4 | 0.5 | 1.4 |
| FiT scheme | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.6 |
| STPIS (IT) | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.9 |
| UNFTa | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Debt raising costs | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 1.2 |
| Equity raising costs | 1.1 | 1.1 | 1.0 | 0.6 | 0.5 | 4.4 |
| Self insurance | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 5.8 |
| FiT direct tariff costs | 3.4 | 6.8 | 10.0 | 12.7 | 15.3 | 48.2 |
| Revised opex proposal | 63.5 | 68.0 | 72.1 | 76.3 | 78.6 | 358.5 |

Source: ActewAGL, *Revised regulatory proposal*, p. 35.
Note: Totals may not add up due to rounding.
(a) The UNFT amounts are rounded to zero.

## 9.4 Submissions

The AER received submissions from the Energy Market Reform Forum (EMRF) and the Energy Users Association of Australia (EUAA) on ActewAGL's and the NSW DNSPs' opex. These submissions did not raise issues specific to ActewAGL's revised regulatory proposal but focussed on issues relevant to all DNSPs operating in the

NSW and ACT regions. The AER has addressed these concerns in the NSW final decision.[134]

The AER also received a submission from ActewAGL in relation to the FiT scheme, which is considered by the AER in section 9.5.3 of this chapter.

## 9.5 Issues and AER considerations

### 9.5.1 Revised cost escalators

ActewAGL escalated its base year opex using labour cost escalators and inflation.

#### 9.5.1.1 Labour cost escalators

**AER draft decision**

The AER did not accept ActewAGL's proposed labour cost escalator for the electricity, gas and water (EGW) sector in the ACT. The AER applied Econtech's wages growth forecasts in the EGW sector in ACT. Given actual wage data was available for 2007–08, the AER applied the actual wage increase provided for under ActewAGL's Enterprise Bargaining Agreement (EBA) for that period.

The AER did not accept ActewAGL's proposed general wage escalator. The AER applied Econtech's updated general wage forecasts to such labour, including ActewAGL's outsourced services, those being pole inspection, vegetation management and plant operator programs.

The AER did not accept the corporate services labour escalator proposed by ActewAGL. The AER did not consider the proposed escalator was an appropriate measure of labour market trends for this type of labour. The AER applied Econtech's general wage forecasts to ActewAGL's corporate services labour. The draft decision on labour cost escalators is shown in table 9.3.

**Table 9.3: AER draft decision on ActewAGL's EGW and general labour forecasts (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Average |
|---|---|---|---|---|---|---|---|---|
| EGW wages/EBA | –0.5 | 2.0 | 3.7 | 3.6 | 3.3 | 3.1 | 2.4 | 3.2 |
| General labour | 0.6 | 1.0 | 1.1 | 0.7 | 0.7 | 0.8 | 0.6 | 0.8 |

Source: AER, *Draft decision*, pp. 235, 237.

**Revised regulatory proposal**

ActewAGL accepted the EGW and general labour cost escalators applied by the AER in its draft decision. ActewAGL re–engaged SKM to review the draft decision and,

[134] AER, *Final decision, NSW distribution determination*.

based on that advice, it determined that the AER's approach to labour forecasts was reasonable.[135]

ActewAGL stated its interpretation of the transitional chapter 6 rules, particularly clause 6.5.6(c)(2)[136] considers a DNSP's opex must be assessed in light of the circumstances of the relevant DNSP. ActewAGL therefore, considered it inappropriate to apply a general wage escalator to its corporate services labour component, as it is essentially a weighted average of labour cost growth across different industries.[137] ActewAGL further advised its corporate services labour could not reasonably be considered as general labour as:

- 72 per cent of its Distribution Corporate Division fell within the property and business services category of the Australian and New Zealand Standard Industrial Classification (ANZSIC)
- the remaining 28 per cent of its Distribution Corporate Division fell within the finance and insurance category of ANZSIC[138]
- corporate services labour accounted for 17 per cent of its full-time equivalent staff[139] as at 9 February 2009.[140]

It further advised that positions categorised as corporate services labour included:[141]

- corporate finance
- IT services
- legal/secretariat positions
- human resource management
- corporate facilities management
- audit services.

ActewAGL stated that, similar to its corporate service employees, the cost of retail labour should be escalated by a specific escalator to reflect the cost of this labour. ActewAGL also stated that retail labour consisted of marketing, communication and customer accounts employees. It considered that this labour fell into either the business services or finance category of ANZSIC.[142] ActewAGL advised that retail labour accounted for 9.8 per cent of its total full–time equivalent staff as at 9 February 2009.[143] Further, it advised the types of positions categorised as retail services labour included customer account service and corporate services positions.[144]

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135 ActewAGL, *Revised regulatory proposal*, p. 11.
136 ActewAGL incorrectly referred to this as clause 6.5.6(e).
137 ActewAGL, *Revised regulatory proposal*, p. 11.
138 ActewAGL, *Revised regulatory proposal*, p. 11.
139 ActewAGL refers to total full time staff covered by its EBA, being ActewAGL Distribution, ACTEW and ActewAGL Retail.
140 ActewAGL, Request for information, 19 February 2009.
141 ActewAGL, Request for information, 10 February 2009.
142 ActewAGL, *Revised regulatory proposal*, p. 12.
143 ActewAGL refers to total full time staff covered by its EBA, being ActewAGL Distribution, ACTEW and ActewAGL Retail.
144 ActewAGL, Request for information, 10 and 19 February 2009.

ActewAGL developed escalators for corporate services and retail labour by using forecasts prepared by Econtech.[145] It used the labour cost forecasts prepared by Econtech for the property and services and finance and insurance categories to develop its corporate services labour escalator. This was achieved by using the proportion of ActewAGL employees within these two ANZSIC categories as weights, and then averaging the two labour cost forecasts provided by Econtech.[146] ActewAGL's proposed escalators for corporate services and retail labour are set out in table 9.4.

**Table 9.4: ActewAGL's nominal corporate services and retail labour escalators (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| Corporate services labour | 5.5 | 5.6 | 5.8 | 5.5 | 5.3 | 5.1 | 4.6 |
| Retail labour | 5.9 | 6.3 | 6.4 | 5.9 | 5.5 | 5.3 | 4.7 |

Source: ActewAGL, *Revised regulatory proposal*, p. 13.

ActewAGL provided additional information relating to its EBA rates, in response to an information request from the AER. It advised the period for its new EBA was 1 July 2008 to 30 June 2011 and that the annual wage increases detailed in its EBA (in nominal terms) were:[147]

- 5 per cent from the first pay period on or after 1 July 2008
- 5 per cent with effect from the first pay period or on after 1 July 2009
- 5 per cent with effect from the first pay period on or after 1 July 2010.

ActewAGL also highlighted components of its labour costs that it considered the AER needed to consider in its determination. ActewAGL advised a new single salary spine with performance targets (stretch targets) was included in its EBA. Where staff, not covered by the competency agreements, met these performance targets they would receive an extra 3 per cent on their base salary. This is in addition to the above mentioned wage increases. Further, ActewAGL's EBA included an annual attraction and retention allowance for its electrical workers, which is in addition to the annual wage increases detailed in the EBA.[148]

**Consultant review**

The AER re-engaged Econtech to provide an update on its wage forecasts for the EGW sectors in NSW, ACT, Tasmania and nationally.[149] Econtech's EGW labour cost growth rates for ACT are shown in table 9.5.

[145] Econtech, *Labour cost growth forecasts*, 13 August 2007, attachment D.
[146] ActewAGL, *Revised regulatory proposal*, p. 13.
[147] ActewAGL, Request for information, 10 February 2009.
[148] ActewAGL, Request for information, 10 February 2009.
[149] Econtech, *Updated labour cost growth forecasts*, 25 March 2009.

**Table 9.5: Econtech's real labour escalation rates for the EGW sector in ACT and Australia (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| ACT | 9.3 | –1.5 | 3.1 | 3.6 | 2.9 | 2.5 | 1.5 |
| Australia | –0.7 | –1.0 | 2.8 | 3.1 | 2.1 | 1.5 | 0.5 |

Source: Econtech, *Updated labour cost growth forecasts*, 25 March 2009, pp. 30–31.

Econtech determined these forecasts using an updated version of its labour cost model (LCM).[150] In particular, the forecasts provided by Econtech reflect the following factors:[151]

- an enhanced approach to labour cost forecasting, which was initially used in the September 2008 report
- national accounts data up to December 2008 (published by the Australian Bureau of Statistics (ABS))
- average weekly earnings data up to November 2008 (obtained by request from the ABS)
- the Federal Government stimulus packages announced in December 2008 and February 2009.

Econtech noted the revisions to the ABS average weekly earnings data series for the August 1996 to May 2008 period, which arose as a result of the ABS quantifying the extent of misreporting with data providers.[152]

Econtech acknowledged that its updated labour cost growth forecasts differ considerably to its labour forecasts published in September 2008. Econtech linked the immediate slowing of labour cost growth projections with the deteriorating global financial situation and anticipation that Australia will slip into recession in 2009. Econtech further noted deteriorating consumer and business confidence, declining dwelling investment, credit markets remaining frozen and expected increases in unemployment rates as contributing factors to Australia's forecast declining economic performance.[153]

Econtech considered that the updated short to medium–term labour growth forecasts vary the most, compared to projections in September 2008, as a result of downward revisions to business investment for the period 2008–09 to 2010–11. Econtech further considered that the longer term labour growth projections are largely unaffected due to its anticipation that Australia will begin to recover from the recession in late 2010.[154]

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150 This model was purpose-built by Econtech for its report to the AER in August 2007.
151 Econtech, *Updated labour cost growth forecasts*, p. 4.
152 ABS, *Information paper: revisions to average weekly earnings series*, August 2008, Cat No: 6302.0.553.001, November 2008.
153 Econtech, *Updated labour cost growth forecasts*, pp. 7–8.
154 Econtech, *Updated labour cost growth forecasts*, pp. 8–9.

Econtech observed that a recent crash in commodity prices has had implications for labour demand in the mining industry and consequently, wages growth in that sector. This has had a flow on effect for EGW labour forecasts, where competition for workers with similar skills—namely, electricians and electrical and other engineers from the mining and construction industries—has slowed.[155] This slowing in labour demand has resulted in slowing wage growth in the EGW sector, which has fallen (compared to Econtech's September 2008 forecasts) particularly in the immediate period to 2009–10.[156] This is consistent with the inverse observations by Econtech relating to increases in wages growth, due to the recent mining and construction boom, which were exacerbated by a skills shortage and businesses being forced to offer higher wages to attract skilled workers.[157]

At the national level, the projected growth rate for the EGW sector is expected to perform better relative to the mining and construction industries. This outcome is consistent with Econtech's observations in its September 2008 report, which noted that given the essential nature of utility services, DNSPs have a greater imperative to attract and maintain skilled workers.[158]

Econtech made the following observations on the utility sector in the ACT:[159]

- the economic outlook has been less affected compared to other states, given its dependence on the government sector
- the current economic downturn has resulted in labour cost forecasts being revised downwards due to public sector job losses and an easing housing market
- EGW wages are expected to ease primarily in the short–term due to an expected slowdown in economic growth during 2009–10, however, deceleration is not as dramatic as for other states
- the forecast EGW average annual real growth rate (at 2.9 per cent) is expected to be higher than the all–industry average (at 1.0 per cent) for the next regulatory control period.

As part of its report, Econtech also provided an update on general labour forecasts for all industries across Australia and the ACT.[160] Econtech's general labour cost growth rates are shown in table 9.6.

**Table 9.6: Econtech's real general labour escalation rates for ACT (per cent)**

| | 2007–08 | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|---|
| ACT | –0.8 | –2.5 | 0.5 | 1.3 | 1.0 | 0.9 | 0.2 |

Source: Econtech, *Updated labour cost growth forecasts*, p. 30.

155 Econtech, *Updated labour cost growth forecasts*, p. 7.
156 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, 19 September 2008, p. 25.
157 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, p. 23.
158 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, p. 23; and Econtech, *Updated labour cost growth forecasts*, p. 3.
159 Econtech, *Updated labour cost growth forecasts*, pp. 17–18.
160 Econtech, *Updated labour cost growth forecasts.*

**AER considerations**

***EGW wages and general labour***

The AER notes, in its revised regulatory proposal, ActewAGL accepted the EGW labour escalators for the EGW sector in the ACT, in addition to the general labour escalators applied by the AER in the draft decision.[161] Further, the AER notes ActewAGL did not comment on the timing issues relating to cost escalators raised in CEG's report. CEG was commissioned by the NSW DNSPs to review the AER's cost escalators applied in the draft decision.[162] CEG considered that while the AER's approach was largely reasonable, it had concerns with the timing calculations applied in the draft decision. Specifically:

- Econtech forecasts for EGW wages and general wages growth were in financial year average terms, not in June to June terms
- EBA rates were not correctly timed to interpolate to EGW rates, resulting in the model double counting inflation for some years.

***Updated labour cost escalators***

In the draft decision, the AER applied Econtech's general wage growth forecasts for all industries across Australia to escalate direct labour costs incurred by ActewAGL.[163] However, the AER notes the application of Econtech's EGW labour growth forecasts, which are based on state/territory specific data, and Econtech's general labour growth forecasts, which are based on national data, are inconsistent. The AER is of the view that ACT specific general labour escalators should be applied to ActewAGL's general wages, as it reflects the economic circumstances and performance of the ACT and is likely to be a better predictor of future trends in wages growth in the ACT. Therefore, for this final decision the AER will apply Econtech's all industries wage growth forecast for the ACT as ActewAGL's general labour escalator.

The AER considers that CEG's recommendations regarding the appropriate timing of the escalators the AER applied in the draft decision are generally reasonable. The AER has rectified the issues raised by CEG and has applied the same modelling to ActewAGL labour forecasts, as with other NSPs, to ensure a consistent approach for all cost escalators in the next regulatory control period.[164]

The AER further engaged in a briefing with ActewAGL, and other NSPs, regarding concerns with Econtech updating its forecasts after the NSPs had submitted their revised regulatory proposals or revised revenue proposals. To ensure a robust and transparent process on the updating of labour wage growth forecasts, the AER facilitated a briefing for ActewAGL and other NSPs. At the briefing Econtech provided an overview of the economic models used to derive its labour wage forecasts and the economic assumptions underlying its updated forecasts. The AER also outlined refinements to its escalations model from the draft decision.

161 ActewAGL, *Revised regulatory proposal*, p. 11.
162 CEG, *Escalators affecting expenditure forecasts*.
163 AER, *Draft decision*, p. 236.
164 For further information, see: AER, *Final decision, NSW distribution determination*, appendix L.

***Enterprise Bargaining Agreement***

For this final decision, the AER has adopted actual wage data increases for 2007–08 provided for under ActewAGL's EBA. Further, the AER has applied ActewAGL's 2008–09 EBA rates to its EGW labour escalation. For the next regulatory control period, the AER has adopted Econtech's updated EGW labour cost growth forecasts. The AER does not consider it appropriate to use ActewAGL's EBA rates for the next regulatory control period as this would move ActewAGL from an incentive based framework to a cost of service recovery framework. This means ActewAGL still has an incentive to negotiate with its employees to obtain productivity savings under its EBA.

*Electrical workers attraction and retention allowance*

The AER has reviewed ActewAGL's new EBA and can confirm it provides for an annual attraction and retention allowance for ActewAGL's electrical workers which is to be applied in addition to ActewAGL's EBA rates.[165]

Based on the information provided by ActewAGL, the AER weighted the proposed allowance against the proportion of ActewAGL's electrical workers, relative to its entire workforce, to determine an EBA rate of 5.9 per cent for 2008–09. The AER considers it reasonable to apply its calculated EBA rate for 2008–09 only, given the AER will be applying Econtech's updated EGW labour growth forecasts from 2009–10 to 2013–14.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal and the additional information provided, the AER is satisfied that the application of the above EBA rate for 2008–09 to ActewAGL's EGW labour opex component results in expenditure which reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors.

*Performance targets*

The AER has reviewed the information provided by ActewAGL regarding the inclusion of performance targets (also known as stretch targets) of 3 per cent as an additional labour cost to apply to its workers not under a competency agreement.[166]

The AER notes ActewAGL's performance target labour costs are paid to workers, above their base salary if they meet performance targets. The AER is not satisfied that ActewAGL has demonstrated how individual performance bonuses paid to employees would result in higher productivity levels for the entire organisation, and therefore the need to allow the cost impact to ActewAGL's opex.

The AER notes that performance bonuses generally reflect individual employee productivity improvements and as such are selective, rather than broad based payments.[167] Any bonus paid by ActewAGL, provided it is less than the cost of employing new staff to increase output by the equivalent productivity increase, should

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165 ActewAGL's new EBA is for 1 July 2008 to 30 June 2011.

166 This amount is proposed to be in addition to the 5 per cent annual wage increase as specified in ActewAGL's EBA.

167 The AER notes Econtech's labour cost growth forecasts are adjusted for productivity growth which is applicable to all NSPs across their entire workforce. For further discussion, see: Econtech, *Updated labour cost growth forecasts*, pp. 20–26.

result in cost savings for ActewAGL.[168] Therefore, the AER is not satisfied that ActewAGL has appropriately quantified the increase to its labour costs through its application of performance targets and individual productivity relative to increased productivity of ActewAGL in its entirety.

The AER also notes that the only other NSP to apply for a performance related rate above the EBA allowance is Transend in its 2009–14 revenue proposal.[169] Transend sought to include performance amounts with the (base) EBA rate and this was rejected by the AER.

Under the current incentive framework, the AER approves a forecast allowance that a DNSP must spend as efficiently as possible. The AER considers that allowing cost escalation to include the performance targets would result in a move towards a cost of service model for labour cost. The AER notes that it is:

- only required to provide regulated businesses a reasonable opportunity to recover efficient costs
- not required to provide compensation for every decision made by a DNSP that impacts on its costs.

The AER considers that the use of ActewAGL's negotiated EBA wage rate for 2007–08 to 2008–09 will provide a reasonable proxy of real wage cost increases across the organisation.[170] The AER considers that extending ActewAGL's EBA to include individual employee performance payments (along with any other individual payments businesses may choose to allow its staff) will undermine the incentive framework for businesses to operate efficiently.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal and the additional information provided, the AER is not satisfied that the application of performance targets to ActewAGL's EGW labour opex component results in expenditure which reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors.

***Corporate services labour***

The AER has reviewed the information provided by ActewAGL and considers that the application of ActewAGL's corporate services labour escalator does not result in forecast opex that reflects the efficient costs a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives.

The AER notes that by operation of clauses 6.5.6(c)(3) and 6.5.6(d) of the transitional chapter 6 rules, in accepting a DNSP's forecast of required opex the AER must be satisfied the total forecast opex reasonably reflects a realistic expectation of cost inputs required to achieve the opex objectives. The AER does not consider that applying ActewAGL's corporate services labour escalator reflects the opex objectives. The AER notes the proposed corporate services labour escalator was based

168 That is, while labour costs may increase, total costs per unit of output will decrease.

169 Transend, *Revised revenue proposal*, p.33.

170 Following 2007–08 to 2008–09, EGW cost escalators will be applied for the next regulatory control period.

on wages growth in the finance and insurance, and property and business services sectors at a national level.[171] The AER considers the application of an escalator based on national data, and not State or Territory specific data, to be inconsistent with AER practice which is to apply labour escalators that reflect the economic circumstances and performance of the relevant state or territory. The AER considers that ActewAGL's proposed corporate services labour escalator does not accurately reflect the performance of the finance and insurance, and property and business services sectors within the ACT. The AER therefore, is not satisfied ActewAGL's corporate services labour escalator reflects a realistic expectation of cost inputs, which would be required to achieve the opex objectives.

The AER notes the data used by ActewAGL to derive its corporate services labour escalator was sourced from Econtech's 2007 report.[172] The AER therefore, obtained updated wage growth forecasts (by industry) from Econtech, given the change in economic conditions since 2007.[173] The AER weighted the two categories ActewAGL used to calculate its escalator[174] and deflated the data to determine an updated, real corporate services labour escalator.[175] The AER notes significant differences between ActewAGL's proposed corporate service labour escalator and that derived by the AER, which is to be expected given the current economic slowdown. The AER further compared the cumulative totals of the updated corporate services labour escalator with Econtech's updated general labour forecasts for the ACT (as set out in table 9.6) and found that the results are not materially different. The AER considers that the methodology applied by ActewAGL to derive the corporate services labour escalator does not accurately reflect the economic circumstances and performance of the respective service industries in the ACT. The AER considers the application of the general wage escalator is relevant to ActewAGL in these circumstances, as it appropriately reflects opex that would be incurred by ActewAGL.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal and the additional information provided, the AER is not satisfied that ActewAGL's approach in applying a corporate services labour escalator to its corporate services opex results in expenditure which reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors.

***Retail labour***

The AER has reviewed the information provided by ActewAGL and considers that the application of ActewAGL's retail labour escalator does not result in forecast expenditure that reflects the efficient costs a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives.

The AER notes clause 6.10.3(b) of the transitional chapter 6 rules specifies a DNSP may only make revisions to its regulatory proposal:

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171 Econtech, *Labour cost growth forecasts*, 13 August 2007, attachment D.

172 Econtech, *Labour cost growth forecasts*, 13 August 2007.

173 This approach is consistent with that taken in the draft decision, see: AER, *Draft decision*, p. 236; and Econtech, *Updated labour cost growth forecasts*, attachment C.

174 In accordance with proportions specified, see: ActewAGL, *Revised regulatory proposal*, p. 11.

175 The CPI figures used to deflate the forecast of nominal wage growth by industry were sourced from: Econtech, *Australian National State and Industry Outlook*, 23 January 2009.

> …so as to incorporate the substance of any changes required to address matters raised by the draft distribution determination or the AER's reasons for it.

ActewAGL did not include the application of a retail labour escalator in its regulatory proposal, therefore the AER did not consider the application of a retail labour escalator in its draft decision. The AER considers the inclusion of ActewAGL's retail labour escalator in its revised regulatory proposal to be new information. Therefore the AER is not required to address ActewAGL's proposed retail labour escalator. Further, the AER considers that the general labour escalator for the ACT (as outlined in table 9.7) appropriately reflects opex that would be incurred by ActewAGL for the opex component that it has since categorised, in its revised regulatory proposal, as retail labour.

The AER, in accordance with the transitional chapter 6 rules, does not consider it appropriate for ActewAGL to introduce new information in its revised regulatory proposal. The AER, therefore, confirms its position that applying the general labour escalator to ActewAGL's retail labour component opex results in expenditure which reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors.

***Application of labour cost escalators***

For this final decision, the AER has adopted Econtech's updated ACT EGW wage growth forecasts for the next regulatory control period. The AER has remodelled the forecasts to address CEG's timing issues and applied these updated forecasts for the EGW sector in the ACT for the next regulatory control period. Actual wage data, however, was available for 2007–08 and 2008–09, therefore, the AER has applied actual wage increases provided for under ActewAGL's EBA for those years, which have also been remodelled to address CEG's timing issues.

The AER, for this final decision, has adopted Econtech's updated ACT general labour cost escalators for 2007–08 to 2013–14. The AER, in the draft decision, considered the application of general labour cost escalators to ActewAGL's vegetation management, pole inspection and plant operator programs reflected a reasonable approach to forecasting outsourced services opex.[176] The AER has confirmed the application by ActewAGL of the general wage escalator to its outsourced services.[177] As discussed above, the AER also requires ActewAGL to apply the updated general labour escalator to its retail and corporate services labour components of opex.

**Table 9.7: AER conclusion on ActewAGL's real EGW and general labour escalators (per cent)**

| | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|
| EGW labour | 2.42 | 2.50 | 3.60 | 2.90 | 2.50 | 1.50 |
| General labour | –2.50 | 0.50 | 1.30 | 1.00 | 0.90 | 0.20 |

176 AER, *Draft decision*, p. 103.
177 ActewAGL, Response to request for information, 5 February 2009.

Following a request from the AER, ActewAGL advised that the AER's conclusions result in a reduction of $8.3 million ($2008–09) to its forecast opex.[178]

**AER conclusions**

As a result of its analysis of the revised regulatory proposal, the AER is satisfied that the application of updated EGW wages and general labour forecast escalators for ACT (as set out in table 9.7), which have been adjusted to incorporate timing issues, reasonably reflect the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors.

### 9.5.2 STPIS data collection

**AER draft decision**

In the draft decision, the AER approved ActewAGL's proposed capex and opex relating to acquiring or updating data management systems in preparation for the national distribution STPIS. The AER noted that ActewAGL expected to incur additional costs to establish new systems and processes during the next regulatory control period in order to prepare for the introduction of the national distribution STPIS from 2014.[179]

**Revised regulatory proposal**

In its revised regulatory proposal, ActewAGL proposed an additional opex allowance for the next regulatory control period arising in response to the draft decision on STPIS arrangements.[180]

In order to comply with the STPIS reporting obligations, ActewAGL proposed opex of $0.9 million over five years to cover staffing costs associated with its new project called the 'network connectivity solution' that records interruptions at the customer level and the number of actual inactive accounts on its network.[181] ActewAGL stated that this project is in addition to the STPIS work already costed in its regulatory proposal.

ActewAGL submitted that additional staff are required to maintain the database and ensure that the information recorded is accurate and aligned with other information management systems run by ActewAGL. ActewAGL forecast one additional ongoing staff member in 2009–10, growing to two ongoing staff members in 2010–11.[182] Table 9.8 shows an annual breakdown of STPIS network connectivity project costs proposed by ActewAGL for the next regulatory control period.

178 ActewAGL, Response to request for information, 16 April 2009.
179 AER, *Draft decision*, p. 146.
180 ActewAGL, *Revised regulatory proposal*, pp. 19–22.
181 ActewAGL, *Revised regulatory proposal*, pp. 19–22.
182 ActewAGL, *Revised regulatory proposal*, p. 22.

**Table 9.8: ActewAGL's proposed STPIS network connectivity project costs ($m, 2009–08)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Staffing – data management | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.9 |

Source: ActewAGL, *Revised regulatory proposal*, p. 22.

**AER considerations**

The AER notes the costs associated with the network connectivity project could not be finalised at the time ActewAGL's regulatory proposal was lodged on 2 June 2008. ActewAGL proposed that any significant changes to the national distribution STPIS occurring after the date it submitted its regulatory proposal to the AER, could be addressed in response to the AER's draft distribution determination, or through ActewAGL's proposed 'transitional period' pass through event mechanism.[183]

The AER's final decision on the national distribution STPIS was released in June 2008.[184] ActewAGL stated its revised cost estimates for STPIS reporting requirements reflect the need for additional staff to maintain the new data system required to meet the reporting requirements set out in the national distribution STPIS.[185]

The AER has reviewed the proposed network connectivity project and considers the opex forecasts associated with that project reasonably reflects the additional staffing required and the salary costs for the skill levels required.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal, the AER is satisfied that ActewAGL's additional forecast STPIS opex reasonably reflects the opex criteria including the opex objectives. In coming to this view the AER has had regard to the opex factors.

### 9.5.3 Feed-in Tariff scheme

The introduction of the FiT scheme has impacted on ActewAGL's standard control services capex and opex forecasts (in respect of direct tariff payments, network operations, and IT systems development) and alternative control services capex and opex forecasts (in respect of customer initiated metering installation and inspections). This section considers only the standard control services opex forecasts in respect of the FiT scheme. Consideration of standard control forecast capex is in chapter 8 of this final decision and consideration of the alternative control services capex and opex forecasts is in chapter 18 of this final decision.

183 ActewAGL, *Revised regulatory proposal*, pp. 44–47.
184 AER, *Final decision, Electricity distribution service providers, Service target performance incentive scheme*, June 2008.
185 ActewAGL, email to AER, 25 March 2009.

**AER draft decision**

The AER considered the FiT scheme in the context of a nominated pass through (transitional period) event, but rejected ActewAGL's proposed treatment of the FiT scheme because it was inconsistent with the NER.[186]

**Revised regulatory proposal**

ActewAGL stated that as a result of ACT Government processes, which occurred after ActewAGL had lodged its regulatory proposal, it was now in a position to provide forecasts of likely expenditures associated with implementation of the first stage of the FiT scheme.[187]

ActewAGL proposed a total additional opex allowance of $49 million ($2008–09) for the next regulatory control period consisting of:[188]

- $48 million to cover direct tariff payments—ActewAGL is required to reimburse retailers supplying the eligible customers the difference between the feed–in tariff rate and the 'normal cost of electricity' rate declared by the ACT Government for the output of those customers' generators
- $1 million to cover staffing costs associated with network connections as well as staff to undertake associated metering inspections and installations activities.

The opex associated with network connections, metering maintenance and repair encompasses both standard control and alternative control services opex. Table 9.9 sets out the standard control FiT scheme opex proposed by ActewAGL for the next regulatory control period.

**Table 9.9: ActewAGL's proposed standard control FiT scheme opex ($m, 2009–08)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Direct tariff payments | 3.4 | 6.8 | 10.0 | 12.7 | 15.3 | 48.2 |
| Network operations expenditure | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.6 |
| Total | 3.6 | 7.0 | 10.2 | 12.9 | 15.5 | 49.3 |

Source: ActewAGL, *Revised regulatory proposal*, p. 29.

ActewAGL noted that differences between forecast and actual direct tariff payments may arise as a result of changes to the FiT and 'normal cost of electricity' rates each year, and other changes in policy, both jurisdictional and national, that may change the scope or level of funding for installation of units, or the value of electricity generated by installed units.[189]

ActewAGL also proposed an adjustment mechanism to deal with the risk associated with the forecasts of direct tariff payments.[190] It stated the most efficient adjustment

186 AER, *Draft decision*, p. 168.
187 ActewAGL, *Revised regulatory proposal*, p. 27.
188 ActewAGL, *Revised regulatory proposal*, pp. 27–29.
189 ActewAGL, *Revised regulatory proposal*, confidential attachment 9.
190 ActewAGL, *Revised regulatory proposal*, pp. 29–31.

mechanism is through an annual adjustment to the forecast direct tariff payments to reflect actual payments in the previous regulatory year as part of the annual pricing process. Its proposed approach would remove the uncertainty around the direct tariff payment forecasts, limit the potential for ActewAGL to over or under recover such payments due to forecasting error, and avoid administrative costs associated with pass through applications.[191] This proposed adjustment is similar with that proposed by ActewAGL for its UNFT allowance in its regulatory proposal.

**Submissions**

The AER received one submission from ActewAGL.[192]

ActewAGL noted that stage one of the scheme would come into effect on 1 March 2009, while a second stage likely to apply to larger–scale generation is expected to be announced in June 2009.[193]

ActewAGL provided details on its estimation of direct tariff payments, including factors such as:

- expected number of generation units to be installed
- expected average capacity of units
- expected average output from units
- the FiT rate set by the Ministerial determination
- the 'normal cost of electricity' rate set by the Ministerial determination.

To forecast these variables, ActewAGL used:[194]

- ACT historical photovoltaic generation installation rates, capacity and output measurements
- data from the introduction of FiT schemes in other jurisdictions, including uptake rates and average capacity of units
- data from the German gross FiT scheme and its impact on uptake rates.

ActewAGL restated its proposal that an adjustment mechanism be introduced to recover the direct tariff costs associated with both stages of the scheme. It did not agree with the draft decision that the AER could not approve the proposed pricing adjustment mechanism, in the context of the UNFT allowance, under the transitional chapter 6 rules. ActewAGL stated the AEMC's recent changes to the NER to accommodate SP AusNet's recovery of land easement tax provided additional support to ActewAGL's proposal to recover its FiT scheme direct tariff costs.[195]

ActewAGL also asserted that an adjustment mechanism, applied as part of the annual pricing proposal, would be the most efficient and accurate way to manage uncertainty

191 ActewAGL, *Revised regulatory proposal*, p. 31.
192 ActewAGL, *Distribution determination 2009–14, Submission to the AER*, 16 February 2009.
193 ActewAGL, *Submission to the AER*, p. 4.
194 ActewAGL, *Revised regulatory proposal*, confidential attachment 9, p. 95.
195 ActewAGL, *Submission to the AER*, p. 9.

associated with the FiT scheme, while ensuring that compliance and administrative costs are kept to a minimum.[196]

ActewAGL considered other options for managing its risks with respect to the direct tariff payments under the FiT scheme, including regulatory change event pass through and a nominated (FiT change) event pass through. ActewAGL stated that it did not consider a regulatory change event pass through provided sufficient certainty of cost recovery under the transitional chapter 6 rules.[197] However, it noted a nominated pass through event is consistent with the AEMC's SPAusNet decision. ActewAGL proposed the following definition of a nominated pass through event:[198]

> **Feed-in tariff change event** means a change in the total amount of direct feed–in tariff rebates paid by ActewAGL Distribution in respect of the ACT Feed-in tariff scheme. For the purpose of this definition, the change in the amount of direct feed–in tariff rebates paid by ActewAGL Distribution must be calculated as the difference between:
>
> (1) the amount of scheme direct feed–in tariff costs paid each regulatory year by ActewAGL Distribution, derived from the metered output of generators subject to the scheme; and
>
> (2) the amount of scheme direct feed–in tariff costs which are forecast for the purpose of and included in the Australian Capital Territory distribution determination for each regulatory year of the regulatory control period.
>
> Relevant feed–in rebates under this pass through mechanism are those paid through the operation of the Electricity Feed-in (Renewable Energy Premium) Act 2008, and any amendments to this Act, or through the operation of a new Act implementing the expected second stage of the scheme applying to larger generators.

ActewAGL clarified that an application for a pass through amount would be made within 90 days of the end of the regulatory year and take account of the time value of money. Further, it submitted that the pass through event should not be subject to any materiality threshold as a '…materiality threshold would undermine ActewAGL's ability to recover changes in uptake rates".[199]

ActewAGL also expressed concern about the costs associated with implementing stage two of the FiT scheme. ActewAGL was uncertain whether these costs could fall under the regulatory change event category as defined by the transitional chapter 6 rules.[200]

ActewAGL stated that it could seek to recover additional costs related to stage two of the FiT scheme through a pass through application when the details are announced by the ACT Government.[201] These costs include IT systems, metering, inspection and managing connections, and the direct tariff payments associated with the FiT scheme.

196 ActewAGL, *Submission to the AER*, p. 8.
197 ActewAGL, *Submission to the AER*, p. 11.
198 ActewAGL, *Submission to the AER*, p. 12.
199 ActewAGL, *Submission to the AER*, p. 11.
200 ActewAGL, *Submission to the AER*, p. 8.
201 ActewAGL understand that the ACT government will announce details of stage two of the FiT scheme in June 2009.

However, ActewAGL also stated that it considered its preferred pricing adjustment mechanism would enable it to recover any direct tariff payments arising under stage two of the FiT scheme without any further assessment.[202]

ActewAGL also proposed that costs incurred in the current regulatory control period in respect of the introduction of the FiT scheme—that is, costs incurred in the period 1 March 2009 to 30 June 2009—should be included in the cost estimates for the 2009–10 regulatory year, and hence recovered in the next regulatory control period.[203]

**AER considerations**

This chapter only addresses the standard control services components (direct tariff payments and network operations opex) of the FiT scheme opex forecasts proposed by ActewAGL. The FiT scheme opex relating to metering services is addressed in chapter 18: Alternative control services, of this final decision.

***Forecast opex***

The AER notes that considerable uncertainty surrounds the costs likely to arise due to the introduction of the FiT scheme in the ACT. There is uncertainty around the take up rates expected under the scheme, the capacity and output of generators, and ongoing uncertainty regarding the price differential (between the FiT rate and the normal price of electricity) that will apply in each year under the FiT scheme.

The AER considers that this uncertainty will impact to the greatest extent on the forecast direct tariff payments under the FiT scheme. These payments represent the bulk of the proposed opex costs (around 98 per cent in the next regulatory control period) and will be directly affected by changes in the variables considered.

The AER has reviewed ActewAGL's estimation of direct tariff payments. The AER is satisfied that the forecast participation rates are consistent with benchmark rates as well as those forecast by the ACT Government. The AER also considers that ActewAGL's forecasts of the number, capacity and output of generators are based on reasonable assumptions.

The AER notes that ActewAGL has included $0.3 million in direct tariff payments incurred in 2008–09 in its forecast of direct tariff payments for 2009–10.[204] ActewAGL stated this approach to the recovery of these costs is consistent with the AER's proposal to address these costs as a pass through application. However, the AER considers that clause 6.5.6 of the transitional chapter 6 rules does not allow for expenditure incurred in the current regulatory control period to be included in the opex forecasts for the next regulatory control period.[205] Therefore the AER has excluded this amount from the opex forecast for 2009–10. The AER will consider any pass through application in respect of these costs on its merits, at the time the application is made to the AER.

202 ActewAGL, *Submission to the AER*, p. 8.
203 ActewAGL, *Revised regulatory proposal*, pp. 107–108.
204 ActewAGL, *Revised regulatory proposal*, p. 107.
205 NER, transitional chapter 6 rules, clause 6.5.7(a).

For the reasons discussed above the AER is not satisfied that ActewAGL's forecasts of direct tariff payments reasonably reflect the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

The AER considers the other costs associated with the introduction of the FiT scheme—that is, network operations opex—are only indirectly affected by variations in the factors that will influence participation in the scheme. Further, the cost estimates are based on likely increases in staffing required to implement the FiT scheme arrangements. The AER notes the costs are commensurate with the cost estimates of similar services provided by ActewAGL.

For the reasons discussed above, the AER is satisfied that the forecast opex for the implementation of the FiT scheme (excluding direct tariff payments) reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

***Adjustment mechanism***

The AER notes that differences between forecast and actual direct tariff payments could arise throughout the next regulatory control period as:

- the tariff rate set by the ACT Government is not known beyond one year in advance of the current financial year
- it is difficult to accurately determine the customer/generator uptake rate of the FiT scheme, and there is uncertainty as to when stage two of the scheme will begin
- there may be a change in the ACT Government's policy on the FiT scheme during the next regulatory control period.

The newness of the FiT scheme in the ACT means that ActewAGL has not had sufficient time to test the accuracy of its direct tariff payment forecasts, nor has it been able to develop its forecasts with the benefit of historical data. Under these circumstances the AER considers it is reasonable that ActewAGL not be subject to the risk associated with direct tariff payment forecasting error.

The AER notes ActewAGL's argument that the AER may introduce a pricing adjustment mechanism under section 15(2) of the NEL—that is, the AER 'has the power to do all things necessary or convenient to be done for or in connection with the performance of its functions'.[206]

However, section 15(2) does not provide the AER with an unfettered power to do anything. The AER considers it is a power to 'do all things necessary or convenient' so long as in so doing the AER remains within and does not exceed the regulatory framework as provided for under the NEL and NER. The AER considers that section 15(2) does not empower the AER to introduce a new exception to the operation of clause 6.18 of the transitional chapter 6 rules in respect of the distribution pricing rules.

The transitional chapter 6 rules only provide specific exceptions for when a DSNP's maximum average allowed revenue is able to be adjusted. Clauses 6.18.7 and

[206] ActewAGL, *Revised regulatory proposal*, p. 30.

6.18.2b (5A) of the transitional chapter 6 rules state that revenue adjustments can be made for transmission use of system (TUOS) charges and in the case of the NSW DNSPs, the Climate Change Fund. As the transitional chapter 6 rules do not provide a more general exception or an exception specific to the FiT scheme, the AER considers that a pricing proposal cannot be used to adjust revenues in relation to the FiT scheme. This is consistent with the AER's conclusion regarding ActewAGL's proposed UNFT adjustment mechanism, as discussed in the draft decision and section 9.5.4 of this chapter.

As noted above the AER considers that ActewAGL should not bear the risk of forecasting error, in respect of the direct tariff payments made under the FiT scheme. The AER is of the opinion that differences between actual and forecast direct tariff payments to the retailer should form the basis of a nominated pass through event under the relevant provisions of the transitional chapter 6 rules. The AER considers this mechanism is consistent with the transitional chapter 6 rules, and is consistent with the AEMC's decision in respect of the easement tax that impacted SP AusNet.

The AER is of the view that treating the differences associated with forecasting direct tariff payment costs through the pass through mechanism as a nominated event would mitigate the uncertainty associated with forecasting these costs. This approach is also consistent with the ACT Government's intention that the cost of the scheme is to be recovered from the ACT community. The AER has further considered the pass through mechanism in chapter 16 of this final decision.

***Conclusion***

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal, the AER is not satisfied that ActewAGL's forecast direct tariff payments reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors. The AER considers that a reduction of $0.3 million is required in the 2009–10 regulatory year, resulting in a total direct tariff payment forecast of $47.9 million ($2008–09) for the next regulatory control period.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal, the AER is satisfied that ActewAGL's forecast opex of $0.6 million ($2008–09) associated with network operations arising from the implementation of the FiT scheme (excluding direct tariff payments) reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

The AER considers that differences between the forecast and actual direct tariff payments should form the basis of a nominated pass through event in the next regulatory control period. The AER will consider any pass through application in respect of these costs on its merits, at the time the application is made to the AER.

### 9.5.4 Utilities Network Facilities Tax

**AER draft decision**

In the draft decision, the AER rejected ActewAGL's proposed forecast of UNFT liability for the next regulatory control period. The AER adjusted the proposed UNFT forecast and reduced the amount from $20.9 million to $20.7 million ($2008–09).[207]

The AER also rejected ActewAGL's proposal to adjust for differences between forecast tax and actual tax payable through the adjustment mechanism during the next regulatory control period. The AER did not consider that the transitional chapter 6 rules allowed the pricing process to be used to adjust for expenditures other than TUOS charges.[208]

**Revised regulatory proposal**

ActewAGL accepted the draft decision in respect of the AER adjusted UNFT forecast for the next regulatory control period.

ActewAGL stated it considered its proposal to adjust for under and over recoveries is allowable under section 15(2) of the NEL.[209] However, ActewAGL stated it would accept the draft decision not to allow such adjustments on the condition that the materiality threshold for the pass through assessment be set to zero.[210]

**AER considerations**

The AER maintains its draft decision not to incorporate an adjustment mechanism for under or over recoveries of the UNFT in the next regulatory control period. It considers that as the UNFT has been in place since 2007, ActewAGL should be able to incorporate reasonable estimates of its likely tax liability into its opex forecasts.

The AER considers that it is inappropriate to use the annual pricing mechanism to adjust for discrepancies between forecast and actual UNFT liabilities—that is, make adjustments to ActewAGL's maximum average allowed revenue. The transitional chapter 6 rules provide specific exceptions for when a DSNP's maximum average allowed revenue is able to be adjusted. Clauses 6.18.7 and 6.18.2(b)(5A) of the transitional chapter 6 rules state that revenue adjustments can be made in the specific circumstances of TUOS and in the case of the NSW DNSPs, the Climate Change Fund. As the transitional chapter 6 rules do not provide a more general exception or an exception specific to the UNFT, the AER considers that a pricing proposal should not adjust revenues in relation to the UNFT.

The AER notes ActewAGL's submission that the AER may do so on the basis of section 15(2) of the NEL which states that the AER 'has the power to do all things necessary or convenient to be done for or in connection with the performance of its functions.'[211] However, section 15(2) does not provide the AER with an unfettered power to do anything. The AER considers it is a power to 'do all things necessary or convenient' so long as in so doing the AER remains within and does not exceed the

207 AER, *Draft decision*, pp. 117–118.
208 AER, *Draft decision*, pp. 117–118.
209 ActewAGL, *Revised regulatory proposal*, pp. 30–32.
210 ActewAGL, *Revised regulatory proposal*, p. 32.
211 ActewAGL, *Revised regulatory proposal*, p. 30.

regulatory framework as provided for under the NEL and NER. The AER considers that section 15(2) does not empower the AER to introduce a new exception to the operation of clause 6.18 of the transitional chapter 6 rules in respect of the distribution pricing rules.

The AER notes that the UNFT liability may vary due to a change in the determined rate set by the ACT Government. In such a circumstance, the transitional chapter 6 rules allow ActewAGL to apply to the AER for a cost pass through, as a tax change event. The AER will consider any pass through application in respect of these costs on its merits, at the time the application is made to the AER.

### 9.5.5 Debt raising costs

Debt raising costs are incurred each time debt is rolled over, and may include underwriting fees, legal fees, company credit rating fees and other transaction costs. The AER has accepted that debt raising costs are a legitimate expense for which a DNSP should be provided an allowance.[212]

**AER draft decision**

In the draft decision, the AER did not accept ActewAGL's proposal to include in its opex forecast a benchmark allowance for debt raising costs equal to 0.0936 per cent (9.36 basis points) of the benchmark debt share (60 per cent) of the opening regulatory asset base (RAB) in each year of the next regulatory control period.[213]

The AER considered that the approach proposed by ActewAGL in its regulatory proposal was not appropriate as it implied 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. Accordingly, the AER maintained its approach of providing benchmark debt raising costs in accordance with the 2004 Allen Consulting Group (ACG) methodology,[214] which assumes refinancing of debt with each regulatory determination, as applied in previous transmission determinations.[215]

Applying the ACG methodology to ActewAGL, the AER approved an allowance of 9.2 basis points per annum (bppa) over the notional debt component of the RAB in each year, resulting in a total allowance of $1.8 million ($2008–09) over the next regulatory control period.[216]

**Revised regulatory proposal**

ActewAGL provided a revised estimate of direct and indirect debt raising costs, of 15.5 bppa, resulting in a total proposed debt raising allowance of $3 million ($2008–09)

212 AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 14 June 2007, pp. 94–97; AER, *Final decision, SP Ausnet transmission determination 2008–09 to 2013–14,* January 2008, pp. 148–150; and AER, *Final decision, ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008, pp. 84–85.

213 AER, *Draft decision*, pp. 105–107.

214 ACG, *Debt and equity raising transaction costs*, December 2004.

215 AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 14 June 2007, pp. 94–97; AER, *Final decision, SP Ausnet transmission determination 2008–09 to 2013–14*, January 2008, pp. 148–150; and AER, *Final decision, ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008, pp. 84–85.

216 AER, *Draft decision*, p. 105.

over the next regulatory control period.[217] ActewAGL submitted that this estimate was supported by its consultant, the Competition Economists Group (CEG).[218]

The AER notes that ActewAGL, the NSW DNSPs, TransGrid and Transend (the NSPs) have all relied on essentially the same CEG report as the core of their arguments on this matter.[219]

Table 9.10 provides ActewAGL's revised regulatory proposal on debt raising costs.

**Table 9.10: ActewAGL's revised regulatory proposal on debt raising costs ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL's revised regulatory proposal | 0.5 | 0.6 | 0.6 | 0.6 | 0.7 | 3.0 |

Source: ActewAGL, *Revised regulatory proposal*, p. 33.

**Submissions**

EnergyAustralia noted that all the NSPs proposed the same allowance for debt raising costs (15.5 bppa on the debt component of RAB) and that this was the same position stated in their respective regulatory proposals. Given the evident consistency across proposals, EnergyAustralia requested that all reports and supporting documents which it had submitted as part of its regulatory proposal and revised regulatory proposal be considered by the AER in making its final determination for ActewAGL for the next regulatory control period.[220]

EnergyAustralia's further submission on the draft decision attached the Joint Industry Association's (JIA) submission to the AER's weighted average cost of capital (WACC) review.[221] The JIA stated that indirect and direct debt raising costs were direct substitutes (in line with the CEG report), and that the AER needed to adjust its previous methodology upwards (to at least 19.5 bppa) to provide an allowance for indirect costs.[222] Additionally, JIA questioned the appropriateness of the direct cost proxy used in the ACG methodology and argued that each NSP should specify the timing and size of each debt issue in their regulatory proposal rather than accepting allowances based on average AER assessments.[223]

**Consultant review**

The AER engaged Dr John C. Handley, Associate Professor in Finance at the University of Melbourne, to review the submitted material on this issue, including the

217 ActewAGL, *Revised regulatory proposal*, p. 33.
218 CEG, *Debt and Equity Raising Costs*, January 2009, in ActewAGL, *Revised regulatory proposal*, confidential, appendix 15.
219 CEG, January 2009.
220 EnergyAustralia, *Submission on AER's draft decisions for other network service providers*, 16 February 2009, p. 3.
221 EnergyAustralia, *Further submission*, 16 February 2009, attachment V.
222 JIA, *Network Industry Submission: Debt and Equity Raising Costs*, 11 November 2008, pp. 20–21.
223 JIA, pp. 20–21.

regulatory proposal and revised regulatory proposal submitted by ActewAGL, and all relevant accompanying consultant reports.[224]

In his report, Associate Professor Handley segregated debt raising costs into two key areas: indirect (underpricing) and direct. On the underpricing of debt capital, he stated:[225]

> The key issue is whether the AER's approach to estimating the cost of debt for the regulated firm is appropriate. If it is then, by definition, no compensation for underpricing is necessary, otherwise double counting would arise.

Associate Professor Handley then reviewed the methodology adopted by the AER, noted CEG's review of this methodology and specifically considered the Cai, Helwege and Warga (2007) paper that found no evidence of underpricing on investment grade bond offerings. He concluded:[226]

> In summary, assuming allowed revenues are determined using an appropriate estimate of the cost of debt (and noting that both the AER and CEG believe this to be the case), then it is my view that, underpricing should not be allowed as a cost of raising debt capital.

On the direct costs of raising debt capital, Associate Professor Handley noted the debate regarding the measurement of direct costs, amortisation and inflation. Where relevant, detailed comments drawn from his review are included in the AER considerations, set out in appendix H of this final decision.

**AER considerations**

The AER's detailed considerations of ActewAGL's proposed debt raising costs are presented in appendix H of this final decision. The AER notes that the consultancy reports submitted by ActewAGL on these matters are also applicable to the AER's considerations concerning the regulatory proposals of the NSW DNSPs, and TransGrid's and Transend's revenue proposals. The AER considers that its approach should be consistent across each of these businesses. Accordingly, appendix H sets out the AER considerations of all material submitted as part of the current regulatory processes and is applicable to the AER's final decisions for ActewAGL, the NSW DNSPs, TransGrid, and Transend.

In summary, the AER considers that the proposed allowance for indirect debt raising costs is inconsistent with the regulatory framework. If indirect costs were actually incurred in practice,[227] the AER expects that such costs would already be taken into account through estimates of the cost of debt. This view is supported by Associate Professor Handley.[228]

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224 Handley, J. C., *A Note on the Costs of Raising Debt and Equity Capital: Report prepared for the Australian Energy Regulator*, 12 April 2009. Associate Professor Handley is a leading academic on cost of capital issues and has been advising the AER as part of its 2009 WACC review.
225 Handley, pp. 15–16.
226 Handley, p. 17.
227 The AER considers that there is no reliable empirical evidence that indirect debt raising costs exist.
228 Handley, pp. 14–17.

Regarding the appropriate benchmark for direct debt raising costs, the AER considers that the amount applied in the draft decision—based on the ACG approach—is appropriate.[229] The AER considers that the ACG approach is more likely to provide the best estimate of direct debt raising costs to be incurred by the benchmark regulated business rather than the methodologies proposed by the NSPs and their consultants. Among other reasons, this is because the ACG approach is based on market observations of Australian firms raising capital, rather than foreign firms in foreign markets.

Table 9.11 shows the updated build up of debt raising costs and the total benchmark for various bond issues, based on the ACG's methodology.

**Table 9.11: 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): Standard & Poor's ratings | 2.5 | 1.3 | 0.8 | 0.6 |
| Issue credit rating | 3.5 (2.5) basis points up front: Standard & Poor's 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: AER updated figures based on the methodology in ACG, *Debt and equity raising transaction costs: final report to the ACCC*, December 2004.
(a) Rounded to zero.

The AER maintains its gross underwriting fee and bond issue size benchmarks which were set out in the draft decision, and which were updated according to the ACG methodology.[230] Based on the ACG methodology, ActewAGL will require around two bond issues in the next regulatory control period. As such, the AER considers that an allowance of 9.2 bppa for debt raising costs is a reasonable benchmark for ActewAGL. Using the post–tax revenue model (PTRM), this benchmark is multiplied by the debt component of ActewAGL's opening RAB to provide an average allowance of around $0.4 million per annum ($2008–09).

229 AER, *Draft decision,* pp. 105–06.
230 AER, *Draft decision*, p. 106.

The AER's conclusion on benchmark debt raising costs for ActewAGL over the next regulatory control period is set out in table 9.12.

**Table 9.12: AER conclusion on ActewAGL's debt raising costs ($m, 2007–08)**

| | 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 |

For the reasons discussed and as a result of the AER's analysis of ActewAGL's revised regulatory proposal and additional information, the AER is not satisfied that ActewAGL's proposed debt raising cost allowance reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors. The AER considers the benchmark debt raising forecast set out in table 9.12 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.

### 9.5.6 Equity raising costs

In raising new equity capital a business may incur costs such as legal fees, brokerage fees, marketing costs and other transaction costs. These are upfront expenses, with little or no ongoing costs over the life of the equity. Whilst the size of the equity a firm will raise is typically at its inception, there may be points in the life of a firm—for example, during capital expansions—where it chooses additional external equity funding (instead of debt or internal funding) as a source of capital, and accordingly may incur equity raising costs.

The AER has accepted that equity raising costs are a legitimate cost for a benchmark efficient firm only where external equity funding is the least–cost option available.[231] A DNSP should only be provided an allowance for equity raising costs where cheaper sources of funding—for instance, retained earnings—are insufficient, subject to the gearing ratio and other assumptions about financing decisions being consistent with regulatory benchmarks.

**AER draft decision**

In the draft decision, the AER confirmed ActewAGL's regulatory proposal that it would be able to fund its proposed capex over the next regulatory control period with retained cash flows. Accordingly, the AER did not include an allowance for benchmark equity raising costs for the next regulatory control period.[232]

[231] AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12,* 14 June 2007, p.100*; Final decision, SP AusNet transmission determination 2008–09 to 2013–14,* January 2008, p. 144; and AER, *Final decision, ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008, p. 88.

[232] AER, *Draft decision*, p. 108.

**Revised regulatory proposal**

ActewAGL submitted that new information on equity raising costs had become available since it submitted its regulatory proposal.[233]

ActewAGL referred the AER to the CEG report (confidential), provided as appendix 15 to its revised regulatory proposal.[234]

The AER notes that ActewAGL, the NSW DNSPs, TransGrid and Transend have all relied on essentially the same CEG report as the core of their arguments on this matter.[235] ActewAGL's revised regulatory proposal on equity raising costs is set out in table 9.13.

**Table 9.13: ActewAGL's revised regulatory proposal on equity raising costs ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Equity raising allowance | 1.1 | 1.0 | 0.9 | 0.6 | 0.5 | 4.2 |

Source: ActewAGL, *Revised regulatory proposal*, p. 33.

**Submissions**

EnergyAustralia noted that all the NSPs were proposing the same allowance for equity raising costs (7.6 per cent of the amount raised) and that this was the same position as advocated in their respective regulatory proposals. Given the evident consistency across proposals, EnergyAustralia requested that all reports and supporting documents which it had submitted as part of its regulatory proposal and revised regulatory proposal be considered by the AER in making its final determinations on all NSPs for the next regulatory control period.[236]

EnergyAustralia also provided the JIA submission to the AER's WACC review.[237] The JIA stated that indirect and direct equity raising costs were direct substitutes (in line with the CEG report), and that the AER needed to adjust its previous methodology to provide an allowance for indirect equity raising costs.[238] JIA stated that using internal cash flows to fund new capex is not costless, and that infrastructure businesses must satisfy their investors by providing a high dividend yield (8 per cent) each year.[239]

**Consultant review**

Associate Professor Handley was engaged by the AER to review the submitted material on this issue, including the regulatory proposal and revised regulatory proposal submitted by ActewAGL, and all relevant accompanying consultant reports.

233 ActewAGL, *Revised regulatory proposal*, p. 33.
234 CEG, January 2009.
235 CEG, January 2009.
236 EnergyAustralia, *Submission on other network service providers*, p. 3.
237 EnergyAustralia, *Submission on AER's issues paper on WACC,* 24 September 2008.
238 JIA, p. 17.
239 JIA, pp. 11–17.

Associate Professor Handley considered the arguments made on the underpricing of equity capital, and noted that both CEG and Carlton relied upon the assumption that new shares were not sold to existing shareholders.[240] Associate Professor Handley viewed this assumption as unreasonable. He also considered it inappropriate to provide an allowance for underpricing costs associated with raising equity capital as they are inconsistent with the regulatory framework:[241]

> …under the regulatory framework the appropriate return on (equity) capital is determined by the CAPM and therefore any allowance for underpricing costs would effectively amount to an increment being added to the CAPM - a position which could only be justified on policy rather than theoretical grounds.

Associate Professor Handley considered the indirect costs of retained earnings, rights issues and dividend reinvestment plans, and concluded in each case that it was not appropriate to provide an allowance for such costs.[242]

Associate Professor Handley also considered the direct costs of raising equity capital, noting the different methods (placements, rights issues and dividend reinvestment plans) and the level of agreement on these direct costs. He advised that the reasonable range for direct equity raising costs is between 2 and 3 per cent of the amount raised.[243]

Finally, Associate Professor Handley considered the benchmark cash flow modelling applied to determine the equity requirement. He noted many of the assumptions were 'arbitrary in the sense that they are simply inputs into the modelling process,'[244] but stated:[245]

> The key issue is to ensure that any assumptions made here are consistent with the overall regulatory framework.

Associate Professor Handley analysed the concerns raised in relation to payment of debt principal for maintaining the assumed gearing ratio, and the payout of dividends in order to value imputation credits. In both cases, Associate Professor Handley noted that the NSPs' concerns were valid and that the AER should amend its benchmark cash flow analysis to take account of these concerns.[246]

**AER considerations**

The AER's detailed considerations of ActewAGL's proposed equity raising costs are presented in appendix H of this final decision. The AER notes that the consultancy report submitted by ActewAGL on these matters are also applicable to the AER's considerations concerning the regulatory proposals of the NSW DNSPs, and revenue proposals of TransGrid and Transend. The AER considers that its approach should be consistently applied across each of these businesses. Accordingly, appendix H sets out the AER considerations of all material submitted as part of the current regulatory

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240 Handley, pp. 7–8.
241 Handley, p. 11.
242 Handley, pp. 4–14.
243 Handley, p. 27.
244 Handley, p. 32.
245 Handley, p. 32.
246 Handley, pp. 31–34.

processes and is applicable to the AER's final decisions for ActewAGL, the NSW DNSPs, TransGrid and Transend.

In summary, the AER considers that the proposed allowance for indirect equity raising costs is inconsistent with the regulatory framework. To the extent that indirect equity raising costs exist, they can reasonably be expected to be included in the existing return on equity allowance which is based on the expected market returns through the CAPM parameters. Alternatively, they are not relevant to the benchmark firm as they relate to the impact on individual shareholders rather than the returns in aggregate (at the firm level). This view is supported by Associate Professor Handley.[247]

In relation to direct equity raising costs, the AER considers that the benchmark cost applied in the AER's draft decision for the NSW DNSPs remains the best estimate of costs applicable to the benchmark regulated NSP. The benchmark direct equity raising cost applied in the draft decision for the NSW DNSPs was based on the ACG methodology, which used recent domestic market data.[248] The AER also notes that this benchmark equity raising cost is consistent with the range recommended by Associate Professor Handley.[249]

The AER has given consideration to the consultant reports and submissions concerning the benchmark cash flow analysis that is applied to determine the extent to which equity raising is required. CEG argued against the draft decision on the appropriate level of dividends,[250] while the NSW DNSPs and TransGrid submitted that the draft decision understated the appropriate level of dividends.[251] This resulted in a higher level of retained earnings, which inturn, resulted in a lower external equity requirement. Further, CEG stated that, by lowering dividends, a firm's ability to distribute imputation credits is reduced.[252] CEG also argued for an allowance for the cost of retained earnings.[253] The AER has decided to amend the benchmark cash flow analysis to ensure consistency with the cash flow assumptions in the PTRM. However, it has also taken the level of equity raising through dividend reinvestment plans into account. Further, the AER has decided that it would be inappropriate to include an allowance for the cost of retained earnings.

In summary, the changes to the benchmark equity raising cash flow analysis (from the approach applied in the draft decision) include:

- dividends are linked to the level of imputation credits earned in the PTRM (rather than applying a dividend payout ratio to net profit after tax)
- dividend reinvestment is assumed to be 30 per cent of dividends paid (based on available evidence)

247 Handley, pp.7–12
248 AER, *Draft decision,* pp. 195–197.
249 Handley, p. 27.
250 ActewAGL, *Revised regulatory proposal*, Attachment 15, pp. 24–25.
251 EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46; TransGrid, *Revised regulatory proposal*, p. 81
252 ActewAGL, *Revised regulatory proposal*, Attachment 15, p. 29
253 ActewAGL, *Revised regulatory proposal*, Attachment 15, pp. 29–30

- a benchmark cost of 1 per cent has been applied to equity raised through dividend reinvestment plan
- an error in the presentation of the capex funding requirement has been corrected (in the draft decision the capex funding requirement inappropriately included a 'grossed–up' WACC adjustment)
- the amount of capex assumed to be funded by debt has been linked to the increase in the debt component of the RAB to maintain consistency with the benchmark gearing assumption in the PTRM.

The AER's conclusion on benchmark equity raising costs for ActewAGL is set out in table 9.14.

**Table 9.14: AER conclusion on ActewAGL's benchmark equity raising cost ($m, nominal)**

| Cash flow analysis | AER final decision | Notes |
|---|---|---|
| Dividends | 70.6 | Set to distribute imputation credits assumed in the PTRM |
| Dividends reinvested | 21.2 | 30 per cent of dividends paid |
| Cost of dividend reinvestment plan | 0.2 | Dividends reinvested multiplied by benchmark cost (1 per cent) |
| Capex funding requirement | 291.7 | This is the forecast capex funding requirement (not the capex value that includes a half year WACC adjustment) |
| Debt component | 126.2 | Set to equal 60 per cent of RAB increase (not capex) |
| Equity component | 165.5 | Residual of capex funding requirement and debt component |
| Retained cash flows available for reinvestment | 162.8 | Includes dividends reinvested |
| External equity requirement | 2.6 | Equal to equity component less retained cash flows |
| External equity raising cost | 0.1 | External equity requirement multiplied by benchmark direct cost (2.75 per cent) |
| Total equity raising cost ($2008–09) | 0.3 | Sum of dividend reinvestment plan cost and external equity raising cost |

ActewAGL proposed to include equity raising costs under a perpetuity stream as part of its forecast opex allowance.[254] The AER considers that there is merit in treating the equity raising cost allowance as a part of ActewAGL's RAB—that is, to amortise the allowance. This would improve transparency, given that the nature of the allowance is associated with capex, and ensure that future revenue resets for ActewAGL would be administratively simpler in the provision of such an allowance.

Further, the AER notes that treating the equity raising cost allowance in perpetuity or in the RAB would be net present value (NPV) neutral. In the 2004 ACG report, it was recommended that equity raising costs be added to the RAB and amortised along with other assets:[255]

> If the regulator has determined that an allowance for the SEO [seasoned equity offering] cost of raising equity for ongoing capital expenditure should be provided for, we recommend that this amount be added to the RAV [regulatory asset value] (i.e. included as part of the capital expenditure cost) and depreciated over the life of the relevant assets.

Accordingly, the amount specified above will be amortised over the life of ActewAGL's RAB for the purposes of providing the equity raising cost allowance associated with the forecast capex over the next regulatory control period.[256] This approach is also consistent with the AER's revenue determination for Powerlink.[257]

For the reasons discussed and as a result of the AER's analysis of ActewAGL's revised regulatory proposal and additional information, the AER is not satisfied that ActewAGL's proposed equity raising cost allowance reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors. The AER considers the revised benchmark equity raising cost allowance associated with ActewAGL's forecast capex, as set out in table 9.14, 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.

### 9.5.7 Self insurance

**AER draft decision**

The AER accepted ActewAGL's proposed allowances for self insurance for the following risks:

- theft of assets
- counterparty credit risk.

[254] ActewAGL, *Revised regulatory proposal*, p. 35.
[255] ACG, *Debt and equity raising transaction costs*, December 2004, p. xiii.
[256] A standard life of 44.5 years for standard control services and 40 years for alternative control services for amortisation purposes, consistent with ActewAGL's weighted average asset life, has been assumed.
[257] AER, *Decision, Powerlink*, p. 102.

The AER indicated that for other risks it was not satisfied that ActewAGL, based on the advice from SAHA International Limited (SAHA),[258] had provided robust analysis which supported the probability of an event occurring or the costs associated with the event, and therefore the calculation of the self insurance premium.[259] The AER considered that ActewAGL's proposed self insurance allowances did not reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives, or a realistic expectation of those costs, and made adjustments accordingly. The AER reduced ActewAGL's self insurance allowance from $7.9 million to $1.8 million ($2008–09) for the next regulatory control period.[260]

**Revised regulatory proposal**

ActewAGL did not accept the reductions to the self insurance allowance determined by the AER and commissioned SAHA to respond to the draft decision.[261]

SAHA prepared a generic report in relation to self insurance costs for ActewAGL, Country Energy, EnergyAustralia, Integral Energy and TransGrid.[262] The SAHA report provided comments regarding the AER's assessment of self insurance and a response to the AER's rejection of allowances for each of the businesses.

***AER approach to assessing self insurance premiums***

In response to the draft decision to not provide a self insurance allowance for specific risks the following comments were made by ActewAGL:[263]

- the AER appear to have assessed the proposed self insurance premiums without reference to relevant industry practice. ActewAGL stated that a superior interpretation of reasonableness would be one that recognises consistency of the proposal with the principles and methods adopted by a reasonable practitioner—that is, an actuary, risk manager or insurance assessor
- in rejecting the self insurance premiums, the AER did not propose an alternative value for the self insurance premium or an alternative means of mitigating the risk. ActewAGL stated that, in these cases, the AER, in not refuting that each has a non–zero probability and impact, has effectively valued the risk exposure at zero and additionally it has not sought to justify its position.

SAHA stated that the AER appears to have adopted a number of sub–criteria in assessing whether the self insurance premiums reasonably reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives.[264] SAHA suggested that these sub–criteria appear to include that

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258 SAHA provides strategic, commercial, economic, corporate finance and financial consulting services. See SAHA website http://www.sahainternational.com/SAHA/SERVICES/pc=PC_90006.

259 SAHA, *ActewAGL Electricity Networks – Self Insurance Risk Quantification, Final Report*, confidential, 20 May 2008.

260 AER, *Draft decision*, p. 117.

261 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, 14 January 2009.

262 Each of these businesses proposed self insurance allowances in their regulatory proposals and engaged SAHA to determine the original risk estimates and associated self insurance premiums. Since many of the issues raised in the AER's draft decisions in relation to self insurance are similar across these businesses, SAHA provided a single report in response.

263 ActewAGL, *Revised regulatory proposal*, p. 56.

264 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 3.

a zero self insurance risk allowance will more reasonably reflect the efficient costs that a prudent operator would incur than SAHA's valuation when:[265]

- that business has never borne a cost resulting from the risk
- the historical data supporting the derivation of that risk is deemed to be for a period that is not long enough
- qualitative evidence has been used to support a risk quantification, even if this qualitative evidence is used in conjunction with quantitative evidence
- the quantification relies on data derived from similar events that have affected other electricity businesses.

Further, SAHA suggested that efficient estimates can be derived in the absence of perfect historical data and that 'reasonable practitioners' adopt similar approaches to those used by SAHA in order to determine premiums in the absence of such data.[266] SAHA stated that these practitioners leverage off available information and use professional judgement to determine premiums.[267] SAHA also stated that its self insurance estimates were reviewed by an actuary.[268]

SAHA noted that the AER does not appear to question the validity of any of the risks presented.[269] Accordingly, SAHA suggested that if the AER maintains its position that the self insured quantifications for a number of the risks do not reasonably reflect the efficient costs associated with the risks, then the businesses should still be compensated in some way for bearing that risk, or alternatively, they must be allowed to adopt an alternative risk mitigation strategy.[270] SAHA stated that the AER should inform the DNSPs of the preferred method for mitigating these risks, or any adjustments that could be made to the proposed current quantification.[271]

***Revised self insurance allowances***

Based on SAHA's recommendations, ActewAGL proposed that self insurance allowances be reinstated for the following events:[272]

- bushfire
- damage to poles and lines from severe and catastrophic storms
- third party claims associated with key asset failure
- general public liability.

ActewAGL stated that it had revised its self insurance allowance to exclude costs proposed in its regulatory proposal associated with:[273]

- earthquakes greater than magnitude five on the Richter Scale

265 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 3.
266 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 20.
267 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 19.
268 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 21.
269 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 24.
270 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 24.
271 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 25.
272 ActewAGL, *Revised regulatory proposal*, pp. 56–65.
273 ActewAGL, *Revised regulatory proposal*, p. 65.

- major bushfires ignited by a third party.

ActewAGL indicated that these events should be covered under a cost pass through mechanism and therefore amended its nominated pass through events in its revised regulatory proposal to include such events.[274]

ActewAGL stated that the removal of major bushfires ignited by a third party as a self insurance allowance is contingent on the AER accepting ActewAGL's proposed revisions to the major natural disaster pass through event definition contained in its revised regulatory proposal.[275] ActewAGL also indicated that, should the AER not approve ActewAGL's proposed self insurance allowance for catastrophic storms, major bushfires ignited by ActewAGL's own assets and third party claims resulting from key asset failure, these risks should be addressed through an appropriate pass through mechanism.[276]

The revised self insurance allowance proposed by ActewAGL is set out in table 9.15.

**Table 9.15: ActewAGL's revised self insurance allowance ($m, 2008–09)**

| | AER draft decision | Revised regulatory proposal |
|---|---|---|
| Total self insurance premium | 1.8 | 7.9 |

Source: ActewAGL, *Revised regulatory proposal*, p. 32.

**AER considerations**

Details of the AER's assessment of ActewAGL's revised proposed self insurance allowance are provided at appendix G.

The AER considers that its approach to the assessment of ActewAGL's self insurance claims and the proposed alternative self insurance amounts is consistent with the requirements of the transitional chapter 6 rules.

Based on its assessment of the relevant opex factors in the transitional chapter 6 rules, the AER considers it necessary to rely on the information provided in the regulatory proposal (consistent with clause 6.5.6(e)(1)) in determining whether the proposed self insurance allowances reasonably reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives. As such, where the information concerning an individual self insurance claim was inadequate—that is, it did not appear to support the claim—the AER has not accepted the forecast (consistent with clause 6.5.6(d) of the transitional chapter 6 rules).

Similarly, in determining a substitute self insurance value, the AER relied on the information included in the regulatory proposal (as required by clauses 6.12.1(4)(iii) and 6.12.3(f) of the transitional chapter 6 rules). For a number of risks, based on the information provided to the AER in the regulatory proposal and revised regulatory proposal, the only value that the AER could estimate for an event for self insurance costs was zero because there was no information on which to base an alternative

274 ActewAGL, *Revised regulatory proposal*, pp. 58 and 61.
275 ActewAGL, *Revised regulatory proposal*, p. 61.
276 ActewAGL, *Revised regulatory proposal*, p. 65.

amount. Such a value is not meant to indicate that the self insurance event may or may not occur, rather, the AER has assigned a cost of zero due to the (lack of) information provided in the regulatory proposal.

The AER does not consider that ActewAGL's proposed reinstatement of allowances for self insurance reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives. The AER is not satisfied that ActewAGL, based on advice from 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 calculation of the self insurance premiums.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal, the AER is satisfied that the amended estimate of the total self insurance allowance for the next regulatory control period set out in table 9.16, based on the accepted self insurance premiums and substitute values detailed in appendix G, reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

**Table 9.16: AER conclusion on self insurance allowance for ActewAGL ($m, 2008−09)**

| | Revised regulatory proposal | AER final decision |
|---|---|---|
| Total self insurance | 7.9 | 4.4 |

Note: ActewAGL's self insurance premiums in the original and revised SAHA report are in 2007–08 dollar terms. The AER converted these to 2008–09 dollar terms using ActewAGL's proposed 2.7 per cent escalation.

Note: AER final decision includes standard control and alternative control

## 9.6 AER conclusion

The AER has reviewed ActewAGL's forecast total opex of $359 million ($2008–09) and for the reasons outlined in this chapter, the AER 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, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

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) of the transitional chapter 6 rules 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.

For the reasons discussed and after considering the advice of Wilson Cook and undertaking its own analysis of ActewAGL's proposed opex, the AER has applied a reduction of $18 million to ActewAGL's proposed opex. This represents a reduction of around 5 per cent of ActewAGL's proposed opex of $359 million and results in a amended total opex allowance of $341 million.

This amended 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) of the transitional chapter 6 rules. The AER is satisfied that the amended total opex of $341 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. The amended opex allowance is set out by opex category in table 9.17.

**Table 9.17: AER conclusion on ActewAGL's total opex allowance ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL's revised proposed opex | | | | | | |
| Controllable opex | 53.0 | 54.0 | 54.9 | 56.6 | 56.3 | 274.8 |
| UNFT | 3.9 | 4.0 | 4.1 | 4.3 | 4.3 | 20.6 |
| Debt raising | 0.5 | 0.6 | 0.6 | 0.6 | 0.7 | 3.0 |
| Equity raising | 1.1 | 1.1 | 1.0 | 0.7 | 0.5 | 4.4 |
| Self insurance[a] | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 7.5 |
| FiT scheme direct tariff payments | 3.4 | 6.8 | 10.0 | 12.7 | 15.3 | 48.2 |
| ActewAGL's revised proposed total opex | 63.5 | 68.0 | 72.1 | 76.3 | 78.6 | 358.5 |
| AER total opex | | | | | | |
| Controllable opex | 51.4 | 52.1 | 53.2 | 55.0 | 54.7 | 266.4 |
| UNFT | 3.9 | 4.0 | 4.1 | 4.3 | 4.3 | 20.6 |
| Debt raising | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 1.8 |
| Equity raising[b] | – | – | – | – | – | – |
| Self insurance[a] | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 4.1 |
| FiT scheme direct tariff payments | 3.1 | 6.8 | 10.0 | 12.7 | 15.3 | 47.9 |
| Demand management innovation allowance[c] | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.5 |
| AER total opex | 59.7 | 64.2 | 68.6 | 73.3 | 75.7 | 341.4 |

Note: Totals may not add up due to rounding.

(a) Based on allocation for standard control services.

(b) The AER has allowed ActewAGL to amortise $0.3 million ($2008–09) for benchmark equity raising costs associated with forecast capex in the next regulatory control period.

(c) Refer to chapter 15 for details on this allowance.

Table 9.18 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 9.18: AER conclusion on ActewAGL's controllable opex ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL revised controllable opex | 53.0 | 54.0 | 54.9 | 56.6 | 56.3 | 274.8 |
| Adjustments to labour escalators | –1.5 | –1.9 | –1.7 | –1.6 | –1.6 | –8.3 |
| AER controllable opex | 51.4 | 52.1 | 53.2 | 55.0 | 54.7 | 266.4 |

## 9.7 AER 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 reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors. The AER's reasons for this decision are set out in section 9.6 of the draft decision and section 9.5 of this final decision.

The AER's estimate of the total opex required by ActewAGL for the next regulatory control period, that reflects the opex criteria taking into account the opex factors is set out in table 9.17 of this final decision.

# 10 Estimated corporate income tax

## 10.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision and the AER's assessment of estimated corporate income tax liabilities for ActewAGL during the next regulatory control period. No submissions were received on this issue.

## 10.2 AER draft decision

The AER determined that the inputs used by ActewAGL in the post–tax revenue model (PTRM) to calculate the expected cost of corporate income tax were in accordance with the transitional chapter 6 rules.[277] The AER considered that ActewAGL's proposed tax remaining and tax standard lives were appropriate. The AER also considered ActewAGL's proposed tax asset base of $473 million as appropriate and reasonable.[278] On the basis of these inputs, the AER used the PTRM to calculate the allowance for corporate income tax set out in table 10.1.

**Table 10.1: AER draft decision 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 |

Source: AER, *Draft decision*, p. 127.

## 10.3 Revised regulatory proposal

ActewAGL submitted a revised allowance for corporate income tax in its revised regulatory proposal.[279] The method used by ActewAGL to calculate the income tax allowance was consistent with the draft decision. However the proposed tax asset base was revised to $476 million as a result of a higher estimate of capex in 2008–09.[280] The tax estimate for 2008–09 has been updated to reflect minor escalation changes to the 2008–09 estimated capex.[281] ActewAGL's proposed allowance for corporate income tax calculated by the PTRM is presented in table 10.2. These figures include the impact of the revised tax asset base and other revised inputs to the PTRM such as the weighted average cost of capital, capex and opex.

277 AER, *Draft decision*, p. 127.
278 AER, *Draft decision*, p. 127.
279 ActewAGL, *Revised regulatory proposal*, pp. 68–69.
280 ActewAGL, *Revised regulatory proposal,* RFM (standard control), confidential.
281 ActewAGL, *Revised regulatory proposal*, p. viii.

**Table 10.2: ActewAGL's proposed corporate income tax allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Tax allowance | 5.3 | 6.2 | 6.4 | 6.1 | 6.3 | 30.3 |

Source: ActewAGL, *Revised regulatory proposal*, p. 69.

On 4 March 2009 ActewAGL provided a further revised estimate of its proposed tax asset base of $475 million.[282] This figure includes 2007–08 actuals for capex and tax depreciation rather than estimates.

## 10.4 Issues and AER considerations

The method used to calculate the tax asset base is consistent with the method accepted by the AER in its draft decision. Accordingly, the AER considers ActewAGL's revised tax asset base of $475 million appropriate. The AER notes that ActewAGL's revised regulatory proposal includes tax standard and tax remaining lives that are consistent with those accepted in the draft decision.

## 10.5 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. Consistent with the draft decision, the AER considers that ActewAGL's proposed tax remaining and tax standard lives are appropriate. The AER also considers the updated tax asset base of $475 million appropriate and reasonable. On the basis of these inputs, the PTRM has calculated the allowance for corporate income tax presented in table 10.3.

**Table 10.3: AER conclusion on ActewAGL's corporate income tax allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Tax allowance | 4.7 | 5.5 | 5.7 | 5.4 | 5.6 | 26.9 |

## 10.6 AER decision

In accordance with clause 6.12.1(7) of the transitional chapter 6 rules the estimated cost of corporate tax to ActewAGL for each regulatory year of the next regulatory control period is specified in table 10.3 of this final decision.

282 ActewAGL, Email to the AER, attachment 2, Revised RFM, 4 March 2009.

# 11 Depreciation

## 11.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision regarding the annual allowance for regulatory depreciation—also referred to as the return of capital. Regulatory depreciation sums the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB).

This chapter also sets out the AER's assessment of ActewAGL's proposed asset lives used in the post–tax revenue model (PTRM) to calculate its depreciation schedule which is then used to determine the regulatory depreciation allowance for the next regulatory control period. No submissions were received on this issue.

## 11.2 AER draft decision

The AER did not accept ActewAGL's proposed depreciation schedule as it did not consider that the schedule complied with the transitional chapter 6 rules.[283]

While the AER accepted ActewAGL's approach to depreciate its opening RAB (existing assets) within the single asset category based on the proposed remaining life, the AER considered it appropriate to include a more detailed breakdown of ActewAGL's forecast capex (new assets).[284] ActewAGL provided the asset classes and standard lives which will apply to its forecast capex from 1 July 2009 onwards. The AER reviewed these asset classes and standard lives and considered them to be reasonable.[285]

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER determined ActewAGL's depreciation schedule and regulatory depreciation allowance. Table 11.1 sets out the AER's draft decision on ActewAGL's regulatory depreciation allowance for the next regulatory control period.[286]

**Table 11.1: AER draft decision on ActewAGL's 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 |

Source: AER, *Draft decision*, p. 131.

## 11.3 Revised regulatory proposal

ActewAGL proposed a revised regulatory depreciation schedule in response to the draft decision, reflecting changes to opening RAB and forecast capex.[287] The revised

283 AER, *Draft decision*, p. 131.
284 AER, *Draft decision*, p. 131.
285 AER, *Draft decision*, p. 131.
286 AER, *draft Decision*, table 11.3, p. 131.
287 ActewAGL, *Revised regulatory proposal*, table 6.1 p. 68.

regulatory depreciation schedule resulted in the calculation of the revised regulatory depreciation allowance as set out in table 11.2.

**Table 11.2: ActewAGL's revised regulatory depreciation allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Regulatory depreciation allowance | 14.5 | 16.2 | 17.9 | 19.5 | 21.3 | 89.4 |

Source: ActewAGL, *Revised regulatory proposal*, p. 68.

# 11.4 Issues and considerations

## 11.4.1 Asset life inputs

In its revised regulatory proposal ActewAGL used standard asset life inputs that were inconsistent with the standard asset life inputs approved in the draft decision.[288] ActewAGL confirmed that this was an error.[289] Accordingly, the AER has amended the standard asset life inputs to the PTRM.

## 11.4.2 Updating input data

The AER updated the input data used by ActewAGL to determine its regulatory depreciation allowance. The updated input data incorporates changes to the opening RAB and capex allowance as discussed in chapters 6 and 8 of this final decision.

ActewAGL updated the estimated remaining asset life for existing assets, which is used to calculate regulatory depreciation. The updated estimated remaining asset life incorporates ActewAGL's actual capex for 2007–08, which differs from the forecast capex used in the draft decision. The AER has reviewed ActewAGL's updated remaining asset life and considers that it has been calculated appropriately.

# 11.5 AER conclusion

The AER has reviewed the inputs to the PTRM used by ActewAGL to calculate its depreciation schedule in accordance with clause 6.5.5 of the transitional chapter 6 rules. As a result of required adjustments to asset life inputs, changes to the opening RAB and changes to the capex allowance, the AER has not approved the depreciation schedule proposed by ActewAGL in its revised regulatory proposal.

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER has determined ActewAGL's depreciation schedule. The depreciation schedule is used to calculate the 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.

[288] ActewAGL, *Revised regulatory proposal*, RFM.
[289] ActewAGL, Email to the AER, 19 February 2009.

**Table 11.3: AER conclusion on ActewAGL's regulatory depreciation allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Regulatory depreciation allowance | 15.2 | 17.0 | 18.8 | 20.5 | 22.3 | 93.9 |

## 11.6 AER decision

In accordance with clause 6.12.1(8) of the transitional chapter 6 rules the AER has not approved the depreciation schedule submitted by ActewAGL. The AER has determined the depreciation schedule for ActewAGL which results in the regulatory depreciation allowance set out in table 11.3 of this final decision.

# 12 Cost of capital

## 12.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on ActewAGL's weighted average cost of capital (WACC), including the averaging period of the risk–free rate, debt risk premium and inflation forecast raised by ActewAGL in its revised regulatory proposal.

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 set out in chapter 9 and the analysis of corporate tax is set out in chapter 10 of this final decision.

## 12.2 AER draft decision

In the draft decision, the AER determined a nominal vanilla WACC of 9.82 per cent for ActewAGL. The AER stated it would 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 12.1 sets out the WACC parameter values determined in the draft decision. The AER stated it would update the nominal risk–free rate and debt risk premium based on the agreed averaging period as well as the expected inflation rate at a time closer to its final distribution determination.

**Table 12.1: AER draft decision on ActewAGL's WACC parameters**

| Parameter | ActewAGL's proposal | AER's draft decision |
|---|---|---|
| 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% |

Source: AER, *Draft decision,* p. 141.

## 12.3 Revised regulatory proposal

In estimating the WACC for its revised regulatory proposal, ActewAGL proposed that the averaging period used to calculate the risk–free rate and debt risk premium be changed to eliminate the impacts of the global financial crisis. Consistent with this approach, ActewAGL adopted a new averaging period and revised the risk–free rate, debt risk premium and nominal vanilla WACC. ActewAGL rejected the use of only Bloomberg data to estimate the debt risk premium. ActewAGL also proposed a geometric average of the annual inflation rate over a 10–year period for calculating expected inflation.

## 12.4 Submissions

The AER received a submission from EnergyAustralia relevant to the draft decision. ActewAGL did not provide a submission on the cost of capital.

## 12.5 Issues and AER considerations

### 12.5.1 Risk–free rate

**Averaging period decision**

ActewAGL initially proposed an averaging period for the nominal risk–free rate of 20 days ending 30 June 2008. In July 2008, the AER determined that this averaging period was unreasonable and informed ActewAGL of the its decision.[290]

The AER did not agree with ActewAGL's proposed averaging period on the basis that it was too far removed from the date when the AER would publish the final decision. The AER also noted that such an averaging period would be inconsistent with previous regulatory practice by the AER, ACCC and jurisdictional regulators, which set the averaging period for the risk–free rate at a date close to the final decision date. The AER advised that this regulatory practice was supported by finance literature and cited papers by Associate Professor Martin Lally and Professor Kevin Davis.[291]

In July 2008, the AER advised ActewAGL that the risk–free rate would be based on a 20 business day averaging period commencing on 23 February 2009 and ending on 20 March 2009. The AER invited ActewAGL to nominate an averaging period between 1 February 2009 and 20 March 2009 if it disagreed with the AER's nominated averaging period.[292] In response, ActewAGL nominated an averaging

[290] AER, letter to ActewAGL, *ActewAGL's proposed nominal risk–free rate averaging period for the 2009–2014 regulatory control period*, 8 July 2008.

[291] Martin Lally, *The cost of capital for regulated entities, report prepared for the Queensland Competition Authority*, 26 February 2004, p. 63; Martin Lally, *Determining the risk free rate for regulated companies, report prepared for the ACCC*, August 2002, p. 17; and 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.

[292] AER, letter to ActewAGL, *ActewAGL's proposed nominal risk–free rate averaging period for the 2009–2014 regulatory control period*, 8 July 2008.

period of 20 business days commencing 2 February 2009,[293] which the AER accepted (the agreed averaging period).[294]

**AER draft decision**

In the draft decision, the AER determined a nominal risk–free rate of 5.46 per cent based on a 20 day moving average of yields on Commonwealth Government Securities (CGS) with a 10 year maturity for the period ending 17 October 2008.[295] The AER noted that the risk–free rate would be updated, based on the agreed averaging period, at the time of the final decision. The averaging period accepted by the AER was not disclosed due to a request from ActewAGL to keep the period confidential.

**Revised regulatory proposal**

ActewAGL did not agree with the AER's July 2008 averaging period decision and proposed a 20-day averaging period commencing 11 August and ending 5 September 2008. ActewAGL attached a report by Competition Economists Group (CEG) on the selection of an averaging period for the risk–free rate.[296]

The CEG report recommended that the AER set an averaging period for the risk–free rate prior to September 2008 because the global financial crisis became worse at that time, best characterised by events such as Fannie Mae and Freddie MAC in the US being placed in conservatorship on 7 September 2008.[297]

CEG stated that the global financial crisis has resulted in downward biased yields on 10–year nominal CGS and noted that:

- The global financial crisis has increased volatility across the Australian equity market and caused a flight to safety, which has decreased yields on nominal CGS and increased the cost of equity.[298]
- The spread between yields on 10–year CGS and 10–year state government bonds is at historically high levels due to a liquidity premium being paid for CGS.[299]
- There has been a sudden fall in the 10–year break even (market inferred) inflation rate, which is either due to investors' increased demand for the liquidity of nominal CGS or alternatively lower inflation expectations.[300]

[293] Although ActewAGL nominated an averaging period within the AER's specified range, it expressed dissatisfaction with the decision.

[294] AER, letter to ActewAGL, *Nominal risk–free rate averaging period for the 2009–14 regulatory control period*, 20 August 2008.

[295] AER, *Draft decision*, p. 136.

[296] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009.

[297] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, pp. 30–32.

[298] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, pp. 34–38.

[299] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, pp. 38–40.

[300] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, pp. 44–45.

CEG stated that the NER require that an averaging period for the risk–free rate be chosen such that it results in an adequate rate of return:[301]

> Other things being equal, the optimal averaging period is one that is most consistent with providing an accurate estimate of the cost of equity and debt for the regulated business. That is, a cost of equity and debt that, when inserted into the WACC formula in the Rules provides a rate of return to the regulated business equivalent to that required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the regulated business.

CEG stated that an averaging period subject to market conditions post September 2008 would result in an estimate of the cost of equity that results in a rate of return inconsistent with clause 6.5.2(b) of the transitional chapter 6 rules.[302]

CEG stated that the reports by Lally and Davis, which the AER cited in its July 2008 letter to ActewAGL rejecting its proposed averaging period, do not support the AER's averaging period decision. CEG noted that these reports state:[303]

- an averaging period is used to minimise exposure to rates on an aberrant day
- a market risk premium based on historical data should not be accepted uncritically and the market risk premium can be expected to vary over time.

CEG stated that, when 'properly construed', the Lally and Davis reports support the use of an averaging period that avoids the current market conditions, which are aberrant and that the market risk premium is fixed based on historical data.[304]

CEG stated that previous regulatory decisions in Australia[305] as well as decisons in the UK and the US, have adjusted the averaging period for the risk–free rate to account for specific events. CEG stated that these decisions support the use of an averaging period that excludes the impacts of the global financial crisis.[306]

CEG stated that there is no basis to presume that the yield on BBB+ debt prevailing at the beginning of the regulatory control period is a superior proxy for a business' actual cost of debt than 12 months prior. CEG stated that this is particularly true because a regulated business is likely to re–finance or hedge its debt obligations over a longer period of time than one particular averaging period.[307] CEG stated that, given the increased discrepancies between the CBASpectrum and Bloomberg estimates of

301 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, p. 7.
302 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, p. 12.
303 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, p. 13.
304 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, p. 14.
305 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, pp. 14–15.
306 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, p. 16.
307 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, pp. 19–25.

BBB rated corporate bond yields, an averaging period close to the final decision date could result in an inaccurate proxy for a regulated business' actual cost of debt.[308]

Consistent with ActewAGL's regulatory proposal, CEG stated that there are valid reasons for a business to prefer to have certainty about the rate of return it can earn prior to deciding on a capital expenditure program.[309]

Based on the CEG report, ActewAGL proposed an averaging period of 20 business days commencing 11 August 2009 and ending 5 September 2009 for the risk–free rate.[310]

**Submissions**

EnergyAustralia's submission supported ActewAGL's proposal to adopt an averaging period prior to 5 September 2008. EnergyAustralia's submission requested that the AER consider the material presented as part of EnergyAustralia's revised regulatory proposal and submission when assessing ActewAGL's proposals.

**AER considerations**

The AER's detailed considerations of ActewAGL's revised averaging period are presented in appendix I of this final decision. The AER notes that the consultancy report submitted by ActewAGL on this matter is also applicable to the AER's considerations concerning TransGrid's and Transend's revised revenue proposals and the NSW DNSPs' revised regulatory proposals. The AER considers that its approach should be consistently applied across each of these businesses. Accordingly, appendix I sets out the AER's consideration of all material submitted as part of the current regulatory processes and is applicable to TransGrid, Transend and the NSW DNSPs.

In summary, the AER considers that its decision to withhold agreement to the averaging period in ActewAGL's regulatory proposal was reasonable and that the agreed averaging period is consistent with finance theory, regulatory practice, the NER and NEL.

The AER considers the use of an averaging period as close to the start of the next regulatory control period as practically possible is consistent with the forward looking nature of the CAPM and is correct in finance theory. The AER notes that given the evidence at the time, the additional material contained in the revised regulatory proposal does not justify a conclusion that the AER's decision to withhold agreement to the proposed averaging period, and consequently the agreed averaging period, was inconsistent with regulatory practice.

The AER notes that the arguments put forward by ActewAGL regarding an insufficient return on equity is based on the view that the market risk premium (MRP) of 6 per cent in the transitional chapter 6 rules (based on a historical average) is out of line with the current variations in the MRP. In essence, ActewAGL is arguing for a

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308 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, p. 26.

309 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law,* January 2009, p. 26–28.

310 ActewAGL, *Revised regulatory proposal*, attachment 10.

variable MRP to be applied in the CAPM. However, given that the MRP is prescribed in the transitional chapter 6 rules, ActewAGL appeared to suggest that it is reasonable to account for variations in the MRP via adjustments to the risk–free rate. The AER notes that adjusting the risk–free rate averaging period as a mechanism to achieve the outcome equivalent to adopting a higher MRP (due to implied or actual variations to the historical MRP) would circumvent WACC parameters prescribed and would undermine the intended certainty under the regulatory regime which results from these values being prescribed.

The fact that CGS yields are at (or close to historical lows) does not of itself mean they cannot be used. Interest rates move all the time and reflect the markets assessment of the price of money at the time. Expectations about the prospect for prices and growth will influence this assessment. If ActewAGL can lock in an averaging period that it considers achieves the most advantageous rate of return early in the regulatory process based on its view on future interest rate movements then it may create opportunities for ‘gaming’ the regulator if its view transpires to be disadvantageous. In June 2008 when the AER received ActewAGL’s regulatory proposal the interest rate yield curve was downward sloping. The downward sloping yield curve at that time reflects market expectations of lower interest rates in the future. Therefore, setting the risk–free rate based on an averaging period at that time would have lead to systematic ex ante overcompensation of firms relative to the efficient cost of capital and would be inconsistent with the forward looking nature of CAPM—that is, it would not result in an unbiased risk–free rate.

The AER considers that the material provided by ActewAGL in support of its revised regulatory proposal does not reasonably justify that, an averaging period prior to September 2008 is better than a period that is as close as practically possible to the start of the next regulatory control period. Moreover, the agreed averaging period does not exclude the downward movement of the CGS yields commensurate with an easing in monetary policy and a softening in economic growth. The AER considers that the agreed averaging period is not abnormal and setting the risk–free rate using this period is also consistent with the NEL objective of efficient investment. The AER therefore considers that the agreed averaging period does not represent an abnormal period in relation to the observed CGS yields.

The nominal risk–free rate averaging period that the AER has adopted in this final decision is 20 business days commencing 2 February 2009. The 20 business day moving average for CGS yields[311] with a 10–year maturity for the period ending 27 February 2009, results in a proxy nominal risk–free rate of 4.29 per cent (effective annual compounding rate). The AER is satisfied that the proxy nominal risk–free rate has been determined in accordance with clauses 6.5.2(c) and (d) of the transitional chapter 6 rules.

### 12.5.2 Debt risk premium

**AER draft decision**

In the draft decision, the AER determined a benchmark debt risk premium of 3.27 per cent, which was added to the nominal risk–free rate to determine the return on debt

[311] RBA, CGS yields at: http://www.rba.gov.au/Statistics/indicative.html.

for the WACC calculation.[312] The debt risk premium was calculated using Bloomberg estimates of fair yields on long term corporate bonds, based on an averaging period of 20 business days ending 17 October 2008—consistent with the averaging period for the risk–free rate.[313]

The AER used Bloomberg estimates rather than CBASpectrum estimates for the fair yields of 10–year BBB+ rated corporate bonds based on the results of a review conducted during previous revenue determinations.[314] The review concluded that Bloomberg provided better estimates of 10–year BBB+ fair yields than CBASpectrum because they were more consistent with the observed yields on similarly rated actual bonds. The AER noted that the debt risk premium would be updated, based on the agreed averaging period, at the time of the final decision.

**Revised regulatory proposal**

ActewAGL did not agree with the AER's methodology for calculating the debt risk premium. ActewAGL proposed that the averaging period for the debt risk premium should be set prior to 7 September 2008, consistent with ActewAGL's proposed averaging period for the risk–free rate.[315]

ActewAGL proposed that the AER use CBASpectrum estimates of fair yields on BBB+ rated 10–year corporate bonds, based on analysis by CEG and Allen Consulting Group (ACG). ActewAGL argued that the CEG and ACG analysis concluded that CBASpectrum estimates are more accurate than Bloomberg estimates under current market conditions.[316] ActewAGL noted that an alternative to relying solely on one or the other of these data providers would be to take a simple average of Bloomberg and CBASpectrum estimates. Based on its proposed approach, ActewAGL adopted a debt risk premium of 3.43 per cent in its revised regulatory proposal.[317]

**Submissions**

EnergyAustralia's submission stated that CBASpectrum data may provide a more realistic reflection of market conditions. EnergyAustralia stated that, in any case, Bloomberg data by itself is not reflective of observed yields on 10–year corporate bonds. EnergyAustralia requested that the AER consider the material presented as part of EnergyAustralia's revised regulatory proposal and submission when assessing ActewAGL's proposals.

**AER considerations**

The AER notes that a significant divergence has developed over the past nine months between the corporate bond fair yields reported by Bloomberg[318] and CBASpectrum,

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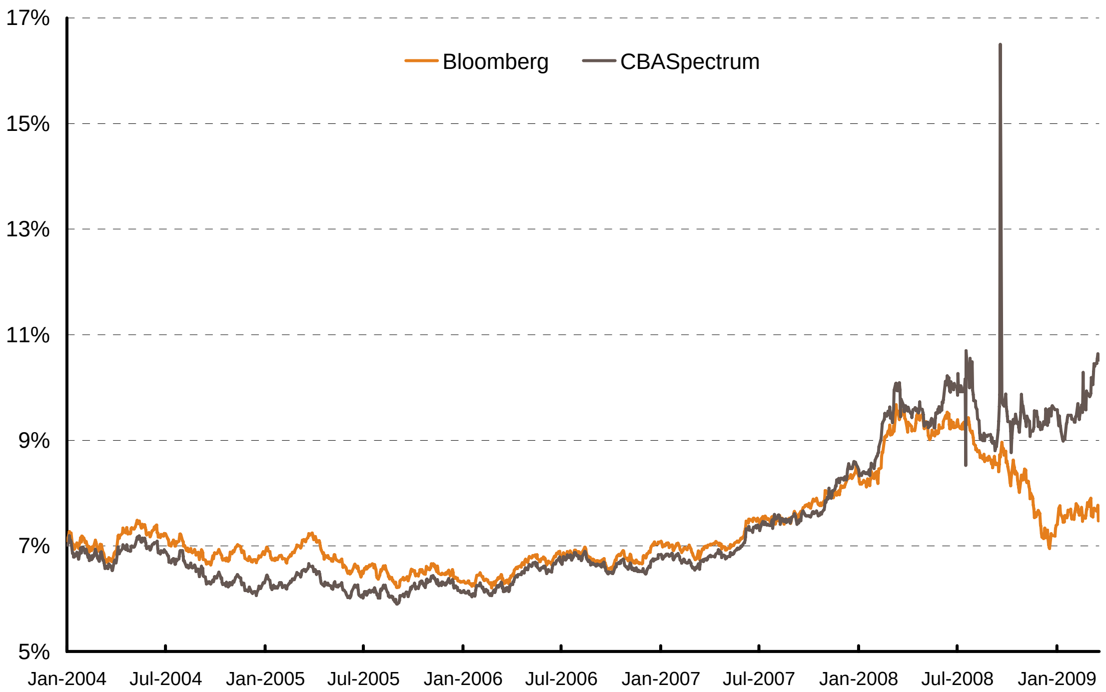
312 AER, *Draft decision*, p. 138.
313 AER, *Draft decision*, pp. 137–138.
314 AER, *Draft decision*, p. 137.
315 ActewAGL, *Revised regulatory proposal*, confidential attachment 10.
316 ActewAGL, *Revised regulatory proposal*, p. 49.
317 ActewAGL, *Revised regulatory proposal*, attachment 3.
318 Bloomberg's 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. Due to a lack of long term BBB+ or similar rated bonds, Bloomberg does not report a 10 year BBB+ fair yield. As set out in the draft decision, the AER has derived the BBB+ 10 fair

as displayed in figure 12.1. Since January 2009, the Bloomberg BBB+ 10–year fair yield has remained relatively steady while the CBASpectrum fair yield has risen sharply. Consequently the difference in the two fair yields surpassed three percentage points on 19 March 2009.

**Figure 12.1: BBB+ 10–year fair yield estimates**




Source: Bloomberg, CBASpectrum and AER analysis.

In previous revenue determinations the AER compared the estimated average daily fair yields for corporate bonds with a BBB+ credit rating from the Bloomberg and CBASpectrum databases.[319] The review indicated that Bloomberg provided estimates of BBB+ rated long–term fair yields that were more consistent with the observed yields of similarly rated actual bonds. However, given the current divergence between the two data sources the AER considers that the fair yields reported by the two sources should be reviewed again.

To undertake the analysis, the AER first identified the BBB+ rated bonds with a maturity of at least two years, which are listed in table 12.2. The AER then compared the observed yields of these bonds as quoted by both Bloomberg and CBASpectrum with the fair yields from the two sources.[320] The AER compared the actual observed bond yields with the fair yields from 2 February to 20 March, covering the averaging periods for the NSW DNSPs, ActewAGL, TransGrid and Transend. The average observed yields, and the average Bloomberg and CBASpectrum fair yields over the period analysed are outlined in table 12.2.

year yield by adding the spread between the A rated 8 and 10 year fair yields to the BBB+ 8 year fair yield.

319 AER, *Draft decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 8 December 2006, pp. 103–104; and AER, *Directlink Joint Venturers' application for conversion and revenue cap, Decision*, 3 March 2006, pp. 211 and 221.

320 For each bond, fair yields were calculated for each day by linear interpolation of the two fair yields that straddled the maturity of the bond.

**Table 12.2: BBB+ rated bonds with a maturity of two years or greater (per cent)**

| Issuer | Maturity | Average observed yield | | Average fair value | |
|---|---|---|---|---|---|
| | | Bloomberg | CBASpectrum | Bloomberg | CBASpectrum |
| Origin Energy | 6 October 2011 | 6.084 | Not reported | 6.202 | 7.698 |
| Tabcorp | 13 October 2011 | 6.295 | 6.446 | 6.213 | 7.710 |
| Lane Cove Tunnel | 9 December 2011 | Not reported | 9.755[a] | 6.301 | 7.808 |
| Coles Group | 25 July 2012 | 6.647 | 6.412 | 6.699 | 8.162 |
| Snowy Hydro | 25 February 2013 | 6.891 | 7.797 | 7.082 | 8.473 |
| Lane Cove Tunnel | 9 December 2013 | Not reported | 11.135[a] | 7.195 | 8.797 |
| Santos | 23 September 2015 | 7.384 | 8.053 | 7.396 | 9.327 |
| Babcock & Brown Infrastructure Group | 9 June 2016 | 7.487[b] | 12.958 | 7.473 | 9.472 |
| Adelaide Airport | 20 September 2016 | 7.280[b] | Not reported | 7.504 | 9.524 |

Source: Bloomberg, CBASpectrum and AER analysis

(a) The yields of the two Lane Cove Tunnel bonds did not change during the period indicating that the bonds were illiquid and no trades had occurred.

(b) The yield reported by Bloomberg was an estimation of the fair price of this bond when compared with bonds in the same sector not a traded price.

Three measures were used to test the differences between the actual reported yields and the fair yields reported by CBASpectrum and Bloomberg:[321]

- mean daily difference
- mean daily absolute difference
- mean daily squared difference.

In the analysis the Origin Energy bond was excluded because CBASpectrum did not report yields for this bond. The two Lane Cove Tunnel bonds were excluded because the bonds were illiquid and Bloomberg did not report yields for them. The Babcock and Brown Infrastructure Group and the Adelaide Airport bonds were excluded because the yields reported by Bloomberg were fair yield estimates not yields based

[321] The mean daily difference is the arithmetic mean of the difference between the observed yield of each bond and its corresponding estimated fair yield calculated daily. The mean daily absolute difference is the arithmetic mean of the absolute difference between the observed yield of each bond and its corresponding estimated fair yield calculated daily. The mean daily squared difference is the arithmetic mean of the difference between the observed yield of each bond and its corresponding estimated fair yield squared, calculated daily.

on prices from observed trades. The results of this analysis are summarised in table 12.3.

**Table 12.3: Fair yield analysis results with Bloomberg observed yields**

| | Bloomberg | CBASpectrum | Average fair yield |
|---|---|---|---|
| Mean daily difference (per cent) | –0.023 | 1.526 | 0.751 |
| Mean daily absolute difference (per cent) | 0.138 | 1.526 | 0.751 |
| Mean daily squared difference (per cent squared) | 0.029 | 2.415 | 0.602 |

Source: Bloomberg, CBASpectrum and AER analysis.
Note: The average fair yield represents the average of the Bloomberg and CBASpectrum fair yields.

As outlined in table 12.3, the mean daily difference between the fair yield and the Bloomberg observed yield was much closer to zero for Bloomberg fair yields. Using Bloomberg fair yields also gave a significantly lower mean daily absolute difference and mean daily squared difference. For the CBASpectrum fair yields the mean daily difference equalled the mean daily absolute difference, which indicates that for every day included in the analysis, the CBASpectrum fair yield was higher than the observed yield reported by Bloomberg for every BBB+ bond with a maturity of at least two years. This analysis suggests that the CBASpectrum fair yields were biased upward in the period from 2 February 2009 to 20 March 2009.

**Table 12.4: Fair yield analysis results with CBASpectrum observed yields**

| | Bloomberg | CBASpectrum | Average fair yield |
|---|---|---|---|
| Mean daily difference (per cent) | –0.329 | 1.241 | 0.456 |
| Mean daily absolute difference (per cent) | 0.618 | 1.275 | 0.659 |
| Mean daily squared difference (per cent squared) | 0.610 | 1.977 | 0.645 |

Source: Bloomberg, CBASpectrum and AER analysis.
Note: The average fair yield represents the average of the Bloomberg and CBASpectrum fair yields.

When the observed bond yields reported by CBASpectrum are used, the mean daily difference between the fair yield and the observed yield is again closest to zero for Bloomberg fair yields. In fact, Bloomberg fair yields again perform best for all three measures. Again, the results for CBASpectrum fair yields are the least favourable for all three measures. The results in table 12.4 also reflect the fact that the observed yields reported by CBASpectrum were mostly higher than the observed yields reported by Bloomberg.

The AER notes that during the period analysed Bloomberg did not report observed yields for all bonds for all trading days. Since late 2007, there have been significant periods of time for which observed yields have not been quoted for particular bonds due to illiquidity in the corporate bond market. The AER notes that it was during late 2007 that the Essential Services Commission of Victoria (ESCV) tested the fair yields of Bloomberg and CBASpectrum for its 2008 gas access arrangement review. As noted by CEG, the ESCV stated in its review that:[322]

> …the analysis conducted in the estimation of the debt premium (below) shows that CBASpectrum has performed better in predicting bond yields than Bloomberg under current market conditions.

This was one of the conclusions of the Allen Consulting Group (ACG)[323] which undertook the analysis referred to by the ESCV. In its report, ACG stated that it considered that:[324]

> … the suggested error in fair yield predictions of Bloomberg of -2 to 4bp is not material and the absence of material over-prediction is consistent with there being no broader theoretical or empirical reasons to suggest that Bloomberg systematically errs in its predictions of fair-value yields.
>
> The suggested error in the CBASpectrum fair-yield predictions is greater than for Bloomberg and, importantly, suggests over-estimates of yields contrary to indications in mid 2007 of systematic negative bias in CBASpectrum fair yield predictions.

At first glance this quote appears inconsistent with the ESCV quote and suggests that the analysis conducted by ACG indicated Bloomberg, not CBASpectrum, performed better in predicting bond yields under the market conditions prevalent during the 20 days business days to 21 December 2007. In fact, the ACG analysis found that over the 20 business days to 21 December 2007 Bloomberg overestimated bond yields by 3.2 basis points on average while CBASpectrum overestimated yields by 17.6 basis points.[325]

However, ACG concluded that:[326]

> As the debt margins derived from Bloomberg relied on extrapolation of fair value yields for 7 and 8 year bonds rather than direct predictions, we suggest that greater weight may be given to the debt margins derived from CBASpectrum, and hence the higher values in these ranges.

Consequently, it appears that the basis for the conclusion that CBASpectrum performed better in predicting bond yields than Bloomberg under the market conditions at that time was because CBASpectrum provided a 10–year BBB+ fair yield estimate while Bloomberg only estimated fair yields for maturities up to eight years.

The AER, therefore, does not consider that the ACG analysis conducted for the ESCV indicated that CBASpectrum performed better at predicting BBB+ bonds yields than Bloomberg. Rather, the AER considers that the ACG analysis found that Bloomberg performed better than CBASpectrum at predicting BBB+ bond yields for bonds with a maturity up to eight years. Because the longest term to maturity of the bonds considered by ACG was eight years the analysis does not indicate whether Bloomberg

322 ESCV, *Gas access arrangement review 2008–2012: Final decision*, 7 March 2008, p. 487.
323 ACG, *Memorandum: Gas access arrangement review 2008: updating estimates of debt margins for 20 trading days to November 2007 and December 2007*, 25 January 2007, p. 4.
324 ACG, *Memorandum*, 25 January 2007, p. 8.
325 ACG, *Memorandum*, 25 January 2007, p. 7.
326 ACG, *Memorandum*, 25 January 2007, p. 8.

or CBASpectrum performed better at predicting the fair yield of BBB+ bonds with a 10–year maturity.

In the final decision for SP AusNet, the AER tested both the CBASpectrum 10–year BBB+ fair yield and the extrapolated Bloomberg BBB eight year fair yield to test which was the best proxy for the Bloomberg BBB 10–year fair yield. The two fair yields were tested over the 18 month period to October 2007 when Bloomberg ceased publishing a BBB 10–year fair yield. The analysis found that the eight year Bloomberg BBB fair yield plus the spread between the eight and 10–year Bloomberg A fair yields was the best proxy over the sample period.[327]

Consequently, the AER considers that the ACG analysis conducted for the ESCV, when considered alongside the analysis the AER undertook in its final decision for SP AusNet, indicates that Bloomberg, not CBASpectrum, performed better in predicting bond yields under the market conditions prevalent during the 20 business days to 21 December 2007.

In conjunction with the analysis that compared observed BBB+ bond yields with the fair yield estimates of Bloomberg and CBASpectrum, the AER has also reviewed the methodologies adopted by these data providers.

The AER notes that the methodologies adopted by Bloomberg and CBASpectrum to estimate fair yields are significantly different. The AER understands, based on work undertaken by NERA Economic Counsulting, that CBASpectrum fair yield estimates for bonds with a given credit rating are based on observed yields for bonds of all credit rating. Thus, the BBB+ 10–year fair yield will be a function of not only the observed yields of BBB+ bonds but also the yields of long dated bonds with other credit ratings. By contrast, Bloomberg's BBB fair yield curve estimates are based only on the observed yields of a sample of BBB–, BBB and BBB+ corporate bonds.[328]

The AER considers that the two methodologies have different strengths and weaknesses. Currently there is a shortage of long dated BBB bonds in the market. This, combined with the methodology it adopts, has resulted in Bloomberg discontinuing its 10–year BBB fair yield.

CBASpectrum, on the other hand, draws on observed yields for all bond ratings when calculating its fair yield for a given rating, thus enabling it to estimate a 10–year BBB+ fair yield estimate. However, in doing so it makes a number of assumptions such as the functional form of the yield curves and that yield curves of different ratings do not cross. Because of these assumptions, when tested against observed bond yields the Bloomberg fair yield estimates for similar rated bonds will usually be found more in alignment.

Another important consideration when comparing the fair yields of Bloomberg and CBASpectrum is the observed yields used by the two data providers to estimate their fair yield curves. This is particularly important in the current economic climate where

327 AER, *Final decision: SP AusNet transmission determination: 2008-09 to 2013-14*, January 2008, pp. 95–98.

328 NERA, *Critique of available estimates of the credit spread of corporate bonds*, May 2005.

the trading of a significant number of bonds is either thin or non–existent. Because bonds are typically traded 'over the counter' rather than on a centralised exchange it can be difficult to observe the market price. The AER understands that CBASpectrum's observed yields are based only on trades that the Commonwealth Bank participates in. By contrast, Bloomberg's observed yields are based on trade information provided to it by a wide range of different financial institutions. Consequently, the AER considers that the observed bond yields reported by Bloomberg provide a better reflection of the true market price than those reported by CBASpectrum.

In reviewing the CBASpectrum methodology, the AER noted that the credit ratings reported by CBASpectrum were sometimes outdated. For example, the Babcock and Brown Infrastructure bond was rated, as at March 2009, as A– in CBASpectrum despite it being re-rated as BBB+ by Standard and Poor's on 6 June 2008. The AER considers that in the current economic climate, where bonds are more likely to be re–rated downward than upward, any delay in updating credit ratings will result in an upward bias to the fair yield estimates of CBASpectrum.

To the extent that the observed bonds used to calculate the fair yields are quite different, the AER considers that this is the most probable cause of the discrepancy in the fair yield estimates of CBASpectrum and Bloomberg. If the observed bonds used were all representative of the credit rating under consideration, then that alone would give rise to only minor sampling variations. However, the key problem is that the market perceived credit rating of all bonds is continually changing and a bonds' credit rating may no longer reflect the market perceived credit rating. As a result of the global financial crisis many existing bonds are no longer regarded by markets as being of investment grade, and pricing and yields change to reflect this. In the current economic climate some bonds are reporting extremely high yields indicating that investors no longer consider those bonds to be of investment grade.

The AER considers that these bonds, which are no longer considered by the market as being of investment grade, should not be included in any sample of bonds used to estimate an efficient benchmark debt risk premium. The AER notes that Bloomberg publishes the bonds, and corresponding yields, that it uses each day to estimate its BBB fair yield curve. The AER reviewed the bonds used by Bloomberg to estimate its BBB fair yield curve during the averaging period (February to March 2009) and found no significant variability in the yields that might suggest inappropriate sample selection. Despite directly contacting CBApectrum, the AER has been unable to confirm which bonds CBASpectrum uses to estimate its fair yields and if it removes any outliers.

The AER also notes that the CBASpectrum fair yields exhibit significantly more variability than the Bloomberg fair yields (see figure 12.1). For example, the CBASpectrum BBB+ 10–year yield had risen to 16.5 per cent on 19 September 2008 from 9.9 per cent the previous day. The next day it returned to 9.8 per cent. The cause of this volatility is unclear.

The AER notes that on 24 March 2009 Tabcorp announced a five year bond issue to be rated BBB+. The prospectus for the proposed Tabcorp bond issue outlines the interest payable will be a variable interest rate. The variable interest rate will be set for each interest period equal to the 3–month bank bill rate[329] plus a ‘margin’ of 4.25 per cent.[330] As at 23 March 2009, the initial interest rate would be 7.28 per cent.[331] The AER notes that on 23 March 2009 the Bloomberg five year BBB fair yield was 7.41 per cent and the CBASpectrum five year BBB+ fair yield was 9.67 per cent. Further, the AER notes that the fair yields represent estimates for fixed interest bonds, not variable interest bonds. While there are ways with converting the yield of a variable rate bond to the yield of an equivalent fixed rate bond, the AER does not consider it appropriate to compare the yields on variable rate bonds with those of fixed rate bonds for the purpose of assessing the fair yield estimates from Bloomberg and CBASpectrum.

Given these considerations, the AER is of the view that Bloomberg fair yields are a better predictor of observed yields CBASpectrum fair yields alone or an average of Bloomberg and CBASpectrum fair yields. Consequently, the AER does not consider it reasonable to use the BBB+ fair yield reported by CBASpectrum or an average of Bloomberg and CBASpectrum fair yields to derive the Australian benchmark rate for corporate bonds with a maturity of 10 years and a credit rating of BBB+. The AER therefore maintains its draft decision to use Bloomberg fair yields for the purposes of determining the benchmark debt risk premium for ActewAGL.[332]

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 adopted for determining the risk–free rate. For this final decision, the 20 business day moving average benchmark debt risk premium for the period ending 27 February 2009, based on BBB+ rated corporate bonds with a maturity of 10 years, is 3.49 per cent (effective annual compounding rate). Adding this debt risk premium to the nominal risk–free rate of 4.29 per cent provides a nominal return on debt of 7.78 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.

### 12.5.3 Expected inflation

**AER draft decision**

The AER determined a 10–year inflation forecast of 2.55 per cent per annum. The inflation forecast was based on a simple average of the Reserve Bank of Australia’s (RBA) forecasts of short term inflation—currently extending out to two years—and the mid–point of the RBA’s target inflation band for the remaining years in the 10–year period.

The AER did not accept the inflation forecast proposed by ActewAGL, which was based on advice commissioned from CEG. ActewAGL’s inflation forecast was

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[329] Tabcorp, *Tabcorp bonds: prospectus for the issue of five year Tabcorp bonds to be listed on ASX*, 24 March 2009, p. 6.

[330] Tabcorp, *Tabcorp bonds margin now set and offer now open*, 1 April 2009, p. 1.

[331] The Tabcorp bond prospectus (on page 1) states that the initial interest rate would be between 7.03 per cent and 7.53 per cent. Based on the confirmed margin of 4.25 per cent this equates to an initial interest rate of 7.28 per cent.

[332] The fair yield as a proxy for the corporate bond yield less the CGS yield as a proxy for the risk–free rate produces the debt risk premium.

calculated using a weighted average mean of professional economic forecasters' short–term inflation expectations and the mid–point of the RBA's long–term target inflation band, yielding an inflation rate of 2.51 per cent per annum.[333]

The AER determined that, consistent with recent transmission determinations, an inflation forecasting methodology based on the RBA inflation forecasts and the mid–point of the RBA's target inflation band is objective and represents the best estimate of forecast inflation.[334] The AER noted that the inflation forecast would be updated using the latest forecasts at the time of the final decision.

**Revised regulatory proposal**

In its revised regulatory proposal, ActewAGL did not agree with the AER's inflation forecasting methodology. ActewAGL stated that the AER should not have used an updated RBA inflation forecast inflation for 2009–10 in the draft decision, unless the proposed inflation forecast was significantly different to the forecast proposed by ActewAGL.[335] ActewAGL also stated that, because its proposed inflation forecasts for 2010–11 to 2013–14 were not significantly different from the AER's forecast inflation for these years, the AER had not demonstrated that ActewAGL's forecasts of inflation were unreasonable.[336]

To calculate a 10–year inflation forecast, ActewAGL's revised regulatory proposal used the AER's inflation forecasts for 2008–09 and 2009–10, adopted its regulatory proposal inflation forecasts for 2010–11 to 2013–14 and applied the mid–point of the RBA's target inflation band for the remaining years.[337] ActewAGL proposed that a geometric average be used as it is more accurate than a simple average. Based on this methodology, ActewAGL proposed an expected inflation estimate of 2.57 per cent per annum.[338]

**AER considerations**

In previous transmission determinations the AER has determined 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 AER does not agree that it should not have rejected ActewAGL's regulatory proposal inflation forecasts in the draft decision because the difference between the AER's forecasts and ActewAGL's was insignificant. The draft decision was made on the basis that the methodology proposed by ActewAGL was not likely to result in the best estimate of expected inflation.

ActewAGL proposed that a geometric average be used instead of a simple average because it provides a more accurate approach to determining the average 10–year

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333 ActewAGL, *Regulatory proposal*, p. 210.
334 AER, *Draft decision*, pp. 139–140.
335 ActewAGL, *Revised regulatory proposal*, p. 10.
336 ActewAGL, *Revised regulatory proposal*, p. 10.
337 ActewAGL, *Revised regulatory proposal*, pp. 10, 49.
338 ActewAGL, *Revised regulatory proposal*, pp. 10, 49.

inflation forecast. The AER recognises there is considerable uncertainty in forecasting inflation. Having assessed ActewAGL's revised regulatory proposal, the AER agrees that a geometric average may provide for a more accurate estimate of expected inflation during the forecast period. The AER also notes that the difference between applying a simple average and a geometric average is marginal.

The AER notes that ActewAGL has not provided any additional material in its revised regulatory proposal to justify a change to the AER's methodology or why an updated inflation forecast should not be adopted.

Inflation forecasts can change in line with market sensitive data. The recent change in short–term inflation expectations has been evident in the past six months, as demonstrated by the RBA's stance on monetary policy. In the draft decision the AER stated it would update the inflation forecast for its final decision. This is consistent with regulatory practice in Australia.

The AER has updated the inflation forecast for the first two years of the next regulatory control period using the latest published RBA inflation expectations as shown in table 12.5.[339] The AER considers that, consistent with its draft decision methodology and based on a geometric average, an inflation forecast of 2.47 per cent per annum produces the best estimate for a 10–year period to be applied in the post–tax revenue model for this final decision.

**Table 12.5: AER 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 | Geometric average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast inflation | 2.75 | 2.00 | 2.50 | 2.50 | 2.50 | 2.50 | 2.50 | 2.50 | 2.50 | 2.50 | 2.47 |

Source: RBA, *Statement on monetary policy*, 6 February 2009, p. 65.

## 12.6 AER conclusion

The AER has determined a nominal vanilla WACC of 8.79 per cent for ActewAGL using the updated risk–free rate and debt risk premium, and other parameters prescribed under the transitional chapter 6 rules. Table 12.6 sets out the WACC parameter values used for this final decision. The AER's WACC is lower than ActewAGL's revised regulatory proposal WACC because of a lower nominal risk–free rate—commensurate with monetary policy and softening in economic growth—adopted for this final decision.

339 RBA, *Statement of Monetary Policy*, 6 February 2009, p. 65.

**Table 12.6: AER conclusion on ActewAGL's WACC parameters**

| Parameter | AER conclusion |
|---|---|
| Risk–free rate (nominal) | 4.29% |
| Risk–free rate (real)[a] | 1.77% |
| Expected inflation rate | 2.47% |
| Debt risk premium | 3.49% |
| Market risk premium | 6.00% |
| Gearing | 60% |
| Equity beta | 1.00 |
| Nominal pre–tax return on debt | 7.78% |
| Nominal post–tax return on equity | 10.29% |
| Nominal vanilla WACC | 8.79% |

(a) The real risk–free rate was calculated using the Fisher equation.

The AER considers that its decision to withhold agreement to the averaging period in ActewAGL's regulatory proposal is reasonable and that the agreed averaging period is consistent with finance theory, regulatory practice, the NER and NEL. The AER considers that the material provided by ActewAGL in support of its revised regulatory proposal does not reasonably justify that an averaging period prior to September 2008 is better than a period that is as close as practically possible to the start of the next regulatory control period.

The AER considers that only Bloomberg data should be used to estimate the debt risk premium based on its analysis of the fair yields reported by Bloomberg and CBASpectrum, observed yields of BBB+ corporate bonds and the methodologies adopted by these two data providers.

Having assessed ActewAGL's revised regulatory proposal, the AER agrees that a geometric average may provide for a more accurate estimate of expected inflation during the forecast period. The AER notes that the difference between applying a simple average and a geometric average is marginal.

The AER maintains its draft decision to apply a methodology to determine a forecast inflation rate over a 10–year period using the RBA's inflation forecasts for the first two years and the mid–point of the RBA's target inflation range for the remaining eight years. The AER considers that, based on a geometric average, an inflation forecast of 2.47 per cent per annum produces the best estimate of a 10–year inflation forecast to be applied in the post–tax revenue model for this final decision.

## 12.7 AER decision

In accordance with clause 6.12.1(5) of the transitional chapter 6 rules the rate of return to apply to ActewAGL is 8.79 per cent.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the other appropriate amounts, values or inputs to apply to ActewAGL in respect of WACC parameters are as specified in table 12.6 of this final decision.

# 13 Service target performance incentive arrangements

## 13.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision and how the AER intends to apply its service target performance incentive scheme (STPIS) arrangements to ActewAGL.

## 13.2 AER draft decision

In consultation with ActewAGL, the AER 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,[340] the data reporting requirements were aligned with the requirements of the national distribution STPIS, published in June 2008.[341]

The AER stated that it would collect and monitor ActewAGL's service performance data during the next regulatory control period but revenue would not be placed at risk under the data collection process during this period.[342]

While noting that full compliance may not be realised before the commencement of the next regulatory control period, the AER stated it expects ActewAGL to implement measures to achieve full compliance with the national distribution STPIS as soon as practical, but no later than December 2009.[343]

## 13.3 Revised regulatory proposal

In response to the draft decision data collection requirements, ActewAGL proposed to implement a 'network connectivity solution' to establish the ability to record interruptions at the individual customer level.

It submitted that the solution will deliver accurate and timely data, compliant with the AER's reporting requirements.[344] ActewAGL stated that the solution will provide the ability to better plan and manage its network, assets, resources, reporting, fault resolution and provide customers with improved service.[345] However, it stated that the development of the network connectivity solution is a complex and lengthy project, and is not expected to be completed until 2013.[346] Given this, it noted that full

340 AER, *Final decision, Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations*, February 2008.
341 AER, *Final decision, Electricity distribution network service providers, Service target performance incentive scheme*, June 2008.
342 AER, *Draft decision*, p. 146.
343 AER, *Draft decision*, p. 146.
344 ActewAGL, *Revised regulatory proposal*, p. 20.
345 ActewAGL, *Revised regulatory proposal*, p. 20.
346 ActewAGL, *Revised regulatory proposal*, p. 21.

compliance with the data reporting requirements would not be achievable within the timeframe set in the draft decision.[347]

## 13.4 Submissions

The Energy Users Association of Australia (EUAA) and Energy Market Reform Forum (EMRF) made submissions in the context of STPIS arrangements for the NSW DNSPs. Specifically the EUAA and EMRF stated that a STPIS should be applied in the next regulatory control period.[348] The AER has considered these submissions in its review of STPIS arrangements for ActewAGL. Further details on the submissions are included in chapter 12 of the NSW DNSP final decision.[349]

## 13.5 Issues and AER considerations

**Application of STPIS regime**

The AER notes the EUAA's and EMRF's submissions that a STPIS should be applied during the next regulatory control period. In late 2007, the AER consulted on the STPIS arrangements to apply in the ACT and NSW for the next regulatory control period. The AER's decision, reasoning and responses to submissions received during that process are detailed in the STPIS final decision, published in February 2008.[350]

The AER will collect and monitor service performance data from ActewAGL during the next regulatory control period, and expects to apply financial rewards and penalties from the beginning of the 2014–19 regulatory control period. In addition, ActewAGL will continue to have an obligation to publish its performance data and report to the jurisdictional regulators in accordance with its utility licence. The AER considers that these two measures will continue to support the transparent reporting of reliability outcomes for ActewAGL's customers during the next regulatory control period. The collection of data will also ensure that a robust data set is available for setting meaningful and appropriate performance targets under the national distribution STPIS from 1 July 2014.

**ActewAGL's network connectivity solution**

The AER considers the scope of ActewAGL's proposed network connectivity solution to be an appropriate response to meeting the data reporting obligations for the next regulatory control period, as set out in the draft decision. It represents a significant project for ActewAGL and the AER acknowledges that it will take time before the new systems are fully operational. To this end, ActewAGL will not be expected to achieve full compliance with the requirements of the national distribution STPIS by December 2009. However, the AER does expect ActewAGL to implement the project as soon as practical.

[347] ActewAGL, *Revised regulatory proposal*, p. 21.
[348] EUAA, *Submission to AER's draft decision and revised DNSP proposals – review of the regulatory proposals by the NSW electricity distributors*, 16 February 2009; and EMRF, *A response, AER NSW electricity distribution revenue reset, AER draft decision*, February 2009.
[349] AER, *Final decision, NSW distribution determination*, section 12.4.
[350] AER, *Final decision, STPIS ACT and NSW*, February 2008.

ActewAGL has proposed additional opex and capex to establish and manage its proposed network connectivity solution. The AER's considerations on the expenditure associated with this project are set out at chapters 8 and 9 of this final decision.

## 13.6 AER conclusion

The AER notes that under clause 6.6.2(h) of the transitional chapter 6 rules it must monitor and collect information from any or all of the NSW DNSPs and ActewAGL on matters relevant to be included in the STPIS for the purpose of developing, amending or applying a STPIS for the regulatory control period commencing on 1 July 2014.

The AER maintains its draft decision to collect and monitor ActewAGL's service performance data during the next regulatory control period. Revenue will not be placed at risk during this period.

The AER acknowledges that full compliance with the data reporting requirements will not be realised before December 2009. However, the AER expects ActewAGL to implement measures to achieve full compliance with the national distribution STPIS as soon as practical.

In implementing the data reporting requirements, the AER expects to accumulate a reliable 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 to ActewAGL will be the subject of consultation under the framework and approach process, prior to the 2014−19 distribution determination.

The AER will not apply a STPIS to ActewAGL for the next regulatory control period. Clause 6.12.1(9) of the transitional chapter 6 rules requires the AER to make a decision on how any applicable STPIS will apply to ActewAGL. As a STPIS will not apply to ActewAGL, the AER is not required to make a decision with respect to a STPIS under clause 6.12.1(9) of the transitional chapter 6 rules for ActewAGL.

Further, as the AER has not applied a STPIS to ActewAGL for the next regulatory control period, it has not specified how a STPIS will apply to ActewAGL as set out in clause 6.3.2(a)(3) of the transitional chapter 6 rules.

# 14 Efficiency benefit sharing scheme

## 14.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision and how the AER intends to apply its efficiency benefit sharing scheme (EBSS) to ActewAGL. No submissions were received on this issue.

An EBSS shares between DNSPs and distribution network users the efficiency gains or losses derived from the difference between a DNSP's actual opex and the forecast opex allowance for a regulatory control period. The AER published an EBSS, under clause 6.5.8(a) of the transitional chapter 6 rules, which established a scheme that will apply to ActewAGL from 1 July 2009.[351] The EBSS will not have a direct financial impact on ActewAGL until the 2014–19 regulatory control period. ActewAGL will then receive carryover benefits/penalties for efficiency gains/losses made during the next regulatory control period.

## 14.2 AER draft decision

The AER stated it would apply the EBSS released in February 2008 to ActewAGL for the next regulatory control period. It specified the following opex cost categories would be excluded from the operation of the EBSS for the next regulatory control period:[352]

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs
- the utilities network facilities tax (UNFT)
- non–network alternatives costs.

These categories were in addition to the costs associated with any pass through events that would be directly excluded by the EBSS.

## 14.3 Revised regulatory proposal

In its revised regulatory proposal, ActewAGL stated that, in addition to the excluded cost categories listed in the draft decision, direct feed–in tariff payment costs and equity raising costs should also be excluded from the EBSS.[353]

ActewAGL proposed that the opex in table 14.1 be used for EBSS purposes.

351 AER, *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, February 2008.
352 AER, *Draft decision*, p. 155.
353 ActewAGL, *Revised regulatory proposal*, p. 36.

**Table 14.1: ActewAGL proposed opex for EBSS purposes ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Revised opex proposal | 63.5 | 68.0 | 72.1 | 76.3 | 78.6 | 358.5 |
| Adjustment for debt raising costs | –0.5 | –0.6 | –0.6 | –0.6 | –0.7 | –3.0 |
| Adjustment for self insurance | –1.5 | –1.5 | –1.5 | –1.5 | –1.5 | –7.5 |
| Adjustment for insurance | –0.7 | –0.7 | –0.7 | –0.7 | –0.7 | –3.3 |
| Adjustment for superannuation | –3.2 | –3.3 | –3.4 | –3.6 | –3.6 | –17.2 |
| Adjustment for UNFT | –3.9 | –4.0 | –4.1 | –4.3 | –4.3 | –20 6 |
| Adjustment for FiT direct tariff payments | –3.4 | –6.8 | –10.0 | –12.7 | –15.3 | –48.2 |
| Adjustment for equity raising costs | –1.1 | –1.1 | –1.0 | –0.6 | –0.5 | –4.4 |
| Revised forecast opex for EBSS purposes | 49.1 | 49.9 | 50.8 | 52.3 | 52.0 | 254.2 |

Source: ActewAGL, *Revised regulatory proposal*, p. 37.

# 14.4 Issues and AER considerations

## 14.4.1 Excluded cost categories

**AER draft decision**

In the draft decision for ActewAGL, the AER concluded that the following cost categories should be excluded from the operation of the EBSS:[354]

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs
- non–network alternatives costs.

The primary considerations for excluding these cost categories were whether the cost category was controllable and how actual expenditure for that cost category would be used in setting opex forecasts for the following regulatory control period.

**Revised regulatory proposal**

ActewAGL proposed that, in addition to the cost categories excluded by the AER in the draft decision, direct feed–in tariff payments and equity raising costs should also be excluded from the operation of the EBSS.[355]

354 AER, *Draft decision*, p. 154.
355 ActewAGL, *Revised regulatory proposal*, p. 36.

ActewAGL considered that the timing and quantum of direct feed–in tariff payments were outside its control. ActewAGL noted that the uptake, size and capacity of microrenewable generators in the ACT will also be influenced by the feed–in tariff rate which is set by the ACT Government. Consequently, ActewAGL argued that feed–in tariff payments would be uncontrollable, and thus should be excluded from the operation of the EBSS.[356]

ActewAGL argued that equity raising costs should also be excluded from the EBSS on the basis that they would not be influenced by the efficiency of ActewAGL's service delivery.[357]

**AER considerations**

As outlined in the draft decision, the AER considers that there are two factors that should be considered when assessing whether an opex category should be excluded from the EBSS.[358] The first factor is whether or not the opex is controllable. The AER does not consider it appropriate for the EBSS to apply to cost categories over which a DNSP has no control.

The second factor is how actual expenditure for a cost category is used in setting opex forecasts for the following regulatory control period. The AER considers that if future opex allowances for a given cost category are not based on actual opex in the next regulatory control period, then that cost category should be excluded from the EBSS.

The AER notes that the *Electricity Feed-in (Renewable Energy Premium) Act 2008* was not passed by the ACT legislative assembly until after ActewAGL submitted its regulatory proposal. Consequently, ActewAGL did not propose direct feed–in tariff payments as an excluded cost category in its regulatory proposal. The AER also notes that the feed–in tariff rate and the quantum of energy produced by microrenewable generators in the ACT are both beyond the control of ActewAGL. Therefore, the AER considers that these costs should be excluded from the operation of the EBSS.

The AER also considers that it would be inappropriate to apply the EBSS to equity raising costs because, like debt raising costs, forecast equity raising costs are based on a benchmark efficient firm rather than the historical costs of ActewAGL. In the draft decision, the AER did not list equity raising costs as an excluded cost category because it did not provide ActewAGL an allowance for equity raising costs. This is because ActewAGL did not meet the required threshold based on benchmark cash flow analysis. To the extent that benchmark cash flow analysis based on the capex allowance demonstrates that a DNSP should be provided with an allowance for equity raising cost, the AER has considered in other regulatory decisions that it is more appropriate to amortise the allowance.[359] In this decision the AER maintains the view that equity raising costs should be amortised, that is, added to the RAB. Consequently, equity raising costs are excluded from the operation of the EBSS.

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356 ActewAGL, *Revised regulatory proposal*, p. 36.
357 ActewAGL, *Revised regulatory proposal*, p. 36.
358 AER, *Draft decision*, pp. 152–153.
359 AER, *Draft decision, NSW distribution determination*, pp. 195–197.

## 14.5 AER conclusion

The AER will apply the EBSS released in February 2008 to ActewAGL for the next regulatory control period.[360]

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 relating to defined benefit and retirement schemes
- UNFT payments
- direct feed–in tariff payments
- non–network alternatives costs.

These categories are in addition to the costs associated with any pass through events that are directly excluded by the EBSS.

The forecast controllable opex outlined in table 14.2 will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.[361]

**Table 14.2: AER conclusion on ActewAGL's forecast controllable opex for EBSS purposes ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Total forecast opex | 59.7 | 64.2 | 68.6 | 73.3 | 75.6 | 341.4 |
| Adjustment for debt raising costs | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 1.8 |
| Adjustment for self insurance | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 4.1 |
| Adjustment for insurance | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 3.8 |
| Adjustment for superannuation | 3.2 | 3.3 | 3.4 | 3.5 | 3.6 | 16.9 |
| Adjustment for UNFT payments | 3.9 | 4.0 | 4.1 | 4.3 | 4.3 | 20.6 |
| Adjustment for direct feed–in tariff payments | 3.1 | 6.8 | 10.0 | 12.7 | 15.3 | 47.9 |
| Adjustment for non–network alternatives | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.5 |
| Forecast opex for EBSS purposes | 47.5 | 48.1 | 49.0 | 50.7 | 50.3 | 245.7 |

Note: Numbers may not add up due to rounding.

[360] AER, *EBSS for ACT and NSW*.
[361] AER, *EBSS for ACT and NSW*, pp. 5–6.

In accordance with clause 6.3.2(a)(3) of the transitional chapter 6 rules the EBSS to apply to ActewAGL is specified in section 14.5 of this final decision.

## 14.6 AER decision

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules, the EBSS 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
- utilities network facilities tax payments
- direct feed–in tariff payments
- non–network alternatives costs.

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

# 15 Demand management incentive scheme

## 15.1 Introduction

This chapter sets out the demand management incentive scheme (DMIS) to apply to ActewAGL for the next regulatory control period. The DMIS which will apply to ActewAGL is a demand management innovation allowance (DMIA) scheme.

In February 2008 the AER released a DMIA scheme to apply to ActewAGL in the next regulatory control period.[362] Between February 2008 and the release of the draft decision, the AER carried out further investigation on the optimum design of the DMIA, and developed a replacement DMIA. The replacement DMIA aims to provide incentives for ActewAGL to pursue innovative broad based non–network solutions to growing demand and constraints on its network.

## 15.2 AER draft decision

The draft decision, subject to the agreement of ActewAGL (as the affected DNSP), was to amend the DMIA published on 29 February 2008, by replacing it with a replacement DMIA, as specified in the AER's *Demand management incentive scheme for the ACT and NSW distribution determinations* (the replacement DMIA).[363] The replacement DMIA was published concurrently with the AER's draft distribution determination for ActewAGL, on 28 November 2008.

The AER sought a submission from ActewAGL on the replacement DMIA. If ActewAGL agreed that the original DMIA should be replaced by the replacement DMIA, it was required to provide written confirmation of its agreement for the purposes of clause 6.6.3(c) of transitional chapter 6 rules.[364]

## 15.3 Revised regulatory proposal

ActewAGL provided its agreement that the original DMIA be replaced by the replacement DMIA for application to ActewAGL in the next regulatory control period.[365] However, ActewAGL raised a number of issues with both the original and replacement DMIA schemes.

ActewAGL noted that neither scheme will allow it to recoup revenues associated with tariff based demand management projects, as the AER considered that DNSPs would be able to recoup the costs associated with tariff based demand management through higher customer prices. ActewAGL submitted that, as it is subject to an average revenue cap, it is unable to increase its average prices within the regulatory control period, and as such is unable to recoup the foregone revenue costs of tariff based demand management.[366]

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362 AER, *Final decision: Demand management incentives schemes for the ACT and NSW 2009 distribution determinations*, February 2008.
363 AER, *Draft decision*, p. 165.
364 AER, *Draft decision*, p. 163.
365 ActewAGL, *Revised regulatory proposal*, p. 76.
366 ActewAGL, *Revised regulatory proposal*, p. 76.

ActewAGL also raised its concern that the administrative costs associated with the DMIA reporting requirements may inadvertently consume a disproportionate share of its allowance under the scheme.[367]

## 15.4 Submissions

The AER received one submission relating to the application of the DMIS to ActewAGL from the Total Environment Centre (TEC). The AER also received several other submissions on the application of the DMIA to the NSW DNSPs, which are also relevant to the application of the scheme to ActewAGL. Submissions on the NSW DNSPs were received from the City of Sydney, EnergyAustralia, the Energy Users Association of Australia and Integral Energy. The AER's consideration of these submissions is provided in the final decision on the NSW DNSPs distribution determination.[368]

The TEC's submission indicated that it supports the concept of the DMIA, but stated that the size of the allowance is insufficient to stimulate significant new demand management. It recommended that the DMIA should be set at 5 per cent of the forecast capex allowance for each DNSP. The TEC stated that it is not clear how DNSPs will distinguish between demand management carried out under the DMIA and that carried out as normal business practice. [369]

The TEC recommended that the DMIA should operate on a use–it–or–lose–it basis, otherwise the DNSPs' may be able to defer demand management spending indefinitely.[370] It also recommended that the DMIA criteria include 'value of capital and operating expenditure avoided or deferred'.[371]

The TEC recommended that the AER adopt and further develop the NSW Demand Management Code of Practice, and apply the code to DNSPs on a national basis.[372]

The TEC also recommended that the AER develop demand management reporting models for all DNSPs and TNSPs, similar to that required under the DMIA. It recommended that the AER issue an annual consolidated report on all non–network solutions investigated and implemented, including those that were unsuccessful.[373]

## 15.5 Issues and AER considerations

### 15.5.1 The replacement DMIA

The AER notes ActewAGL's agreement to replace the original DMIA with the replacement DMIA for the next regulatory control period. Accordingly, the DMIS that will apply to ActewAGL for the next regulatory control period will be the

367 ActewAGL, *Revised regulatory proposal*, p. 32.
368 AER, *Final decision, NSW distribution determination*, chapter 14, pp. 253–255.
369 TEC, *Submission to AER, NSW/ACT distribution demand management incentive allowance (DMIA)*, 16 February 2009, p. 2.
370 TEC, *Submission on the DMIA*, p. 2.
371 TEC, *Submission on the DMIA*, p. 4.
372 TEC, *Submission on the DMIA*, p. 4.
373 TEC, *Submission on the DMIA*, p. 5.

replacement DMIA which was published concurrently with the draft decision and draft distribution determination for ActewAGL, on 28 November 2008.

### 15.5.2 Forgone revenue

In expressing its concern regarding the recovery of foregone revenue for tariff based demand management under an average revenue cap, ActewAGL raised a new issue that was not considered in the various consultation processes undertaken prior to the development of the DMIA schemes. The AER considers that this concern is likely to have a limited effect on ActewAGL's incentives or ability to carry out tariff based demand management in the next regulatory control period.

ActewAGL's regulatory proposal described in detail its current use of price as a tool to manage demand and influence a demand side response.[374] In reference to the draft decision on the form of control for standard control services, ActewAGL stated:[375]

> The ability to use price as a tool for demand management is possible because ActewAGL Distribution has had the flexibility to set prices and price structures to meet customer needs, while at the same time promoting efficient outcomes.

The draft decision on the form of control mechanism for the next regulatory control period was to apply a maximum revenue cap, as was applied by the ICRC in the current regulatory control period and as proposed by ActewAGL. This control mechanism will allow ActewAGL the flexibility to continue its current tariff based demand management program. The AER considers that, given there is to be no change to the control mechanism applying to ActewAGL, the current incentives for ActewAGL to carry out tariff based demand management, independent of any DMIS, will remain unchanged.

In any case, the AER considers that the application of the replacement DMIA will not reduce the incentive to carry out tariff based demand management. Rather, the DMIA will provide an additional incentive, through allowing the recovery of the implementation costs of tariff based demand management, which in the current regulatory control period are funded by ActewAGL. Accordingly, the AER considers that it is appropriate to apply the replacement DMIA to ActewAGL in the next regulatory control period.

### 15.5.3 Administrative costs

The AER notes ActewAGL's concern regarding the administrative costs of the replacement DMIA.[376] In amending the DMIA published in February 2008, the AER reduced the administrative costs of the scheme by removing the prior approval stage of cost recovery. The AER considers that the administration and reporting requirements of the replacement DMIA are necessary to ensure that the scheme is accountable and transparent.

[374] ActewAGL, *Regulatory proposal*, pp. 232–238.
[375] ActewAGL, *Regulatory proposal*, p. 237.
[376] ActewAGL, *Revised regulatory proposal*, p. 76.

### 15.5.4 Magnitude of the DMIA

The TEC recommended increasing the magnitude of the DMIA.[377]

DNSPs are obliged to undertake demand management where it is an efficient response to network constraints, as part of normal business operations.[378] The DMIA 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 a DNSP's current expenditure on demand management, rather it builds upon the existing incentives to carry out demand management in the regulatory framework. The AER considers that the allowance provided under the DMIA will provide a sufficient incentive for ActewAGL to further develop its demand management initiatives and capability over the next regulatory control period.

### 15.5.5 Operation of the DMIA

The TEC recommended that the DMIA should operate on a use–it–or–lose–it basis, otherwise DNSPs may be able to defer demand management spending indefinitely.[379] The AER notes that this recommendation was taken up in the design of the AER's replacement DMIA, and that the allowance under the scheme is provided ex ante, on a use–it–or–lose–it basis.

The TEC also recommended that the DMIA criteria include 'value of capital and operating expenditure avoided or deferred'.[380] The AER considers that this requirement is counter to the objective of the DMIA, which is to provide an allowance for innovative, untested demand management projects that may not result in direct and quantifiable deferrals of capex in the short term, but may provide dynamic network benefits over the long term.

The TEC stated that it is not clear how DNSPs will distinguish between demand management carried out under the DMIA and that carried out as normal business practice, and raised its concern that DNSPs may be able to recover demand management projects twice.[381] Criteria 5(c) of the DMIA requires that costs recovered under the scheme must not be included in forecast capital or operating expenditure approved in the distribution determination for the next regulatory control period, or under any other incentive scheme in that determination.[382] The AER considers that this precludes DNSPs from submitting for recovery of costs of demand management projects under the DMIA that have also been funded under the broader capex and opex allowances.

### 15.5.6 General demand management issues

The TEC recommended that the AER develop demand management reporting models for all DNSPs and TNSPs, based on the reporting requirements of the DMIA. It also recommended that the AER issue an annual consolidated report on all non–network solutions investigated and implemented, including those that were unsuccessful, and

377 TEC, *Submission on the DMIA*, p. 2.
378 NER, transitional chapter 6 rules, clauses 6.5.6(e)(10) and 6.5.7(e)(10).
379 TEC, *Submission on the DMIA*, p. 2.
380 TEC, *Submission on the DMIA*, p. 4.
381 TEC, *Submission on the DMIA*, p. 3.
382 AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations, Demand management innovation allowance scheme*, November 2008, p. 5.

that the AER should adopt and further develop the NSW Demand Management Code of Practice.[383]

The AER is currently developing annual reporting guidelines for DNSPs, in the form of a regulatory information order (RIO). In August 2008, the AER released an issues paper on the development of a RIO for all DNSPs in the NEM.[384] The AER intends to release a draft RIO in mid 2009, for comment by interested parties. Information proposed to be sought and made public includes DNSPs' demand management programs and expenditures.

## 15.6 AER conclusion

The AER's decision is to amend the DMIA published in its final decision on DMIS, released on 29 February 2008, by replacing it with the replacement DMIA for application to ActewAGL over the next regulatory control period.

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 – Demand management innovation allowance scheme,* November 2008.

In accordance with clause 6.3.2(a)(3) of the transitional chapter 6 rules the application of the demand management incentive scheme to apply to ActewAGL is as specified in this section 15.6.

## 15.7 AER decision

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules 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 – Demand management innovation allowance scheme*, November 2008.

383 TEC, *Submission on the DMIA*, p. 5.

384 AER, *Issues paper—Electricity distribution network service providers—Annual information reporting requirements*, August 2008.

# 16 Pass through arrangements

## 16.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision and the AER's assessment of ActewAGL's proposed pass through events to apply during the next regulatory control period.

The pass through provisions of the transitional chapter 6 rules 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. In order for costs to be passed through, a 'pass through event' must occur.

The NER defines specific events that constitute pass through events. In addition to these defined events, the transitional chapter 6 rules provide that events may be nominated in a distribution determination that will constitute pass through events for the next regulatory control period.[385]

## 16.2 AER draft decision

In the draft decision the AER accepted the proposed major natural disaster event as a nominated pass through event for ActewAGL but amended the proposed definition. The AER did not consider that ActewAGL's other proposed pass through events met the AER's assessment criteria and therefore did not accept the following events:

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

## 16.3 Revised regulatory proposal

In its revised regulatory proposal ActewAGL rejected the draft decision not to nominate as a pass through event the transitional period event and submitted that the major natural disaster event definition should be amended.

It proposed that the following events be nominated pass through events:

> **A transitional period event**: Any event that falls within the definition of a cost pass through event set out in the NER or which is approved as a cost pass through event by the AER in its final determination for ActewAGL Distribution for the 2009–14 period, and which occurs during the period 2 June 2008 to 30 June 2009.[386]

[385] See definition of 'pass through event' in chapter 10 of the NER.

[386] ActewAGL, *Revised regulatory proposal*, p. 72. The proposed definition also appears in ActewAGL, *Regulatory proposal*, p. 272.

> **A major natural disaster event**: Any major natural disaster (but excluding any insured events – that is, those events for which the costs of external insurance or self insurance has been approved by the AER) 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.[387]
>
> **A force majeure event**: Any major fire, flood, earthquake, storm or other weather–related or natural disaster, act of God, riot, civil disorder, rebellion or other similar cause beyond the control of the DNSP (but excluding any insurable events – that is, those events for which external insurance or self insurance is feasible) that occurs during the next regulatory control period and materially changes the costs to the DNSP of providing direct control services.[388]

ActewAGL stated that although the draft decision accepted its proposed major natural disaster event, the AER adopted an alternative definition for the event. It argued that the draft decision definition to exclude cases where the event is 'insurable' or where external or self insurance is 'feasible' is not appropriate.[389] ActewAGL contended that a major natural disaster should only be excluded from the definition if the distribution determination approved either external insurance or a self insurance allowance for the event.[390]

ActewAGL did not propose the force majeure event in its regulatory proposal (submitted in June 2008). It noted that in the draft decision for the NSW DNSPs the AER accepted EnergyAustralia's proposal to include a force majeure event as a nominated pass through event and that this event would also apply to Country Energy and Integral Energy, even though they did not propose the event. ActewAGL considered that this event captures some events not included in the major natural disaster event.[391]

## 16.4 Submissions

**Introduction of a feed–in tariff scheme**

ActewAGL stated that the ACT Government had passed legislation establishing a feed–in tariff (FiT) scheme coming into effect on 1 March 2009 that will materially affect its forecast costs in the next regulatory control period.

ActewAGL reiterated its revised regulatory proposal that an annual pricing adjustment mechanism applying to direct tariff payments incurred under the FiT scheme would ensure that it is able to recover the costs associated with the scheme's implementation. ActewAGL considered the annual pricing adjustment is the most appropriate mechanism to achieve efficient cost recovery.[392]

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387 ActewAGL, *Revised regulatory proposal*, p. 73.
388 ActewAGL, *Revised regulatory proposal*, p. 74. The proposed definition also appears in AER, *Draft decision, NSW distribution determination*, pp. 286–287.
389 ActewAGL, *Revised regulatory proposal*, p. 73.
390 ActewAGL, *Revised regulatory proposal*, p. 73.
391 ActewAGL, *Revised regulatory proposal*, p. 74.
392 ActewAGL, *Submission to the AER*, p. 10.

As an alternative approach to recovering the efficient costs associated with the FiT tariff scheme, ActewAGL submitted that there is scope under the NER to approve an additional specific pass through event that will allow it to adjust its revenue as part of the annual pricing process.[393] It also considered that a pass through event of this kind should not be subject to any materiality threshold.[394] ActewAGL proposed a FiT event be a nominated pass through event, defined as:

> **Feed-in tariff change event** means a change in the total amount of direct feed–in tariff rebates paid by ActewAGL in respect of the ACT Feed-in tariff scheme. For the purpose of this definition, the change in the amount of direct feed–in tariff rebates paid by ActewAGL must be calculated as the difference between:
>
> (1) the amount of scheme direct feed–in tariff costs paid each regulatory year by ActewAGL, derived from the metered output of generators subject to the scheme; and
>
> (2) the amount of scheme direct feed–in tariff costs which are forecast for the purpose of and included in the ACT distribution determination for each regulatory year of the regulatory control period.
>
> Relevant feed–in rebates under this pass through mechanism are those paid through the operation of the *Electricity Feed-in (Renewable Energy Premium) Act 2008,* and any amendments to this Act, or through the operation of a new Act implementing the expected second stage of the scheme applying to larger generators.[395]

**Transitional period event**

ActewAGL submitted that the transitional period event, as defined in its regulatory proposal, be accepted as the rejection of this event exposes it to the risk of being unable to recover the efficient costs of delivering distribution services that it considers is inconsistent with section 7A of the NEL.[396]

**Materiality threshold**

ActewAGL proposed that the materiality threshold for a tax change event associated with the utilities network facilities tax (UNFT) be set at zero to ensure it is able to recover the efficient cost of that scheme.

## 16.5 AER issues and considerations

### 16.5.1 Criteria for assessing the pass through events proposed by ActewAGL

**Provisions of the NEL and NER**

The transitional chapter 6 rules provide that the AER may nominate events in its determination that will constitute pass through events for the next regulatory control

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393 ActewAGL stated that it does not consider the regulatory change event provides sufficient certainty of cost recovery of this regulatory obligation and that no other defined pass through events appear to address this risk. ActewAGL, *Submission to the AER*, pp. 10–11.

394 ActewAGL, *Submission to the AER*, p. 12.

395 ActewAGL, *Submission to the AER,* p. 12.

396 ActewAGL, *Revised regulatory proposal*, p. 72.

period. Neither the NEL nor the NER provide any direct guidance to the AER on the matters it should take into account in deciding which events should be accepted as nominated pass through events. Guiding principles in the NEL and the general structure of the incentive regime, however, provide indirect guidance to the AER.

ActewAGL referred[397] to the revenue and pricing principles in section 7A(2) of the NEL which provides:

> (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.

In general, the requirement to provide a reasonable opportunity for DNSPs to recover at least the efficient costs of providing direct control network services and complying with regulatory obligations must be balanced against the need to provide effective incentives required under of section 7A(3) in the NEL:

> (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.

A pass through provides an opportunity to recover efficient costs that could not reasonably be accounted for in the distribution determination. It is limited in its application as it has the potential to undermine the incentive to effectively manage network risk in a least cost manner.

The transitional chapter 6 rules provide that DNSPs are granted allowances for total capex and opex programs for the regulatory control period, generally being five years. The AER does not approve allowances for individual projects or individual cost items; DNSPs have discretion to manage the total expenditure allowances. This means that a DNSP is free to spend an allowance in the manner it sees fit. If costs associated with a particular activity increase, a DNSP may spend more of its allowance on that activity than was contemplated at the time of its regulatory proposal. Similarly, a DNSP may spend less of its allowance on a particular activity if the costs associated with that activity turn out to be less than the forecast provided at the time of the regulatory proposal. This flexibility allows DNSPs to revise their expenditure

397 ActewAGL, *Revised regulatory proposal*, p. 72.

priorities as circumstances change in the ordinary course of business over time, consistent with the maintenance of service standards.

In deciding what types of events should be pass through events, the AER must balance the requirement to allow DNSPs the opportunity to recover at least efficient costs, with the requirement to ensure that DNSPs are provided with effective incentives to manage their expenditure.

**Relevant factors for nominating events as pass through events**

The draft decision listed eight criteria as factors to which the AER will have regard in determining whether an event should be nominated as a pass through event:[398]

- 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 the DNSP at the time of submitting its regulatory proposal
- the event is not already insured against (either external or self–insured)
- the event cannot be self–insured because a self insurance premium cannot be calculated or the potential loss to the relevant DNSP is catastrophic
- the party who is in the best position to manage the risk is bearing the risk
- the passing through of the costs associated with the event would undermine the incentive arrangements within the regulatory regime.

No issues were raised in the ActewAGL revised regulatory proposal regarding the use of these criteria to make a decision as to whether a proposed event should be a pass through event for ActewAGL.

The AER has further considered the above criteria. The fourth criterion relates to foreseeability of an event. Both foreseeable and unforeseeable events have the potential to materially impact on a DNSP's financial position. However, unforeseeable events will, by their very nature, be difficult to define. An unforeseeable event that materially impacts on a DNSP's ability to provide direct control services should not be precluded from pass through solely on the basis that is not possible to specifically define the event in advance of its occurrence. The AER therefore considers that nominated pass through events should be divided into two categories:

i. **Specific nominated pass through events**—these are foreseeable events that can easily be defined. An event is only a specific nominated pass through event if the AER nominates the event in this distribution determination. The AER has considered the above eight criteria in deciding what events should be specific nominated pass through events.

398 AER, *Draft decision*, p. 167.

ii. **A general nominated pass through event**—this will apply to unforeseeable events. This event is a set of broadly defined circumstances, the occurrence of which will constitute a general nominated pass through event. The AER will determine throughout the next regulatory control period whether an event constitutes a general nominated pass through event.

**Specific nominated pass through events**

A specific nominated event must be foreseeable in terms of its occurrence during the regulatory control period, despite the timing and/or cost impact being unforeseeable at the time the AER makes its distribution determination. In such circumstances, the AER considers it preferable that these costs be included when the costs of these activities are able to be forecast on a reasonable basis and when the timing of these events is known with certainty.

An event will be considered foreseeable if, at the time the AER makes its distribution determination, the event was more likely to occur than not to occur during the regulatory control period. An example of such an event is the retail project event that the AER decided to accept as a nominated pass through event in its draft decision for the NSW DNSPs.[399] Public statements made by the NSW Government suggest that this event is more likely than not to occur during the next regulatory control period.[400] Such an event is therefore considered foreseeable.

**General nominated pass through events**

The AER recognises the possibility of events occurring during a regulatory control period that are uncontrollable, unforeseen, and have a material impact on costs. Examples of such an event include a major natural disaster such as a bushfire or earthquake, and liability for claims relating to asbestos or electric and magnetic fields. In these situations, although the occurrence of the event may be a possibility, its occurrence is unforeseen as there are no reasons to consider the event is more likely to occur than not to occur during the next regulatory control period.

If an unforeseeable and uncontrollable event would have a material impact on a DNSP's costs such that it would jeopardise the DNSP's ability to provide direct control services in accordance with the requirements of the NEL and NER, it is appropriate that costs associated with the event should be passed through to consumers. Where an event is of such an unusual and unexpected nature, and the associated costs are likely to have such an impact on the returns of the business that the ability to provide services in accordance with the NEL and the NER would be jeopardised, it may be appropriate that the costs associated with the event should be passed through to customers immediately.

Unforeseeable events are not easily defined. Therefore, rather than attempting to specifically define all unforeseeable events that could occur during a regulatory control period, the AER considers it is appropriate to define a general set of circumstances, the occurrence of which will constitute a general pass through event.

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[399] AER, *Draft decision, NSW distribution determination*, pp. 286–287.

[400] For example, NSW Premiers Office, *Strengthening the NSW Economy: energy reforms begin new phase*, 5 March 2009.

The AER considers that an unforeseeable and uncontrollable event should be classified as a general pass through event in the following circumstances:

- an uncontrollable and unforeseeable event that falls outside of the normal operations of the business, such that prudent operational risk management could not have prevented or mitigated the effect of the event, occurs during the next regulatory control period
- the change in costs of providing distribution services as a result of the event is material, and is likely to significantly affect the DNSP's ability to achieve the opex objectives and/or the capex objectives (as defined in the transitional chapter 6 rules) during the next regulatory control period
- the event does not fall within any of the following definitions:
  - 'regulatory change event' in the NER (read as if paragraph (a) of the definition were not a part of the definition)
  - 'service standard event' in the NER
  - 'tax change event' in the NER
  - 'terrorism event' in the NER
  - 'feed–in tariff event' in this final decision
  - 'smart meter event' in this final decision (read as if paragraph (a) of the definition were not a part of the definition)
  - 'emissions trading scheme event' in this final decision (read as if paragraph (a) of the definition were not a part of the definition).

An event will be considered unforeseeable for the purposes of this definition if, at the time of submitting a regulatory proposal, despite the occurrence of the event being a possibility, there was no reason to consider that the event was more likely to occur than not to occur during the regulatory control period.

The AER will assess the DNSP's ability to achieve the opex objectives and/or the capex objectives in the same manner as it would assess the DNSP's ability to achieve those objectives under the NER as part of a distribution determination.

If a general pass through event occurs, a DNSP may apply to the AER for a pass through of the costs associated with the event under clause 6.6.1 of the transitional chapter 6 rules. In assessing an application for a pass through event (whether the event is a specific nominated event, a general nominated event, or an event defined in the transitional chapter 6 rules), the AER will take into account the matters listed in clause 6.6.1(j) of the transitional chapter 6 rules. These matters include the need to ensure the DNSP recovers only incremental costs, and the efficiency of the DNSP's decisions and actions in relation to the risk of the event, including whether the DNSP has failed to take reasonable action to reduce the magnitude of the event.

**Materiality**

The transitional chapter 6 rules require that a positive change event must have a material impact on costs before it can be passed through to consumers. The AER considers that a materiality threshold should apply to all nominated pass through events.

In the absence of a significant materiality threshold, DNSPs may seek to pass through costs of a non-material nature that could be accommodated by the DNSP in the normal course of its operational activities and budget management. To do otherwise could potentially undermine the DNSPs' incentives to manage expenditure efficiently. Therefore, the AER considers that a significant materiality threshold should generally apply to pass through events.

The AER considers that a pass through event will have a material impact if the costs associated with the event would exceed 1 per cent of the smoothed revenue requirement specified in the final decision in the years of the regulatory control period that the costs are incurred.

Given the potentially broad nature of a general nominated pass through event, and that it will only apply where the event would have a significant impact on the financial returns of the DNSP, this materiality threshold must be satisfied. The AER considers that this materiality threshold must be satisfied in order for costs associated with a pass through event to warrant immediate pass through to customers under a general nominated pass through event, rather than waiting for costs to be re–assessed at the following regulatory control period.

In some circumstances, however, the AER may determine that a lower materiality threshold is appropriate. Costs associated with a specific nominated event were not included in the forecast costs at the time of the regulatory determination because, at the time the regulatory proposals were submitted, the precise timing of the event and/or the cost impact of the event could not be forecast on a reasonable basis. In these circumstances, it is appropriate that a lower materiality threshold be adopted that represents the administrative costs of assessing such an application. The costs associated with these events would have been included, without regard to the materiality of the financial impact of the event on the DNSP, had the necessary information been available at the time of the final decision. The costs of assessing a cost pass through may, in certain circumstances, be very low. As specific nominated pass through events are narrowly defined, the AER considers that a low materiality threshold will not undermine incentives to manage expenditure efficiently.

### 16.5.2 Proposed nominated pass through events the AER accepts

**Feed-in tariff event**

In section 9.5.3 (of the opex chapter) of this final decision the AER has not approved ActewAGL's proposed pricing adjustment in relation to the implementation of a FiT scheme as the transitional chapter 6 rules only allow pricing adjustments associated with transmission use of system charges.

The AER acknowledges that discrepancies between forecast and actual direct tariff payments may arise from the implementation of the scheme. On that basis, the AER considered it appropriate for ActewAGL to recover from or return to users any discrepancy between forecast and actual direct tariff payments of the FiT scheme via a nominated pass through event.

ActewAGL has not had time in which to test the accuracy of its direct tariff payment forecasts, nor has it been able to develop its forecasts with the benefit of actual data.[401] The AER considers it is reasonable in this instance that ActewAGL bear minimal risk associated with direct tariff payment forecasting error. Therefore the AER considers it appropriate that the materiality threshold for this pass through event is fairly low for the next regulatory control period. On that basis, the AER will apply a low materiality threshold, equivalent to the reasonable costs of assessing the application to this event.

Taking into account the criteria listed in section 16.5.1 of this final decision, the AER considers that passing through any discrepancy between the forecast and actual direct tariff payments arising under the FiT scheme be nominated as a specific nominated pass through event. The reasons for this conclusion are:

- the event is not already captured by the defined event definitions
- the event is clearly identified
- the event is uncontrollable
- the event is not insurable
- although the event is foreseeable, ActewAGL can not reasonably forecast the cost impact of the scheme at this time
- the event does not undermine the incentive for ActewAGL to pursue productivity improvements since it can not control or influence the parameters which impact the direct tariff payments under the FiT scheme (for example, generator take up rate, capacity or output or the difference between the normal cost of electricity and the FiT).

The AER considers that ActewAGL's proposed FiT event definition requires amendment to reflect that the event only applies to any discrepancy between forecast and actual direct tariff payments arising in the next regulatory control period.

The AER therefore decides to nominate the implementation of the FiT scheme as a specific nominated pass through event, defined as:

> Feed-in tariff direct payment event means a change in the total amount of direct feed–in tariff direct tariff payments paid by ActewAGL in respect of the ACT Feed-in tariff scheme. For the purpose of this definition, the change in the amount of direct tariff payments paid by ActewAGL must be calculated as the difference between:
>
> (1) the amount of direct tariff payments paid by ActewAGL in each regulatory year of the next regulatory control period, derived from the metered output of generators subject to the scheme, and the applicable feed–in tariff rate applying to the metered output; and

[401] The *Electricity Feed-in (Renewable Energy Premium) Act 2008 (ACT)* was passed by the ACT legislative assembly on 2 July 2008. ActewAGL submitted its regulatory proposal on 2 June 2008.

(2) the amount of scheme direct tariff payments which were forecast for the purpose of and included in the ACT distribution determination for each regulatory year of the next regulatory control period.

Relevant direct tariff payments under this pass through mechanism are those paid through the operation of the *Electricity Feed-in (Renewable Energy Premium) Act 2008 (ACT)*, and any amendments to this Act, or through the operation of a new Act implementing the expected second stage of the scheme applying to larger generators.

**Smart meter event**

In the draft decision, the AER rejected the smart meter event proposed by ActewAGL on the basis that this event would constitute a regulatory change event that was already covered under the defined events set out in the NER.[402] In its revised regulatory proposal, ActewAGL did not seek further consideration of this event. Given the AER's revised approach to cost pass throughs, as outlined above, the AER has reconsidered this particular event.

In December 2008, the MCE released an exposure draft of amendments to the NEL to facilitate and support the accelerated roll out and trials of smart meters in participating jurisdictions.[403] It is therefore reasonable to suggest that a smart meter event is expected to occur during the next regulatory control period, and accordingly the event satisfies the foreseeability requirement.

Taking into account the criteria listed in section 16.5.1 of this decision, the AER considers that the smart meter event should be nominated as a specific nominated pass through event. The reasons for this conclusion are:

- the event is uncontrollable because if the event occurs, ActewAGL will be legally obliged to undertake trials and/or roll outs
- the event is foreseeable, although the timing and cost impact can not be reasonably forecast, as the timing and scope of the obligation is not known at this time
- the event is not insurable
- passing through the costs will not undermine regulatory incentives, given that the obligation will be imposed externally.

The AER therefore has included this specific nominated pass through event with the following definition:

**Smart meter event:** an event which results in an obligation being externally imposed on ActewAGL to install smart meters for some or all of its customers, or to conduct large scale metering trials during the course of the next regulatory control period, regardless of whether that requirement takes the form of the imposition of a statutory obligation or not, and which:

(a) falls within no other category of pass through event; and

(b) increases the costs of ActewAGL providing direct control services.

402 AER, *Draft decision*, p.168.

403 MCE, Standing Committee of Officials, *Bulletin No. 140*, 23 December 2008. Available: www.mce.gov.au

**Emission trading scheme event**

ActewAGL did not propose a nominated pass through event in relation to the possible introduction of an emission trading scheme. However, the AER considers that this is an event which is foreseeable and uncontrollable and for which costs have not been included in the final decision. On this basis, the event would constitute a specific nominated pass through event. In addition, the AER considers that as this event has been included in the final decisions for the NSW DNSPs, for the purpose of consistency, the event should also apply to ActewAGL. An emission trading event will be defined, as it is for the NSW DNSPs, as:

> **Emissions trading scheme event:** an event which results in the imposition of legal obligations on ActewAGL arising from the introduction or operation of a carbon emissions trading scheme imposed by the Commonwealth or ACT Government during the course of the next regulatory control period and which:
>
> (a) falls within no other category of pass through event; and
>
> (b) materially increases the costs of providing direct control services.

### 16.5.3 Proposed nominated pass through events the AER does not accept

**Transitional period event**

The draft decision noted that no provision is made in the NER to cover the event described by ActewAGL.[404] The AER indicated that costs incurred for an event which occurs between a DNSP's submission of its regulatory proposal and the commencement of the next regulatory control period can be passed through in an application made in the next regulatory control period provided the application is made within 90 days of the pass through event occurring.[405]

ActewAGL stated that a number of potential events could occur in the transitional period—the period between the submission of its regulatory proposal (2 June 2008) and end of the current regulatory control period (30 June 2009). It proposed that the AER reconsider the inclusion of the transitional event as a nominated pass through event. ActewAGL stated that the rejection of this event may expose it to the risk of being unable to recover the efficient costs of delivering distribution services, which it considered is inconsistent with section 7A of the NEL.[406]

The AER has further considered the application of the pass through provisions of the transitional chapter 6 rules in the context of ActewAGL's proposed transitional period event. The AER no longer considers that the costs associated with an event that occurs in a regulatory control period can be passed through in an application made in the next regulatory control period even if the application is made within 90 days of the pass through event occurring. This is because the transitional chapter 6 rules require that the costs associated with a pass through event must be passed through in the regulatory control period in which the event occurs.

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404 AER, *Draft decision*, p. 168.
405 AER, *Draft decision*, p. 168.
406 ActewAGL, *Revised regulatory proposal*, p. 72.

As ActewAGL's proposed event involves passing through the costs of an event in a subsequent regulatory control period to that in which the event actually occurred, the AER considers that the transitional chapter 6 rules do not permit this as a pass through event.

**Major natural disaster event and a force majeure event**

In the draft decision the AER accepted a major natural disaster as a nominated pass through event, but amended ActewAGL's proposed definition.[407] ActewAGL argued that it was inappropriate to exclude cases where the event is 'insurable' or where external or self insurance is 'feasible' and that an event should only be excluded from the pass through event if the final decision approved either external insurance or a self insurance allowance.[408]

In the NSW draft decision the AER accepted EnergyAustralia's proposed force majeure event as a nominated pass through event for all the NSW DNSPs although Country Energy and Integral Energy did not propose the event.[409]

ActewAGL proposed that the force majeure event accepted for the NSW DNSPs be added to the nominated pass through events in its determination.[410] ActewAGL did not propose a force majeure event in its regulatory proposal.

ActewAGL did not explicitly state why it considered it appropriate to include both events. There is an overlap between the AER's definitions of the major natural disaster event and the force majeure event accepted in the respective ACT and NSW draft decisions. The force majeure event, however, covers a broader range of scenarios. ActewAGL also acknowledged this relationship.

The draft decision proposed to allow the major natural disaster event as a specific nominated event. The AER's revised approach of considering foreseeability as a threshold question (as discussed in section 16.5.1 of this final decision) leads to a different conclusion to that proposed in the draft decision.

The AER acknowledges that the occurrence of a major natural disaster event or a force majeure event during the next regulatory control period are possibilities, however, there is no reason to suggest that they are expected to occur. These events are therefore not foreseeable.

Taking into account the factors listed in section 16.5.1 of this final decision, the AER considers that a major natural disaster event and the force majeure event should not be nominated as a specific nominated pass through event. The reason for this conclusion is that the occurrence of such an event during the next regulatory control period is not foreseeable.

The AER considers that there is a risk in attempting to capture all natural disaster type events in a single definition. It would be undesirable for a similar event occurring in two jurisdictions to be recoverable under the pass through provisions in one

407 AER, *Draft decision*, p.171.
408 ActewAGL, *Revised regulatory proposal*, p. 73.
409 AER, *Draft decision, NSW distribution determination*, pp. 286–287.
410 ActewAGL, *Revised regulatory proposal*, p. 74.

jurisdiction, and not recoverable in another jurisdiction based simply on the drafting of the event. Rather than attempting to capture all appropriate events in a specific definition, the AER considers that these types of events should be considered under the general nominated pass through event if they occur.

Although the major natural disaster event and the force majeure event are not specific nominated pass through events, if the circumstances described in the proposed events occur during the next regulatory control period and materially impact ActewAGL's costs, the events may constitute a general nominated pass through event. In such circumstances, ActewAGL could apply to the AER for pass through of these costs. As with any general nominated pass through event, the AER would assess such an application having regard to this final decision and the requirements of the NER.

### 16.5.4 Materiality threshold

ActewAGL noted that the draft decision was silent on the materiality threshold to apply to pass through events. It stated that the materiality threshold for a tax change events (such as the UNFT and FiT scheme) must be set at zero to ensure it can fully recover the cost of the tax.[411] It considered that applying the draft decision, in conjunction with a materiality threshold, imposes uncompensated risks upon it.

In section 16.5.1 above the AER set out how it will generally assess materiality.

## 16.6 AER conclusion

### 16.6.1 Specific nominated pass through events

The AER accepts a FiT event as a nominated pass through event for ActewAGL:

> **Feed-in tariff direct payment event** means a change in the total amount of direct feed–in tariff direct tariff payments paid by ActewAGL in respect of the ACT Feed-in tariff scheme. For the purpose of this definition, the change in the amount of direct tariff payments paid by ActewAGL must be calculated as the difference between:
>
> (1) the amount of direct tariff payments paid by ActewAGL in each regulatory year of the next regulatory control period, derived from the metered output of generators subject to the scheme, and the applicable feed–in tariff rate applying to the metered output; and
>
> (2) the amount of scheme direct tariff payments which were forecast for the purpose of and included in the ACT distribution determination for each regulatory year of the next regulatory control period.
>
> ActewAGL must present verifiable accounts setting out the actual direct tariff payment in each regulatory year, from which to calculate the difference between forecast and actual direct tariff payments.
>
> Relevant direct tariff payments under this pass through mechanism are those paid through the operation of the *Electricity Feed-in (Renewable Energy Premium) Act 2008*, and any amendments to this Act, or through the

411 ActewAGL, *Revised regulatory proposal*, pp. 74–75.

operation of a new Act implementing the expected second stage of the scheme applying to larger generators.[412]

The AER accepts a smart meter event as a nominated pass through event for ActewAGL:

> **Smart meter event**: an event which results in an obligation being externally imposed on ActewAGL to install smart meters for some or all of its customers, or to conduct large scale metering trials during the course of the next regulatory control period, regardless of whether that requirement takes the form of the imposition of a statutory obligation or not, and which:
>
> (a) falls within no other category of pass through event; and
>
> (b) increases the costs of ActewAGL providing direct control services.
>
> The AER accepts a FiT event as a nominated pass through event for ActewAGL.

The AER accepts an emissions trading event as a nominated pass through event for ActewAGL:

> **Emissions trading scheme** event: an event which results in the imposition of legal obligations on ActewAGL arising from the introduction or operation of a carbon emissions trading scheme imposed by the Commonwealth or ACT Government during the course of the next regulatory control period and which:
>
> (a) falls within no other category of pass through event; and
>
> (b) materially increases the costs of providing direct control services.

### 16.6.2 General nominated pass through event

The AER nominates a general nominated pass through event for ActewAGL.

> **A general nominated pass through event** occurs in the following circumstances:
>
> - an uncontrollable and unforeseeable event that falls outside of the normal operations of the business, such that prudent operational risk management could not have prevented or mitigated the effect of the event, occurs during the next regulatory control period
>
> - the change in costs of providing distribution services as a result of the event is material, and is likely to significantly affect the DNSP's ability to achieve the operating expenditure objectives and/or the capital expenditure objectives (as defined in the transitional chapter 6 rules) during the next regulatory control period
>
> - the event does not fall within any of the following definitions:
>
> > 'regulatory change event' in the NER (read as if paragraph (a) of the definition were not a part of the definition);
> >
> > 'service standard event' in the NER;

[412] ActewAGL, *Submission to the AER,* p. 12.

‘tax change event’ in the NER;

‘terrorism event’ in the NER;

‘feed–in tariff direct payment event’ in this final decision;

‘smart meter event’ in this final decision (read as if paragraph (a) of the definition were not a part of the definition);

‘emissions trading scheme event’ in this final decision’ (read as if paragraph (a) of the definition were not a part of the definition).

For the purposes of this definition:

- an event will be considered unforeseeable if, at the time the AER makes its distribution determination, despite the occurrence of the event being a possibility, there was no reason to consider that the event was more likely to occur than not to occur during the regulatory control period

- ‘material’ means the costs associated with the event would exceed 1per cent of the smoothed revenue requirement specified in the final decision in the years of the regulatory control period that the costs are incurred.

For the reasons set out in this chapter, the AER considers that the other events proposed by ActewAGL should not be nominated as specific nominated pass through events. However, even if an event is not a nominated specific pass through event, if the event occurs, the AER notes ActewAGL may apply to the AER during the next regulatory control period for a pass through where a general nominated pass through event occurs. The AER will determine whether a general nominated pass through event occurs during the next regulatory control period.

In assessing an application for a pass through event (whether the event is a specific nominated event, a general nominated event, or an event defined in the transitional chapter 6 rules), the AER will take into account the matters listed in clause 6.6.1(j) of the transitional chapter 6 rules. These matters include the need to ensure ActewAGL recovers only incremental costs, and the efficiency of ActewAGL’s decisions and actions in relation to the risk of the event, including whether ActewAGL has failed to take reasonable action to reduce the magnitude of the event.

## 16.7 AER decision

In accordance with clause 6.12.1(14) of the transitional chapter 6 rules the nominated pass through events that are to apply to ActewAGL for the next regulatory control period are a feed–in tariff direct payment event, a smart meter event, an emissions trading scheme event, and a general pass through event as defined in section 16.6 of this final decision.

# 17 Maximum allowable average revenue

## 17.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision and its calculation of annual revenue requirements for ActewAGL for the provision of standard control services for each year of the next regulatory control period. This chapter also sets out X factor values used to calculate the maximum allowable average revenue (MAAR) to apply to the standard control services provided by ActewAGL.

No submissions were received on ActewAGL's building block or revenue calculations.

## 17.2 AER draft decision

The draft decision resulted in a nominal total revenue requirement over the next regulatory control period of $779 million as set out in table 17.1, compared with $823 million proposed by ActewAGL. The differences reflected:

- updated weighted average cost of capital (WACC) parameters
- minor reductions to opex and capex reflecting escalation reductions
- correction of errors.

**Table 17.1: AER draft decision on ActewAGL's total revenue requirements and X factors ($m nominal)**

| | 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) | 2 878 338 | 2 925 120 | 2 971 701 | 3 018 337 | 3 066 270 |
| Revenue yield (¢/kWh) | 4.78 | 5.00 | 5.23 | 5.47 | 5.72 |
| Expected revenues | 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: AER, *Draft decision*, p. 179.
(a) Negative values for X indicate real price increases under the CPI-X formula.

In setting X factors the AER maintained ActewAGL's approach of achieving real annual increases in its MAAR of two per cent for years two to five of the next regulatory control period. The effect of the draft decision was therefore translated into a reduction in the size of the X factor in year one.

## 17.3 Revised regulatory proposal

ActewAGL's revised regulatory proposal set out a nominal total revenue requirement of $868 million over the next regulatory control period, as shown in table 17.2.

**Table 17.2: ActewAGL revised regulatory proposal total revenue requirements and X factors ($m nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Regulatory depreciation | 14.5 | 16.2 | 17.9 | 19.5 | 21.3 |
| Return on capital | 61.0 | 67.1 | 72.5 | 77.7 | 82.0 |
| Tax allowance | 5.3 | 6.2 | 6.4 | 6.1 | 6.3 |
| Operating expenditure | 65.1 | 71.5 | 77.8 | 84.5 | 89.2 |
| Annual revenue requirements | 145.9 | 161.0 | 174.7 | 187.8 | 199.0 |
| Energy sales (MWh) | 2 935 965 | 2 878 896 | 2 900 156 | 2 919 789 | 2 933 886 |
| Revenue yield (¢/kWh) | 5.40 | 5.65 | 5.91 | 6.18 | 6.47 |
| Expected revenues | 158.6 | 162.7 | 171.4 | 180.6 | 189.8 |
| Forecast CPI (%) | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 |
| X factors[a] (%) | –28.69 | –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 X factors of –28.69 per cent (i.e. a real increase) for the first year of the regulatory control period and –2.00 per cent for subsequent years. This results in the NPVs of the revenue requirements and expected revenues being equal over the regulatory control period as shown in table 17.3. ActewAGL's approach to setting X factors appears to be similar to that adopted in its initial proposal, that is, real average price increases of 2.00 per cent for years 2 to 5 for the next regulatory control period, with a corresponding value for year 1 which equates expected and required revenues in NPV terms.

The associated difference between the annual revenue requirement and expected revenue in the final year of the period is $9.1 million or 4.59 per cent.

**Table 17.3: ActewAGL's revised proposed annual revenue requirements and expected revenues ($m nominal)**

| | NPV | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|
| Annual revenue requirements | 643.3 | 145.9 | 161.0 | 174.7 | 187.8 | 199.0 |
| Expected revenues | 643.3 | 158.6 | 162.7 | 171.4 | 180.6 | 189.8 |
| Difference (%) | 0.00 | 8.72 | 1.06 | –1.87 | –3.87 | –4.59 |

Source: ActewAGL, confidential PTRM.

Key features of ActewAGL's revised revenue requirements, in comparison to the draft decision, included:

- a $68 million increase in opex, the majority of this relating to the feed–in tariff scheme
- an increase in the return on capital, reflecting a higher WACC (10.31 per cent compared to the draft decision of 9.82 per cent)
- slowing growth in energy sales forecasts (an average increase of 0.23 per cent per year, compared to 1.58 per cent in the draft decision), which requires offsetting increases in average prices and therefore X factors.

## 17.4 Summary of building block components

The following sections summarise the AER's assessment of each of the building blocks that make up ActewAGL's annual revenue requirements. 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 final decision. The return on capital using the WACC determined by the AER in chapter 12 of this final decision is outlined in this chapter.

The AER notes 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.

### 17.4.1 Asset base roll forward and indexation

The AER has determined the opening value of ActewAGL's regulatory asset base (RAB) to be $599 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 post–tax revenue model (PTRM), as shown in table 17.4.

**Table 17.4: AER forecast roll-forward of ActewAGL's regulatory asset base ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Opening RAB | 598.7 | 650.3 | 695.6 | 739.4 | 775.8 |
| Net capital expenditure[a] | 66.8 | 62.4 | 62.5 | 56.9 | 55.8 |
| Indexation of opening RAB | 14.8 | 16.1 | 17.2 | 18.3 | 19.2 |
| Straight-line depreciation | –30.1 | –33.1 | –36.0 | –38.8 | –41.5 |
| Closing RAB | 650.3 | 695.6 | 739.4 | 775.8 | 809.3 |

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.

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 that the method for indexing ActewAGL's RAB for each year of the next regulatory control period will be the same as that used to escalate its MAAR for that relevant year—that is, to apply the percentage change in the sum of four quarters to December consumer price index (CPI), all groups weighted average of eight capital cities, published by the Australian Bureau of Statistics (ABS). This method will be used to roll forward ActewAGL's RAB for the purposes of the AER's distribution determination for the regulatory control period commencing on 1 July 2014.

### 17.4.2 Return on capital

The AER considers that ActewAGL's proposed return on capital has been calculated in accordance with the PTRM, however this amount has been affected by its conclusions regarding other inputs to the PTRM, particularly WACC parameters.

The AER's final decision is to apply a nominal vanilla WACC of 8.79 per cent, which compares to the 10.31 per cent in ActewAGL's revised regulatory proposal, and is comprised of a post–tax nominal return on equity of 10.29 per cent and a pre–tax nominal return on debt of 7.78 per cent. These figures are calculated using observed market data as at 27 February 2009.

### 17.4.3 Depreciation

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 17.6 shows the resulting figures for this final decision.

### 17.4.4 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 final 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 31.53 per cent for this final decision. Table 17.5 shows the AER's estimate of ActewAGL's tax payments.

**Table 17.5: AER modelling of net tax allowance ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| Tax payable | 9.4 | 11.0 | 11.4 | 10.8 | 11.1 |
| Value of imputation credits | –4.7 | –5.5 | –5.7 | –5.4 | –5.6 |
| Net tax allowance | 4.7 | 5.5 | 5.7 | 5.4 | 5.6 |

### 17.4.5 Operating expenditure

As discussed in chapter 9 of this final decision, the AER has determined a total opex allowance for ActewAGL of $341 million ($2008–09) during the next regulatory control period. Table 17.6 shows the annual opex allowance, which equals an average amount of $73.7 million per annum in nominal terms.

## 17.5 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 17.6.

The AER's final decision results in a total (nominal) revenue requirement over the next regulatory control period of $793 million, which is $75.2 million lower than the $868 million proposed by ActewAGL. This mainly reflects the AER's decision to apply a lower WACC of 8.79 per cent, which contributes $56.4 million to this difference, as well as its decision on ActewAGL's forecast opex, which contributes a further reduction of $19.7 million.

The AER considered ActewAGL's proposed approach of having a larger X factor (and implied price increase) in year 1 of the regulatory control period, with X factors of –2.00 per cent in years 2 to 5 of the regulatory control period. The AER considered that maintaining an X factor of –2.00 per cent for years 2 to 5 of the regulatory control period, when combined with the adjustments resulting from this final decision, would have resulted in a variance between expected and required revenues at the end of the regulatory control period that was unreasonably large. The AER considered various values of X factors for years 2 to 5 of the regulatory control period, deciding that –4.00 per cent, with a corresponding X factor for year one of the regulatory control period of –13.82 per cent, resulted in a difference between expected and required revenues in year 5 of the regulatory control period of 2.02 per cent.

**Table 17.6: AER conclusion on ActewAGL's revenue requirements and X factors ($m, nominal)**

| | 2008–09 | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|
| Regulatory depreciation | | 15.2 | 17.0 | 18.8 | 20.5 | 22.3 |
| Return on capital | | 52.6 | 57.1 | 61.1 | 65.0 | 68.2 |
| Tax allowance | | 4.7 | 5.5 | 5.7 | 5.4 | 5.6 |
| Operating expenditure | | 61.2 | 67.4 | 73.8 | 80.8 | 85.5 |
| Annual revenue requirements | | 133.7 | 147.1 | 159.4 | 171.7 | 181.6 |
| Energy sales (MWh) | 2 906 274 | 2 932 862 | 2 916 011 | 2 907 581 | 2 898 320 | 2 888 942 |
| Revenue yield (¢/kWh) | 4.09 | 4.77 | 5.08 | 5.42 | 5.77 | 6.15 |
| Expected revenues | 118.9 | 139.9 | 148.2 | 157.5 | 167.3 | 177.8 |
| Forecast CPI (%) | | 2.47 | 2.47 | 2.47 | 2.47 | 2.47 |
| X factors[a] (%) | | –13.82 | –4.00 | –4.00 | –4.00 | –4.00 |

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

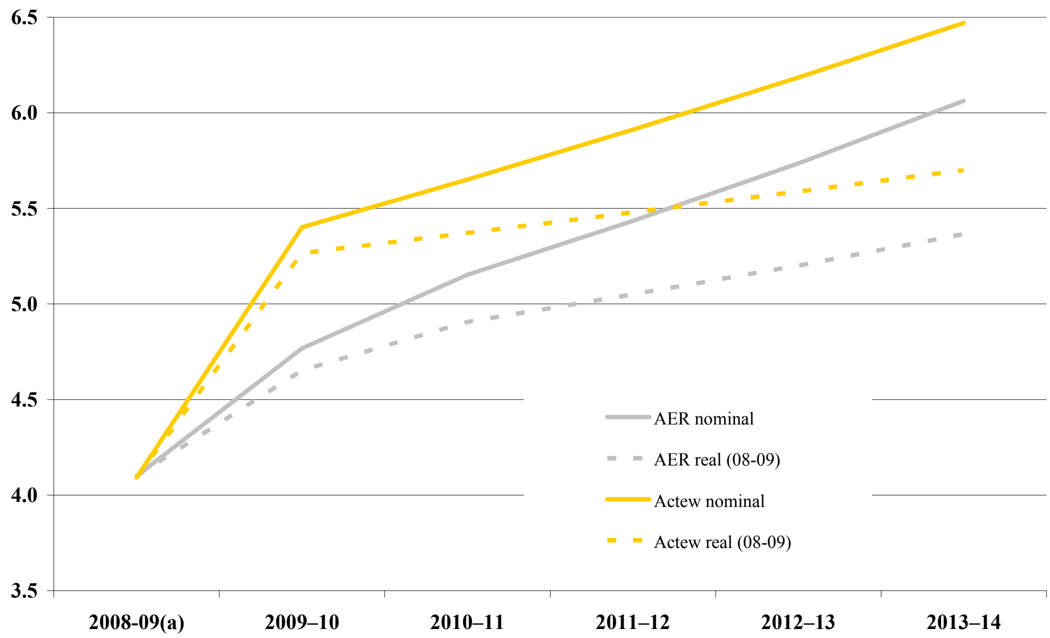
These values comply with the requirements of clause 6.5.9 of the transitional chapter 6 rules in that the NPVs of the annual revenue requirement and expected revenues for the regulatory control period are equal, and the difference between these amounts in the final year of the regulatory control period are minimised. These outcomes are illustrated in table 17.7.

**Table 17.7: AER conclusion on ActewAGL's annual revenue requirements and expected revenues ($m, nominal)**

| | NPV | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|---|
| Annual revenue requirements | 612.3 | 133.7 | 147.1 | 159.4 | 171.7 | 181.6 |
| Expected revenues | 612.3 | 140.0 | 148.3 | 157.6 | 167.4 | 177.9 |
| Difference (%) | 0.00 | 4.67 | 0.86 | –1.12 | –2.46 | –2.02 |

The implied average price paths, in terms of expected revenues per kWh, of ActewAGL's regulatory proposal and the AER's final decision, are illustrated in figure 17.1. For an average end user, annual electricity costs are expected to increase by 4.15 per cent in 2009–10, and 1.36 per cent per year for the remainder of the next regulatory control period.[413]

**Figure 17.1: AER final decision and ActewAGL revised regulatory proposal – implied average prices**




[413] That is, a residential customer with an annual bill of $1200, of which approximately 30 per cent is attributable to distribution prices.

In accordance with clauses 6.3.2(a) and 6.5.9 of the transitional chapter 6 rules, the AER decides the annual revenue requirement and X factor for each year of the next regulatory control period for ActewAGL as listed in table 17.8.

**Table 17.8: AER conclusion on ActewAGL's X factors and annual revenue requirements ($m, nominal)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 |
|---|---|---|---|---|---|
| X factors (%) | –13.82 | –4.00 | –4.00 | –4.00 | –4.00 |
| Annual revenue requirement | 133.7 | 147.1 | 159.4 | 171.7 | 181.6 |

## 17.6 AER 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 ActewAGL's annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 17.8 of this final decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the X factors to apply to ActewAGL are as set out in table 17.8 of this final decision.

In accordance with clause 6.3.2(a)(2) of the transitional chapter 6 rules the appropriate methodology for indexation of the regulatory asset base is as specified in section 17.4.1 of this final decision.

In accordance with clause 6.3.2(a)(5) of the transitional chapter 6 rules any other amounts, values or inputs on which ActewAGL's building block determination is based are as specified in section 17.4 of this final decision.

# 18 Alternative Control Services

## 18.1 Introduction

This chapter sets out the AER's consideration of issues regarding alternative control services raised in response to the draft decision. This chapter also sets out the AER's decisions regarding:

- ActewAGL's alternative control services
- the control mechanism to apply to these services
- monitoring and compliance arrangements for 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 AER draft decision

The draft decision specified that, consistent with the approach applied by the ICRC, the form of control mechanism to apply to ActewAGL's alternative control services was a revenue allowance based on a building block analysis, with maximum allowable revenues (MAR) to be escalated each year by CPI.[414]

The AER approved a MAR for ActewAGL of $40 million for alternative control services for the next regulatory control period. This resulted in a $P_0$ adjustment in 2009–10 of 31.34 per cent and further revenue adjustments in line with CPI for the remainder of the regulatory control period.[415] The AER's conclusion on ActewAGL's MAR for alternative control services is set out in table 18.1.

**Table 18.1: ActewAGL maximum allowed revenue—alternative control services ($m, 2008–09)**

| | 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 factor (%) | –31.34 | – | – | – | – | n/a |

Source: AER, *Draft decision*, p. 193.

## 18.3 Revised regulatory proposal

ActewAGL's revised regulatory proposal incorporated additional expenditures of $3.4 million relating to the implementation and operation of the ACT feed–in tariff

414 AER, *Draft decision*, p. 193.
415 AER, *Draft decision*, p. 193.

(FiT) scheme.[416] ActewAGL further adjusted its alternative control services opex forecasts to reflect revised or updated elements of the standard control services opex forecasts. These elements include:[417]

- past capex and opening RAB
- cost escalators
- debt raising costs
- equity raising costs
- self insurance allowance.

## 18.4 Submissions

The AER received a submission from ActewAGL regarding the FiT scheme, and its proposed cost recovery mechanism for direct tariff payments (discussed in chapter 9 of this final decision).[418]

## 18.5 AER issues and considerations

### 18.5.1 Feed-in tariff

**AER draft decision**

The AER considered the FiT scheme in the context of a nominated pass through (transitional period) event, but did not accept ActewAGL's proposed treatment of the FiT scheme because it was inconsistent with the NER.

**Revised regulatory proposal**

ActewAGL explained that the *Electricity Feed-in (Renewable Energy Premium) Act 2008* (ACT) which was effective from 1 March 2009 requires it to:[419]

- connect the generator to the network to enable electricity generated by the generator to be supplied to the network
- reimburse retailers for the difference between the amount payable for electricity generated by the generator and the normal cost of that electricity
- pass on to the occupier any additional metering costs in relation to the electricity generated by the generator.

ActewAGL stated that after it submitted its regulatory proposal, the FiT scheme legislation passed the ACT Legislative Assembly, and the ACT Government then provided information to ActewAGL and relevant retailers on the details of the scheme.[420] This information enabled ActewAGL to estimate its likely capex and opex costs associated with the introduction of the scheme. ActewAGL therefore updated its capex and opex forecasts in respect of costs arising from the introduction of the FiT

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416 ActewAGL, *Revised regulatory proposal*, p. 35.
417 ActewAGL, *Revised regulatory proposal*, pp. 35–36.
418 ActewAGL, *Submission to the AER*.
419 ActewAGL, *Revised regulatory proposal*, p. 23.
420 ActewAGL, *Revised regulatory proposal*, p. 27.

scheme. ActewAGL stated it considers this approach is consistent with the requirements of clause 6.10.3 of the transitional chapter 6 rules.[421]

ActewAGL stated it must, in most cases, install either an additional meter or new replacement meter at a site where a micro–renewable generator is being connected to the network.[422]

ActewAGL provided revised opex and capex forecasts to include expenditure expected to be incurred as a result of the introduction of the FiT scheme in the ACT.[423]

***Opex***

ActewAGL stated existing meter boxes are not suitable for the additional meter or replacement meter. ActewAGL noted it is also necessary to undertake a pre–meter installation inspection at the time that a connection application is being assessed. ActewAGL increased its alternative control services opex forecast by $0.5 million ($2008–09) to cover additional operations and maintenance tasks arising from the introduction of the FiT scheme.[424]

***Capex***

ActewAGL noted it will be required to replace additional meters as a result of the FiT scheme. ActewAGL stated its current meter replacement scheme is largely limited to replacing meters that are at the end of their operational life. In most cases, meters replaced as a result of the FiT scheme will not be at the end of their operational life.[425]

ActewAGL claimed it will need to undertake meter replacement or additional metering at each connection site, in addition to meters replaced as a result of the current meter replacement program. ActewAGL forecast additional capex in respect of metering obligations arising from the FiT scheme of $2.7 million ($2008–09) over the next regulatory control period.[426]

**AER considerations**

The introduction of the FiT scheme has impacted on ActewAGL's standard control services capex and opex forecasts and alternative control services capex and opex forecasts. As such, the forecast expenditure associated with the forecast FiT scheme is also considered at chapters 8 and 9 of this final decision.

The AER notes that ActewAGL was not able to provide a reasonable forecast of the costs of the FiT scheme in its regulatory proposal as the legislation establishing the scheme had not yet passed the ACT Legislative Assembly.

The AER has reviewed the information provided by ActewAGL on the timing of the introduction of the FiT scheme in the ACT and considers amending ActewAGL's capex and opex forecasts are appropriate for recovering the costs associated with implementing the FiT scheme.

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421 ActewAGL, *Revised regulatory proposal*, p. 27.
422 ActewAGL, *Revised regulatory proposal*, p. 27.
423 ActewAGL, *Revised regulatory proposal*, p. 29.
424 ActewAGL, *Revised regulatory proposal*, pp. 27–28.
425 ActewAGL, *Revised regulatory proposal*, p. 28.
426 ActewAGL, *Revised regulatory proposal*, p. 28.

***Capex***

The forecast FiT scheme capex is comparable with similar costs for standard control services and is based on the:

- expected number of generation units installed
- average capacity of units
- average output from units
- FiT rate set by Ministerial determination
- 'normal cost of electricity' rate set by Ministerial determination.

To forecast these variables, ActewAGL has used:[427]

- ACT historical photovoltaic generation installation rates, capacity and output measurements
- data from the introduction of FiT schemes in other jurisdictions, including uptake rates and average capacity of units
- data from the German gross FiT scheme and its impact on uptake rates.

Accordingly, the AER is satisfied that the forecast participation rates used by ActewAGL are based on the best available data at this time. Further, the AER considers ActewAGL's forecasts of the number, capacity and output of meters it will need to install are also based on reasonable assumptions reflecting the best available information at this time.[428]

The AER is further satisfied that the unit costs of relevant meters which are based on the factors set out above are reasonable.

***Opex***

ActewAGL's estimates of alternative control opex arising from the implementation of the FiT scheme relate to additional meter inspections required to pre–empt problems that may arise with meter installations. As noted above, the AER considers that ActewAGL has used reasonable assumptions to estimate the likely participation rates in the FiT scheme.

The AER is further satisfied that the unit costs of the meter inspection tasks are comparable to costs already reviewed by the AER and provide a reasonable estimate of the costs to the ActewAGL of its likely opex arising from the FiT scheme.[429]

### 18.5.2 Updated costs and values

**Regulatory asset base**

In the draft decision, the AER considered that ActewAGL's opening regulatory asset base (RAB) for alternative control services for the next regulatory control period was appropriate.

427 ActewAGL, *Revised regulatory proposal*, confidential attachment 9, p. 95.
428 ActewAGL, *Revised regulatory proposal*, confidential attachment 9, p. 100.
429 ActewAGL, email response to AER on STPIS and FiT, 25 March 2009.

Consistent with the treatment of standard control services RAB, ActewAGL adjusted its opening RAB to account for updated capex data for 2007–08 and 2008–09, and inflation data as required by the draft decision.[430] The AER has reviewed the updated data and accepted them for the purposes of establishing ActewAGL's opening RAB. The updated RAB includes forecast FiT capex for 2008–09. ActewAGL's updated opening RAB of $39 million, as at 1 July 2009, is shown in table 18.2.

**Table 18.2: ActewAGL's updated roll forward calculation ($m, nominal)**

| | 2004–05 | 2005–06 | 2006–07 | 2007–08 | 2008–09 | 2009–10 |
|---|---|---|---|---|---|---|
| Opening RAB | 33.2 | 33.3 | 33.7 | 34.8 | 36.6 | 38.7 |
| Net capital expenditure | 1.1 | 1.3 | 1.9 | 2.9 | 3.2 | n/a |
| Depreciation | –1.8 | –1.8 | –1.9 | –2.0 | –2.2 | n/a |
| Indexation | 0.8 | 0.9 | 1.2 | 0.8 | 1.7 | n/a |
| 2003–04 adjustment | | | | | –0.5 | n/a |
| Closing RAB | 33.3 | 33.7 | 34.8 | 36.6 | 38.7 | n/a |

Source: ActewAGL, *Revised regulatory proposal*, Attachment 4, Revised roll forward model (alternative control).

**Capex**

The draft decision provided ActewAGL with an alternative control services forecast capex allowance of $18 million ($2008–09).

ActewAGL's revised alternative control services capex forecast is shown in table 18.3. This represents a 13 per cent increase in total alternative control services net capex compared to the amount included in ActewAGL's regulatory proposal, and a 14 per cent increase compared to the amount approved in the draft decision.

**Table 18.3: ActewAGL's revised alternative control services capex forecast ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Capex | 6.8 | 3.7 | 3.6 | 3.6 | 3.5 | 21.2 |

Source: ActewAGL, *Revised regulatory proposal*, p. 35.

The AER notes the increase in forecast capex is driven by the capex related to the FiT scheme. The AER has reviewed the FiT scheme capex proposed by ActewAGL, and as discussed in section 18.5.1, considers ActewAGL has provided reasonable estimates of its likely capex in relation to the FiT scheme.

However, the AER notes that the FiT scheme capex forecast includes $0.2 million capex incurred in 2008–09 in the forecast for the 2009–10 regulatory year. The AER considers that clause 6.5.7 of the transitional chapter 6 rules does not allow for

[430] AER, *Draft decision*, p. 59.

expenditure incurred in the current regulatory control period to be included in the capex forecasts for the next regulatory control period.[431] For this reason the AER does not accept that this amount is to be included in the capex forecast for 2009–10.

Further, as noted in the draft decision, the AER has updated the capex escalators applied to estimates of alternative control services capex so that they are equivalent to the escalators used in forecasting standard control services capex.[432]

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal, the AER is not satisfied that ActewAGL's forecast capex for alternative control services reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

The capex forecast for alternative control services for the next regulatory control period that the AER is satisfied reasonably reflects the capex criteria is set out in table 18.4.

**Table 18.4: AER conclusion on forecast capex for alternative control services ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Revised regulatory proposal capex | 6.8 | 3.7 | 3.6 | 3.6 | 3.5 | 21.2 |
| AER adjustment to FiT scheme capex | –0.2 | 0.0 | 0.0 | 0.0 | 0.0 | –0.2 |
| AER adjustments to cost escalators | –0.4 | –0.2 | –0.2 | –0.2 | –0.2 | –1.1 |
| AER's capex allowance | 6.3 | 3.5 | 3.4 | 3.5 | 3.3 | 19.9 |

Note: Totals may not add up due to rounding.

**Opex**

The draft decision provided ActewAGL with an alternative control services forecast opex allowance of $8.7 million ($2008–09).

ActewAGL's revised alternative control services forecast opex is set out in table 18.5. This represents an 8 per cent increase in total alternative control services opex compared to the amount included in ActewAGL's regulatory proposal, and a 15 per cent increase compared to the amount approved in the draft decision.

431 NER, transitional chapter 6 rules, clause 6.5.7(a).
432 AER, *Draft decision*, p. 189.

**Table 18.5: ActewAGL's revised alternative control services opex forecast ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| AER draft decision | 2.1 | 1.7 | 1.7 | 1.5 | 1.6 | 8.5 |
| Cost escalator adjustment | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 |
| Debt raising adjustment | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |
| Equity raising adjustment | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 |
| Self insurance | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.4 |
| FiT scheme | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.5 |
| Total opex | 2.4 | 1.9 | 1.9 | 1.7 | 1.8 | 9.8 |

Source: ActewAGL, *Revised regulatory proposal*, p. 36.

The AER notes the changes to ActewAGL's forecast opex for alternative control services are driven by variations to cost escalators, debt and equity raising costs, self insurance and the costs of the FiT scheme. Each of these cost components has been estimated by ActewAGL and apportioned between standard control and alternative control services. The AER has considered each of the opex forecasts adjustments proposed by ActewAGL with respect to standard control services is discussed in chapter 9. The AER's analysis and conclusions on these matters in respect of standard control services are not repeated here, but are maintained in respect of alternative control services. The AER's decisions on these matters are as follows.

The AER is not satisfied that ActewAGL's forecast opex for:

- cost escalators (as discussed in section 9.5.1) and
- debt raising costs (as discussed in section 9.5.5) and
- equity raising costs (as discussed in section 9.5.6) and
- forecast self insurance premiums (as discussed in section 9.5.7),

reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

The AER is, however, satisfied that ActewAGL's forecast FiT scheme opex (as discussed in section 18.4.1), updated to reflect the AER's cost escalators, reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal, the AER is not satisfied that ActewAGL's forecast opex for alternative control services reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

The opex forecast for alternative control services for the next regulatory control period, that the AER is satisfied reasonably reflects the opex criteria, is set out in table 18.6.

**Table 18.6: AER conclusion on forecast opex for alternative control services ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| ActewAGL revised regulatory proposal | 2.4 | 1.9 | 1.9 | 1.7 | 1.8 | 9.8 |
| Cost escalator adjustment | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |
| Debt raising adjustment[a] | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | –0.1 |
| Equity raising adjustment[b] | –0.1 | –0.0 | –0.0 | –0.0 | –0.0 | –0.2 |
| Self insurance adjustments[a] | –0.0 | –0.0 | –0.0 | –0.0 | –0.0 | –0.2 |
| AER total opex | 2.2 | 1.8 | 1.9 | 1.7 | 1.8 | 9.4 |

(a) Rounded to zero.
(b) The AER will allow ActewAGL to capitalise $0.1 million ($2008–09) for benchmark equity raising costs for the next regulatory control period.
Note Totals may not add up due to rounding.

## 18.6 AER conclusion

As determined in section 18.7 of the draft decision and in accordance with the control mechanism 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 AER has decided to approve a MAR for ActewAGL of $39 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 29.30 per cent and allowed revenues adjusted in line with CPI each year for the remainder of the next regulatory control period.

ActewAGL must demonstrate compliance with the control mechanism by submitting its schedule of metering charges to the AER each year, as specified in section 18.7 of the draft decision.

ActewAGL's MAR for alternative control services is set out in table 18.7.

**Table 18.7: ActewAGL maximum allowed revenue—alternative control services ($m, 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Unsmoothed revenue requirement | 7.3 | 7.5 | 7.9 | 8.1 | 8.6 | 39.6 |
| Smoothed revenue requirement | 7.5 | 7.7 | 7.9 | 8.1 | 8.3 | 39.4 |
| X factors[a] (%) | –29.3 | 0.0 | 0.0 | 0.0 | 0.0 | n/a |

(b) Negative value for the X factor indicates real price increases under the CPI–X formula.

## 18.7 AER decision

In accordance with clause 6.12.1(12) of the transitional chapter 6 rules the:

- 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 revenue for ActewAGL in each year of the next regulatory control period is set out in table 18.7 (smoothed revenue requirement) of this final decision
- the X factor to apply in each year of the next regulatory control period is set out in table 18.7 of this final decision.

In accordance with clause 6.12.1(13) of the transitional chapter 6 rules 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 regulatory proposal, as soon as practicable after prices for each regulatory year are determined.

# Glossary

| | |
|---|---|
| AASB | Australian Accounting Standards Board |
| ABS | Australian Bureau of Statistics |
| ACG | Allen Consulting Group |
| agreed averaging period | 20 business days commencing 2 February 2009 |
| ANZSIC | Australian New Zealand Standard Industrustrial Classification |
| AUD | Australian dollar |
| bppa | basis points per annum |
| CAM | cost allocation method |
| CAPM | capital asset pricing model |
| CBD | central business district |
| CEG | Competition Economists Group |
| CFC | Construction Forecasting Council |
| CGS | Commonwealth government securities |
| CIE | Centre for International Economics |
| CPRS | Carbon Pollution Reduction Scheme |
| DMIA | demand management innovation allowance |
| DMIS | demand management incentive scheme |
| DRP | dividend reinvestment plan |
| EBA | enterprise bargaining agreement |
| EBSS | efficiency benefit sharing scheme |
| EGW | electricity, gas and water |
| EMRF | Energy Market Reform Group |
| EMS | Energy and Management Services Pty Ltd |
| ESCV | Essential Services Commission of Victoria |
| ESIPC | Electricity Supply Industry Planning Council |
| EUAA | Energy Users Association of Australia |
| FiT | feed–in tariff |
| GIS | geographic information systems |
| GWh | giga watt hour |
| HRC | hot rolled coil |
| HV | high voltage |
| JIA | Joint Industry Association |
| KPMG | KPMG Australia |
| LCM | labour cost model |

| | |
|---|---|
| LME | London Metal Exchange |
| MAAR | maximum allowed average revenue |
| MAR | maximum allowed revenue |
| MCE | Ministerial Council on Energy |
| MMA | McLennan Magasanik Associates |
| MRP | market risk premium |
| MVA | mega volt amperes |
| MVAr | mega var, mega volt amperes reactive, (one thousand kilovolt amperes reactive) |
| MW | mega watt |
| MWh | mega watt hour |
| NAB | National Australia Bank |
| NCC | negotiable component criteria |
| NDSC | negotiated distribution service criteria |
| NIEIR | National Institute of Economic and Industry Research |
| NPV | net present value |
| NSP | network service provider |
| NYMEX | New York Mercantile Exchange |
| original DMIA | the DMIA applied by the AER in: AER, *Final Decision: Demand management incentives schemes for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008. |
| PIAC | Public Interest Advocacy Centre |
| POE | probability of exceedence |
| PPI | producer price index |
| PTRM | post–tax revenue model |
| QCA | Queensland Competition Authority |
| RAB | regulatory asset base |
| RBA | Reserve Bank of Australia |
| replacement DMIA | the DMIA published in November 2008: AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme*, November 2008. |
| RFM | roll forward model |
| RIO | regulation information order |
| SAHA | SAHA International Limited |
| SAIDI | system average interruption duration index |
| SEO | seasoned equity offer |
| SKM | Sinclair Knight Merz Pty Ltd |

| | |
|---|---|
| SRP | ACCC, *Statement of principles for the regulation of electricity transmission revenues*, 8 December 2004 |
| standard control services guideline | AER, *Final decision: Control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations*, February 2008 |
| STPIS | service target performance incentive scheme |
| TEC | Total Environment Centre |
| TNSP | transmission network service provider |
| TOU | time of use |
| TUOS | transmission use of system |
| TWI | trade weighted index |
| UK regulator | Office of Gas and Electricity Markets (Ofgem) |
| UNFT | Utilities Network Facilities Tax |
| USD | United States dollar |
| WACC | weighted average cost of capital |
| YTM | yield to maturity |

# Appendix A: Assigning customers to tariff classes

## Procedures for assigning or reassigning 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 to 1 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[433]
   (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 or reassigning 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.

**Reassignment of existing customers to another existing or a new 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

[433] The AER interprets 'connection' to include the installation of any technology capable of supporting timed based tariffs.

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.

**Objections to proposed assignments and reassignments**

6. ActewAGL must notify the customer concerned in writing of the tariff class to which the customer has been assigned or reassigned by ActewAGL, prior to the assignment or reassignment occurring. If ActewAGL does not know the identity of the customer then it must notify the customer's retailer instead. The notice must include advice that the customer may request further information from ActewAGL, may object to the proposed assignment or reassignment and, if the customer objects to the proposed assignment or reassignment and that objection is not resolved to the satisfaction of the customer, the customer may request the ACT Civil and Administrative Tribunal 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 assignment or reassignment, ActewAGL must reconsider the proposed assignment or reassignment, taking into consideration the factors in sections 3 and 4 above, and notify the customer in writing of its decision and the reasons for that decision.
9. If a customer's objection to a tariff assignment or reassignment is upheld by the ACT Civil and Administrative Tribunal, then any adjustment which needs to be made to prices will be done by ActewAGL as part of the next annual review of prices.

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

10. 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.
11. If the AER considers that the method provided under section 10 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.
12. If the AER considers the method provided in accordance with section 10 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

**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 clause 6.12.1.

## 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 4

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

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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.

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## 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.

## D.1 For a visit to re–energise or de–energise a premises

### D.1.1 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.

### D.1.2 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.

### D.1.3 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 D.1.1 and D.1.2.

### D.1.4 After hours – re–energise

A site visit to a customer's premises outside the hours of paragraph D.1.3 to reconnect the supply of electricity following the disconnection in paragraphs D.1.1 and D.1.2, at the request of a customer.

### D.1.5 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.

## D.2 Temporary connections

### D.2.1 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.

### D.2.2 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.

### D.2.3 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.

## D.3 Modify service connection

### D.3.1 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.

### D.3.2 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.

## D.4 Upgrade service from single to three phase

### D.4.1 Overhead

A site visit to a customer's premises to upgrade the service from single to three phase at the customer's request where load does not justify three phase [434] and where the electricity is supplied by overhead service cables.

### D.4.2 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 the customer requests three phase for other reasons.[435] 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.

### D.4.3 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.

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[434] ActewAGL, *Service and installation rules for connection to the electricity distribution ne*twork, 13 March 2007, clause 3.10, p. 17.

[435] ActewAGL, *Service and installation rules*, p. 17.

## D.5 Other miscellaneous services

### D.5.1 Installation defect

Re–visiting a site following obstructed access at previous visit or site visit due to non–compliance with the DNSP's service and installation rules.

### D.5.2 Issue of copies of electrical drawings

Provision of copies of electrical drawings that show existing low and high voltage circuitry (geographically and schematically) and adjacent project drawings to enable the preparation of a design drawing and submit it for certification.

### D.5.3 De–energising wires

De–energising wires to allow safe approach, for example, for tree pruning, plant operation, oversize loads and construction activities.

## D.6 Operational and maintenance services for small embedded generators other than residential (photovoltaic)

### D.6.1 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.

### D.6.2 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 use of system overs and unders account

To demonstrate compliance with clause 6.18.7 of the transitional chapter 6 rules and this final decision for the next regulatory control period, the AER requires ActewAGL to maintain a transmission use of system (TUOS) 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) of the transitional chapter 6 rules.

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 TUOS overs and unders account for the most recently completed regulatory year, the current regulatory year and 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, or the equivalent nominal rate of return approved by the ICRC for the 2004–09 regulatory control period
3. 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 six 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.

ActewAGL must provide details of its calculations in the format set out in table E.1 of this final decision.

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 may be, positive or negative amounts.

Amounts provided for the most recently completed regulatory year must be audited or otherwise verifiable. Amounts for the current regulatory year and next regulatory year will be regarded as estimates and forecasts respectively.

In proposing variations to the amount and structure of TUOS charges, ActewAGL is to achieve a zero expected balance on its TUOS overs and unders account at the end of each regulatory year in the next regulatory control period.

**Table E.1: Example calculation of TUOS overs and unders account ($'000)**

| | year t–2 (actual) | year t–1 (estimate) | year t (forecast) |
|---|---|---|---|
| Revenue from TUOS charges | 36 221 | 36 836 | 40 968 |
| | | | |
| Transmission charges to be paid to TNSPs | 25 214 | 27 602 | 35 791 |
| Settlement residue payments | | | |
| Avoided TUOS payments | 572 | 638 | 681 |
| Inter–DNSP payments | 8579 | 9575 | 10 221 |
| Total transmission related payments (net of residue) | 34 365 | 37 816 | 46 694 |
| Over (under) recovery for financial year | 1856 | –980 | –5726 |
| | | | |
| **Overs and unders account** | | | |
| Annual rate of interest applicable to balances | 9.70% | 9.70% | 9.70% |
| Semi-annual rate of interest | 4.74% | 4.74% | 4.74% |
| | | | |
| Opening balance | 3624 | 5919 | 5467 |
| Interest on opening balance | 351 | 574 | 530 |
| Over/ under recovery for financial year | 1856 | –980 | –5726 |
| Interest on over/ under recovery | 88 | –46 | –271 |
| Closing balance | 5919 | 5467 | 0 |

# Appendix F: Changes to tariff structures and the maximum allowable average revenue and side constraint formulas

Changes to tariff structures can occur for customers in the following circumstances:

- The introduction of new tariffs or tariff components (for example, introducing a step rate for the usage component of the domestic tariff).
- Adjustments to existing tariffs or tariff components (for example, changing the threshold on an inclining block tariff or the time bands associated with time of use tariffs). This situation is essentially the same as introducing new tariffs or tariff components.
- When customers move between existing tariffs (from origin tariffs to alternative tariffs).

The side constraint formula applying to the control mechanism will require adjustments for those tariffs subject to a change in structure. Specifically, adjustments will be required to:

- the historical quantity weights ( $q_k^{ct-1}$ ) for the tariff and
- the values of the current tariff components ( $d_k^{t-1}$ ) in the side constraint formula.

The historical quantity weightings ( $q_i^{ct-1}$ ) used in the maximum allowable average revenue (MAAR) formula will also require adjustment when changes to tariff structures occur.

This appendix sets out the approach to estimating the historical quantity weights and the substitute values for the current tariff components used when calculating compliance with the side constraint and MAAR formulas. For simplicity of presentation, any discussion in this appendix in relation to $q_k^{ct-1}$ for the side constraint should be taken to be equally applicable to $q_i^{ct-1}$ for the MAAR.

## F.1 Introducing new tariffs or tariff components

### 18.7.1 The value of $q_k^{ct-1}$

Both the MAAR and side constraint are calculated using audited and/or verifiable historical quantities of consumption. However, historical quantities for any new tariffs/tariff components will not be available for two years.

In order to incorporate new tariff structures in the MAAR and the side constraint, the AER requires reasonable estimates to be submitted by ActewAGL, based on the quantities that would have been sold, if the new tariff/tariff components were already in place during the calendar year 'ct–1'. The AER has adopted the following process, which was developed by IPART for the NSW DNSPs in the current regulatory control period, in order for ActewAGL to arrive at these estimates.

First, ActewAGL must nominate the origin tariffs/tariff components, which represent the tariffs/tariff components that the customers, who will be moved to the new network tariffs/tariff components, are currently being charged.

Second, ActewAGL must provide reasonable estimates of $q_k^{ct-1}$ for all applicable units of measure (e.g. kWh, kW) for both, the new tariffs/tariff components, and the origin tariffs/tariff components. ActewAGL must make the following assumptions when calculating these reasonable estimates:

1. The only customers who would have moved to the new network tariff/tariff component in the calendar year 'ct–1' did so due to a change in tariff structures initiated by ActewAGL and as permitted under the customers' standard network connection contract.[436] This means that no new customers are included in the estimate,[437] nor customers who request to change tariff either voluntarily, or do so through the actions of a retailer.
2. Customers have the same consumption and load profile on the new tariff/tariff component as they did on the origin tariff/tariff component. This implies that the sum of the reasonable estimates for the calendar year 'ct–1' for each unit of measure on the new tariff/tariff component plus the reasonable estimates for the calendar year 'ct–1' for each unit of measure on the origin tariff/tariff component, equals the actual quantities that occurred for the origin tariff/tariff component in the calendar year 'ct–1'.

In the year after a new tariff/tariff component has been introduced, there will still be no full year of historical data available to be used for $q_k^{ct-1}$, hence ActewAGL will be required to again submit reasonable estimates for both the new tariff/tariff component and the corresponding origin tariff/tariff component. At this time, however, ActewAGL may base the reasonable estimates on the actual quantities that have occurred to date on the new tariff/tariff components and origin tariff/tariff components. ActewAGL must demonstrate how it has arrived at the estimates.

### 18.7.2 The value of $d_k^{t-1}$

The $d_k^{t-1}$ of the corresponding origin tariff/tariff components will be used as the $d_k^{t-1}$ for the new tariff/tariff components, where both the origin and new tariff components are measured in the same units of measure. If there is no corresponding origin tariff/tariff components with the same units of measure, $d_k^{t-1}$ will be set to zero.

436 Each customer has a standard network connection contract with its DNSP and a separate contract with its respective retailer who manages the relationship with ActewAGL on the customer's behalf.

437 New customers have been allowed for in the growth assumption used when setting the X factor.

### 18.7.3 Example 1: Introducing a step rate or inclining block tariff component

This example assumes that a domestic tariff with a single variable rate is amended so that there are now two variable rates based on a customer's level of consumption. For each of the 25 000 customers on this tariff, their historical consumption is split between consumption up to 5000kWh per annum and any residual consumption above this amount. Under this approach, the total consumption for this tariff class of 200 000MWh is split, 150 000MWh against variable rate 1 and 50 000MWh against variable rate 2 as shown in the example set out in table F.1.

**Table F.1: Determining $d_k^{t-1}$ and $q_k^{ct-1}$ in Example 1**

| Tariff reform | | $d_k^{t-1}$ | $q_k^{ct-1}$ |
|---|---|---|---|
| **Origin tariff – standard domestic** | | | |
| Fixed charge | \$ pa per customer | \$30 | 25 000 customers |
| Variable rate (all consumption) | c/kWh | 0.04 | 200 000MWh |
| **Proposed tariff with new component** | | | |
| Fixed charge | \$ pa per customer | \$30 | 25 000 customers |
| Variable rate 1 (consumption ≤ 5000kWh pa per customer) | c/kWh | 0.04 (as per orgin tariff) | 150 000MWh |
| Variable rate 2 (consumption > 5000kWh pa per customer) | c/KWh | 0.04 (as per orgin tariff) | (200 000 – 150 000) = 50 000MWh |

Note: While the variable rates (1 & 2) that ActewAGL proposes for the next year ($d_k^t$) are likely to differ, the divergence in these rates is constrained by the side constraints for this tariff class as a whole.

## F.2 Customers transferred by ActewAGL to an alternative tariff

### 18.7.4 The value of $q_k^{ct-1}$

If ActewAGL proposes to move a number of customers across to an alternative existing tariff,[438] the side constraint formula will not fully reflect the actual tariff change for the customers being transferred, as the overall tariff change observed by

[438] ActewAGL may decide to transfer customers if a customers' consumption or load profile has changed and ActewAGL decides it is no longer appropriate for them to remain on the same tariff. Alternatively ActewAGL may change the structure of an existing tariff to suit the majority of customers. Appendix A sets out the procedures a DNSP must adhere to in assigning or reassigning customers to tariff classes.

these customers will reflect not only the side constraint on the alternative tariff but the difference between the origin tariff the customer was on and the alternative tariff they are being transferred to. In these circumstances, the AER will require ActewAGL to submit reasonable estimates for $q_k^{ct-1}$ for each origin tariff that the customer is currently on, and the new tariff that ActewAGL will move the customers to, taking the transfer into account.

For compliance purposes, the assumptions ActewAGL must make when calculating the reasonable estimates are:

1. The customer movement occurred in the calendar year 'ct–1'.
2. The customers only moved as a result of a change in tariff structures initiated by ActewAGL and as permitted under the customers' standard network connection contract. The estimates are not to include customers who choose to move at their discretion or movements caused by a retailer's action.
3. Customers have the same consumption and load profile under either tariff.

Reasonable estimates will also be required in the year following the movement as there will still be no full year of historical data available.

### 18.7.5 The value of $d_k^{t-1}$

As for the introduction of new tariffs/tariff components, the $d_k^{t-1}$ for the corresponding origin tariff components will be used as the $d_k^{t-1}$ for the new tariff components.

### 18.7.6 Example 2: Re–assigning some customers from the domestic flat rate tariff to the domestic TOU tariff

The example set out in table F.2 assumes 10 000 customers with consumption of 70 000MWh will be moved by ActewAGL from the domestic tariff to the domestic time of use (TOU) tariff. Both tariffs remain in existence and there will be customers on both. The allocation of the 70 000MWh across the peak, shoulder and off–peak reflect historical consumption patterns.

**Table F.2: Determining $d_k^{t-1}$ and $q_k^{ct-1}$ in Example 2**

| **Tariffs** | | $d_k^{t-1}$ | $q_k^{ct-1}$ |
|---|---|---|---|
| **Domestic** | | | |
| Fixed charge | $ pa per customer | $30 | (25 000 existing – 10 000) =15 000 customers |
| Variable rate (any time) | c/kWh | 0.04 | (200 000 existing – 70 000) = 130 000 MWh |
| **Domestic TOU – existing customers** | | | |
| Fixed charge | $ pa per customer | $22 | 5000 existing |
| Peak rate | c/kWh | 0.09 | 10 000MWh existing |
| Shoulder rate | c/kWh | 0.05 | 10 000MWh existing |
| Off-peak rate | c/kWh | 0.02 | 10 000MWh existing |
| **Domestic TOU – customers being transferred** | | | |
| Fixed charge | $ pa per customer | $30 (as per domestic) | 10 000 customers |
| Peak rate | c/kWh | 0.04 (as per domestic) | 25 000MWh |
| Shoulder rate | c/kWh | 0.04 (as per domestic) | 20 000MWh |
| Off-peak rate | c/kWh | 0.04 (as per domestic) | 25 000MWh |

Note: The domestic TOU tariff ActewAGL proposes for next year ($d_k^t$) will apply equally across all (15 000) customers now on that tariff, which must be within the side constraint for this tariff class as a whole.

## F.3 The AER's assessment of reasonable estimates

When assessing the reasonableness of quantity estimates provided by ActewAGL, the AER will take the following information into account:

1. the actual audited and/or verifiable quantities sold in relevant units under the origin tariff in previous years
2. a forecast of the number of distribution customers that ActewAGL states will move to the new tariff/tariff components, and the reasons for the move
3. a forecast of the number of distribution customers that ActewAGL expects will remain on the origin tariff
4. a forecast of the quantities that ActewAGL expects will be sold, in relevant units, to those distribution customers that are to be moved to the new tariff/tariff components

5. a forecast of the quantities that ActewAGL expects will be sold, in relevant units, to those distribution customers that will remain on the origin tariff

6. a forecast of the distribution tariff, and associated revenue, ActewAGL expects will be payable by those distribution customers that will be moved to the new tariff/tariff components

7. a forecast of the distribution tariff, and associated revenue, ActewAGL expects will be payable by those distribution customers that will remain on the origin tariff

8. the approach ActewAGL used to determine its forecasts (for 2–7 above).

9. the materiality of the reasonable estimates

10. further information as required by the AER.

# Appendix G: Self insurance

This appendix sets out the AER's assessment of ActewAGL's proposed self insurance allowance in its opex forecast for the next regulatory control period.

## AER considerations

### AER approach to assessing self insurance premiums

The AER considers that its approach to the assessment of ActewAGL's self insurance claims and the proposed alternative self insurance amounts is consistent with the requirements of the transitional chapter 6 rules.

Clause 6.5.6(c) of the transitional chapter 6 rules states that the AER must accept ActewAGL's forecast opex if it is satisfied that the total of the forecast opex reasonably reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives. Clause 6.5.6(d) of the transitional chapter 6 rules requires that if the AER is not satisfied, it must not accept the forecast opex.

Further, clause 6.12.1(4)(ii) of the transitional chapter 6 rules states that where the AER does not accept the forecast opex, the AER must set out its reasons for that decision and an estimate of the total of ActewAGL's required opex for the regulatory control period that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

The opex factors which must be taken into account in deciding whether or not the AER is satisfied with the proposed costs or in determining a substitute amount are set out in clause 6.5.6(e) of the transitional chapter 6 rules.

In determining the prudence and efficiency of ActewAGL's self insurance claims, the AER considers that the following opex factors, included in the transitional chapter 6 rules, are of most relevance:

- clause 6.5.6(e)(1)—the information included in or accompanying the building block proposal
- clause 6.5.6(e)(3)—analysis undertaken by or for the AER and published before the distribution determination is made in its final form
- clause 6.5.6(e)(4)—benchmark opex that would be incurred by an efficient DNSP over the (next) regulatory control period
- clause 6.5.6(e)(5)—the actual and expected opex of the DNSP during any preceding regulatory control periods.

Each of these opex factors and their application is discussed below.

In assessing ActewAGL's self insurance under clause 6.5.6(c) of the transitional chapter 6 rules the AER notes that it must have regard to the information included in or accompanying the building block proposal as outlined in clause 6.5.6(e)(1) of the transitional chapter 6 rules. Therefore, the transitional chapter 6 rules imply that the regulatory proposal should include sufficient information to justify ActewAGL's self insurance cost forecasts, or in the event that the AER does not accept the forecasts, that there is sufficient information for which the AER may substitute an alternative forecast. This interpretation is supported by clause 6.12.3(f) of the transitional chapter 6 rules which states that:

> If the AER refuses to approve an amount, value or methodology referred to in clause 6.12.1, the substitute amount, value or methodology on which the distribution determination is based must be:
>
> (1) determined on the basis of the current regulatory proposal; and
>
> (2) amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

The AER considers that it is not the intent of the transitional chapter 6 rules that the AER generate forecasts on behalf of ActewAGL where it has not provided adequate information in its regulatory proposal. Instead, the AER considers that the onus is on ActewAGL to provide the necessary information to support its forecasts.

ActewAGL noted that the AER is not in a position to make informed decisions about the proposed self insurance allowances without the assistance of experts—that is, an actuary, risk manager or insurance assessor. Clause 6.5.6(e)(3) of the transitional chapter 6 rules states that the AER may have regard to analysis undertaken by or for the AER. The AER notes that it is not required by the transitional chapter 6 rules to engage an expert to review any opex forecast proposed by ActewAGL. Further, it is not always necessary to seek the assistance of an expert to decide whether an opex forecast is reasonable. Depending on the level of information provided, the AER may be able to satisfy itself that the forecast expenditure is reasonable or unreasonable, without the help of an expert.

In considering clause 6.5.6(e)(4) of the transitional chapter 6 rules, the AER notes that benchmarking of self insurance costs could potentially provide an indication of the reasonableness of a self insurance claim. However, the AER notes that there:

- is no agreed definition of the individual events that should be included in a self insurance claim—the included events are at the discretion of the individual DNSP
- appears to be no agreed definition on what each of those defined events is to cover.

Since self insurance events and their associated costs are not readily comparable across businesses, it is unlikely that benchmarking will provide reasonable self insurance costs for an individual DNSP.

In considering clause 6.5.6(e)(5) of the transitional chapter 6 rules, the AER notes that self insurance was not provided for ActewAGL in the current regulatory control period.[439]

[439] ICRC, *Investigation into prices for electricity distribution services in the ACT – Final Decision*, March 2004.

Based on its assessment of the relevant opex factors in the transitional chapter 6 rules, the AER considers it necessary to rely on the information provided in the regulatory proposal (consistent with clause 6.5.6(e)(1)) in determining whether the proposed self insurance allowances reasonably reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives. As such, where the information concerning an individual self insurance claim was inadequate—that is, it did not appear to support the claim—the AER has not accepted the forecast (consistent with clause 6.5.6(d) of the transitional chapter 6 rules).

Similarly, in determining a substitute self insurance value, the AER relied on the information included in the regulatory proposal (as required by clauses 6.12.1(4)(ii) and 6.12.3(f) of the transitional chapter 6 rules). For a number of risks, based on the information provided to the AER in the regulatory proposal and revised regulatory proposal, the only value that the AER could assign to an event was zero because there was no information on which to base an alternative amount. Such a value is not meant to indicate that the self insurance event may or may not occur, rather, the AER has assigned a cost of zero due to the (lack of) information provided in the regulatory proposal.

Generally, the self insurance premiums proposed by ActewAGL were accepted where the business was able to provide historical data related to the incidence and cost of an event in order to calculate the premiums. In the absence of such information, the AER accepts that a self insurance premium may be derived on the basis of information from other sources, including qualitative information. However, in such circumstances, as with any opex forecast, the onus is on the business to provide a compelling rationale for the use of that information or set of assumptions and to explain how such information has been used to derive the cost forecast (self insurance premium).

In a number of instances, SAHA justified its probability calculations on the basis that the assumed probability is a much more reasonable assumption, and produces an outcome that more ‘reasonably reflects the efficient cost that a prudent operator’ is likely to incur over the next regulatory control period, when compared with the AER’s approach of excluding the proposed cost associated with this risk in its entirety. The AER does not consider that such an assertion represents an appropriate justification for the probabilities and associated self insurance premiums presented by SAHA.

Further, it is not sufficient for SAHA to simply state that a self insurance premium is reasonable without providing evidence in support of this claim. It is not adequate, for example, to suggest that since an event has occurred in another electricity business that it is also likely to occur in ActewAGL.[440] Nor is it sufficient to apply a probability to the occurrence of such an event based on the occurrence in another business. The onus is on the business to provide the necessary information to support its forecasts to allow the AER to determine whether the forecast opex reasonably reflects the efficient costs that a prudent operator in the circumstances of the relevant

[440] For example, the nature of the operations and assets, location of the network and risk mitigation programs to protect assets and income can influence the likelihood of an event occurring and the financial impact of that event.

DNSP would require to achieve the opex objectives. Such supporting information should reasonably include:

- the rationale used to determine the reasonableness of the forecast
- the process that the business underwent in determining the probability and cost estimates
- the factors that led the business to believe that the experience in another business can be applied to the business in question and how these factors have been translated into a premium
- why one value for the forecast risk is preferred over another.

SAHA indicated that its self insurance estimates were reviewed by an independent actuary. Based on this review, the reviewing actuary concluded that '…the approach adopted by SAHA is sensible given the nature of the risks involved and the assumptions are not unreasonable' and suggested that '…the self insurance figures presented in the report (are) not unreasonable for recognition as an operating expense.'[441]

In relation to the review the AER notes that:

- the scope of the review was limited to an examination of the methodology used by SAHA for determining risk and assessing the assumptions for reasonableness
- the review was restricted to the information supplied by SAHA, and the supporting information and data was not sighted by the actuary
- the actuary noted that '…more detailed actuarial investigation is required to improve the quality of our assessment'[442]
- the review did not include identification of the risks which are self insured
- the review states that '…a wide range of assumptions can be made which may be considered reasonable but may result in significantly different risk premiums'[443]
- no details of the actuary findings were provided in the review and the actuary did not review the final SAHA report to determine if its suggestions and recommendations were incorporated. [444]

The AER is concerned that, in relation to the self insurance premiums, SAHA indicated that '…supporting data used to derive those figures were approved and signed off by an independent actuary'[445], whereas the review indicates that supporting information and data was not sighted by the actuary.[446] The AER is also concerned that the actuary considers that more investigation is required to improve the quality of the assessment and that it has not reviewed the final SAHA report to verify inclusion of its suggestions and recommendations. In light of these issues the AER is not

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441 ActewAGL, *Revised regulatory proposal,* attachment 16a.
442 ActewAGL, *Revised regulatory proposal*, attachment 16a.
443 ActewAGL, *Revised regulatory proposal,* attachment 16a.
444 ActewAGL, *Revised regulatory proposal,* attachment 16a.
445 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 6.
446 ActewAGL, *Revised regulatory proposal,* attachment 16a.

satisfied with SAHA's statement that its self insurance estimates have been approved by an independent actuary.

Given the limitations in scope and analysis, the AER is unsure of the usefulness of the review. In particular, without a robust assessment of the entire self insurance premium calculations, including an examination of the underlying data used to calculate the premiums, it is not clear what the AER is suppose to derive from such a review. Based on the scope and analysis presented, the review simply represents an assessment of the process applied by SAHA to the data provided by SAHA—it provides no assurance to the AER that the resultant premiums are appropriate. Similarly, the review provides no information on whether the premiums were derived on the same or similar basis to that which would be used by the actuary (if these were derived by the actuary from the bottom up) or that the proposed premiums are the same or similar to those that the actuary would have produced.

While the AER accepts that an actuary reviewed SAHA's self insurance estimates, the review is not equivalent to an actuarial preparation of self insurance estimates. Based on its previous assessment of self insurance proposals, the AER notes that the preparation of self insurance estimates by an actuary typically involves the collection of historical and other relevant information, the application of quantitative techniques to obtain frequency and severity factors for identified risk categories and the use of risk modelling to obtain simulated distribution parameters.[447]

ActewAGL and SAHA stated that where the AER has decided to reject a self insurance premium for a particular risk it should allow ActewAGL to mitigate such risks in another way. The AER notes that it is not required under the NER to propose alternative means of mitigating risks that ActewAGL may face during the next regulatory control period. Rather, it is required to assess the forecast opex put forward by ActewAGL, either accept or reject the forecast opex, and propose a substitute value based on the requirements set out in the transitional chapter 6 rules.

Notwithstanding the above, in assessing the revised self insurance premiums proposed by ActewAGL, the AER has considered whether the risks for which a self insurance allowance is being proposed may be more appropriately treated as pass through events under the transitional chapter 6 rules.

## Revised self insurance allowances

### Bushfire risk

SAHA's original 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.

SAHA originally calculated self insurance premiums in relation to:

- very minor bushfires—that is, bushfires causing less than one acre of property damage

[447] See for example ElectraNet, *Transmission Network Revenue Proposal 1 July 2008 to 30 June 2013*, appendix K, May 2007.

- minor bushfires—that is, bushfires causing more than one acre of property damage
- major bushfires—that is, a catastrophic bushfire similar to the 2003 Canberra bushfire.

***Bushfires ignited by ActewAGL's own assets***

In the draft decision, the AER accepted the self insurance premium for very minor bushfires.

In relation to minor bushfires ignited by ActewAGL's assets, SAHA indicated that ActewAGL had no historical records of such an event. 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.

In the draft decision, the AER rejected the claim for self insurance, indicating that it considered that the process for determining the probability of a minor bushfire in ActewAGL's network was not sufficiently robust. In particular, the data upon which the ActewAGL probability was determined (based on the NSW Rural Fire Service data) was not appropriate given that:

- it related to one of the worst bushfire seasons in NSW history (2002–03)
- 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.

In response, SAHA defended the use of bushfire information from the NSW Rural Fire Services, indicating that it does not believe that the percentage of bushfires ignited by different sources (electrical power lines and third parties) is likely to change significantly, even when the data was from the worst bushfire season.[448]

The AER notes the above point, but also notes that SAHA has not addressed issues in relation to distinguishing between bushfires caused by distribution and transmission power lines or whether the data also incorporates very small 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.

Based on the assessment above, the AER is not satisfied that the self insurance premium for a minor bushfire ignited by ActewAGL's own assets reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives.

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[448] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 39.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in ActewAGL's original and revised regulatory proposals.

In relation to a major bushfire ignited by ActewAGL's assets, SAHA's original report noted that ActewAGL has never started a major bushfire. 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. SAHA indicated that since ActewAGL's operating region covers a small area of land, and not much of that is rural, SAHA considered it reasonable to adopt a conservative 1 in 300 year probability for the risk of ActewAGL starting a major bushfire. 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.

In the draft decision, the AER stated that there was no basis for the adoption of the 1 in 300 year 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 a 1 in 500 year probability. As a result, the AER rejected the associated self insurance premium on the basis that the probability of occurrence has not been reasonably determined.

SAHA responded to this point by indicating that, based on the limited information available, the 1 in 300 year probability is consistent when compared with the probabilities derived for the NSW DNSPs and TransGrid.[449] SAHA also noted that the probability is much more reasonable when compared with the AER's approach of excluding the cost associated with the risk in its entirety.[450]

The AER notes that SAHA has provided no further information to demonstrate that such an assumption is reasonable. For example, SAHA has not explained the derivation of the 1 in 300 year probability for ActewAGL or provided an explanation of how the 1 in 300 year probability is 'consistent' when compared with those derived for other businesses, other than to indicate that the other businesses' assets are more likely to start a fire than ActewAGL. The AER considers that such an assertion is insufficient to demonstrate that the 1 in 300 year probability is reasonable.

In response to SAHA's argument that the calculated probability (and resultant premium) is more reasonable than the zero premium provided by the AER in the draft decision, the AER does not consider that this constitutes a sufficient rationale in support of the 1 in 300 year probability adopted by SAHA.

Based on the assessment above, the AER is not satisfied that the self insurance premium for a major bushfire ignited by ActewAGL's own assets reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in ActewAGL's regulatory proposal and revised regulatory proposal.

[449] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 32.
[450] SAHA, *Response to the AER's Draft Decision – Self Insurance,* confidential, p. 32.

***Bushfires ignited by a third party***

The self insurance premium for bushfires ignited by a third party consists of a premium for minor bushfires and a premium for major bushfires.

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.

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).[451] In particular, SAHA relied upon a functional relationship between damage costs and area burnt by bushfires proposed by CIE.[452] In addition, SAHA calculated the proportion of power lines in the ActewAGL network relative to lines in NSW and applied this to the CIE outputs to derive an estimate of land burnt in the ACT.

In the draft decision, the AER rejected the claim for self insurance in relation to minor bushfires ignited by third parties, in particular, noting 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
- the functional relationship between damage costs and area burnt proposed by CIE cannot be relied upon
- 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 variation in bushfire damage cost can be explained by the amount of hectares burnt.[453]

In response, SAHA indicated that the term inception date might be misleading and should have expressed this as '...the period of assessment where data was recorded and available was from 1997 to 2008'.[454] SAHA also indicated that it did not use the costs identified in the CIE report to determine damage area.[455] Further, in support of its cost calculations, SAHA provided additional information from the Council of Australian Governments report—*National Inquiry on Bushfire Mitigation and Management*—dated December 2004, which listed all the main bushfires that have occurred in each state and territory in Australia. SAHA suggested that this data supports the damage areas calculated by SAHA (44 000 hectares and 80 000 hectares for minor and major bushfires respectively).[456]

The AER notes SAHA's clarification in relation to the use of the inception date in determining self insurance premiums.

451 CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, November 2000.
452 CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, pp. 112–113.
453 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, p. 113.
454 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 32.
455 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.
456 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 34.

The AER notes that its draft decision did not indicate that SAHA used the costs in the CIE report, rather that it used the functional relationship in the CIE report to establish costs associated with a minor bushfire ignited by a third party.[457] As indicated in the draft decision, and confirmed by SAHA in its response to the draft decision[458], SAHA used the functional relationship from the CIE report to establish:

- the value of minor bushfires (and from this the ratio of major to minor bushfires)
- the average hectares of land burnt during a minor and major bushfire.

SAHA then applied the average hectares of land burnt during a minor bushfire to ActewAGL's average value of assets per square kilometre to determine the value of damage caused by a minor (or major) bushfire.[459]

Clearly, if the function relationship developed in the CIE report is not robust, then the value of damage caused by a minor (or major) bushfire calculated by SAHA (based on this functional relationship), cannot be relied upon. As indicated in the draft decision, the AER identified a number of issues with the functional relationship derived in the CIE report. In particular:

- based on an examination of the historical data underpinning the CIE modelling, the AER is unable to unambiguously match the values provided in the CIE report with those in the base data[460]
- 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[461]
- 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 variation in bushfire damage cost can be explained by the amount of hectares burnt.[462]

Further, the AER has identified issues associated with SAHA's application of the CIE report to determine the damage area associated with a minor bushfire. SAHA suggested that minor bushfires cause $58.5 million damage.[463] This value can be derived from the average annual area burnt by small to medium bushfires in Australia[464] and the functional relationship between damage costs and area burnt for

457 AER, *Draft decision*, p. 111.
458 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.
459 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.
460 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. See: http://www.ema.gov.au/ema/emadisasters.nsf/webEventsByCategory?OpenView&Start=1&Count=30&Expand=1#1.
461 The AER notes that the CIE acknowledges this point and suggests, therefore, that the derived relationship is conservative.
462 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, p. 113.
463 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.
464 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, table 7.5, p. 112. Note the CIE indicates that these refer to small to medium bushfires i.e. minor bushfires. See CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, p. 108.

major bushfires.[465] Based on this approach, the resultant value of $58.5 million represents the total cost associated with all minor bushfires in Australia in a single average year.

SAHA used this value to determine a ratio of major to minor bushfires.[466] SAHA then used this ratio to derive damage associated with a single minor bushfire—SAHA indicated that a single minor bushfire would damage 44 000 hectares.[467]

However, the AER notes that SAHA has incorrectly used 80 000 hectares as the amount of area burnt by a major bushfire (rather than 800 000 hectares[468]) and that the ratio derived by SAHA actually represents all minor bushfires in a single year in Australia rather than a single bushfire and therefore cannot be used to calculate the damage associated with a single minor bushfire.[469]

In relation to the additional supporting data provided by SAHA, the AER notes that SAHA has not clarified how a major bushfire is defined in the data. Nor has SAHA explained the distinction between a minor and major bushfire in the additional information. It is therefore not possible from the additional information to determine the damage area associated with a minor bushfire.

Based on the above, the AER is not satisfied that the premium associated with minor bushfires caused by third parties reflects the efficient costs of a prudent operator in the circumstances of ActewAGL to achieve the opex objectives and rejects the self insurance premium.

Based on the lack of supporting information provided in the regulatory proposal and the revised regulatory proposal, the AER is unable to develop an alternative probability for such bushfires or to determine an appropriate average cost.

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.[470]

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 assets igniting a major bushfire, mainly due to the sheer number of bushfires started by third parties as compared with ActewAGL

465 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, chart 7.7, p. 113. The cost function in the CIE report predicts a damage cost of $133 000 for every 1000 hectares burnt by wildfire. According to the CIE report, the average annual area burnt by small to medium bushfires in Australia = 440,000 hectares. Hence the damage cost = 440 × $133 000 = $58.5 million.

466 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.

467 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 33.

468 See the section on major bushfires ignited by a DNSPs own assets for a discussion of this value and its appropriateness to the analysis.

469 The AER notes that, using the ratio in its corrected format results in a final value for area burnt by all minor bushfires in Australia of 440,000 hectares (consistent with the value provided in table 7.5 of the CIE report).

470 SAHA, *ActewAGL Self Insurance Risk Quantification*, confidential, p. 39.

assets. 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.

In calculating the costs associated with a major bushfire ignited by a third party, SAHA relied on information relating to the 2003 Canberra bushfires.

In the draft decision, the AER rejected the total self insurance premium in relation to major bushfires ignited by a third party on the basis that the probability of occurrence had not been reasonably determined. The AER noted that SAHA had provided no evidence in support of the proposed 1 in 100 year probability.

In response, SAHA maintained 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 assets igniting a major bushfire. In addition, SAHA stated that the 1 in 100 year probability was a much more reasonable assumption when compared with the AER's approach of excluding the cost associated with this risk in its entirety.[471]

The AER notes that SAHA has provided no further information to demonstrate that such an assumption is reasonable. For example, SAHA has not explained the derivation of the 1 in 100 year probability for ActewAGL or provided an explanation of why the 1 in 100 year probability represents a reasonable assumption for the return period of such a fire. SAHA does, however, indicate that such an event is more likely than the proposed 1 in 300 year probability associated with ActewAGL assets igniting a major bushfire. The AER notes that, while the relativities between such events are important, it does not provide sufficient evidence to demonstrate that the 1 in 100 year probability applied to third party bushfires is reasonable.

In response to SAHA's argument that the calculated probability (and resultant premium) is more reasonable than the zero premium provided by the AER in the draft decision, the AER does not consider that this constitutes a sufficient rationale in support of the 1 in 100 year probability adopted by SAHA.

Based on the assessment above, the AER is not satisfied that the self insurance premium for a major bushfire ignited by a third party reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the original and revised regulatory proposals.

***Summary***

The AER maintains its draft decision and does not accept the self insurance allowances for ActewAGL for both minor and major bushfires caused by ActewAGL's own assets or a third party. Accordingly, the AER does not accept the proposed self insurance premiums of $173 000 per annum for ActewAGL.

471 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 32.

**Poles and lines**

ActewAGL sought self insurance in relation to damage to its poles and lines as a result of:

- 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. In the draft decision, the AER accepted the self insurance premium associated with consequential damage to third parties ($35 000 per annum).

***Storm damage***

In relation to storm events, ActewAGL proposed self insurance for both severe and catastrophic storms.

*Severe storms*

SAHA indicated that ActewAGL records show that there were five severe storm incidents from financial year 2002–03 to 2006–07, which equates to one incident per year. SAHA indicated that it was difficult to determine the cost of a severe or catastrophic storm—ActewAGL does not record costs associated with each storm. However, SAHA indicated that, from past experience, ActewAGL would expect at least $1 million to repair and replace damage to its assets due to a 'severe' storm.

SAHA noted that the AER did not provide an explanation in rejecting the estimated annualised cost incurred by ActewAGL for severe storm.

The AER acknowledges that it did not originally provide an explanation for the rejection of the self insurance premium associated with severe storms. The AER originally rejected the premium on the basis that the cost information associated with a severe storm was unconvincing—SAHA indicated that ActewAGL did not maintain records of costs associated with a severe storm but expected that damage was at least $1 million. While the AER maintains that such a statement does not provide sufficient information for the AER to determine the robustness of the cost claim, the AER has since examined costs associated with severe storms for each of the NSW DNSPs as part of their regulatory proposals. The AER notes that the NSW DNSPs indicated similar minimum costs associated with severe storms. The AER therefore considers that ActewAGL's proposed costs associated with a severe storm of $1 million represent a reasonable approximation. Based on this conclusion and the historical incidence of severe storms, the AER accepts ActewAGL's proposed self insurance premium associated with severe storms.

*Catastrophic storms*

SAHA determined the probability of a catastrophic storm 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'.[472] SAHA determined the potential cost to ActewAGL of a catastrophic storm based on a pro–rata application of the cost associated with the recent NSW Lower Hunter storms.

In the draft decision, the AER rejected the self insurance premium associated with a catastrophic storm on the basis that it considered that the media statement relied upon by SAHA did not constitute a robust assessment of the probability of a catastrophic storm impacting ActewAGL's network.

In response, SAHA argued that there is a real risk of such an event occurring and maintained that a 1 in 30 year probability for a catastrophic storm reasonably reflects the efficient costs that a prudent operator would incur.[473] In support of this argument, SAHA provided additional information.

SAHA presented storm information from the Emergency Management Australia (EMA) Disaster Database for NSW and the ACT for the last 20 years. SAHA acknowledged that it is difficult to assess the specific damage caused by these storms to powerlines as this is not quantified in the database, but suggested that in all likelihood, many of them would be classified as a catastrophic storm. In particular, SAHA suggested that it is clear that one of the storms listed for the ACT would clearly meet this criterion.[474]

The AER notes that ActewAGL defined a catastrophic storm as follows:

> …ActewAGL considers it reasonable to define a catastrophic storm to be a storm similar in nature to the 2007 Lower Hunter Valley occurrence that impacted EnergyAustralia's assets. According to EnergyAustralia, this low probability but high consequence event impacted their SAIDI by more than 198 minutes and the total cost (capital and operations) tied to this catastrophic storm was estimated to be $16,200,000, 16 times more than typically expected from a severe storm.[475]

The AER notes that SAHA has provided no cost or system average interruption duration index (SAIDI) information to confirm that the storms in the EMA Disaster Database, and assumed by SAHA to represent catastrophic storms, were in fact catastrophic as defined by ActewAGL. In particular, the AER notes that the storm identified by SAHA as catastrophic in the ACT was not identified as a catastrophic storm in ActewAGL's regulatory proposal.

SAHA suggested that relying on the information contained in the EMA Disaster Database to derive the self insurance premium is a conservative approach. SAHA noted that the EMA Disaster Database is limited in detail beyond the last 10 years and therefore there is a major risk in using the full dataset to derive the overall probability of a catastrophic storm impacting electricity assets as incidents mentioned at a high level in the EMA Disaster Database may not have discussed in enough detail the impact that they had on electricity assets.[476] In addition, SAHA noted that even over

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472 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.
473 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 46.
474 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 43.
475 ActewAGL, Email received from ActewAGL, 17 September 2008, p. 6.
476 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 44.

the past 20 years, '…it is difficult to gauge the exact magnitude of the damage based on the qualitative evidence provided in the database.'[477]

The AER considers that there is doubt as to how many of the storms identified in the EMA Disaster Database (and used by SAHA) were in fact catastrophic storms according to the definition provided by ActewAGL. As a result, the AER concludes that the additional information provided by SAHA provides no further support for the 1 in 30 year probability applied to ActewAGL.

SAHA noted that a key aspect of the recent catastrophic Hunter Valley storms in NSW appears to have been the wind speed generated. SAHA uses information from Geoscience Australia examining wind speeds in the Sydney region and return periods related to these wind speeds to support the 1 in 11 year probability applied to a catastrophic storm in the EnergyAustralia network and the 1 in 30 year probability applied to ActewAGL.[478]

SAHA suggested that the data show a return period in the Williamtown region (in close proximity to Newcastle) of 1 in 10 years for wind gusts of 119 km/hr. SAHA noted that this is similar to the wind gusts recorded in Newcastle (part of the area affected by the Hunter Valley storms) and therefore provides support for the 1 in 11 year return period calculated for EnergyAustralia.[479]

Based on additional information provided by SAHA, the AER has determined that the Hunter Valley storms involved maximum wind gusts averaging around 130 km/hr.[480] Further, based on the information provided in the Geoscience Australia report,[481] the AER considers that a return period for a storm involving maximum wind gusts of around 130 km/hr is more likely to be 55 years. The data show that a 10 year return period can be expected for maximum wind gusts of 119 km/hr in Williamtown, with a 100 year return period expected for wind gusts of 140 km/hr. The same return period is estimated for similar maximum wind gusts averaged over the entire Sydney region. All things being equal, this suggests that maximum wind gusts averaging around 130 km/hr could be expected to occur every 55 years in Williamtown and the Sydney region in general (i.e. half way between a 10 year and a 100 year return period).

SAHA also indicated that the materially lower wind speed average recorded in Richmond suggests that inland NSW may be less prone to large wind gusts and that this confirms that the probability of a catastrophic storm for ActewAGL should be lower than for EnergyAustralia.[482]

The AER considers that this may well be the case, but this observation does not explain the derivation of the 1 in 30 year probability for ActewAGL or the relativity of the probabilities between ActewAGL and EnergyAustralia.

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477 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 44.

478 Geoscience Australia, *A Statistical Model of Severe Winds*, 2007

479 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 43 – 44.

480 Based on an average of maximum wind gusts of 135 km/h at Norah Head and 124 km/hr at Newcastle - SAHA report confidential, p.44 and http://www.bom.gov.au/weather/nsw/sevwx/0607summ.shtml

481 Geoscience Australia, *A Statistical Model of Severe Winds*, 2007, p. 48, http://www.ga.gov.au/image_cache/GA10911.pdf

482 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 45.

While the regulatory proposal provided a proxy for the costs associated with a catastrophic storm (reflecting the costs associated with the Hunter Valley storms), the AER considers that it is not possible to develop an alternative self insurance premium for catastrophic storms from the information provided by SAHA. In particular, the AER considers that it is not able to develop a reasonable probability of occurrence based on the information provided since:

- no cost (or SAIDI) information is provided in the data in relation to other storms. It is therefore not possible to determine if previous storms were catastrophic as defined by SAHA
- SAHA questioned the robustness of the data provided, indicating that there is insufficient information provided in the EMA Disaster Database and that it is virtually impossible to use the database to determine the impact of large scale storms beyond the last 10 years[483]
- it is not clear that maximum wind gusts are necessarily indicative of a catastrophic storm (maximum wind gusts do not form part of the definition of a catastrophic storm as defined by SAHA). Further:
  - the Casino storm in 2001 registered winds up to 140km/hr[484], but was not identified by Country Energy as a catastrophic storm
  - the Hunter Valley storm of 1998 recorded winds of 150km/hr[485], but was not previously identified by EnergyAustralia as a catastrophic storm.

Based on the assessment above, the AER is not satisfied that the self insurance premium for a catastrophic storm reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the original and revised regulatory proposals.

***Unrecoverable third party damage***

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 calculated the risk premium for third party damage as the probability of third party damage multiplied by the financing costs (associated with the replacement assets) and repair costs associated with damaged assets.

ActewAGL indicated that a portion of this premium was already included in its regulatory proposal.[486] SAHA therefore subtracted this amount from its original estimate to derive an adjusted risk premium.

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483 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 43.
484 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 44.
485 EMA Disasters Database, Available: http://www.ema.gov.au/ema/emadisasters.nsf/6a1bf6b4b60f6f05ca256d1200179a5b/3b219e6acb810a48ca256d3300057f80?OpenDocument

In the draft decision, the AER rejected the self insurance premium on the basis 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 noted that the amount included by ActewAGL in its baseline opex appeared to be based on previous experience with these events.

In response, SAHA indicted that it does not consider the absence of a significantly long data set enough of a reason to exclude this risk quantification in its totality. SAHA noted the AER's concerns that 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. However, it indicated that it was unable to comment on the method that ActewAGL used to derive the amounts included in its baseline opex forecasts, and therefore could not provide specific comment on whether the AER's rationale for excluding the risk is reasonable or not.[487]

The AER notes that the self insurance premium has not been rejected simply on the basis of the length of the data set. Rather, the AER notes that an amount for this risk has already been included in ActewAGL's baseline opex for the next regulatory control period—the SAHA proposal seeks self insurance for an additional amount based on the latest year of data. The AER maintains that a reasonable estimation of costs would incorporate the historical information or analysis on which the baseline amount was determined and the most recent data. In this way it would be possible to obtain a longer term view of the behaviour of these costs. As it currently stands, it is not possible to determine whether the most recent data represents a longer term trend or simply an outlier value. SAHA has provided no information to explain why the recent data differs from that included in the baseline expenditure and is not able to explain how the baseline amount was derived.

The AER notes that the rejection of the proposed self insurance premium applies only to the additional amount proposed for self insurance. The amount already incorporated in the baseline opex is not affected by this final decision.[488]

Based on the assessment above, the AER is not satisfied that the self insurance premium for unrecoverable third party damage reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the original and revised regulatory proposals.

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486 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.

487 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 46.

488 The baseline amounts were accepted by the AER in its review of aggregate opex forecasts for the next regulatory control period in the draft decision.

***Summary***

Based on the information provided, the AER accepts the proposed self insurance premium associated with severe storms of $518 000 per annum.

The AER maintains its draft decision and does not accept the self insurance allowance for ActewAGL for damage to poles and lines as a result of a catastrophic storm and in relation to unrecoverable third party damage. Accordingly, the AER does not accept the proposed self insurance premium of $524 000 per annum for ActewAGL.

**Key assets including consequential damage to a third party's property**

ActewAGL sought self insurance for costs associated with the failure of power transformers and circuit breakers, including consequential damage/liability to a third party's property as a result of failure of these assets.

In the draft decision, the AER accepted the self insurance premium for costs associated with the failure of power transformers and circuit breakers, but rejected the claim associated with third party claims. The AER rejected the self insurance premium in relation to third party damage on the basis that the probability of occurrence had not been reasonably determined.

In response, SAHA suggested that the AER rejected the self insurance allowance for third party claims on the basis that ActewAGL had never experienced such an event.[489] SAHA indicated that it is difficult to quantify this risk, but believed that its probability and consequence estimates were reasonable, and moreover, that its estimates were more reasonable than a zero self insurance allowance as proposed by the AER.[490]

The AER notes that it did not reject the proposed premium on the basis of no historical information, rather, the AER rejected the premium on the basis that there was no information provided in the regulatory proposal on which to determine that the premium was reasonable. In its original report, SAHA's argument for the adoption of a 1 in 24 year probability for such an event consisted of a statement that, notwithstanding that there have been no previous claims:

> SAHA considers it reasonable to assume that there can potentially be one future incident during next regulatory period that can have an above deductible impact on 3rd party properties. Translating this assumption, there is a 1 in 24 years (since ActewAGL's inception) probability of this above deductible consequential 3rd party damage occurring.[491]

The AER agrees that this risk may well exist for ActewAGL, however, based on the limited information provided, the AER is unable to accept that the 1 in 24 year probability adopted by SAHA is reasonable. SAHA has provided no rationale for the adoption of this particular probability.

In response to SAHA's argument that the calculated premium is more reasonable than the zero premium provided by the AER in the draft decision, the AER does not

489 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 47.
490 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 47.
491 SAHA, *ActewAGL Self Insurance Risk Quantification*, confidential, p. 59.

consider that this constitutes a sufficient rationale in support of the 1 in 24 year probability adopted by SAHA.

Based on the assessment above, the AER is not satisfied that the self insurance premium for third party claims arising from key asset failure reflects the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the original and revised regulatory proposals.

ActewAGL indicated that, if the AER rejects self insurance in relation to third party claims, then the AER should allow ActewAGL to adopt a cost pass through for this risk.[492]

The AER notes that rejection of a self insurance premium does not mean that the event is automatically considered a cost pass through event. The acceptance of an event for self insurance or cost pass through relies on an assessment of the particular event (and the associated costs). In the case of self insurance, the AER is required to determine whether the operating cost (the premium) is prudent and efficient under the transitional chapter 6 rules. Where the AER is not satisfied that this is the case, the AER is required under the transitional chapter 6 rules to reject the premium. The AER is then required to determine an alternative value with reference to the opex criteria in the transitional chapter 6 rules. The AER is not required to provide an alternative means of addressing risk associated with an event.[493]

***Summary***

The AER maintains its draft decision and does not accept the forecast self insurance allowance for ActewAGL for third party claims arising from key asset failure. Accordingly, the AER does not accept the proposed self insurance premium of $2000 per annum for ActewAGL.

**General public liability**

General public liability risk covers incidents where ActewAGL is liable for injuries or other losses suffered by members of the general public as a result of its (or its employees) negligence or fault. ActewAGL sought self insurance of $2000 per annum in relation to general public liability for claims above the existing external insurance deductible.

In its original report, SAHA indicated that whilst ActewAGL had no experience with such events, Integral Energy had been affected by this risk twice in the last 5 years. SAHA therefore adopted a 1 in 24 year probability of such an event for ActewAGL.[494]

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492 ActewAGL, *Revised regulatory proposal*, p. 64.

493 Notwithstanding this point, in assessing the revised self insurance premiums proposed by ActewAGL, the AER has considered whether the risks for which a self insurance allowance is being proposed may be more appropriately treated as pass through events.

494 SAHA, *ActewGL Self Insurance Risk Quantification*, confidential, p. 29.

In the draft decision, the AER did not accept the self insurance premium for ActewAGL, stating that it considered that the basis for determining the probability of these events was not robust. In particular, the AER noted:

- Integral Energy's recent experience with above deductible general liability claims is not relevant to ActewAGL, because of differences between Integral Energy's network and circumstances, and those of ActewAGL
- there is no rationale for the application of a 24 year period as the basis for the probability calculation because there is nothing inherently important about the inception date of ActewAGL.

In its response to the AER, SAHA suggests that general public liability is a credible risk that could affect each business at some point in the future, and therefore should be included as a self insured risk premium.[495]

As previously discussed, the AER's role is not to identify potential risks faced by ActewAGL, but is to assess the proposed operating costs (self insurance premiums). Accordingly, the AER is not concerned whether or not an event is possible, but rather, whether the premium is reasonable based on the evidence provided.

In relation to the AER's concerns associated with the application of Integral Energy's experience with such claims to ActewAGL, SAHA suggested that:

> it would be preferable if the AER could clearly outline what these differences (between the DNSPs) are, and how they would lead them to believe that none of the other businesses could ever be exposed to this risk.[496]

As indicated, the AER has not concluded that ActewAGL could never be exposed to such risks, but rather, that it cannot accept the self insurance premium based on the information provided. The AER considers that, in the first instance, the onus is on the DNSP to justify the application of the experience of Integral Energy to its business, identify the factor inherent in their businesses vis-à-vis Integral Energy, and explain the application of this relationship in developing the 1 in 24 year probability. It is not sufficient to suggest that since an event has impacted another DNSP that it is therefore likely to impact ActewAGL. Further, the AER does not consider that it is reasonable to apply a probability to such an event without explaining the considerations undertaken in developing that probability.

SAHA also suggested that the application of a 1 in 24 year probability represented a discount to the Integral Energy probability (2 in 5 years) and the Country Energy and EnergyAustralia probabilities.[497] [498]

The AER has received no evidence to support that the calculated probability is reasonable. In particular, no information has been provided by SAHA to clarify the relationship between the 2 in 5 year probability experienced by Integral Energy and

[495] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 50.
[496] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 50.
[497] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 50.
[498] The AER notes that neither Country Energy nor EnergyAustralia recorded such an event. Rather, SAHA derived probability estimates for these businesses based on the experience of Integral Energy.

the 1 in 24 year probability applied to ActewAGL (or the 2 in 11 year probability applied to EnergyAustralia and Country Energy). It is not clear from the SAHA analysis, for example, why a probability of 1 in 50 years may not be more appropriate for ActewAGL.

Based on the above, the AER is not satisfied that the self insurance premium for general public liability for claims above the existing external insurance deductible reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the original and revised regulatory proposals.

***Summary***

The AER maintains its draft decision and does not accept the forecast self insurance allowance for general public liability risk for ActewAGL. Accordingly, the AER does not accept the proposed self insurance premium of $2000 per annum for ActewAGL.

### Risks which should be treated as pass through events

ActewAGL stated that it had revised its self insurance allowance to exclude costs proposed in its regulatory original proposal associated with: [499]

- earthquakes greater than magnitude five on the Richter Scale
- major bushfires ignited by a third party.

ActewAGL indicated that these events should be covered under a cost pass through mechanism and therefore amended its nominated pass through events in its revised regulatory proposal to include such events.[500]

ActewAGL also indicated that, should the AER not approve ActewAGL's proposed self insurance allowance for catastrophic storms, major bushfires ignited by ActewAGL's own assets and third party claims resulting from key asset failure, these risks should be addressed through an appropriate pass through mechanism.[501]

The AER considers that the choice between managing an event through self insurance or cost pass through should reflect the nature of the event. For example, such a decision should rely primarily on whether the frequency and cost associated with an event can be robustly determined and whether the event would result in catastrophic losses to the business.

For a number of risks including earthquakes, the impact of catastrophic storms and major bushfires, the AER notes that it is difficult to derive a self insurance premium because of the low frequency of these events and the potential for catastrophic losses. For the following risks the AER considers that they should be dealt with under the pass through provisions of the chapter 6 transitional rules:

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499 ActewAGL, *Revised regulatory proposal*, p. 65.
500 ActewAGL, *Revised regulatory proposal*, pp. 58 and 61.
501 ActewAGL, *Revised regulatory proposal*, p. 65.

- earthquakes above magnitude five
- a major bushfire ignited by ActewAGL's own assets (not covered under insurance or in ActewAGL's baseline opex)
- a major bushfire ignited by a third party (not covered under insurance or in ActewAGL's baseline opex)
- damage to poles and lines as a result of a catastrophic storm (not covered under insurance or in ActewAGL's baseline opex).

The treatment of pass through provisions of the chapter 6 transitional rules is discussed in chapter 16 of this final decision.

### Administrative arrangements

The AER notes ActewAGL's view that when an allowance for self insurance is determined by the regulator as efficient, the DNSP is provided with flexibility in expenditure subject to relevant obligations and service standards being met.[502] However ActewAGL does not have any reporting (recognition or disclosure) arrangements in place to account for the risk it is bearing in connection with self insured events.

The future obligation that arises from a commitment to self insure events is not like other operating expenses. Self insurance is different in nature to other opex, in that the AER is approving opex now in lieu of the efficient cost of an external insurance premium. However, the expectation is that in approving the opex allowance for self insurance ActewAGL cover the cost of the self insured event, when that event occurs at a future date. The AER considers that the risk of meeting the costs of an event should it arise needs to be disclosed.

The AER understands that the current guidance in the Australian Accounting Standards Board 137 Provisions, Contingent Liabilities and Contingent Assets (AASB 137), prohibits a provision being recognised if there is no present obligation, no probable outflow of resources and no reliable estimate of the amount of the obligation.[503] Under these criteria self insurance events cannot be a recognised as a provision with reference to AASB 137.

The AER notes that self insurance events are similar in nature to contingent liabilities which are defined under AASB 137 as a possible obligation that arises from past events and whose existence will be confirmed only by the occurrence or non occurrence of one or more uncertain future events not wholly within the control of an entity.[504] The standard describes contingent liabilities as liabilities that are not recognised as they are either a possible obligation which is yet to be confirmed or a present obligation which cannot be reliably estimated or is not probable.[505]

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502 ActewAGL, Email received from ActewAGL, 17 March 2009, p. 6.
503 AASB 137, *Provisions, Contingent Liabilities and Contingent Assets*, paragraph 14.
504 AASB 137, paragraph 10.
505 AASB 137, paragraph 13 (b).

AASB 137 does not require that contingent liabilities are recognised,[506] but it does require that certain disclosures are made in the financial accounts of the entity which are responsible for bearing the risk of these liabilities.

As part of the administrative arrangements for self insurance, the AER considers it is prudent practice for ActewAGL to disclose self insurance events each regulatory year and provide a brief description of the nature of the self insurance event in accordance with AASB 137. The standard also requires, where practical, disclosure of:[507]

- an estimate of the financial effect of the liability
- an indication of the uncertainties relating to the amount or timing of the outflow and
- the possibility of any reimbursement.

Accordingly, the AER requires ActewAGL to disclose self insurance events as a contingent liability in accordance with AASB 137 in their audited accounts.

## AER conclusion

For the reasons set out above, the AER considers that the proposed self insurance allowances do not reflect the efficient costs that a prudent operator in the circumstances of ActewAGL would require to meet the opex objectives. Accordingly, under clause 6.5.6(d) of the transitional chapter 6 rules, the AER has not accepted the forecast self insurance allowances. Further, consistent with the requirements of clause 6.12.1(4)(ii) of the transitional chapter 6 rules, the AER has provided substitute values for the associated self insurance premiums.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal, the AER is satisfied that the amended estimates of the total self insurance allowances for the next regulatory control period set out in table G.1, based on the above accepted self insurance premiums and substitute values, reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

**Table G.1: AER conclusion on self insurance allowance for ActewAGL over the next regulatory control period ($m, 2008−09)**

| | Revised regulatory proposal | AER final decision |
|---|---|---|
| Total self insurance | 7.9 | 4.4 |

Note: ActewAGL's self insurance premiums in the original and revised SAHA report are in 2007–08 dollar terms. The AER converted these to 2008–09 dollar terms using ActewAGL's proposed 2.7 per cent escalation.

[506] AASB 137, paragraph 27.
[507] AASB 137, paragraph 86.

# Appendix H: Benchmark debt and equity raising costs

The AER concurrently assessed the revised revenue proposals of two TNSPs (TransGrid and Transend) and the revised regulatory proposals of four DNSPs (ActewAGL, Country Energy, EnergyAustralia and Integral Energy). Within this appendix these six regulated businesses are collectively referred to as the network service providers (NSPs). For convenience, within this appendix the term regulatory proposal should be taken to include the term revenue proposal, where the AER is referring to the NSPs. Within this appendix the AER has also used the term draft decision to refer to any and all of the relevant draft decisions affecting the NSPs. Where it has been necessary to refer to a draft decision for just one of the NSPs, within this appendix the AER has identified the specific business when referencing the draft decision, rather than applying the generic term draft decision, as defined in the shortened forms.

## Debt raising costs

### Rationale for joint consideration

The NSPs have proposed the same unit rate to determine the allowance for debt raising costs, a total of 15.5 basis points per annum (bppa) to be applied to the debt component of the regulatory asset base (RAB) each year.[508] This total unit rate is comprised of 3.0 bppa for indirect debt raising costs and 12.5 bppa for direct debt raising costs.

The shared position of the NSPs is reinforced by reliance on substantially the same consultant reports. In the regulatory proposals submitted by five of the six NSPs (excluding ActewAGL), variants of a Competition Economists Group (CEG) consultancy report were submitted.[509] In the revised regulatory proposals, a report by CEG is referenced and submitted by all six NSPs—that is, all submitted versions are identical.[510] TransGrid and EnergyAustralia both submitted an additional report by Tony Carlton, from the University of NSW, although there are some variations

508 TransGrid, *Revised revenue proposal*, p. 78; Transend, *Revised revenue proposal*, p. 57; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 107; Integral Energy, *Revised regulatory proposal*, p. 43; and ActewAGL, *Revised regulatory proposal*, p. 33.

509 CEG, *Nominal Risk Free Rate, Debt Risk Premium and Debt and Equity Raising Costs for TransGrid*, May 2008; CEG, *Nominal Risk Free rate and Debt and Equity Raising Costs for Transend*, May 2008; CEG, *Nominal Risk Free Rate, Debt Risk Premium and Debt and Equity Raising Costs for Country Energy*, May 2008; CEG, *Nominal Risk Free Rate, Debt Risk Premium and Debt and Equity Raising Costs for EnergyAustralia*, May 2008; CEG, *Nominal Risk Free Rate, Debt Risk Premium and Debt and Equity Raising Costs for Integral Energy*, April 2008.

510 CEG, *Debt and Equity Raising Costs: A response to the AER 2008 draft decisions for electricity distribution and transmission*, January 2009. Cited by TransGrid, *Revised revenue proposal*, p. 77; Transend, *Revised revenue proposal*, p. 57; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 105; Integral Energy, *Revised regulatory proposal*, p. 43 and ActewAGL, *Revised regulatory proposal*, p. 33.

between the two versions.[511] Further, EnergyAustralia's submission requested that all reports and supporting documents which it had submitted as part of its regulatory proposal and revised regulatory proposal be considered by the AER in making its final determination for all the NSPs.[512]

Other relevant submissions were also received by the AER, from the following organisations:

- TransGrid—a report by the Strategic Finance Group (SFG)[513]
- Powerlink—regarding aspects of the draft decision for TransGrid[514]
- Joint Industry Association (JIA)— including a report by CEG that merges parts of the May 2008 and January 2009 CEG reports with new analysis (note that this report was additionally submitted as an attachment to EnergyAustralia's revised regulatory proposal).[515]

Due to the consistency between the opex provisions of the NER under which the debt raising cost proposals are assessed, the NSPs' revised regulatory proposals and the supporting consultancy reports, the AER jointly assessed the debt raising costs of the NSPs. The AER's analysis and conclusions are contained in this appendix, which is reproduced in each of the AER's final decisions for the NSPs.

The AER considers that it is important for a consistent methodology to determine the appropriate allowance for benchmark debt raising costs to be applied in its final decisions for the NSPs.[516]

### Rationale for draft decisions

In making the draft decisions, the AER's consideration of debt raising costs took account of the requirements of the NER. This includes the requirement that forecast opex for the NSPs reasonably reflects the efficient costs that a prudent operator in the circumstances of the relevant NSP would require to achieve the opex objectives.[517]

The draft decisions were consistent with the relevant parameter values specified in the NER, including that the benchmark firm maintains a 60 per cent gearing ratio and issues debt at a BBB+ credit rating.[518]

Using the parameters specified in the NER, the AER constructed a model of the methodology by which a benchmark firm issues debt. Throughout this appendix the

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511 Carlton, T., *Indirect Costs of Equity and Debt Raising: Report prepared for EnergyAustralia*, 12 January 2009; and Carlton, T., *Indirect Costs of Equity and Debt Raising: Report prepared for TransGrid*, 12 January 2009.

512 EnergyAustralia, *Submission on other network service providers*, 16 February 2009.

513 SFG, *Debt and equity issuance costs for a benchmark transmission business*, 20 March 2009.

514 Powerlink, *Draft Decision TransGrid Transmission Determination 2009–10 to 2013–14*, 16 February 2009.

515 JIA, *Network Industry Submission: Debt and Equity Raising Costs*, 11 November 2008 and CEG, *Debt and equity raising costs: A report for the APIA, ENA and Grid Australia*, 11 November 2008.

516 This approach is essentially the same as that employed by the AER for its draft decisions.

517 For DNSPs, see clause 6.5.6(c)(2) of the transitional chapter 6 rules. For TNSPs, see clause 6A.6.6(c)(2)of the NER.

518 AER, *TransGrid draft decision*, p. 137; AER, *Transend draft decision*, p. 190; AER, *NSW DNSP draft decision*, p. 186 and AER, *ACT draft decision*, p. 107.

benchmark firm is a reference to a benchmark efficient NSP that is a pure play regulated electricity network operating in Australia without parent ownership. Assumptions about how such a benchmark firm issues debt were stated in the draft decisions. For example:

- the benchmark firm was assumed to issue public debt in the Australian market, in order to maintain consistency with the domestic capital asset pricing model (CAPM) that is applied to determine the regulated rate of return[519]
- the debt was assumed to be raised in order to fund organic growth, rather than acquisitions or non–core investments, as the benchmark firm does not undertake such activities.[520]

The NSPs challenged the AER's assumption regarding the issuance of public debt in the Australian market and consistency with the domestic CAPM framework in their revised regulatory proposals. This is discussed below. Other assumptions (stated above) made by the AER in its modelling of the benchmark debt issue were not challenged by the NSPs, and accordingly, the AER considers that these assumptions remain valid for this final decision.

## Indirect costs of debt raising

The AER rejected the proposed 3 bppa allowance for indirect debt raising costs (also known as underpricing) in the draft decisions.[521] All of the NSPs rejected the draft decision on this issue and resubmitted[522] the 3 bppa indirect cost allowance in their revised regulatory proposals.[523] The NSPs referred to consultant reports submitted as part of their revised regulatory proposals to justify the claim for indirect costs of debt raising.

### Interpreting the NER prescribed BBB+ credit rating

The AER notes that the NER specifies:[524]

519 AER, *TransGrid draft decision*, p. 137; AER, *Transend draft decision*, p. 191; AER, *NSW DNSP draft decision*, p. 186 and AER, *ACT draft decision*, p. 105.

520 AER, *TransGrid draft decision*, p. 136; AER, *Transend draft decision*, p. 188; AER, *NSW DNSP draft decision*, p. 185 and AER, *ACT draft decision*, p. 105.

521 AER, *TransGrid draft decision*, pp. 137–138; AER, *Transend draft decision*, pp. 189–190; and AER, *NSW DNSP draft decision*, pp. 185–187. Note that indirect costs were not included as part of the original ActewAGL proposal, and so were not rejected in the ACT draft decision.

522 In the case of ActewAGL, this was not a resubmission but rather submission for the first time. The AER notes that the NER restricts the presentation of material in a revised regulatory proposal to matters addressed in the draft decision, and that this would ordinarily prevent ActewAGL from making such a methodological shift between regulatory proposal and revised regulatory proposal. However, the AER considers that regulatory consistency is paramount on this issue, such that the decision made for all other NSPs will be applied to ActewAGL as well.

523 TransGrid, *Revised revenue proposal*, p. 78; Transend, *Revised revenue proposal*, p. 57; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 107; Integral Energy, *Revised regulatory proposal*, p. 43 and ActewAGL, *Revised regulatory proposal*, p. 33.

524 The clause cited here applies to DNSPs, see clause 6.5.2(e) of the transitional chapter 6 rules. For TNSPs, the relevant clause is almost identical; see clause 6A.6.2(e) of the NER: 'The debt risk premium for a regulatory control period is the premium determined for that regulatory control period by the AER as the margin between the annualised nominal risk–free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a BBB+

> The debt risk premium for a regulatory control period is the premium determined for that regulatory control period by the AER as the margin between the 10 year commonwealth annualised bond rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity of 10 years and a credit rating of BBB+ from Standard and Poor's.

The AER observes this clause when it determines the debt risk premium associated with assumed debt issuance of the benchmark firm. To estimate the BBB+ benchmark corporate bond rate, the AER applies an established methodology based on the use of Bloomberg fair yield curves. CEG examined this methodology, and endorsed its use in its report accompanying the regulatory proposals:[525]

> In our opinion this approach is reasonable and the AER has shown that it does not result in a material error or an obvious bias (at least when measured against recent history).

CEG also tested the AER's methodology against an alternative approach and found the AER's methodology to be superior. In the draft decisions, the AER considered that the Bloomberg fair yield curves were therefore accepted as the best estimate of the cost of debt for the benchmark BBB+ debt issue.[526]

The AER notes that, in the revised regulatory proposals, issues have been raised in relation to the Bloomberg and CBASpectrum data sources used for establishing the debt risk premium. The AER's consideration of these issues is set out in section 12.5.2 of this final decision.

The AER notes that, although there is general agreement on the existence of direct costs of raising debt, CEG claim that additional indirect debt raising costs exist. CEG defined indirect costs in terms of underpricing, stating that:[527]

> Underpricing is a cost to all businesses who, in order to ensure the success of a debt issue, need to issue debt at a discount to the price it subsequently trades. This is true for all firms irrespective of their credit rating.

This explanation for underpricing—that it is required to sell debt—was explicitly mentioned by the NSPs in their revised regulatory proposals.[528]

For debt issues, CEG stated that there is a simple relationship between yield and price:[529]

> In the case of debt, a lower price implies a higher interest rate.

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credit rating from Standard and Poor's and a maturity equal to that used to derive the nominal risk–free rate.'

525 CEG, May 2008 (TransGrid), p. 7, paragraph 13; CEG, May 2008 (Transend), p. 7, paragraph 14; CEG, May 2008 (Country Energy), p. 7, paragraph 14; CEG, May 2008 (EnergyAustralia), p. 4, paragraph 14 and CEG, April 2008 (Integral Energy), p. 7, paragraph 13.

526 AER, *TransGrid draft decision*, pp. 93–94; AER, *Transend draft decision*, pp. 150–151; AER, *NSW DNSP draft decision*, pp. 225–226 and AER, *ACT draft decision*, pp. 137–138.

527 CEG, January 2009, p. 45, paragraph 150.

528 For example, see EnergyAustralia, *Revised regulatory proposal*, p. 106 and TransGrid, *Revised revenue proposal*, p. 78.

529 CEG, January 2009, p. 44, paragraph 149.

The AER further notes that Associate Professor Handley highlighted the key issue that distinguishes debt underpricing from equity underpricing:[530]

> …if a firm issues debt securities at a discount to the fair market price then there is a [sic] immediate gain to the new investors (who acquire the securities at a lower price) and an immediate cost to the firm in the form of lower proceeds received from the issue. In other words, unlike with equity securities, the higher the underpricing the lower the proceeds raised at the time of issue.

That is, Associate Professor Handley considered that if such underpricing exists, it will be included in measures of yield, in the manner of all other costs of debt. The AER therefore considers that the key issue is whether its approach to estimating the cost of debt for the benchmark regulated firm encapsulates the 'underpricing' effects.

The AER considers that the use of fair yield curves represent the best estimate of the expected cost of debt. Systematic underpricing, such as that proposed by CEG as applying to all firms irrespective of credit rating, should be readily detected and included in the fair yield curves. The AER considers that on these grounds, no allowance for underpricing is justified, taking into account the views of Associate Professor Handley:[531]

> In summary, assuming allowed revenues are determined using an appropriate estimate of the cost of debt, and noting that both the AER and CEG believe this to be the case, then it is my view that, underpricing should not be allowed as a cost of raising debt capital.

This is consistent with the draft decisions, which stated that:[532]

> If firms effectively issue at a higher yield than BBB+, for example due to underpricing the debt, the firms are effectively issuing higher yielding lower grade debt. The proposed underpricing premium is therefore inconsistent with the assumed BBB+ benchmark.

The AER considers that granting an indirect cost allowance on top of an efficient benchmark measure of the BBB+ cost of debt would be double counting, and systematically allowing a higher rate of return than that required by the NER. Accordingly, the AER considers that to the extent indirect debt raising costs represent a rate of return in excess of NER requirements, the proposed allowance for indirect debt raising costs is inappropriate.

**Absence of supporting empirical evidence**

TransGrid stated that there is a 'significant body of empirical evidence demonstrating that underpricing is a cost to businesses raising debt.'[533] CEG stated in similar terms that:[534]

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530 Handley, J. C., *A note on the costs of raising debt and equity capital*, 12 April 2009, p. 15.

531 Handley, April 2009, p. 17.

532 AER, *TransGrid draft decision*, p. 137; AER, *NSW DNSP draft decision*, p. 186; and AER, *Transend draft decision*, p. 190.

533 TransGrid, *Revised revenue proposal*, p. 78.

534 CEG, January 2009, p. 45, paragraph 150.

> The finance literature we have referred to has demonstrated that the answer to this empirical question is that underpricing does exist. **This empirical fact cannot be assumed away**. [emphasis in original]

The AER does not consider that the NSPs or their consultants on this issue (SFG,[535] Carlton and CEG) have submitted reliable evidence that debt underpricing exists.

SFG discussed conceptual issues relating to indirect equity raising costs at length, and then argued that these reasons 'apply equally to the issuance of debt and equity capital'.[536] The AER considers that such a claim is not supported, in that the mechanistic difference between equity raising and debt raising is sufficient to invalidate such a combined approach.[537] The AER observes that for empirical measures of the cost of raising debt, SFG referred directly to the CEG report, and provided no independent analysis.[538]

Carlton noted several theoretical reasons for indirect debt raising costs. He also mentioned two research papers on the subject, and argued that there are differences between the United States and Australian debt markets.[539] However, the CEG reports encompass all of Carlton's arguments, and present greater detail on most aspects. The AER therefore considers that thorough consideration of the CEG reports adequately addresses the issues covered by Carlton.

CEG's argument on indirect debt raising costs relied on a working paper by Saunders, Palia and Kim.[540] The authors of this paper do not find empirical evidence of underpricing in debt issues, stating:[541]

> …given the difficulty of generating one–day returns [a measure of underpricing] for a sufficient number of debt IPOs [initial public offerings], we did not directly calculate one–day returns.

That is, Saunders et al did not examine the existence of debt underpricing, as they did not possess the data to investigate this question.

The AER notes that Saunders et al referred to an earlier paper, by Datta, Datta and Patel as an anecdotal aside on debt underpricing.[542] CEG cited the Saunders et al working paper in its first report, stating:[543]

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535 The AER notes that the SFG report was received on 21 March 2009, more than one month after submissions closed on 16 February 2009. In this instance, the AER was able to consider all material within the SFG report on debt raising costs despite the late submission of this report. However, the AER notes that it has the right to reject late submissions, particularly where there is insufficient time to afford due consideration to the arguments therein.

536 SFG, March 2009, p. 12.

537 This point is also made by Handley, April 2009, p. 4.

538 SFG, March 2009, p. 17.

539 Carlton, January 2009 (EnergyAustralia), pp. 32–33 and Carlton, January 2009 (TransGrid), pp. 39–41.

540 Kim, D., Palia, D., and Saunders, A., *The Long–Run Behaviour of Debt and Equity Underwriting Spreads*, Draft Paper, January 2003.

541 Kim, Palia and Saunders, January 2003, p. 5.

542 Datta, S., Iskandar–Datta, M. and Patel, A. *The Pricing of Initial Public Offers of Corporate Straight Debt*, Journal of Finance, Vol. 52(1), March 1997, pp. 379–396.

> Nevertheless, for a very small sample of 50 firms, Datta, Datta and Patel (1997) estimate first day returns on corporate debt to be close to zero (0.15%).

This 15 basis point return is the foundation of CEG's suggestion of an allowance of 3.0 bppa for indirect costs (spread across the life of a 5–year bond). The AER notes that the Saunders et al working paper also states:[544]

> Datta, Datta and Patel (1997) show in a small sample of 50 firms that first day (short term) returns on corporate bond issues were **insignificantly different from zero**. [emphasis added]

This quote refers to analysis by Datta et al, using the standard statistical methodology to investigate the significance of a data point, which concluded that the first–day returns were equivalent to zero. Datta et al did not find empirical evidence of underpricing for debt issues.

Alternative empirical evidence presented by CEG included a paper by Cai, Helwege and Warga.[545] This paper found that offerings[546] of investment grade bonds (those rated BBB or better) demonstrate overpricing of 1 basis point—that is, the lender pays a premium, lowering the rate of interest paid by the borrower.[547] Cai et al did, however, find underpricing for high–yield, speculative grade bonds (those rated BB or lower, including unrated bonds) of 14.9 basis points. CEG argued in its first report that BBB debt, being at the 'edge of investment grade', would be more underpriced than the average investment grade debt and therefore lie somewhere between 0 and 14.9 basis points.[548]

In the draft decisions, the AER stated that there was no evidence that such a trend existed.[549] If such a trend was present, Cai et al would likely have detected it via regression analysis. However, the study did not present such analysis.

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543 CEG, May 2008 (TransGrid), p. 20, paragraph 63; CEG, May 2008 (Transend), p. 20, paragraph 64; CEG, May 2008 (Country Energy), p. 20, paragraph 63; CEG, May 2008 (EnergyAustralia), p. 15, paragraph 57 and CEG, April 2008 (Integral Energy), p. 20, paragraph 63.

544 Kim, Palia and Saunders, January 2003, p. 3, footnote 2.

545 Cai, N., Helwege, J., and Warga, A. (2007) *Underpricing in the Corporate Bond Market,* The Review of Financial Studies I, 20(5), pp. 2021–2046.

546 The figures quoted here are for non–initial offerings of debt—that is, all debt offerings excluding the very first offering of debt by a firm. Although Cai et al also investigated (and separately report) initial offerings, CEG did not consider that these findings were relevant to the benchmark firm. The AER agrees that non–initial debt is the appropriate data point for consideration.

547 CEG, May 2008 (TransGrid), p. 20, paragraph 65. Note that the overpricing is incorrectly reported by CEG as .01 of a basis point, rather than 1 basis point. See also CEG, May 2008 (Transend), p. 20, paragraph 66; CEG, May 2008 (Country Energy), p. 20, paragraph 65; CEG, May 2008 (EnergyAustralia), p. 16, paragraph 59 and CEG, April 2008 (Integral Energy), p. 20, paragraph 65.

548 CEG, May 2008 (TransGrid), p. 20, paragraph 66; CEG, May 2008 (Transend), p. 20, paragraph 67; CEG, May 2008 (Country Energy), pp. 20–21, paragraph 66; CEG, May 2008 (EnergyAustralia), p. 16, paragraph 60 and CEG, April 2008 (Integral Energy), pp. 20–21, paragraph 66.

549 AER, *TransGrid draft decision* p. 137; AER, *Transend draft decision*, p. 190 and AER, *NSW DNSP draft decision*, p. 186.

In the January 2009 CEG report, submitted by the NSPs with their revised regulatory proposals, CEG responded to the draft decision on this issue by repeating two points made in the May 2008 CEG report.[550]

First, CEG cited the Livingston and Zhou (2002) finding that BBB rated private debt is issued at a higher yield (measured by the spread over Treasury bonds) than public debt.[551] The AER considers this does not provide a strong rationale for consideration of the existence of underpricing. The existence of a different yield between private and public debt neither confirms nor denies the existence of underpricing when issuing either form of debt.

Second, CEG referred to its earlier statement regarding the Cai et al paper. CEG offered that the 'common sense observation that the lower a firm's credit rating the harder it will be to market new debt issues because of the increasing uncertainty associated with the value of that debt'.[552] The AER considers that there are other equally plausible explanations consistent with the observed data that do not involve the existence of underpricing of BBB grade debt. For example, it may be that the uncertainty of debt value increases dramatically once the investment/speculative threshold is crossed, but remains constant prior to reaching this threshold. Alternatively, it may be that the higher compensation provided by the direct yield of lower rated debt offsets the increased debt marketing difficulties, such that no indirect cost is incurred. In other words, a higher yield may be sufficient to attract investors to lower grade debt.

The AER does not consider the material cited by CEG in support of this argument to be empirical evidence. The interpolation of bond underpricing between investment grade bonds and speculative grade bonds assumes a known relationship between credit ratings and issuance prices relative to the face value of the debt issued. No theoretical basis or empirical evidence has been provided by CEG to support this relationship. Accordingly, the AER maintains its position that adequate empirical evidence on BBB underpricing has not been provided by the NSPs, within their regulatory proposals, revised regulatory proposals or associated consultant reports.

Finally, the AER considers there are substantial problems with concluding that the benchmark firm issuing debt in Australia will incur underpricing costs, on the basis of an overseas study. No evidence that BBB+ debt is sold (on average) at a discount in Australia has been provided to support the NSPs' arguments on underpricing. The NSPs have argued that there are significant differences between debt raising costs in the United States and Australia, and that the debt raising costs in the United States were lower than in Australia. For example, EnergyAustralia stated:[553]

> It is more than likely that the cost of raising debt in the US is lower than the cost of raising debt in Australia because of the depth of the US financial market. This is consistent with [sic] recent paper by Bortolotti, Megginson and Smart (cited in the Carlton report) which found that the US has the lowest cost of raising equity in the world.

550 CEG, January 2009, pp. 45–46, paragraphs 151–154 (which cite paragraphs 56 and 66 of the May 2008 (TransGrid) CEG report).

551 CEG, January 2009, p. 45, paragraph 152.

552 CEG, January 2009, pp. 45–46, paragraphs 153–154.

553 EnergyAustralia, *Revised regulatory proposal*, p. 106. A similar statement is made in TransGrid, *Revised revenue proposal*, p. 42, paragraph 141.

The AER does not consider that the Bortolotti et al paper, which deals solely with equity raising costs, is relevant to debt raising costs.[554] Further, the AER does not consider that Carlton provided any empirical evidence of debt underpricing in Australia, but instead presented anecdotal statements from market practitioners that the Australian market is illiquid and therefore a more expensive place to issue debt.[555] Carlton also stated:[556]

> Anecdotally we would consider that foreign issuers would pay a premium; the "first time issuers" premium of 6 bp per annum to 12 b.p. [sic] per annum may be a useful estimate of this premium.

The AER notes that there is no empirical support for the existence of a foreign issuer premium, or that it would be equivalent to a first–time issuer premium. Most importantly, the AER notes that the Carlton report does not present empirical evidence of underpricing on Australian debt, or empirical evidence of a relationship between Australian and United States debt raising costs.

The AER has not 'assumed away' empirical evidence. Rather, the empirical evidence presented by the NSPs and their consultants does not support the claims made. The AER considers that it has not been provided with empirical evidence of debt underpricing for BBB+ rated bonds in any country, or evidence of debt underpricing in Australia.

**Relationship between indirect and direct debt raising costs**

The NSPs submitted that the direct and indirect debt raising costs are interdependent and cannot be considered in isolation.[557] TransGrid stated that an increase in direct debt raising costs leads to a decrease in indirect debt raising costs, and vice versa.[558] The key argument made by CEG for this substitutability is that direct debt raising costs are related to the marketing of the debt—if the debt itself becomes cheaper (via an increase in indirect cost), then it is easier to sell and marketing costs will drop.[559]

While several studies were cited by CEG for equity issues, the AER considers that no conclusive empirical evidence was presented linking direct and indirect debt raising costs for BBB+ debt.

The AER notes that when the Saunders et al working paper (which formed the basis of much of the CEG report on this issue) was accepted for publication in 2008, all

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554 Bortolotti, B., Megginson, M. and Smart, S., *The Rise of Accelerated Seasoned Equity Underwritings,* Journal of Applied Corporate Finance, 2008, vol. 20(3), pp. 35–57.

555 Carlton, January 2009 (EnergyAustralia), pp. 32–33; and Carlton, January 2009 (TransGrid), p. 40.

556 Carlton, January 2009 (EnergyAustralia), p. 33; and Carlton, January 2009 (TransGrid), p. 40.

557 For example, EnergyAustralia, *Revised regulatory proposal*, p. 107.

558 TransGrid, *Revised revenue proposal*, p. 78.

559 CEG, May 2008 (TransGrid), pp. 11–12, paragraphs 26–30; CEG, May 2008 (Transend), pp. 11–12, paragraphs 27–31; CEG, May 2008 (Country Energy), p. 11–12, paragraphs 26–30; CEG, May 2008 (EnergyAustralia), pp. 8-9, paragraphs 24–27 and CEG, April 2008 (Integral Energy), pp. 11–12, paragraphs 26–30.

comments regarding underpricing had been removed.[560] The explanation offered by Saunders et al is as follows:[561]

> An analysis of the relationship between direct and indirect costs is an interesting issue. It is plausible that issuers and underwriters bargain over both the direct and indirect costs of issue, resulting in these two costs being jointly endogenously determined. However, difficulties in identifying suitable instrumental variables for IPOs, SEOs, and debt issues are significant enough that we leave tests of this relationship to future work.

This indicates that no empirical relationship had been established between these two cost categories by Saunders et al, which was the primary source of academic material cited by CEG.

In conclusion, the AER has considered the evidence presented by TransGrid and its consultants on the relationships between indirect and direct debt raising costs. The AER has not been provided with any peer–reviewed empirical evidence to support the claim that indirect and direct debt raising costs must be considered jointly. Moreover, the AER is mindful of the absence of evidence for indirect costs (as discussed above). On this basis, the AER considers there is no need to account for any interaction effects between indirect and direct debt raising costs.

### AER conclusion—indirect debt raising costs

The AER has considered the evidence presented by the NSPs and their consultants on indirect debt raising costs. In conclusion, the AER considers:

- an indirect cost allowance would be inconsistent with the BBB+ credit rating specified in the NER
- there is no empirical evidence to support the claim that BBB debt is underpriced
- there is no need to account for any interaction effects between indirect and direct debt raising costs.

On this basis, consistent with its draft decisions, the AER considers it inappropriate to include an allowance for indirect debt raising costs.

### Direct debt raising costs

#### Regulatory precedent—the Allen Consulting Group approach

To determine direct debt raising costs for the draft decisions, the AER adopted the methodology established by the Allen Consulting Group (ACG) in its 2004 report.[562] In developing its methodology, ACG considered evidence from a wide range of sources on international debt raising costs, regulatory practice in Australia, and domestic and international bond markets.

[560] Kim, D., Palia, D., and Saunders, A., *The Impact of Commercial Banks on Underwriting Spreads: Evidence from Three Decades*, Journal of Financial and Quantitative Analysis, December 2008, vol. 43(4), pp. 975–1000.
[561] Kim, Palia and Saunders, December 2008, p. 977.
[562] ACG, *Debt and Equity Raising Transaction Costs*, December 2004, pp. 27–53.

To ensure relevance to the context in consideration, ACG assessed actual debt issued by Australian utility and infrastructure companies, including domestic bonds, term loans and international bonds. ACG broke down the direct debt raising costs into gross underwriting fees, legal and road show fees, company credit rating fees, issue credit rating fees, registry fees and paying fees.[563] A recommendation was made for the costs of each of these categories, based upon available evidence including Bloomberg and Standard and Poor's data. Since a proportion of these costs are fixed, the number of bonds issued in a regulatory control period has a material effect on debt raising costs. The ACG methodology determines the number of standard–size issues that are required to fund the debt portion of the opening RAB of each regulated firm, and apportions fixed and variable costs on this basis. This gives a benchmark percentage, which is applied to the debt portion of the RAB each year to determine the debt raising cost allowance.

Consistent with previous transmission determinations, the AER applied this approach to calculate the allowance for direct debt raising costs in the draft decisions.[564]

**Alternative to the ACG approach**

The NSPs disputed the draft decision on direct debt raising costs, and proposed allowances of 12.5 bppa in their revised regulatory proposals.[565] The NSPs, through CEG, relied on a working paper by Saunders, Palia and Kim as an alternative estimate of direct debt raising costs.[566] In the draft decision, the AER considered that this work was not relevant as it measured debt issued by non–regulated US firms. Further, the AER considered that the high variance in debt issuance costs presented in the paper suggested that use of the market–wide average debt raising cost was not appropriate.[567]

In reiterating the Saunders et al working paper as providing an appropriate estimate, TransGrid and EnergyAustralia responded to the draft decision in the following three ways:[568]

- the AER sample contained the same biases as the Saunders et al sample, including US firms and excluding regulated utilities[569]
- the use of US–based data would produce a lower estimate than Australian–based data, since the market there was more liquid[570]
- 'the private debt market has ceased to exist in the wake of the global financial crisis', and so could not be used as an estimate.[571]

563 ACG, December 2004, p. 52.
564 AER, *TransGrid draft decision*, p. 139; AER, *Transend draft decision*, pp. 191–192; AER, *NSW DNSP draft decision*, p. 188 and AER, *ACT draft decision*, p. 106.
565 TransGrid, *Revised revenue proposal*, p. 78; Transend, *Revised revenue proposal*, p. 57 and EnergyAustralia, *Revised regulatory proposal*, p. 107.
566 Kim, Palia and Saunders, January 2003.
567 AER, *TransGrid draft decision*, p. 138.
568 CEG included a fourth argument; that the AER was inconsistent in taking one portion of a study and ignoring other portions of the same study. This issue is not relevant to the choice between Kim, Palia & Saunders and ACG, and is dealt with later in this appendix.
569 TransGrid, *Revised revenue proposal*, p. 77; EnergyAustralia, *Revised regulatory proposal*, p. 106. See also CEG, May 2009, p. 43, paragraph 142.
570 TransGrid, *Revised revenue proposal*, p. 77; EnergyAustralia, *Revised regulatory proposal*, p. 106. See also CEG, May 2009, p. 43, paragraph 141.

The AER refutes the NSPs' claims and notes:

- the ACG data is exclusively based on Australian firms operating in the utilities and infrastructure sectors.[572] It is incorrect for TransGrid to state that this is not the case, or that 'such data is not publicly available'[573]
- no empirical evidence has been presented by any NSP or consultants to support the claim that liquidity issues cause a debt premium in Australia relative to the USA. Regardless, the AER considers numerous factors in addition to liquidity must be considered
- CEG consider that the private debt market still exists, and note anecdotal evidence of a private–placed National Australia Bank (NAB) debt issue 'at the time of writing'.[574]

The AER considers that the key question is which of the two methodologies best estimates the direct costs incurred by a benchmark firm issuing debt under the regulatory framework in Australia. The AER considers that if the desired target cannot be measured directly, the closest matching alternative should be selected. This is analogous to CEG's statement:[575]

> If one is attempting to estimate the cost of something it is preferable to use data on the cost of that thing rather than data on the cost of something else.

A comparison of the main characteristics of the two approaches is included in table H.1, with areas of difference from a benchmark firm shaded on the table.

**Table H.1: Comparison of study characteristics with the benchmark scenario**

| | Firm Location | Debt Market | Firm Type | Debt Type |
|---|---|---|---|---|
| Benchmark firm[a] | Australian | Australian[b] | Regulated electricity network | Public |
| ACG (Bloomberg/ S&P) | Australian | USA[c] | Regulated utility and infrastructure | Private |
| Saunders, Palia & Kim (2003) | USA | USA | Excludes all regulated firms | Public |

Source: Compiled from ACG (2004) and CEG (2008).

(a) For clarity, the AER restates that the benchmark efficient NSP is a pure play regulated electricity network operating in Australia without parent ownership.

(b) While the benchmark debt issue is in the Australian market (consistent with the cost of debt being based on Australian corporate bond yields); in practice, a firm may choose to establish a debt portfolio that includes foreign bonds where it believes this is more efficient, bearing the risk and rewards of this action.

(c) Although the ACG methodology estimates underwriting spread from the US market, it does include Australian estimates for other components of debt raising costs.

571 TransGrid, *Revised revenue proposal*, p. 77.

572 The full list of companies is included at appendix A of the 2004 ACG report, and includes energy sector companies Australian Gas Light, United Energy, ETSA Utilities and SPI Australia.

573 TransGrid, *Revised revenue proposal*, p. 77.

574 CEG, January 2009, pp. 40–41, paragraphs 135–136.

575 CEG, January 2009, p. 36, paragraph 119.

The AER observes that neither measure of direct debt raising costs is a perfect match for the benchmark firm. Both the ACG methodology and the Saunders et al approach are based on US market data, not Australian market data. The ACG sample differs from the benchmark in one additional way; it measures private debt rather than public debt. However the Saunders et al sample differs from the benchmark in two additional ways; it is based on US firms (not Australian) and its sample excludes all regulated firms.

Given that the two approaches vary from the benchmark scenario in differing ways, the closest match will be that approach whose differences have the smallest combined impact. The common difference arising from measurement of US debt markets rather than Australian debt markets can be discounted as equally impacting upon both approaches.

The ACG approach uses private debt issuance costs rather than public debt issuance costs. The AER considers that this difference will exert limited (if any) systematic bias on the measurement of direct debt raising costs. It makes this inference on the basis of the Livingston and Zhou study that found no significant difference between public and private debt raising costs.[576] The AER is aware that this study was based on US firms and that it used a range of firms (based on market distribution) rather than exclusively regulated utilities. Nonetheless, the AER considers that Livingston and Zhou does not provide evidence of any difference between public and private debt issuance costs. To exclude this study from application to the benchmark firm, the NSPs would have to argue that the public/private difference exists for regulated firms but not for the market as a whole. No theoretical rationale for such a statement exists, and no empirical evidence has been presented to support such a statement. Accordingly, the AER considers that the ACG methodology provides a very close proxy to the benchmark scenario (except for the shared imperfection of measuring US market data).

The Saunders et al approach excludes all regulated firms from analysis, rather than using a sample that consists entirely of regulated utilities.[577] The AER considers that this will have a significant systematic influence on the measurement of direct debt raising costs. The AER observes that although the Saunders et al working paper finds average direct debt raising costs of 68 basis points, the fifth percentile direct costs lie at 23 basis points, while the 95th percentile lie at 353 basis points.[578] The AER considers that given this large range, it is inappropriate to take the sample average and apply it to a set of firms that do not intersect with the original sample. Saunders et al find that firm–specific characteristics account for the majority of variation (51.7 per cent) in direct costs.[579] The AER considers that this further supports the inference that regulated utilities would significantly deviate from the sample average direct debt raising costs. Finally, research papers that compare regulated firms and utilities to other firms find that their status has a significant influence on direct debt

576 Livingston, M. and Zhou, L. (2002) *The Impact of Rule 144A Debt Offerings Upon Bond Yields and Underwriter Fees,* Financial Management, Winter 2002, pp. 5–27.

577 Kim, Palia and Saunders, 2003, p. 7. The AER notes that a sample consisting purely of regulated electricity networks would be the best match for the benchmark firm.

578 Kim, Palia and Saunders, 2003, p. 35, table 1.

579 Kim, Palia and Saunders, 2003, p. 40, table 6.

raising costs.[580] The AER therefore considers that exclusion of regulated firms is a significant departure from the benchmark scenario.

The Saunders et al approach also differs from the benchmark as it is based on US firms rather than Australian firms. The AER considers that although cross–country differences are numerous, the effect of firm location will be overshadowed by the effect stemming from debt market location. Since both the ACG and Saunders et al approaches issue debt in the US, the additional difference stemming from the firm being located in the US is not expected to be of great significance.

Overall, the AER considers that the appropriate benchmark should be determined according to the ACG approach, which is based upon the cost of Australian regulated utilities issuing private debt in the United States. The AER considers this to be closer to the benchmark scenario than the Saunders et al approach, which is based on American non–regulated firms issuing public debt in the United States.

**Consideration of components from one report**

CEG stated the AER was inconsistent to take one proposition from the Livingston and Zhou study—that public debt has the same issuance costs as private debt—and reject another proposition from the same study, that gross underwriter spread is between 8.8 bppa and 9.6 bppa.[581]

The AER considers that the joint acceptance of two propositions from one research paper depends upon the degree to which the two propositions are linked in that paper. Research papers may include chains of logic that develop serially across the paper, but frequently include several investigative approaches, each of which stands in isolation. There may be no relationship between the two propositions, in which case the AER considers it is appropriate for a party to accept one and reject the other on merit. Inconsistency would only occur where it is shown that the relevant propositions in the paper are dependent on each other. Even if the two propositions are part of one chain of reasoning, then it is still logically defensible to accept the earlier proposition, but reject the latter on the grounds that an error of fact, logic or relevance occurred after the first proposition (and before the second). However, it would be inconsistent to accept a later proposition that was wholly dependent upon an earlier proposition, where the earlier proposition had been rejected as incorrect.

In considering CEG's claim, the two propositions may be summarised as follows:

1. the Livingston and Zhou regression supports that the issuance costs of public debt and private debt do not differ
2. the issuance costs projected from the full Livingston and Zhou regression will be equal to issuance costs of the benchmark firm.

However, proposition one is not dependent on proposition two. Therefore the AER considers that it is entitled to use its own estimate of direct debt raising costs. The AER considers that these propositions are part of the same logic chain, flowing from

580 See Eckbo and Masulis, *Adverse selection and the rights offer paradox,* Journal of Financial Economics, 1992, vol. 32, pp. 293–332; and Livingston and Zhou, 2002, p. 25, table VIII.

581 CEG, January 2009, p. 39, paragraph 129. Note that gross underwriting spread is not the total direct costs; this point is further elaborated later in this discussion.

the same regression analysis. However, as the first proposition is made earlier in the Livingston and Zhou argument, an acceptance of this proposition by the AER does not infer that the second proposition must also be accepted. The AER considers that there is no inconsistency in rejecting the second proposition if the AER is convinced that the logic of argument breaks down after the first proposition. The two propositions are considered below.

**Interpretation of the Livingston and Zhou regression**

CEG stated that the Livingston and Zhou study found a gross underwriter spread of between 8.8 bppa and 9.6 bppa.[582] The underwriter spread is not the total direct debt raising cost as it does not include other relevant fixed costs or rating costs. This range is derived from a regression that investigated the relationship between gross underwriter spread (as the dependent variable) and a range of independent variables.[583]

The AER notes that the widely accepted scientific framework emphasises the need for caution when applying a regression projection to new data points that differ substantially from the data used in its derivation. For example, there will generally be a significant difference between the debt risk premium of the Livingston and Zhou sample of public firms,[584] and the debt risk premium on the public bond issued by the benchmark firm.[585] The AER notes that the full regression was conducted to observe the impact of Rule 144A placements relative to other placement methods, and that this purpose does not match the purpose for which CEG applied the regression results. In particular, the AER observes that Livingston and Zhou chose not to include the presence or absence of industry regulation as an independent variable, and that such a variable would be particularly pertinent to CEG's interpretation and projection.

The AER notes that CEG derived an upper bound for direct debt raising costs, and that CEG stated this calculation followed the generally accepted best practice of using all independent variables for a projection, regardless of statistical significance. However, the AER observes that CEG omitted two variables, *Log of Proceeds*[586] and *Percentage of Years of Call Protection*,[587] and miscalculated another, *Log of Issue Frequency*.[588] The inclusion and correction of these variables in the regression

582 CEG, January 2009, p. 38, paragraph 127.

583 Livingston and Zhou, 2002, p. 25, table VIII.

584 Livingston and Zhou, 2002, p. 12, table I. The rule 144A bonds had average debt risk premium of 351 basis points, which mitigates but does not eliminate this risk.

585 The AER notes that although debt risk premiums change over time, the benchmark firm debt risk premium is currently more than three times the Livingston and Zhou public bond average.

586 Log of proceeds is expressed in $US dollars, so the $AU 200 million benchmark bond size was converted to ln(150).

587 Call protection refers to the inability of the issuer of the bond to 'call back' (i.e. force redemption) earlier than the maturity of the bond. Since the regulated benchmark firm can predict its cash flow and gearing, it can safely issue 100 per cent call protected bonds to reduce borrowing costs.

588 The January 2009 CEG report considered only the case of Integral Energy, which would make 11 issues in 10 years (and therefore 3.3 issues in the 3 years of the study). Figures relevant for other NSPs can be derived using reasonable assumptions (60 per cent of RAB is debt, issue size of $AU 200 m, $AU/$US exchange rates of $0.72).

projection[589] would result in the range of underwriting spreads presented in table H.2.[590]

**Table H.2: Corrected regression projections of gross underwriter spread for each NSPs**

| Issuer | TransGrid | Transend | Country Energy | Energy Australia | Integral Energy | Actew AGL |
|---|---|---|---|---|---|---|
| Total cost (bp) | 56.1 | 60.9 | 56.1 | 54.0 | 56.7 | 62.2 |
| Annual cost (bppa)[a] | 7.46 | 8.10 | 7.46 | 7.18 | 7.54 | 8.27 |

Source: AER analysis, based on Livingston and Zhou (2002).
(a) Annual figures have been derived using the CEG amortisation methodology.

The gross underwriter spreads range from 54.0 to 62.2 bppa, which is between 4.8 and 13 basis points lower than the CEG–quoted best estimate of 67 bppa. If amortised over 10 years (as per the CEG methodology, using a real weighted average cost of capital (WACC) of 6.99 per cent) this equals an allowance of between 7.18 and 8.27 bppa.

The AER notes that gross underwriter spread is not the only type of direct cost. Direct costs also include legal fees, rating fees and other costs. In the latest update of the AER methodology, a gross underwriter spread of 6.0 bppa was applied to all NSPs with other costs adding between 3.2 and 2.0 bppa. While the correction of CEG errors reduces the difference, the Livingston and Zhou regression projection remains at least 1.18 bppa higher than the underwriting allowance of 6.0 bppa which was included in the draft decision.

The AER notes that marked differences in approach have resulted in a material difference between the two estimates of underwriting costs. The Livingston and Zhou regression analysis is based upon amortised 10–year debt, rather than straight division of five–year debt as per the ACG methodology.[591] The ACG methodology was based on Australian utility and infrastructure companies issuing debt that closely matches the benchmark firm. In contrast, the Livingston and Zhou estimate is impaired by the difficulties in projecting from regression analysis, as detailed above, and is based on US firms issuing debt in the US market.

Accordingly, the AER concludes that the underwriting estimate of 6.0 bppa, based on ACG's methodology, is most appropriate for determining the level of direct debt raising costs that would be incurred by the benchmark efficient entity. Other direct debt raising costs must be added to this gross underwriting spread such as legal and roadshow, company credit rating, issue credit rating, registry and paying fees. The AER notes that no estimate of these figures is made by CEG (or Saunders et al), and

589 The AER notes that seven other significant variables, including six rating variables and the *First Time Debt Dummy*, would have no impact on the projection and were also omitted from the CEG table.

590 The regression is dependent on the number of debt issues made by the firm; since this varies across NSPs, a range of gross underwriter spreads results.

591 Separate consideration of the amortisation/straight division issue is provided later in this appendix.

that therefore the ACG methodology remains the only viable approach for estimating these costs.

### AER conclusion—direct debt raising costs

The AER notes the view of Associate Professor Handley, who concluded that an appropriate range for total direct debt raising costs was between 8 and 12 bppa.[592] The AER views the upper end of this range, derived from Saunders et al (~12 basis points) and the Livingston and Zhou full regression (~10 basis points) as being unreliable, for the reasons detailed earlier in this appendix.

In conclusion, the AER considers that:

- the exclusion of regulated firms from the Saunders, Palia and Kim working paper makes it an inferior estimate of direct debt raising costs when compared to the ACG methodology
- the problems associated with applying a regression projection and the incorrect firm location makes the full Livingston and Zhou regression projection an inferior estimate of direct debt raising costs when compared to the ACG methodology
- an individual component of the Livingston and Zhou paper (namely the equivalence of public and private debt raising costs) can be accepted separately to the full Livingston and Zhou regression projection.

On this basis, consistent with its draft decisions, the AER concludes that the ACG methodology is the most reliable and accurate method for setting direct debt raising costs, and that it will be applied for all NSPs.

### Other issues

#### Current market conditions

CEG argued that the cost of issuing debt is likely to be at historically high levels and that an estimate from the top end of any historical range is appropriate.[593] CEG base this claim on the rapid change in the global economy in the past year.

The AER notes that this issue was not addressed in the draft decisions, as the likely impact of the global financial crisis was not yet evident. The AER notes the change in the economic outlook for the Australian economy since mid–2008 has been reflected in official forecasts by Treasury.[594] The rapid change in the economic outlook is closely linked to the global financial crisis which manifested itself in the second half of 2008. The global financial crisis has been portrayed as being the most serious economic event affecting developed economies since the great depression of the 1930s.[595]

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592 Handley, April 2009, p. 30.

593 CEG, January 2009, p. 42, paragraph 140. Note that the effects of current market conditions on the cost of debt (in contrast to the cost of issuing debt) are considered in detail in section 12.5.2 of this final decision.

594 The Treasury, *Updated Economic and Fiscal Outlook*, February 2009. Available: http://www.budget.gov.au/2008-09/content/uefo/html/index.htm.

595 IMF, *World Economic Outlook*, October 2008.

Given this extraordinary change in circumstances within the economic environment, the AER has decided to consider the updated information relating to debt raising costs in making its final decision.

Pursuant to the ACG methodology, the AER sets debt raising costs on the basis of a long–term benchmarking approach. The benchmark debt raising costs applied in the draft decision reflect a 2008 update of the ACG 2004 findings on debt raising costs. The standard debt issuance costs are set based on a benchmarked sample of debt issues over the time period 2000–2008.

While there will always be volatility in debt markets and variation in the cost of raising debt, the AER approach, consistent with the NER framework, takes a long–term view of debt raising costs. The AER's update, based on benchmarked data over 2000 to 2008, found that the appropriate gross underwriting fee for issuing debt remains at 6.0 bppa. The 2008 update included three additional bond issues by BHP on 26 March 2007 as set out in table H.3. The average underwriting fees on these bonds were consistent with the 2006 update benchmark.

**Table H.3: BHP Billiton international bond issues, 26 March 2007**

| Issuer | Years to maturity | Issue size ($millions) | Total gross underwriting fees |
|---|---|---|---|
| BHP Billiton | 2 | $1080.4 | 0.10% or 5.0 bppa |
| BHP Billiton | 5 | $771.7 | 0.35% or 7.0 bppa |
| BHP Billiton | 10 | $926.0 | 0.45% or 4.5 bppa |

Source: AER analysis, based on data from Bloomberg.

The only evidence put forward by CEG that an estimate from the top end of the historical range is appropriate was the bond issue from NAB in the US private placement market. CEG argued that NAB's issue costs of 7.6 bppa indicates the AER's estimate of 6 bppa is too low.

The AER notes that the NAB issue was for a tenor of 3 years while the benchmark estimate by the AER used a tenor of 5 years.[596] Further, the underwriting cost observed for one bank debt issue is not, in isolation, an appropriate benchmark for setting debt raising costs.

The AER does not consider the evidence in relation to one bond issue is sufficient to justify choosing a figure from the top end of historical range and depart from the AER's methodology of a long–term benchmarking approach to setting debt raising costs.

[596] The AER notes that, as a number of costs are likely to be one–off fixed costs, going from three to five years maturity will reduce the basis points per year cost.

**Amortisation of debt raising costs**

In its report, CEG argued that the current debt issuance methodology used by the AER is biased as it fails to take into consideration the time value of money.[597]

The AER's methodology involves dividing total issuance costs by the debt maturity to obtain an annual allowance, rather than equating the net present value of the yearly payments with the total debt issuance cost using an appropriate discount rate.

The AER notes that this issue was not raised by the NSPs in their regulatory proposals, but was raised for the first time in their revised regulatory proposals. This issue was not raised in response to a matter addressed in the draft decision. As such the AER considers it need not review the variation to the methodology as requested by the NSPs.[598] Notwithstanding this aspect, the AER has undertaken a review of the NSPs' proposed variation to the methodology.

The AER acknowledges that an adjustment for time value of money is generally appropriate when upfront costs are repaid over time. In this instance, following the ACG methodology, no such adjustment is made. However, the key outcome is that the AER's conservative approach does not under compensate the NSPs.[599] The modelling employed by the AER to estimate debt issuance costs assumes that five year maturity bonds are issued. The ACG methodology simply divides the total debt issuance cost of a five year bond by five, to derive an annual allowance.

However, the NER requires that the benchmark bond is of a ten year term.[600] Therefore, if amortisation were to be undertaken in accordance with the term of the bond specified in the NER, it would be based on a ten year horizon, involving the change of bond term from five years to ten years. Given that a proportion of debt issuance costs are made up of fixed costs, the debt issuance costs for a ten year bond will not be significantly larger than the debt issuance costs of a five year bond. The amortised cost of ten year debt issuance costs would provide a lower allowance than the simple division of five year debt issuance costs.[601] The AER considers that the current ACG methodology is therefore a conservative approach, in that the NSPs are no worse off (and in fact are likely to be slightly better off) than under an amortisation approach.

On this matter, Associate Professor Handley considered that the differences between amortisation and simple division are not sufficient to warrant consideration.[602]

The AER has assessed the evidence presented by the NSPs and their consultants on amortisation costs. On the basis of this assessment, the AER considers there is no requirement to amend the methodology applied in the draft decision, for the following reasons:

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597 CEG, January 2009, pp. 47–48, paragraphs 157–166.

598 For TNSPs, see clauses 6A.14.3(h) and 6A.14.3(c)(3)(ii) of the NER. For DNSPs, see clause 6.10.3(b) of the transitional chapter 6 rules.

599 ACG, 2004, pp. xvi–xix.

600 NER, clause 6A.6.2.

601 AER analysis.

602 Handley, April 2009, pp. 29–30.

- a new methodology cannot be presented in a revised regulatory proposal unless it is addressing a matter raised in the draft decision
- amortisation would have to occur over ten years, not five, so the allowance would be unlikely to increase (and may even decrease).

Overall, the AER is satisfied that its methodology ensures that the NSPs will have the opportunity to recover at least the efficient costs, as is required by the NER.[603]

**Inflation of debt issuance costs**

CEG argued that the non–underwriting transaction costs in debt issues should be indexed for inflation.[604] The AER notes that this issue was not raised in the NSPs' regulatory proposals, but raised for the first time in their revised regulatory proposals. This issue was not raised in response to a matter addressed in the draft decision. As such the AER considers it need not review the variation to the methodology as requested by the NSPs. Notwithstanding this aspect, the AER has undertaken a review of the NSPs' proposed variation to the methodology.[605]

The AER considers that the argument for inflation indexing raised by CEG is not theoretically sound. Given that issuance costs are expressed as a percentage (total debt issuance costs divided by debt size), it is inconsistent to focus on the changes in the numerator without considering the effects on the denominator. The AER considers that while the fixed costs may increase by inflation, the size of the debt issue will also increase by inflation.

The AER considers that this problem is illustrated by consideration of an extreme case. If inflation was to be applied only to fixed costs and not to the amount of debt issued, then at some future point the percentage cost of issuing debt would surpass 100 per cent. The AER considers that this is not a plausible outcome, as the amount of debt issued would not be enough to cover the costs associated with the debt issue. In this case, the debt market would not exist.

The AER notes the view of Associate Professor Handley, who advocated that the effect of any proposed inflation indexation is below a reasonable threshold of materiality.[606]

The AER has considered the argument presented by the NSPs for an allowance for indexation. On the basis of this assessment, the AER considers there is no requirement to index debt issuance costs, for the following reasons:

- a new methodology cannot be presented in a revised regulatory proposal unless it is addressing a matter raised in the draft decision
- the indexation of debt issuance costs without also adjusting for changes to bond issue size is likely to result in implausible outcomes in the long–term.

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603 For TNSPs, see clauses 6A.14.3(h) and 6A.14.3(c)(3)(ii) of the NER. For DNSPs, see clause 6.10.3(b) of the transitional chapter 6 rules.
604 CEG, January 2009, p. 49, paragraphs 167–169.
605 For TNSPs, see clauses 6A.14.3(h) and 6A.14.3(c)(3)(ii) of the NER. For DNSPs, see clause 6.10.3(b) of the transitional chapter 6 rules.
606 Handley, April 2009, pp. 29–30

### Summary of debt raising cost considerations

The AER has considered the arguments made by the NSPs on debt raising costs, including consultant reports and all relevant submissions.

The AER considers that there is no basis for an allowance for the indirect costs of debt raising. The AER has found no reliable empirical evidence of the existence of underpricing. If indirect costs do in fact occur in practice, the current methodology of providing an allowance for the cost of debt would detect and include compensation as part of the debt yield. Therefore, separate compensation would result in double counting and be inconsistent with the regulatory framework.

The AER considers that the ACG methodology represents the best estimate of the direct costs of debt raising. This is determined by the close proximity of the ACG approach to the benchmark scenario; issuance of BBB+ rated public debt by the benchmark firm in Australian debt markets. The AER considers that none of the proposed alternative methodologies are appropriate, principally because of their failure to consider the characteristics of debt issued by regulated utilities.

The AER considers that there is no reason to deviate from the established approach as a result of transient market conditions. Finally, the AER finds no evidence of material under–compensation for the benchmark firm sufficient to warrant methodological change to accommodate amortisation and inflation.

For the NSPs, the AER has maintained the application of the established ACG methodology to determine the appropriate benchmark allowance for direct debt raising costs in this final decision. This allowance will be dependent upon the number of standard sized debt issues required by each NSP. The allowance, expressed in bppa, will then be applied to the debt portion of each NSP's RAB for each year of the next regulatory control period to determine the benchmark debt raising costs included in the opex forecast.

## Equity raising costs

### Rationale for joint consideration

Similar to the approach for debt raising costs, the NSPs have adopted a joint position in relation to proposed equity raising costs. In their revised regulatory proposals, the NSPs have essentially[607] applied the same parameters for equity raising costs:

- a base unit rate for equity raising costs of 7.6 per cent of the external equity required each year[608]
- an allowance for use of retained earnings of 3.8 per cent of retained earnings between normal dividend yield and minimum dividend yield[609]

607 TransGrid stated that retained earnings were not costless and included an allowance in its equity raising calculations, but unlike the other NSPs it did not include the retained earnings allowance in its revised total opex allowance.

608 TransGrid, *Revised revenue proposal*, p. 82; Transend, *Revised revenue proposal*, p. 60; Country Energy, *Revised regulatory proposal*, p. 46; EnergyAustralia, *Revised regulatory proposal*, p. 49; Integral Energy, *Revised regulatory proposal*, p. 47 and ActewAGL, *Revised regulatory proposal*, p. 33

- revision of the AER's cash flow analysis to incorporate the repayment of debt principal and distribution of all imputation credits.[610]

It should be noted that although the theoretical arguments on setting the dividend level were identical across the NSPs, the practical implementation differed:

- Transend implemented a 5.5 per cent dividend yield[611]
- TransGrid and EnergyAustralia implemented a 70 per cent dividend payout ratio[612]
- Integral Energy implemented the 70 per cent dividend payout ratio, but proposed an additional system for tracking imputation credits and compensating the firm.[613]

As with debt raising costs, the shared position of the NSPs is reinforced by reliance on the same consultant reports. In the NSPs' regulatory proposals variants of the CEG report were submitted.[614] In their revised regulatory proposals, a report by CEG is referenced and submitted by the NSPs—all submitted versions are the same apart from the titles.[615] TransGrid and EnergyAustralia also submitted a report by Tony Carlton, although there are some variations between the two versions.[616] EnergyAustralia submitted a report by Professor Bruce Grundy.[617] Further, EnergyAustralia's submission requested that all reports and supporting documents which it had submitted as part of its regulatory proposal and revised regulatory proposal be considered by the AER in making its final determination for all the NSPs.[618]

Integral Energy submitted a report by KPMG[619] and comments on cash flow modelling.[620] TransGrid submitted an additional memorandum by CEG,[621] as well as

609 TransGrid, *Revised revenue proposal*, p. 81; EnergyAustralia, *Revised regulatory proposal*, pp. 48–49; Integral Energy, *Revised regulatory proposal*, p. 45–46. Transend, Country Energy and ActewAGL did not explicitly adopt this position, but referenced support for the January 2009 CEG report.

610 TransGrid, *Revised revenue proposal*, pp. 80–81; Transend, *Revised revenue proposal*, p. 60; EnergyAustralia, *Revised regulatory proposal*, pp. 47–48; Integral Energy, *Revised regulatory proposal*, pp. 46–47. Country Energy and ActewAGL did not explicitly adopt this position, but referenced support for the January 2009 CEG report.

611 Transend, *Revised revenue proposal*, p. 60.

612 TransGrid, *Revised revenue proposal*, p. 81; and EnergyAustralia, *Revised regulatory proposal*, pp. 48–49

613 Integral Energy, *Submission to the AER*, p. 10; see also attachment 3.

614 CEG, May 2008 (TransGrid); CEG, May 2008 (Transend); CEG, May 2008 (Country Energy), CEG, May 2008 (EnergyAustralia); CEG, April 2008 (Integral Energy).

615 CEG, January 2009. Cited by TransGrid, *Revised revenue proposal*, p. 77; Transend, *Revised revenue proposal*, p. 56; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 105; Integral Energy, *Revised regulatory proposal*, p. 43; and ActewAGL, *Revised regulatory proposal*, p. 33.

616 Carlton, January 2009 (EnergyAustralia); Carlton, January 2009 (TransGrid).

617 Grundy, B. D., *A Note on the Costs of Equity Financing*, 13 January 2009.

618 EnergyAustralia, *Submission*, 16 February 2009.

619 KPMG, *Review of Certain Assumptions in the AER's Financial Model to support the draft NSW Distribution Network Revenue 2009–2014*, report to Integral Energy, January 2009.

620 Integral Energy, *Submission to the AER*.

621 CEG, *Memorandum on the Ofgem treatment of Equity raising costs*, 18 February 2009.

a report by SFG.[622] The JIA submitted a report by CEG that merges parts of the May 2008 and January 2009 CEG reports with new analysis.[623]

The AER notes that issues relating to the equity raising costs on the initial opening regulatory asset base are specific to Transend and do not relate to the argument for benchmark equity raising costs associated with forecast capex. Accordingly, any submissions or arguments solely related to this issue are not dealt with in this appendix. All references to ‘equity raising costs’ in this appendix refer to equity raising costs associated with forecast capex.

Due to the consistency between the opex provisions of the NER under which the equity raising cost proposals are assessed, the NSPs’ revised regulatory proposals and the supporting consultancy reports, the AER jointly assessed equity raising costs of the NSPs. The AER’s analysis and conclusions are contained in this appendix, which is reproduced in each of the AER’s final decisions for the NSPs.

The AER considers that it is important for a consistent methodology to determine the appropriate allowance for benchmark equity raising costs to be applied in its final decisions for the NSPs.

### Regulatory framework for equity raising cost allowance

The CAPM encapsulates the return required by the providers of equity capital given the inherent risk in each asset. The WACC determines a total rate of return given mandated assumptions about the gearing of the benchmark firm and the cost of debt capital. This regulatory framework requires the AER to calculate the total return required by investors in aggregate, and includes consideration of company tax, (including the effect of imputation credits). The regulatory framework does not encapsulate personal transaction costs, including the final income tax paid by personal investors, or the rate of return given to any individual capital provider (as opposed to investors in aggregate). Associate Professor Handley noted that to be consistent with this framework, all cash flows need to be expressed on a similar basis:[624]

> In other words, cash flows should be after company tax, before personal tax, after underpricing costs but before other personal (transaction) costs.

The regulatory allowance for equity raising costs should compensate the benchmark firm for the transaction costs incurred as a result of required equity capital raising (referred to as equity raising costs). Such transaction costs may be appropriately considered as part of an NSP’s opex forecasts (while rate of return issues cannot be considered under the opex provisions of the NER). As an opex item, the proposed equity raising cost allowance is subject to the NER requirement that forecast opex reasonably reflects the costs that a prudent operator in the circumstances of the relevant NSP would require to achieve the opex objectives.[625] This is in contrast to an allowance for the return on capital, which is separately described in clause 6A.6.2 of

[622] SFG, March 2009.
[623] CEG, November 2008.
[624] Handley, April 2009, p. 10.
[625] For DNSPs, see clause 6.5.6(c)(2) of the transitional chapter 6 rules. For TNSPs, see clause A.6.6(c)(2) of the NER.

the NER for TNSPs and clause 6.5.2 of the transitional chapter 6 rules for the ACT/NSW DNSPs for the next regulatory control period .[626]

The AER considers that it is essential to correctly characterise the components of the equity raising allowance, to ensure elements more correctly attributable to the rate of return are not included as transaction costs.

**Deviations from the benchmark firm**

The AER notes that many of the NSPs are government owned. The AER considers that this deviation from the benchmark structure is likely to result in windfall gains to the government owned NSPs, as they do not issue shares and therefore do not incur equity raising costs to the extent that the benchmark efficient NSP does.[627] Additionally, the obtained value of imputation credits (gamma) for these government owned NSPs will effectively be zero (rather than 0.5), since the government receives both taxes—paid under the National Tax Equivalence Regime—and dividends as the shareholder. In this instance, imputation credits are of no additional value to the shareholder as any gains are offset by a reduction in taxes received. Despite these deviations from the benchmark firm, the AER considers that it is appropriate to assess the NSPs in accordance with the notional benchmark firm, that is, as a pure play regulated electricity network operating in Australia without parent ownership. This is consistent with competitive neutrality principles for the treatment of government owned firms.

## Indirect costs of equity raising

The NSPs' revised regulatory proposals disputed the draft decision on indirect equity raising costs, also known as underpricing. The NSPs proposed a total equity raising allowance of 7.6 per cent, including both direct and indirect components.[628] TransGrid stated that indirect and direct costs cannot be considered in isolation, but must be jointly determined and measured. The NSPs' revised regulatory proposals generally provided a summary statement in justification of an allowance for indirect costs, referring to consultant reports for evidence.[629]

626 The AER notes that it is undertaking a review of WACC concurrent with its review of TransGrid's and Transend's revenue proposals. The WACC review involves the consideration of parameter inputs into the CAPM and WACC. The AER further notes that for the purposes of the AER's ACT/NSW distribution determinations for the next regulatory control period, the rate of return parameters were set within transitional provisions of the NER.

627 The AER notes that the NSW State Owned Corporations (TransGrid, Country Energy, EnergyAustralia and Integral Energy) have only issued two shares each, one of each pair held by the NSW Treasurer and the other by the NSW Minister for Finance; see State Owned Corporations Act 1989, Part 3, Division 2, Section 20H. Transend has four shares, all held by the Crown in Right of the State of Tasmania; see Transend, *Annual report 2007–08*, p. 41. ActewAGL is a 50/50 partnership between Actew Corporation (a wholly owned ACT government corporation with two shares— held by the ACT Chief Minister and Deputy Chief Minister) and Jemena Networks (ACT), a privately owned company; see ActewAGL, *Annual and Sustainability Report*, 2008, p. 4.

628 TransGrid, *Revised revenue proposal*, p. 82; Transend, *Revised revenue proposal*, p. 60; Country Energy, *Revised regulatory proposal*, p. 46; EnergyAustralia, *Revised regulatory proposal*, p. 49; Integral Energy, *Revised regulatory proposal*, p. 47; and ActewAGL, *Revised regulatory proposal*, p. 33.

629 For example, TransGrid, *Revised revenue proposal*, pp. 80–81; EnergyAustralia, *Revised regulatory proposal*, p. 43.

**Personal transaction costs**

CEG stated that, when equity raising via rights issue occurs, existing shareholders that allow their rights to lapse have their investments diluted. CEG inferred that shareholders may prefer to avoid this dilution by either selling their rights (if renounceable) or taking up the rights before immediately selling the new share (if non–renounceable). CEG noted that either action incurs transaction costs, with the latter action possibly resulting in realisation of capital gains. CEG argued that these transaction costs reflect the indirect cost of a rights issue.[630]

The AER considers that separate compensation for investor level transaction costs, including investor level taxes is inconsistent with the regulatory framework. The regulatory framework specifies that investor returns are post company tax and pre–investor tax.[631] This is consistent with conventional financial theory.

Officer and Hathaway state:[632]

> …the CAPM is typically used in the context of post–company tax but pre–personal tax returns because that is the tax band in which the vast majority of capital market transactions take place.

Finance textbook, Business Finance, states:[633]

> Conventionally, the cost of equity, $k_e$, is defined and measured on an after–company tax, but before personal tax, basis.

Similarly, transaction costs involved with buying and selling shares are outside the regulatory framework. The market risk premium is estimated on a market portfolio that is exclusive of the transaction costs involved in maintaining that portfolio. This was the point made by Associate Professor Handley when he stated:[634]

> The regulatory framework requires the determination of allowed revenues to the regulated firm to be undertaken on an after company but before personal tax basis. In the current context, this is more fully described as a requirement to be undertaken on an after company tax, before personal tax, after underpricing costs but before other personal (transaction) costs basis.

The AER considers that the regulatory framework does not allow for consideration of investor personal tax rates, either as income tax or capital gains tax. Under the regulatory framework, investors are assumed to be indifferent between dividends and capital gains.[635] Accordingly, the possible realisation of a capital gain does not require any allowance or offsetting adjustment.

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630 CEG, January 2009, pp. 14–15, paragraph 37–43.

631 The AER notes that this is why imputation credits are deducted from the regulatory building blocks when determining total allowed revenue for the business; to the extent that they will be redeemed, they are not company taxes but pre–payment of personal taxes.

632 Officer, R. and Hathaway, N. J., *Issues in Cost of Capital for QCA, Report by Capital Research Pty Ltd for Prime Infrastructure submission to the QCA*, March 2004, p. 2.

633 Peirson, G., Brown, R., Easton, S. and Howard, P., *Business Finance: 8th Edition*, McGraw–Hill, 2003, p. 449.

634 Handley, April 2009, p. 10.

635 The Sharpe CAPM assumes indifference between dividends and capital gains because there are no personal income taxes. Additionally, the estimated market risk premium is based on a cumulative return of both dividends and capital gains. This is not to say that dividends are entirely irrelevant

The AER has considered the impact of transaction costs (i.e. brokerage, search costs, bank fees) under the regulatory framework. The AER notes that a transaction occurs when the renounceable right[636] is sold, and that two transactions occur when the non–renounceable right[637] is taken up and a new share sold. However, the AER considers it inappropriate to determine that such transactions are 'extra' or 'forced' transactions—that would accordingly require compensation—without considering the pattern of transaction costs that an investor in the market ordinarily incurs.

CEG considered the case of a benchmark investor with a desired portfolio of investments. If taking up a rights issue shifts this benchmark investor away from its desired portfolio, the investor immediately takes action to restore its optimal mix of assets. The AER notes that, in the extreme case, this investor would need to continually rebalance its investment portfolio in response to any non–systematic price movement of any of its shares. The AER considers that in this case, the constant adjustment of the investor's portfolio would make the cost of one or two additional transactions immaterial. In general, the AER considers it is reasonable to assume that the investor would tolerate some changes within its ideal portfolio, and only rebalance when the changes breach certain boundaries. It may be that in some cases, a rights issue (renounceable or non–renounceable) may not have a sufficiently large effect to cause rebalancing, and all transaction costs would be avoided.

A complete answer can only be determined by a long–term comparison of the transactions required when investing in the benchmark firm with the transactions required from an alternative portfolio of investments. Crucially, there are many other aspects of a benchmark firm that reduce the total number of transactions this investor incurs. The benchmark firm pays dividends regularly, unlike capital–growth–only shares, where the investor must sell (and incur transaction costs) each time they wish to access the return on their capital. The benchmark firm has regulated, transparent cash flows, leading to a stable share value, unlike speculative shares which may require portfolio balancing on the basis of price volatility more often.

The AER considers that to demonstrate the need for an allowance on this issue, empirical evidence is required that shows the transaction costs incurred by providing equity to the benchmark firm exceed those incurred by the market on average. Such evidence would demonstrate that regulated firms incur higher equity raising costs than the market on average, for which the market risk premium is estimated. No such evidence has been provided.

The AER considers that an allowance for individual transaction costs is inconsistent with the compensation of opex under the NER. Efficiently incurred expenses are defined as those incurred by the regulated firm—and it would be economically incorrect to make an allowance for all of these costs as all investors incur investor level taxes and transaction costs.

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(see the discussion on valuation of imputation credits later in the appendix) but that the realisation of capital gain cannot be presumed to be a cost to the investor.

636 A renounceable right is one where the existing shareholder can sell their right to purchase additional shares to another investor.

637 A non–renounceable right is one where the existing shareholder must either purchase the additional shares themselves or let the right lapse. The right cannot be sold to another investor.

The equity raising cost allowance for the NSPs is designed to allow them to recover company transaction costs. The AER considers the NSPs' argument that investor level transaction costs or taxes are incurred by investors due to the use of rights issues or dividend reinvestment programs is not relevant in this context.[638] The NER implies a pre–investor level (post–company tax) CAPM and post–company tax (pre–investor tax) revenue model.[639] This was the point made by Associate Professor Handley when he stated:[640]

> Accordingly, in the current context, observed returns based on dividends, capital gains and (the value of) imputation credits are more fully described as being expressed on an after company tax, before personal tax, after underpricing costs, but before other personal (transaction) costs basis.

Accordingly, the NSPs' argument concerning costs at the investor level is inconsistent with the regulatory framework.

Overall, the AER considers that ad hoc adjustments to the post–company tax and transaction cost CAPM for investor level costs are inappropriate for the following reasons:

- such changes are inconsistent with the NER and with the CAPM as defined in the NER
- the modification of the CAPM for investor level transaction costs has not been shown to be theoretically valid
- such modification could reasonably be expected to lead to systematic over–compensation and monopoly pricing.

The AER notes that it is possible to compare investor–level transaction costs and taxes incurred by investors in Australian NSPs with the average costs incurred by other investors in the Australian market in determining an allowance for equity raising costs. However, the AER notes that implementation of any associated adjustments to allowances would not be consistent with the current rate of return methodology prescribed under the NER, which is based on corporate transaction costs not individual transaction costs.

**Wealth transfer effects**

CEG and Carlton stated that one aspect of indirect costs is the transfer of wealth from original shareholders to new shareholders.[641] CEG further elaborated on the mechanics of wealth transfer, and provided a detailed appendix on the cost of a rights issue.[642] Carlton provided similar analysis that demonstrated wealth transfer effects with a placement, and stated that for any seasoned equity offer (SEO) if the shares are

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[638] For example, see TransGrid, *Revised revenue proposal*, p. 80; EnergyAustralia, *Revised regulatory proposal*, pp. 44–45.
[639] NER, Clause 6.5.3.
[640] Handley, April 2009, p. 10.
[641] CEG, January 2009, pp. 14–15, paragraphs 37–43 and Carlton, January 2009 (EnergyAustralia), p. 9.
[642] CEG, January 2009, pp. 50–52, Appendix A: Costs of a rights issue.

sold at a discount, then the value of the shares of the original shareholders is diluted.[643]

Associate Professor Handley observed that:[644]

> Importantly, the set of investors who take up the new shares may include one or more existing shareholders of the firm, one or more new shareholders to the firm, or a combination of both existing and new shareholders.

The AER observes that in a fully subscribed rights issue (as is likely with the heavily discounted rights issue described in the draft decision), there would be minimal wealth transfer, as existing shareholders would be expected to take up the issue and hence there would not be any new shareholders. Associate Professor Handley observed that CEG and Carlton assume that no existing shareholders participate in their benchmark firm placements and stated this was an unrealistic assumption.[645] The AER concurs with Associate Professor Handley's view. The AER considers that it is more plausible to infer that placements are regularly taken up by a mix of old and new shareholders.

The AER considers that under such a scenario, two sources of overcompensation would likely result. Original shareholders who bought new shares would be overcompensated, since the dilution effect would already be offset by the new shares they purchased, and they would also receive the benefit of the proposed underpricing allowance. Additionally, outside investors who took up new shares would also be overcompensated, since they experience no dilution effect (they had no shares to begin with) but still share in the underpricing allowance (paid to the firm as a whole). Associate Professor summarised this scenario as follows:[646]

> Importantly, this reflects the fact that underpricing costs are not borne by the firm but rather represents a transfer of wealth from one group of investors to another.

On this basis, the AER does not consider that an indirect cost allowance is an appropriate mechanism to address purported wealth transfer effects. Further, the AER considers that the regulatory framework requires consideration of returns at the company level rather than the individual level. To address wealth transfer effects would require the AER to assess returns to individual shareholders which is inconsistent with the regulatory framework.

**Rights issues**

***The indirect costs of a rights issue***

TransGrid stated 'there is no basis for assuming that a rights issue will eliminate the indirect costs of raising equity'.[647] Similar statements were made by

643 Carlton, January 2009 (EnergyAustralia), p. 39.
644 Handley, April 2009, p. 6.
645 Handley, April 2009, p. 8.
646 Handley, April 2009, p. 8.
647 TransGrid, *Revised revenue proposal*, p. 80.

EnergyAustralia.[648] The NSPs also cited evidence from CEG, Carlton and Professor Grundy.

CEG's key argument was that a rights issue shifts costs from the benchmark firm to the individual shareholders, forcing investors to take on an underwriting role. CEG stated:[649]

> …it would be wrong as a matter of logic and economic theory to argue that by forcing existing shareholders to take on the functions of an underwriter the associated costs can be ignored.

Professor Grundy supported CEG's argument and stated that evidence of the existence of indirect costs with rights issued could be seen in the 'rights offer paradox'.[650] He cited a paper by Hansen, [651] which found that the transaction (indirect) costs of rights issues raise the total cost of rights issues above that of placements. Professor Grundy stated that this supports the observation of the relative paucity of rights issues in the marketplace (the 'rights offer paradox').

Carlton also agreed with CEG, and using data from Eckbo, Masulis and Nori, documented the forms that indirect costs will take in a rights issue—including: tax effects; liquidity impact and transaction costs; risk of failure; arbitrage activity and short selling; and anti–dilution clauses to convertible security holders.[652]

The AER considers that each of these arguments is a sub–class of the general transaction cost and wealth transfer arguments that were analysed earlier in this appendix. The AER notes that although these factors may have some predictive ability when explaining the rights offer paradox, none of the perceived indirect costs form an appropriate basis for an equity raising cost allowance. This is the logic followed by Associate Professor Handley when he stated:[653]

> In my view, none of the above suggested indirect costs of a rights issue would warrant compensation.

***The use of rights issues over placements***

In the draft decision, the AER stated that a discounted rights issue should be the benchmark SEO method for determining equity raising costs.[654]

The NSPs contended that private placements were used more heavily than rights issues, and are therefore a more appropriate benchmark.[655] CEG, Carlton and

648 EnergyAustralia, *Revised regulatory proposal*, p. 45.
649 CEG, January 2009, p. 16, paragraph 45–46.
650 Grundy, January 2009, p. 6, paragraphs 17–19.
651 Hansen, R. *The Demise of the Rights Issue,* The Review of Financial Studies, 1989, vol. 1(3), pp. 289–309.
652 Carlton, January 2009 (EnergyAustralia), pp. 8–9, section 1.1.3; and Carlton, January 2009 (TransGrid), pp. 19–20, section 2.1.3. Carlton notes that he did not independently verify the Eckbo, Masulis and Nori paper - see p. 4, footnote 4 (EnergyAustralia version).
653 Handley, April 2009, p. 21.
654 AER, *TransGrid draft decision*, p. 141; AER, *Transend draft decision*, p. 194; and AER, *NSW DNSP draft decision*, p. 191.
655 TransGrid, *Revised revenue proposal*, January 2009, p. 80.; EnergyAustralia, *Revised regulatory proposal*, January 2009, p. 44; CEG, January 2009, pp. 15–16, paragraph 44; Carlton, January 2009 (EnergyAustralia), pp. 2–7; and Grundy, January 2009, p. 7, paragraph 25.

Professor Grundy all argued that if profit–maximising firms choose placements as the most common means of equity raising, placements must therefore be the most efficient method of equity raising. Accordingly placement costs are the most efficient costs available from all SEO methods.[656] The NSPs' consultants stated that the AER should base the equity raising cost allowance on an estimate of the cost of a placement, including direct and indirect cost components.

The AER considers that, even if there was conclusive evidence that a particular method of equity raising was adopted by the majority of the market, this would not necessarily require the benchmark firm to adopt this method. In particular, since the characteristics of the benchmark firm differ markedly from the market average, it is not necessary to automatically accept the average market method as appropriate. To accept the average methodology, the AER considers that empirical evidence regarding the equity choices of efficient firms similar to the benchmark firm would be necessary. The NSPs did not provide evidence regarding the propensity for a regulated Australian electricity network to use placements.

The AER notes that the conclusion that placements are more common than rights issues arises from an inappropriately narrow definition of rights issues by CEG, Carlton and Professor Grundy.[657] A rights issue is offered to existing shareholders in order to raise equity at a discount without diluting aggregate shareholder wealth. Any dividend reinvestment plan (DRP) is therefore effectively a periodic rights issue. This point was explicitly raised by Carlton, who stated in his report 'it is important to observe that a DRP is effectively a non–renounceable rights issue.'[658] Associate Professor Handley also noted the essential equivalence of rights issues and DRPs.[659]

Comparison of all 'rights based' equity methods—considered as the sum of rights issues and DRPs—with private placements, reveals that, for Australian companies, placements are not preferred to offers made to existing shareholders. This is evident in table H.4, which is derived from data cited by both CEG and Carlton:

**Table H.4: Total equity raised from 1991–2000 by method**

| | Rights issues | Reinvested dividends | Total rights based equity | Placements | Other methods[a] | Total |
|---|---|---|---|---|---|---|
| Total 1991–2000 ($m, 2000) | 26.3 | 28.9 | 55.2 | 36.8 | 17.4 | 109.4 |
| Percent of total (%) | 24.0 | 26.4 | 50.4 | 33.6 | 16.0 | 100 |

Source: Based on Brown and Chan (2004), based on ASX Fact Book 2001.
(a) Other methods includes options, calls, staff plans.

656 CEG, January 2009, p. 17, paragraph 47; Carlton, January 2009 (EnergyAustralia), pp. 17–18, section 2.1; and Grundy, January 2009, p. 9, paragraphs 31–32.
657 CEG, January 2009, p. 15–16, paragraph 44; Carlton, January 2009 (EnergyAustralia), pp. 2–7; and Grundy, January 2009, p. 7, paragraph 25.
658 Carlton, January 2009 (EnergyAustralia), p. 29; Carlton, January 2009 (TransGrid), p. 36.
659 Handley, April 2009, p. 22.

Table H.4 demonstrates that rights based equity raising is used in an absolute majority of cases (50.4 per cent) in the Australian market. It also demonstrates that equity raised through rights based equity issues is around 50 per cent larger than that raised through placements. Associate Professor Handley reviewed additional data from KPMG and found a similar pattern of results.[660]

In considering the appropriate allowance for equity raising costs, the AER has analysed recent equity raising activities of regulated utilities in Australia, and considered the potential reasons for undertaking an SEO.[661] The AER has found that equity raisings often occur in order to fund organic growth of the business (internal expansion). In other cases, equity raising is required as a result of changes in business structure, business ownership or industry structure. Table H.5 provides the results of the AER's analysis.[661]

**Table H.5: Equity raised by Australian Utility Firms 1997–2008 ($m)**

| Purpose of SEO | Mergers and acquisitions | Unidentified purpose | Internal expansion | Total |
|---|---|---|---|---|
| **Placements** | | | | |
| Private placement | 2482 | 431 | 66 | 2979 |
| Share placement plan | 306 | 115 | 54 | 475 |
| Total placement | 2788 | 546 | 120 | 3454 |
| **Rights based equity** | | | | |
| DRP | – | – | 1453 | 1453 |
| Rights issue | 1577 | 600 | – | 2177 |
| Total rights issue | 1577 | 600 | 1453 | 3630 |
| Employee shares | – | 94 | – | 94 |
| Total | 4365 | 1240 | 1573 | 7178 |

Source: AER analysis.

While the majority of equity raising activity could be easily allocated to either internal expansion or merger activity, 17 per cent of equity raising activity either could not be allocated to any purpose, or was identified as partially supporting both internal expansion and mergers. Despite the difficulty in allocating this remaining equity, the AER considers the analysis indicates a relationship between equity raising methods and the purpose for which the equity is raised.

660 Handley, April 2009, p. 23.

661 Sample included all equity raising activities between 1997 and 2008 for the following firms: DUET, AGL, AGL Energy, Origin, Babcock and Brown Power, SP AusNet, Alinta, Spark Infrastructure and Envestra. Data was collected from Bloomberg, annual reports, company releases and ASX announcements; initial public offerings were excluded.

Table H.5 shows that while there are a significant number of rights issues, placements are more often chosen to support the majority of merger or acquisition activities. The AER considers that the significant changes in capital structure that occur during a merger or acquisition undermine comparisons with the benchmark firm, which is assumed to only undertake organic growth.[662] In addition, the costs of placements during a merger may be offset by the synergies expected to be generated by the merger itself. As such, the AER considers that the indirect costs of placements are likely to be offset by the indirect benefits of the changes in business structure.

Table H.5 also demonstrates that rights issues are chosen to support the majority of organic growth, with 92 per cent of all identified internal expansion funded via DRP. Placements are used infrequently for internal expansion (approximately 8 per cent of the time). The AER considers that this data, sourced from a sample of Australian regulated utilities over the past decade, provides a more appropriate comparison for the circumstances of the benchmark firm than any other empirical evidence submitted to it to date.

***Non–price differences between placements and rights based equity***

CEG stated that direct pricing for placements is consistently above that of rights issues.[663] CEG argued that no rational firm would willingly pay more than necessary for equity, and therefore inferred that there must be unobserved additional costs for a rights issue.

The AER considers that this argument ignores the existence of non–price differences between placements and rights issues. Placements are an exceedingly fast method to raise additional capital.[664] Empirical research indicates that placements are chosen as an equity raising method by firms under significant financial stress.[665] Such firms are not necessarily selecting equity raising methods on a least–cost basis. The financial stress of these firms requires urgent capital raising regardless of costs, and firms may in fact pay a premium to ensure the equity issue occurs quickly.[666] Accordingly, the AER considers that CEG has inappropriately assumed the existence of unobserved costs of a rights issue, and that equity raising trends may actually reflect the market value of non–price characteristics.

The AER has considered how the benchmark firm might value such a non–price characteristic of equity raising methods. The benchmark regulated firm experiences relatively predictable cash flows, low information asymmetry and a stable industry sector. The AER considers it is reasonable to expect that the benchmark firm’s capital raising activities would occur in a planned and timely matter. Given reasonable management, the benchmark firm will not face financial stress that induces it to make decisions on a least–time basis. Rather, the AER considers the benchmark firm will

[662] ACG, 2004, p. 4.
[663] CEG, January 2009, pp.16–17, paragraphs 45–47, and pp. 19–20, paragraphs 56–60. See also Grundy, January 2009, pp. 5–7, paragraphs 14–22.
[664] Carlton, January 2009 (EnergyAustralia), p. 6; Carlton, January 2009 (TransGrid), p. 17.
[665] Brown, P., Gallery, G. and Goei, O., *Does market misevaluation help explain share market long–run underperformance following a seasoned equity issue?,* Accounting and Finance, 2006, vol. 46, pp. 191–219. Bayless, M. and Chaplinsky, S. J., *Is There A Window of Opportunity for Seasoned Equity Issuance?*, Journal of Finance, 1996, vol. 51(1).
[666] The AER notes that the price observed is not consistent with the efficient price outcome of both the seller and the buyer being unforced.

prepare to raise capital as necessary, and elect equity raising methods generally according to least cost.

Associate Professor Handley also noted the range of factors (timing, equality, certainty of outcome and voting control) that are considered by a firm when choosing the benchmark SEO method, and observed that these indirect costs and benefits did have explanatory power.[667] On this basis, Associate Professor Handley noted the AER statement that a discounted rights issue was the optimal SEO method for all circumstances,[668] but did not consider it to be 'a strong argument' relative to arguments concerning consistency with the regulatory framework.[669]

In conclusion, the AER has considered the evidence presented by the NSPs and their consultants on the selection of a benchmark SEO method. The AER rejects the argument that placements should be the exclusive SEO method chosen by the benchmark firm for the following reasons:

- the benchmark firm should not necessarily adopt the equity raising method used by the majority of the market, as the benchmark firm differs systematically from the average market firm
- the AER's analysis indicates that placements are not the predominant equity raising method in the market. Rather, rights based methods (including DRPs and rights issues) jointly dominate the market
- close examination of Australian utilities demonstrates that placements are mostly used to fund mergers or acquisitions. Equity raising for organic growth, which is the most relevant scenario for the benchmark firm, is principally characterised by DRPs
- any time advantage of placements is irrelevant to the benchmark firm facing stable financials and efficient management.

On this basis, the AER considers that the appropriate benchmark equity raising method should not be restricted to placements. The AER notes that the recent update of the unit cost of SEOs based on the ACG methodology included both rights issues and placements.

**Other issues**

***Announcement effects***

The AER acknowledges the existence of alternative definitions of indirect costs in the financial literature.[670] There is frequently a change in a firm's share price when an equity raising is announced, often labelled as an 'announcement effect'. Some researchers identify this as an indirect cost of the equity raising, reasoning that the

667 Handley, April 2009, p. 13.
668 AER, *TransGrid draft decision*, p. 141; AER, *Transend draft decision*, p. 194; and AER, *NSW DNSP draft decision*, p. 191.
669 Handley, April 2009, p. 13.
670 Handley, April 2009, p. 5, footnote 9.

equity issue precipitated the change in price.[671] The AER notes that announcement effects are not considered an indirect cost by CEG, who stated:[672]

> If an announcement of equity raising signals to investors an unanticipated cash–flow problem at the firm then any consequent fall in the firm's share price cannot be presumed to be a cost of raising equity.

The AER notes that this is also the conclusion drawn by Associate Professor Handley, who stated:[673]

> It is noted that underpricing costs may be measured in a number of different ways, and further, that a reference to underpricing is not a reference to the stock price reaction that may occur on announcement of the security issue.

It is on this basis that CEG argued that Ofgem's rejection of indirect costs in their 2006 price control review[674] was a rejection of announcement effects, not underpricing, and therefore irrelevant to the CEG claim for indirect costs. CEG stated:[675]

> However, the basis of the empirical estimates of indirect costs in our report was, unlike the discussion in Smithers and Co, based on underpricing not announcement effects. That is, indirect cost estimates in our report were based on the difference between the price at which equity traded on the stock market and the price at which it was simultaneously issued to new investors.

The AER notes that Carlton frequently cited announcement effects when discussing the existence of indirect costs. For example:[676]

> The importance of take–up is demonstrated by the Balachandran et al results. They found that for rights issues where the subscription by existing shareholders was low the negative announcement period returns were –3.22%; these negative returns are economically significant, equating to about 6.5% of proceeds received. Firms with high levels of take–up recorded less negative returns of –0.63%.

The AER considers that the exclusion of announcement effects from the definition of indirect costs is appropriate. The AER notes the agreement on this matter by CEG.

***Upward sloping supply of capital***

The AER notes CEG's argument that the supply curve for capital is upward–sloping[677] implying that the AER should allow each NSP to continually increase returns to each set of new investors. This requires that the aggregate return to all investors would also increase over time, as the proportion of old investors decreases, and new investors receive ever–increasing returns. The AER notes that this would occur despite all parameters set under the NER and the transitional chapter 6 rules,

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671 See Eckbo, B., Masulis, R. and Nori, O., *Security Offerings*; in Eckbo, B. (ed.), *Handbook of Corporate Finance*, Elsevier, 2007; cited by Handley, April 2009, p. 5, footnote 9.

672 CEG, *Memorandum*, February 2009, p. 2.

673 Handley, April 2009, p. 5.

674 OFGEM, *Transmission price control review: Final proposals*, 4 December 2006.

675 CEG, Memorandum, February 2009, p. 3.

676 Carlton, January 2009 (EnergyAustralia), p. 10; Carlton, January 2009 (TransGrid), p. 22. See also Carlton, January 2009 (EnergyAustralia), pp. 7, 15, 16, 21; Carlton, January 2009 (TransGrid), pp. 18, 28, 35.

677 CEG, January 2009, p. 12, paragraph 32.

(including beta, market risk premium, debt risk premium, gamma and gearing) remaining constant. The AER considers this outcome is incompatible with the regulatory framework mandated by the NEL and NER.

***Information asymmetry***

The AER notes empirical evidence of share price changes around the issuance of right–based equity, and notes the Hansen (1989) explanation that these changes are due to transaction costs being placed on shareholders. However, the AER recognises that there are other plausible explanations in the academic literature for this empirical evidence. This includes Eckbo and Masulis (1992), who consider Hansen's argument along with other explanations (information asymmetry and agency reasons) for the rights offer paradox.[678] Eckbo and Masulis conclude that there is 'insufficient evidence to suggest that any of these alternative explanations can resolve the rights offer paradox'.[679] This research is particularly relevant given that information asymmetry is one area in which regulated utilities differ markedly from the market average. The 'adverse selection' model developed by Eckbo and Masulis derives share price effects from market attempts to determine the 'true' value of the business. For a benchmark firm, this force is entirely absent (given that all cash flow projections are perfectly transparent and regulated). This research is strengthened by Bohren, Eckbo and Michalsen (1997) who present further evidence that information flows determine the presence and level of underpricing in rights issues.[680]

The AER also notes a large body of research observing that firms issue equity capital to outside investors—that is, a placement rather than a rights issue—when the share price is overvalued. This includes studies by Myers and Majluf (1984), Karpoff and Lee (1991), Spiess and Affleck–Graves (1995), Bayless and Chaplinsky (1996), Jindra (2000), and Brown, Gallery and Goei (2006).[681] Importantly, this means that the observed placement underpricing is not actually a true cost to original investors, since the reduction in prices accompanying an equity raising simply returns their shares to their true worth. The outside investors, although paying a discount to the temporarily overvalued price, have still contributed the true worth of their share, and there is therefore no dilution effect for the original shareholders. Heron and Lie (2004) extend this argument by arguing that managers issue shares to outside investors (via placement) when overvalued and rights issues when undervalued. The authors conclude that a possible reason for low usage of rights issues in the US may be that the major motivation for equity raising is to sell equity when it is overvalued.

[678] Eckbo, B. E. and Masulis, R. W., *Adverse selection and the rights offer paradox*, Journal of Financial Economics, 1992, vol. 32, pp. 293–332.

[679] Eckbo and Masulis, 1992, p. 295.

[680] Bohren, O., Eckbo, B. E. and Michalsen, D., *Why underwrite rights offerings? Some new evidence*, Journal of Financial Economics, 1997, vol. 46(2), pp. 223–261.

[681] Myers, S. C. and Majluf, N. S., *Corporate financing and investment decisions when firms have information that investors do not have*, Journal of Financial Economics, 1984, Volume 13(2), pp. 187–221; Karpoff, J. M. and Lee, D., *Insider Trading Before New Issue Announcements,* Financial Management, Spring 1991, vol. 20(1); Spiess, K. D. and Affleck–Graves, J., *Underperformance in long–run stock returns following seasoned equity offerings*, Journal of Financial Economics, 1995, vol. 38(3), pp. 243–267; Bayless, M. and Chaplinsky, S. J., *Is There A Window of Opportunity for Seasoned Equity Issuance?,* Journal of Finance, March 1996, vol. 51(1); Jindra, J., *Seasoned Equity Offerings, Overvaluation, and Timing*, 2000; and Brown, P., Gallery, G. and Goei, O., *Does market misevaluation help explain share market long–run underperformance following a seasoned equity issue*?, Accounting and Finance, 2006, vol. 46, pp. 191–219.

**Cost of using retained earnings**

The NSPs stated that the marginal cost of using retained earnings has not been considered by the AER, and for this reason the AER had underestimated the cost of raising equity.[682] CEG and Professor Grundy identified five reasons why using retained earnings as equity incurs costs:

- increasing retained earnings lowers the ability to distribute dividends, which therefore lowers the ability to distribute imputation credits to investors[683]
- use of retained earnings lowers the ability to distribute dividends, which causes the firm to deviate from the dividend expected by the current 'dividend clientele', who will react negatively to the firm's behaviour[684]
- using retained earnings avoids the public scrutiny associated with external equity raising, and this public scrutiny is valuable to the business as a signal to the market of the quality of the firm[685]
- use of retained earning delays cash flows to investors, which increases risk[686]
- use of retained earnings forces existing shareholders to reinvest in the firm, deviating from their preferred portfolio and incurring transaction costs or increases in risk from a loss of diversification.[687]

Accordingly, the NSPs' consultants proposed that a retained earnings allowance needs to be provided to the benchmark firm.[688] In arguing for this allowance, CEG reasoned that the first dollar of retained earnings had a marginal cost of zero. CEG considered that the marginal cost of each dollar remained zero, until the point at which the amount of retained earnings impacted negatively on the business, principally by reducing dividends below the normal dividend yield. At the point where external equity was preferred to the use of retained earnings, the marginal cost of each form of equity is assumed to be equal. Assuming a linear increase from zero to the cost of an SEO, CEG argued that the retained earnings allowance for the NSPs should be equal to half the unit cost of the SEO allowance. This allowance would be calculated only on the portion of retained earnings that negatively impact the firm.

The AER notes that this issue was not raised by any of the NSPs in their regulatory proposals, but is a new argument presented in the revised regulatory proposals.

The AER is not aware of any regulatory precedent for applying a cost to retained earnings. ACG stated in its 2004 report:[689]

> Retained earnings have no issue costs and are generally undertaken continuously by regulated entities.

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682 TransGrid, *Revised revenue proposal*, p. 81; Integral Energy, *Revised regulatory proposal*, p. 45; EnergyAustralia, *Revised regulatory proposal*, p. 48.
683 CEG, January 2009, p. 29, paragraph 96 and Grundy, January 2009, p. 10, paragraph 36.
684 Grundy, January 2009, p. 9, paragraph 34.
685 CEG, January 2009, pp. 29–30, paragraph 97; Grundy, January 2009, p. 10, paragraph 35.
686 CEG, January 2009, p. 30, paragraph 99.
687 CEG, January 2009, p. 30, paragraph 100.
688 CEG, January 2009, pp. 31–34, paragraphs 101–115.
689 ACG, 2004, p. 63.

Associate Professor Handley considered each of the arguments raised by the NSPs, and rejected them as either an inappropriate basis for an allowance—for instance, personal transaction costs—or as being adequately dealt with in the discounting process (cash flow profiles through WACC, and imputation credit distribution through gamma). Associate Professor Handley argued that although selection of optimal dividend yield was required for determination of external equity requirements, there was no consequent cost for use of retained earnings, and concluded:[690]

> In summary, it is my view that indirect costs associated with using retained earnings should not be allowed as a cost of raising equity capital.

The AER considers that the NSPs have not provided evidence that there is a cost to the benchmark firm from using retained earnings.

***Theoretical consideration of retained earnings cost allowance***

The AER agrees with CEG that the pecking order theory does not state explicitly that retained earnings always have zero marginal cost.[691] However, the AER considers that CEG's arguments for a retained earnings allowance do not stand up to scrutiny.

CEG and Professor Grundy argued that retained earnings incur a cost to the benchmark firm because they impair the distribution of imputation credits.[692] The AER notes that, since the benchmark equity raising cost cash flow analysis takes account of an appropriate level of benchmark dividends, no such cost of using retained earnings is incurred by the NSP.

Professor Grundy argued that the established dividend clientele would react negatively to a change in dividend levels as a result of increased retained earnings.[693] The AER does not consider that the assumptions concerning benchmark dividends in the benchmark equity raising cost cash flow analysis would result in any negative affect on the purported dividend clientele. Further detail on the AER's assessment of benchmark dividends is discussed below in this appendix.

CEG and Professor Grundy also argued that public scrutiny associated with external equity raising reduces costs to the benchmark firm.[694] The AER considers that this does not apply in the context of a regulated firm whose financial decisions are transparent, regardless of a specific equity issue. Accordingly, the AER considers that this proposed marginal cost of using retained earnings is not applicable in the context of the benchmark firm.

CEG also argued that the backdating of cash flows (via retained earnings) results in increased risk, and therefore, increased cost.[695] The AER considers that this result is dependent on the delayed distribution of dividends, in both the initial and later years of the next regulatory control period. However, the AER notes that dividends are set, independent from the size of retained earnings. For each year, the benchmark

[690] Handley, April 2009, p. 19.
[691] CEG, January 2009, p. 32, paragraph 105.
[692] CEG, January 2009, p. 29, paragraph 96 and Grundy, January 2009, p. 10, paragraph 36.
[693] Grundy, January 2009, p. 9, paragraph 34.
[694] CEG, January 2009, pp. 29–30, paragraph 97; Grundy, January 2009, p. 10, paragraph 35.
[695] CEG, January 2009, p. 30, paragraph 99.

dividend has been determined according to the amount of imputation credits earned in the post–tax revenue model (PTRM) (based on the relevant gamma), prior to deriving retained earnings.

In addition, the AER notes that such a risk increase applies regardless of the source of equity, since it is only dependent on the schedule of payments involved. All investment projects undertaken by the benchmark firm involve initial payments to establish infrastructure, which then return in later years (i.e. a 'backdated cash flow'). All projects would therefore add to 'interest rate risk'. The AER considers a proposed retained earnings allowance would, in effect, allow for NSPs to earn a higher rate of return. The AER consideration of the rate of return is set out in chapter 12 of this final decision.

CEG argued that use of retained earnings incurs costs associated with disrupting investors' preferred portfolios.[696] The AER notes that this is an argument regarding personal transaction costs, and that such arguments were considered in detail earlier in this appendix. The AER considers that no evidence has been provided that the overall transaction costs incurred by investing in a benchmark firm, even with a 'forced transaction,' would exceed the transaction costs from investing in the market portfolio.

The AER considers that the arguments concerning the implementation of a retained earnings allowance, as proposed by CEG, are flawed for the following reasons:

- the linear marginal cost increase from zero per cent to the cost of an SEO cannot be justified
- the average area under the (linear) marginal cost curve is overestimated by the half–of–SEO–percentage rule proposed by CEG
- the selection of the boundary points (minimal dividend yield and normal dividend yield) is contentious.

The AER notes that these flaws are cumulative in effect. The AER considers that, even if such an allowance was theoretically justified, the practical implementation proposed by CEG does not accurately measure the theoretical concept.

***Conclusion on cost of using retained earnings***

The AER has considered the evidence presented by the NSPs and their consultants on the cost of using retained earnings as a source of equity. The AER finds three key reasons to reject the proposals for a retained earnings cost allowance, each of which it considers are independently sufficient to reject the proposal:

- new methodology cannot be presented by an NSP in its revised regulatory proposal
- there is no acceptable theoretical justification for a retained earnings cost allowance
- the implementation proposed by CEG systematically overestimates what it purports to measure and cannot be accepted as an accurate methodology.

696 CEG, January 2009, p. 30, paragraph 100.

On this basis, the AER rejects the claim for an allowance for the cost of using retained earnings.

### Direct cost of raising equity

In previous transmission determinations, the AER has based its estimate of the direct cost of raising equity on the ACG methodology, which recommended a benchmark transaction cost of 3 per cent of the total equity raised.[697] ACG based this unit cost on an analysis of actual SEO raising costs (rights issues and placements) incurred by Australian companies between 1998 and 2004, noting the difficulty obtaining data from firms with characteristics matching that of the benchmark firm (regulated utilities who require funds for internal expansion). With this in mind, ACG adopted the 3 per cent as a conservative estimate, noting that it was 'an upper limit of the likely cost of an SEO associated with capital expenditure within existing regulated activities'.[698] This figure was updated by the AER in 2008, consistent with the ACG methodology, to 2.75 per cent.[699] The ACG methodology only includes rights issues and placements; it does not include dividend reinvestment plans.

The NSPs disputed the draft decision on direct equity raising costs but did not present an alternative unit cost in their revised regulatory proposals.[700] This is in keeping with the NSPs' expressed view that the direct and indirect costs of all capital raising are interdependent and should be jointly decided, and the re–submission of a combined unit cost of 7.6 per cent.[701] CEG decomposed the 7.6 per cent unit cost in its May 2008 report:[702]

> We recommend adopting an estimate of 7.6%. This is approximately the same result as adding Bortolotti, Megginson and Smart's estimate of average global underpricing (4.5%) to the AER's current estimate of direct costs (3%). It is also consistent with the 7.6% estimate of total costs based on the work of Saunders, Palia and Kim (2003). It is also consistent with Lee Lochead and Ritter [sic] (1996) estimate of direct SEO costs for utilities (4.9%) plus the lowest available estimate for underpricing in SEOs (2.5% based on US estimates by Bortolotti et. al.)

The AER notes that the paper by Lee, Lochhead, Ritter and Zhao considers only domestic US firms raising capital in the US market. Accordingly, it is of limited relevance to the benchmark Australian firm raising equity in Australia.[703] Further, the AER notes that Lee et al excludes all rights issues, skewing the obtained estimate of direct costs by the elimination of a significant portion of SEOs. On this basis, the AER considers that the Lee, Lochhead, Ritter and Zhao estimate of direct equity raising costs is not relevant to the benchmark regulated firm in Australia.

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697 ACG, 2004, pp. 64–69.
698 ACG, 2004, p. 65.
699 AER, *NSW DNSP draft decision*, p. 197, footnote 549.
700 TransGrid, *Revised revenue proposal*, pp. 79–82; EnergyAustralia, *Revised regulatory proposal*, pp. 44–47.
701 TransGrid, *Revised revenue proposal*, p. 82; EnergyAustralia, *Revised regulatory proposal*, p. 49.
702 CEG; May 2008 (TransGrid), p. 25, paragraph 84; CEG, April 2008 (Integral Energy), p. 25, paragraph 85; CEG, November 2008 (JIA), p. 27, paragraph 96.
703 Lee, I., Lochhead, S., Ritter, J. and Zhao, Q., *The Costs of Raising Capital*, The Journal of Financial Research, vol. 19(1), pp. 59–74.

No other breakdown of direct costs was provided in the January 2009 CEG report, the report by Professor Grundy or the Carlton report.

Associate Professor Handley noted the acceptance by the NSPs of the 3 per cent unit cost based on the ACG methodology. Associate Professor Handley suggested that a reasonable estimate of the direct cost of raising equity capital from placements and other sources (other than dividend reinvestment plans) was in the range 2.75–3 per cent.[704]

On the basis of its review and assessment of all the material put forward, the AER considers that an allowance of 2.75 per cent, based upon the ACG methodology is an appropriate unit cost for direct equity raising costs (other than DRPs).

#### Implications of the Ofgem decision

CEG argued that the consideration of Ofgem (the UK regulator) precedent should lead to an allowance of 5 per cent for direct equity raising costs,[705] since this was the final unit cost approved by Ofgem in its 2006 price control review.[706]

The AER observes that Ofgem was interested in firms in the United Kingdom when it assessed direct equity raising costs and established a market range of 5–12 per cent. The AER notes that research papers repeatedly find large differences between nations on equity raising costs.[707] Accordingly, in view of the numerous differences in economic, financial and regulatory frameworks between the two countries, the AER does not consider it appropriate to apply direct cost estimates from the United Kingdom to Australian firms.

The AER considers, however, that Ofgem's reasoning regarding the positioning of regulated utilities relative to average market position on equity raising costs is relevant. In both Australia and the UK, regulated utilities have lower information asymmetry, more stable cash flows and better known risk than the market average. Therefore, it is likely that the direct equity raising cost of regulated utilities will be systematically lower than the market wide average direct equity raising cost. This means that although the Ofgem range of 5–12 per cent is not relevant, the Ofgem policy of choosing the lower limit of the range may be of relevance for the AER when positioning likely benchmark direct equity raising costs of regulated utilities relative to the market average equity raising costs.

### Benchmark cash flow analysis—calculation of retained earnings and external equity requirements

In order to determine the amount of equity raising required in recent transmission determinations, the AER has undertaken an assessment of benchmark cash flows calculated in the PTRM. In summary, the analysis calculated the amount of retained earnings which was deducted from the equity portion of forecast capex. The resultant figure, if positive, represented the amount of new equity to be raised.

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704 Handley, April 2009, p. 26.

705 CEG, *Memorandum*, February 2009, p. 2.

706 OFGEM, *Transmission price control review: Final proposals*, 4 December 2006.

707 For example, Chen, H. and Ritter, J., *The Seven Percent Solution*, Journal of Finance, June 1999; Gajewski, J. and Ginglinger, E. *Seasoned Equity Issues in a Closely Held Market: Evidence from France*, European Finance Review, 2002, Vol 6, pp. 291–319.

The NSPs submitted that the benchmark cash flow analysis applied in the draft decision was flawed because consistency was not maintained with the regulatory benchmarks in the PTRM.[708] The issues identified by the NSPs and their consultants included:[709]

- the calculation and assumptions surrounding dividends including the measurement of net profit, payout ratios, implied dividend yields and distribution of imputation credits
- the lack of provision to repay the principal of existing debt.

Citing findings from a review by KPMG, Integral Energy made the following submission:[710]

> The PTRM does not provide sufficient cash flows to enable Integral Energy to pay out a level of dividends and associated imputation credits that is sufficient to support the value that is assumed to flow to shareholders from imputation credits. Under such circumstances the cash flow to equity providers will be lower than that assumed in the PTRM, resulting in a calculated return to equity holders that is lower than the benchmark cost of equity assumed in the inputs; and
>
> The value of imputation credits that is assumed to flow to shareholders in the PTRM can only be supported if dividend payout ratios well in excess of 100% is assumed each year. Even with a 100% dividend payout ratio, there are insufficient accounting profits available to distribute the required level of dividends and imputation credits.

Each of these issues is considered below, in addition to other cash flow issues identified by the AER.

**Assessment of dividends**

The AER's benchmark equity raising cash flow analysis includes an assessment of dividends that are to be subtracted from internal cash flows in the process of calculating the amount of retained earnings that is available for reinvestment through forecast capex. As the equity raising cash flow analysis is not part of the PTRM, the assumptions concerning dividends do not directly affect any cash flows in the PTRM (other than the allowance provided for equity raising costs).[711] However, as the AER has applied a benchmark approach to determining the appropriate allowance for

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708 A broad outline of the steps in the AER's benchmark equity raising cash flow analysis can be seen on page 142–143 of the draft decision on TransGrid's revenue proposal. These steps largely remain valid despite the issues considered in this final decision. Where the steps set out in the draft decision are no longer accurate, specific changes to the methodology are set out in this appendix.

709 For example, TransGrid, *Revised revenue proposal*, pp 80–81; EnergyAustralia, *Revised regulatory proposal*, pp. 47–48.

710 Integral Energy, *Submission,* 16 February 2009, p. 10.

711 Accordingly, claims by NSPs about the impact of the AER's cash flow analysis on returns to equity holders and the level of imputation credits that can be distributed, are only relevant to the consideration of the appropriate allowance for equity raising transaction costs. That is, the cash flow analysis and assumptions do not affect the PTRM or any of the building block calculations apart from the allowance for equity raising transaction costs.

equity raising costs,[712] it agrees with Associate Professor Handley that assumptions should be consistent with the overall regulatory framework.[713]

The NSPs noted that the effective dividend yield assumed in the draft decision was less than 3 per cent.[714] The NSPs submitted that a dividend yield of 8.6 per cent is sustainable in the long–run provided it is less than the return on equity.[715] TransGrid also stated that equity holders expect to receive their return on equity as dividends.[716] CEG was critical of the assumptions concerning the appropriate amount of dividends. While advocating a long–term benchmark dividend yield (rather than a payout ratio), CEG concluded that:[717]

> The appropriate dividend policy should be determined by reference to the level of economic profit. It cannot sensible [sic] be determined by reference to accounting profit (except where this is the best estimate of economic profit).

TransGrid and EnergyAustralia also submitted a report by Carlton which supported an alternative dividend policy based on 100 per cent distribution of imputation credits.[718] TransGrid and EnergyAustralia did not apply the recommendations of the report by Carlton, but suggested that there is merit in further review of his recommended approach.[719]

Integral Energy submitted that the inconsistency between the PTRM and the benchmark equity raising cash flow analysis was attributable to different measures of depreciation:[720]

> The net profit after tax is clearly inconsistent with the face value of imputation credits created for the same time period. This is evidence of the effect that incorporating income taxation, financial accounting and economic value within the PTRM can result in differing views of the same "transactions".
>
> The obvious difference between these three views of financial performance as represented in the PTRM relates to the calculation, application and timing of "depreciation".

Despite raising the concerns supported by it consultants' reports, in their revised regulatory proposals TransGrid, EnergyAustralia and Integral Energy applied dividend assumptions that were consistent with the draft decision. However, given the concerns and criticisms raised by the NSPs regarding the assumptions about dividends, the AER has given further consideration to this issue.

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712 This is in contrast to a direct estimate of the likely costs to be incurred by the regulated business, which in this case is likely to be negligible due to government ownership.

713 Handley, April 2009, pp. 30–33.

714 TransGrid, *Revised revenue proposal*, p. 81; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

715 TransGrid, *Revised revenue proposal*, p. 81; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

716 TransGrid, *Revised revenue proposal*, p. 81.

717 CEG, January 2009, p. 28.

718 Carlton, January 2009 (EnergyAustralia), pp. 27–29, section 3.2.

719 TransGrid, *Revised revenue proposal*, p. 82.

720 Integral Energy, *Submission to the AER*, 16 February 2009, Attachment 3, p. 3.

The PTRM, by design, does not include an assessment of dividends. However, the AER is required by the NER to assume a certain level of utilisation of imputation credits for a benchmark efficient entity when calculating the allowance for corporate income tax.[721] Ultimately, the value of imputation credits can only be realised in the hands of shareholders who may receive imputation credits attached to dividend payments. Accordingly, an issue of consistency arises between the assumed value of imputation credits in the PTRM and the amount of imputation credits that is assumed to be distributed in the AER's benchmark equity raising cash flow analysis.

As noted by Carlton, however, the level of dividends in the equity raising cash flow analysis in the draft decision was generally insufficient to distribute the amount of imputation credits assumed in the PTRM.[722] The dividends assumed in the draft decision were based on a 70 per cent payout ratio applied to accounting net profit after tax. Under the approach applied in the draft decision the degree to which imputation credits were distributed through dividends varied over time and between the businesses.

As required by the NER, the PTRM reduces the allowance for tax based on the assumption that investors receive a value for imputation credits equal to gamma (0.5) times the value of taxes payable. If sufficient imputation credits are not distributed via dividends for this to be achieved and shareholders receive less than the assumed benefit from imputation credits, then the PTRM will not achieve the design objective of providing investors with the expectation of achieving the benchmark return on equity.[723]

Accordingly, to maintain consistency between the assumptions and analysis of the PTRM, the AER considers it appropriate to amend the way dividends are derived in its benchmark equity raising cash flow analysis for this final decision. The AER considers that the approach advocated by Carlton—linking dividends to the amount of imputation credits calculated in the PTRM—has merit. However, the AER does not agree with all of the cash flow assumptions made by Carlton. In particular, the AER considers that the required payout ratio of imputation credits to achieve the value in the PTRM has been misunderstood.

***Background to gamma estimate in the NER***

In the draft decision, the AER determined that an imputation credit payout ratio estimated for the purposes of the gamma parameter (i.e. assumed utilisation of imputation credits) can provide a reasonable estimate of a dividend payout ratio to be used for the purposes of estimating equity raising costs.[724] In the draft decision, the

721 NER, clause 6A.5.3.

722 Carlton, January 2009 (EnergyAustralia), p. 26. See also KPMG, January 2009, pp. 10–11.

723 Under the National Tax Equivalence Regime, the government owned business makes tax equivalent payments to the government (the tax collector as well as the shareholder). While the shareholder may also receive dividends, in this instance it is not able to make any use of imputation credits. It does however receive the full value of tax equivalent payments made (to itself), which is equivalent to a privately owned firm receiving the full value of the potential imputation credits regardless of whether there is any dividend or not. In fact, regardless of the assumed value of gamma, the return to the government will be the same. Therefore the assumed dividend payout in this instance cannot compromise the intended benefits of imputation credits to these shareholders.

724 It is noted that these two payout ratios may not necessarily coincide, as in practice there are methods available to distribute imputation credits other than by attachment to a normal declared

AER stated that a 70 per cent dividend payout ratio is considered as consistent with clause 6A.6.4(a) of the NER and clause 6.5.3 of transitional chapter 6 rules, which deems the utilisation of imputation credits to be 0.5.[725]

This observation was made in the ACCC's TransGrid 2004 draft decision,[726] which informed its view that the assumed utilisation of imputation credits be 0.5 in the 2004 Statement of Regulatory Principles (SRP).[727] The Statement of Regulatory principles subsequently formed the basis of the NER requirement for a gamma of 0.5. Specifically, the ACCC stated that estimates of the average value of imputation credits once distributed, ranged between 50 and 90 per cent.[728] The decision also cited an average dividend payout ratio of approximately 70 per cent before concluding that the gamma value should be 0.5.[729] It is apparent that this conclusion is the product of approximately 70 per cent payout ratio and approximately 70 per cent average valuation (around the middle of the stated range).

***The AER's WACC review***

In December 2008, the AER proposed that the assumed utilisation of imputation credits (i.e. gamma) be increased from 0.5 to 0.65.[730] One of the key assumptions supporting the AER's proposed position on gamma was an imputation credit payout ratio of 100 per cent, following the recommendation of the AER's consultant, Associate Professor Handley. In his report Associate Professor Handley argued that:[731]

> …the generally accepted approach by regulators is to define the value of imputation credits as the product of a credit distribution or payout ratio – representing the proportion of credits generated that are distributed to shareholders, and a credit utilisation or redemption rate – representing the value of a distributed credit…
>
> An alternative view is that a decomposition of gamma along these lines is unnecessary since, for valuation purposes, it is appropriate to assume the distribution ratio is equal to one.

As noted above, the AER stated in its draft decision that the assumed payout ratio of 70 per cent was consistent with the gamma estimate of 0.5 specified by the NER. That is, the estimate of a gamma of 0.5 in the NER was the product of an assumed payout ratio and an assumed utilisation rate.[732] However, Carlton suggested that the payout assumption is required to be 100 per cent citing the AER's WACC explanatory

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dividend (for example, special dividends, off-market share buybacks and DRPs). See AER, *Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters: Explanatory Statement*, 12 December 2008, p. 301.

725 AER, *NSW DNSP draft decision*, p. 195, footnote 547.

726 ACCC, *NSW and ACT Transmission Network Revenue Caps– TransGrid 2004/05–2008/09: Draft decision*, 28 April 2004, pp. 87–88.

727 ACCC, *Statement of principles for the regulation of electricity transmission revenues: Decision*, 8 December 2004, p. 17, point 8.9.

728 ACCC, *TransGrid draft decision*, April 2004, p. 87.

729 ACCC, *TransGrid draft decision*, April 2004, p. 87, footnote 54.

730 AER, *WACC review: Explanatory statement*, 12 December 2008, pp. 13–14.

731 Handley, J.C., *A note on the valuation of imputation credits*, 12 November 2008, p. 4.

732 The product of ~0.7 (payout ratio) and ~0.7 (utilisation) is 0.5, consistent with the required gamma value specified in the NER.

statement that indicates an assumption that 100 per cent of imputation credits are paid out.[733] A similar view was put forward by SFG and KPMG.[734]

The AER does not accept this argument for the purposes of this final decision. As Associate Professor Handley articulates in his report, the assumption of a payout ratio of 100 per cent for valuation purposes represents a departure from the 'generally accepted regulatory practice', which effectively assumes a zero value for retained imputation credits (i.e. 'the Monkhouse approach'). As the prescribed gamma value of 0.5 was estimated on the basis of the Monkhouse approach, the views received from Associate Professor Handley as part of the WACC review are not a relevant consideration for the purposes of this final decision.

The AER maintains that the imputation credit payout ratio assumed for the purposes of estimating the gamma parameter required under the NER provides a reasonable estimate of the dividend payout ratio to be used for the purposes of estimating equity raising costs under the cash flow analysis. Accordingly, the AER considers that a payout ratio of 70 per cent is appropriate for the purposes of this final decision.

***Consideration of methodology for setting dividends***

The AER notes the criticism concerning the apparent disconnect between the PTRM valuation of imputation credits and the value shareholders would actually receive under the draft decision.[735] Carlton stated that for EnergyAustralia, the AER had assumed imputation credits of $292 million in the PTRM while shareholders would only be able to realise a value of $130 million through assumed dividends.

This apparent disconnect arises from two sources. The first relates to the assumption about the value of a distributed imputation credit. Carlton's assumed payout ratio of 100 per cent, to achieve a gamma value of 0.5, relies on 50 per cent utilisation by shareholders. Conversely, as set out above, the AER has indicated that a gamma value of 0.5 is consistent with a payout ratio of about 70 per cent, and about 70 per cent utilisation by shareholders. Adjusting for this misinterpretation of the gamma estimate in the NER, the comparison becomes $292 million in the PTRM and about $182 million ($260 million × 70 per cent) for the realised value of distributed imputation credits under the benchmark equity raising cost cash flow analysis.[736] However, Carlton's point remains valid. That is, imputation credits assumed in the PTRM are greater than the assumed distribution and subsequent valuation of imputation credits within the benchmark equity raising cost cash flow analysis.

Accordingly, to address the issue in its equity raising cash flow analysis, the AER has assumed that dividends are equal to the amount required to distribute 70 per cent of total imputation credits assumed to be earned in the PTRM (total imputation credits earned is equivalent to tax paid). This amount is calculated according to the formula:

$$\text{Dividends} = \left(\frac{\text{Imputation credits earned}}{\text{tax rate}}\right) \times \left(1 - \text{tax rate}\right) \times \text{payout ratio}$$

733 Carlton, January 2009 (EnergyAustralia), p. 26; Carlton, January 2009 (TransGrid), pp. 5–6.
734 SFG, March 2009, pp. 14–15, paragraphs 58–61; KPMG, January 2009, p. 2.
735 Carlton, January 2009 (EnergyAustralia), pp. 23–26, section 3.1.
736 The figure of $260 million is the amount of imputation credits that could be distributed through dividends assumed in the draft decision benchmark equity raising cash flow analysis.

The AER's amendment to the dividend policy applied in the draft decision rectifies the remaining disconnect between the value assumed for imputation credits in the PTRM and in the benchmark equity raising cash flow analysis. The AER has confirmed that for each of the relevant NSPs, the assumed value of imputation credits in the PTRM is consistent with the value realised by shareholders (after being distributed with dividends and utilised by shareholders).[737] This is consistent with the derivation of the gamma value specified in the NER of 0.5.

The AER notes that the dividend yield implied by this approach will vary from business to business and year to year, as it is driven by the amount of the tax building block in the PTRM relative to the RAB. However, the AER considers that consistency between the assumptions made in the PTRM and in the equity raising cash flow analysis is of greater importance than the implied dividend yield in this instance.

**Inclusion of a dividend reinvestment plan**

The AER's estimate of benchmark equity raising costs for recent transmission determinations has been based on the ACG methodology. However the AER has not taken DRPs into account. To the extent that the cost of raising equity through DRPs[738] is less than the benchmark cost applied in the ACG methodology, the AER's recent determinations have overstated the appropriate cost of raising equity through DRPs. The AER applied a benchmark direct unit cost of 2.75 per cent in its draft decision. While Carlton has suggested that indirect costs associated with DRPs should be taken into account,[739] as discussed above, the AER considers that an allowance for such costs would be inappropriate. This view is supported by Associate Professor Handley.[740]

***Direct costs of equity raised through a dividend reinvestment plan***

The ACG suggested that the costs of raising equity should be zero. ACG noted that even when DRPs are underwritten, the level of competition among brokers resulted in no cost for underwriting services as brokers sought to profit by placing stock at a higher price than the standard DRP price.[741] Carlton stated that anecdotal evidence suggests that underwriting fees of around 2.5 per cent are being charged for DRP underwriting.[742] On the basis of the ACG and Carlton estimates, Associate Professor Handley stated that a reasonable estimate of the cost of a DRP is between zero and 2.5 per cent.[743]

However further investigation of Carlton's anecdotal evidence reveals that the figure of 2.5 per cent was only applicable to the portion of equity taken up by the underwriter. In this instance the take up by the underwriter was about half of the

737 For the amounts to precisely equate, the assumed utilisation of imputation credits by shareholders is calculated to be 71 per cent.
738 ACG suggested that the cost of raising equity through a DRP should be zero. ACG, 2004, p. 63.
739 Carlton, January 2009 (EnergyAustralia), pp. 29–30; Carlton, January 2009 (TransGrid), pp. 35–36.
740 Handley, April 2009, pp. 23–24.
741 ACG, 2004, p. 63.
742 Carlton, January 2009 (EnergyAustralia), pp. 29–30; Carlton, January 2009 (TransGrid), p. 36.
743 Handley, April 2009, pp. 26–27.

capital raised which, in turn, implies that the underwriting cost as a percentage of equity raised is about half of 2.5 per cent.[744]

The AER has undertaken its own research of the costs of DRPs among domestic energy network businesses. The AER observed that where reported, costs as a portion of equity raised had a median of 0.75 per cent and a mean of 1 per cent.[745] On the basis of all the information considered including the ACG report and Carlton's anecdotal evidence, the AER considers that a conservative estimate of 1 per cent is appropriate. The AER considers that this figure is the appropriate unit cost to be applied to the amount of equity assumed to be raised through a DRP.

***Amount of equity assumed to be raised through a dividend reinvestment plan***

Associate Professor Handley advised that a reasonable estimate of the amount of equity to be raised by a DRP was 30 per cent. This was based on the observation of the equity raised through DRPs in the Australian market.[746] However, the ACG and Carlton support an estimate of 30 per cent reinvestment of dividends.[747] To reiterate, Associate Professor Handley suggested applying the percentage to required equity, while the ACG and Carlton suggested applying the percentage to the amount of dividends paid. Carlton included data from selected DRPs with an average of 34 per cent reinvestment of dividends.[748] The AER analysed data for Australian energy network businesses and found that about 30 per cent of dividends distributed were returned through a DRP.[749]

On balance the AER considers that it is reasonable to assume that the amount of equity to be raised by a DRP is 30 per cent of dividends paid. Whether this is greater or less than the approach considered reasonable by Associate Professor Handley will depend on the relative magnitude of dividends paid and required equity.[750] However, the AER considers it appropriate to link the level of dividend reinvestment to the assumed dividend payout rather than the total equity required. This will ensure that the assumptions within the equity raising cash flow analysis are internally consistent.

Accordingly, in its benchmark equity raising cash flow analysis the AER has assumed that 30 per cent of dividends paid are available for reinvestment at a cost of 1 per cent. Any further requirement for equity is assumed to come from external sources at a cost of 2.75 per cent as discussed above.

744 Carlton, January 2009 (EnergyAustralia), pp.–41, appendix 4; Carlton, January 2009 (TransGrid), p. 49. The AER notes that 44 percent of dividends were reinvested with the underwriter taking up 22.6 per cent.

745 AER assessment of Bloomberg data and annual reports.

746 Handley, April 2009, pp. 23 and 26.

747 Carlton, January 2009 (TransGrid), p.36; ACG, 2004, p. 63.

748 Carlton, January 2009 (TransGrid), pp. 48–49.

749 AER assessment of data sourced from Bloomberg.

750 Further, while unlikely, where the DRP amount is linked to required equity, a scenario in which proposed capex is relatively high and taxes are relatively low could result in the amount of equity assumed to be sourced from DRP in excess of dividend payments.

**Lack of provision for the repayment of existing debt**

The NSPs applied a negative adjustment to retained earnings to allow for the repayment of debt. The justification for the adjustment is that it is required to maintain the benchmark gearing ratio.[751]

The NER requires the AER to set a WACC for the regulatory control period which includes setting the nominal risk–free rate and the debt risk premium, both with reference to bonds with maturity of 10 years. Under this framework, debt is assumed to be refinanced by the benchmark firm for each regulatory control period. Such financing arrangements do not include any presumption of debt repayment during that period.

However, the PTRM does assume that the level of debt varies from year to year in accordance with movements in the RAB. That is, when the RAB increases, so does the benchmark level of debt along with the benchmark return on debt (interest payments). As the NSPs' RABs are increasing over the next regulatory control period, the AER considers that the benchmark level of debt should increase, not decrease (repayment of debt would decrease debt). This can be seen in the row of the analysis sheet of the PTRM titled 'Repayment of debt'. The fact that this cell contains a negative number in each year of the next regulatory control period confirms that the level of debt is increasing rather than decreasing. Accordingly, the AER considers that the adjustment labelled as repayment of debt is potentially misleading.

The NSPs' justification for its amendment to include repayment of debt into the cash flow analysis was to maintain the benchmark gearing assumption in the PTRM.[752] While not explicitly required by the NER, as discussed above in the context of setting the dividend assumptions, the AER considers it appropriate that the equity raising cash flow analysis aligns with the benchmark gearing assumption required in determining the WACC (and applied in the PTRM). The AER's cash flow analysis for the draft decision has assumed that 60 per cent of capex would be funded by new debt. This appears to be consistent with the benchmark gearing specified in the NER. However, to maintain benchmark levels of gearing, the level of debt must equal 60 per cent of the RAB value (rather than 60 per cent of capex).

Accordingly, to maintain consistency between the benchmark equity raising cash flow analysis and the PTRM, where the RAB increase is less than the expected capex (due to regulatory depreciation), the increase in debt must be less than 60 per cent of capex. Put another way, the amount of capex funded by debt is constrained by the amount of the increase in the debt portion of the RAB. The AER has amended the cash flow analysis from its draft decision such that the increase in debt funding is linked to the row of the analysis sheet of the PTRM titled 'Repayment of debt',[753] rather than being calculated as 60 per cent of capex. The residual of capex less the

751 TransGrid, *Revised revenue proposal*, pp. 80–81, point (e); Transend, *Revised revenue proposal*, p. 60; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

752 TransGrid, *Revised revenue proposal*, pp. 80–81, point (e); Transend, *Revised revenue proposal*, p. 60; EnergyAustralia, *Revised regulatory proposal*, p. 48 and Integral Energy, *Revised regulatory proposal*, p. 46.

753 The repayment of debt is multiplied by minus 1 in order to express the debt component of capex as a positive number.

increase in debt funding is the amount of capex that must be funded through retained earnings and then new equity.[754]

The effect of this adjustment in dollar terms is consistent with the amendment proposed by CEG and adopted in the revised regulatory proposals. However, it also overcomes the inconsistency of an adjustment to repay debt where the RAB is increasing and the regulatory framework assumes debt is refinanced every regulatory control period (rather than repaid). The adjustment implicitly recognises that a portion of retained earnings is attributable to debt rather than entirely equity.

#### Adjustment to forecast capex funding requirement

The AER identified an error in the value assumed to be the funding requirement for capex in the draft decision and in the subsequent revised regulatory proposals. The value inappropriately included an adjustment to increase expected capex by the WACC for half a year. This is done in the PTRM to provide a return on capex during the year it is incurred based on the assumed timing of the incurrence of capex. However, for financing purposes, it is only the net capex value rather than the 'grossed–up' capex value that is of relevance. The AER has therefore corrected this error in its benchmark equity raising cash flow analysis. This results in a lower forecast capex funding requirement.

### Amortisation of allowance

In its draft decision for the NSW DNSPs, the AER expressed a preference for treating an equity raising cost allowance as part of the RAB—that is, to amortise the allowance.[755] This approach is consistent with the AER's 2006 Powerlink transmission determination, which considered the benchmark cash flow analysis to determine the extent of equity raising cost associated with forecast capex for the first time. The AER considers that although the amortisation treatment is equivalent in net present value terms to a perpetuity income stream provided as part of the opex allowance, there are several advantages to this approach:

- it ensures a transparent link between the equity raising cost and the capex that required the equity raising
- it eases administrative implementation in future regulatory resets
- it implements the recommendation made by ACG in its 2004 report.[756]

In accordance with the AER's previous approach, the benchmark equity raising cost allowance for the NSPs will be amortised over the weighted average standard life of the relevant RAB for the purpose of providing the equity raising cost allowance associated with forecast capex for the next regulatory control period.

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754 Using the example described by CEG on page 22–23 of its January 2009 report, the RAB increases from \$100 to \$200 from one year to the next after taking into account depreciation of \$100 and capex of \$200. In its revised benchmark equity raising cash flow analysis, the AER has assumed the debt component of capex is given as the benchmark gearing ratio (60 per cent) multiplied by the increase in RAB value (\$200 less \$100), that is \$60. The AER's previous approach assumed that the debt component of capex was 60 per cent of \$200 (forecast capex).

755 AER, *NSW DNSP draft decision*, p. 197. Note that the preference was not expressed in the TransGrid, Transend, and ActewAGL draft decisions because these draft decisions did not include any such allowance.

756 ACG, 2004, p. xiii.

### Summary of equity raising cost considerations

The AER has considered the arguments made by the NSPs on equity raising costs associated with forecast capex, including consultant reports and submissions.

The AER considers that there is no basis on which to accept the proposed allowance for indirect equity raising costs. The AER notes that personal transaction costs are not an appropriate justification for an allowance under the regulatory framework. Similarly, the AER notes that arguments relying on wealth transfer between investors are not appropriate justification for an allowance, since the regulatory framework specifies investor return in aggregate.

The AER rejects the argument that the benchmark firm would exclusively use placements to issue equity, finding that placements are not the majority market practice. Additionally, the AER considers that the characteristics of the benchmark firm may vary substantially from the market average, such that it would not be bound by majority market practice in any case.

The AER considers that the best estimate of the direct costs of equity raising is 2.75 per cent, the benchmark unit rate calculated in accordance with the ACG methodology and applied in the draft decision. The AER rejects the alternative estimates of direct equity raising costs proposed by the NSPs on the grounds that they deviate substantially from the equity raising conditions relevant to the benchmark firm.

The AER considers that there is a need to adjust the benchmark cash flow analysis to ensure that the gearing ratio is maintained, by linking the debt contribution to capex to the change in RAB each year. Further, the AER has set the dividend level to ensure that the dividends distribute the value of imputation credits assumed in the PTRM (which is based on the assumed gamma value prescribed under the NER). The AER also notes the prevalence of DRPs as a method for raising equity, and adjusts the benchmark cash flow analysis to allow 30 per cent of dividends to be reinvested via DRP at a benchmark cost of 1 per cent of the amount reinvested.

The AER considers that there is no evidence on which to provide an allowance for the proposed costs of using retained earnings as a source of equity.

For each NSP, the AER will apply the amended benchmark cash flow analysis and determine the amount that will be reinvested via DRP over the next regulatory control period. The allowance for the DRP cost will be 1 per cent of the amount reinvested in this way. The AER will then determine the amount of external equity required for the next regulatory control period in excess of that provided by the DRP. The allowance for external equity raising cost will be 2.75 per cent of the amount raised in this way. The two allowances will then be added to the RAB, and amortised over the weighted average standard life of the RAB.

# Appendix I: Risk–free rate averaging period

The AER concurrently assessed the revised revenue proposals of two TNSPs (TransGrid and Transend) and the revised regulatory proposals of four DNSPs (ActewAGL, Country Energy, EnergyAustralia and Integral Energy). Within this appendix these six regulated businesses are collectively referred to as the network service providers (NSPs). For convenience, within this appendix the term regulatory proposal should be taken to include the term revenue proposal, where the AER is referring to the NSPs. Within this appendix the AER has also used the term draft decision to refer to any and all of the relevant draft decisions affecting the NSPs. Where it has been necessary to refer to a draft decision for just one of the NSPs, within this appendix the AER has identified the specific business when referencing the draft decision, rather than applying the generic term draft decision, as defined in the shortened forms.

The AER's consideration of the substantive arguments put forward by the NSPs in their revised regulatory proposals, submissions and consultant reports are set out below.[757]

Following the withholding of agreement to the averaging periods lodged with the regulatory proposals, the AER in consultation with the NSPs established the risk–free rate averaging periods (agreed averaging periods) prior to the draft decision. The AER views its agreed averaging periods decision as part of its draft and final decisions and has reviewed the further material provided by the NSPs as part of this final decision.

The AER notes that the NSPs' consultants appear to have based their advice on a legal interpretation of the NER.[758] CEG stated that it has worked on the basis that when determining the averaging period it is a relevant consideration under the NER that the period should give rise to an estimate of the rate of return that is consistent with:

> …the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non–diversifiable risk.[759]

Although not necessarily agreeing with the NSPs and their consultants' interpretation of the relevant clauses, the AER has considered the key arguments put forward in the revised regulatory proposals and the additional material.

The NSPs' key argument in their revised regulatory proposals is one that suggests an obligation on the AER to move away from the agreed averaging period if that period is set in abnormal times. The alleged abnormality affecting the agreed averaging period was not manifest at the time of the AER's July 2008 decision to withhold

[757] The arguments put forward and consultant reports referred to by each NSP are set out in the cost of capital chapter.

[758] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 4; Prof. Bruce Grundy, *The WACC and the averaging period*, 16 February 2009, p. 5 and Officer R.R., *Expert report prepared in respect of certain matters arising from the AER's NSW draft distribution determination*, 16 February, 2009, p. 4.

[759] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 4.

agreement. The issue therefore is whether the averaging periods in the revised regulatory proposals are reasonable compared with the agreed averaging periods.

## I.1 Theoretical basis for the averaging period

In setting the averaging period close to the start of the next regulatory control period, the AER is seeking to set an unbiased risk–free rate to be applied in the weighted average cost of capital (WACC) formula, to derive an unbiased estimate of the regulated rate of return over the next regulatory control period.

In theory, the risk–free rate on the day that the regulatory determination comes into effect provides the best expectation of the future rate. This reflects the notion that the on–the–day rate fully reveals all the information available in the market. However, using the on–the–day rate exposes the firm to market volatility on a given day. Therefore, an averaging period is used to address the trade–off between 'volatility driven error' (due to exposure to an aberrant day) and 'old information driven error' (invalid past information) in interest rates. The averaging period also allows a firm to hedge its cost of debt over an extended period and counteracts the potential volatility of a single day's observation.

Professor Officer in his review of the CEG report accepted this theoretical position. He noted that:[760]

> In theory, the task of estimating the $Rf_{,t}$ is made easy because it is assumed constant and 'known for certain' at the time the rate is set. In practice there is no observed $Rf_{,t}$, instead the yield on a 10 year Commonwealth Bond/Security (CGS) is used as surrogate. This yield should theoretically be taken from the CGS as close as practical to the start date of the regulated period.

The AER considers the use of an averaging period as close to the start of the next regulatory control period as practically possible is consistent with the forward looking nature of the capital asset pricing model (CAPM) and is correct in finance theory.

## I.2 The market risk premium

CEG stated that, in the NER the market risk premium (MRP) is fixed at 6 per cent but the risk–free rate is set within an averaging period. Therefore, it noted that using the most up to date estimate of the Commonwealth Government Securities (CGS) yield will only result in the most accurate estimate of the cost of equity if investors' cost of equity moves one for one with movements in CGS.[761] CEG also claimed that sampling yields from bond markets at these times (February 2009) and the foreseeable future will result in bond yields being sampled during abnormal market conditions and unreliable estimates of the cost of equity.[762] Further, it noted that in the current

[760] Officer R.R., p. 6.
[761] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 7–12.
[762] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 29.

global financial crisis returns from holding government bonds have had a negative relationship with returns from holding equity.[763]

Strategic Finance Group (SFG) stated that the CAPM does not specify how to estimate the risk–free rate and asserted that it should be estimated in a way that gives the best estimate of the required return on equity when combined with other input parameters.[764] Professor Grundy's underlying argument was that the MRP has increased and therefore an adjustment to the risk–free rate is appropriate. In particular, he stated that CAPM theory does not imply that the best estimate of the return on equity is either obtained by:

- adding 6 per cent to the risk–free rate at the start of the regulatory control period or
- adding 6 per cent to the moving average of the risk–free rate as close as possible to the start of the regulatory control period.[765]

Professor Officer also suggested that the MRP at current times is higher than the MRP derived from long–term averages. Therefore, he noted that setting the risk–free rate which is at a 'low level' at current times relative to 'normal' whilst using a MRP from a more 'normal' time period does not result in an unbiased estimate of the cost of capital.

SFG stated that it is not necessarily the case that a fall in equity values must be caused by an increase in the required return on equity because a fall in future profits could also be the reason. However, based on its analysis, SFG noted that implausibly large reductions in expected corporate profits for implausibly long periods would be required to reconcile equity movements with the required return on equity estimated using the approach set out in the draft decision. Therefore, it concluded that the most plausible conclusion was that the required return on equity had risen over this period.[766]

The AER recognises that the CAPM does not state that the CGS is the best proxy for the risk–free rate. However, the CGS is arguably the most commonly used proxy when applying the CAPM in Australia—suggesting widespread acceptance in practice. In addition, the use of the CGS is specified in the NER.

The AER also recognises that the CAPM does not predict that the cost of equity capital necessarily moves one for one with the risk–free rate.

The AER notes that the arguments put forward by the NSPs regarding an insufficient return on equity is based on the view that the MRP of 6 per cent in the NER (based on a historical average) is out of line with the current variations in the MRP. In essence, the NSPs are arguing for a variable MRP to be applied in the CAPM, but given that it is prescribed in the NER they consider it reasonable to account for variations in the MRP via adjustments to the risk–free rate.

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763 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 11.

764 SFG Consulting, *Review of TransGrid approach to WACC averaging period*, 14 February 2009, pp. 17–18.

765 Grundy, 16 February 2009, pp. 3–4.

766 SFG Consulting, p. 23.

The AER considers that any implied (or actual) MRP changes cannot be addressed in this final decision. The AER notes that even if the MRP has increased somewhat over the last 12 months, it is unclear as to the margin of increase or whether there is an accepted theoretically sound methodology to take account of time varying MRP. The AER considers that a reasonable conclusion that can be drawn from current equity prices (if at all) would only be that the investors' perception of risk appears to have changed recently.

The AER notes that adjusting the risk–free rate averaging period as a mechanism to achieve the outcome equivalent to adopting a higher MRP (due to implied or actual variations to the historical MRP) is an attempt to circumvent WACC parameters prescribed (subject to five yearly reviews) in the NER. It would undermine the intended certainty provided under the regulatory regime which results from these values being prescribed.

Additionally, the AER notes that the NSPs' regulatory asset bases (RAB) are fixed (subject to depreciation and other NER prescribed adjustments) and receive regulated returns that comprise of both returns on equity and debt. Further, the NSPs' regulated cash flows provide significant certainty over earnings, dividends and debt servicing. This fixed RAB coupled with certainty in returns provide significantly more stable shareholder returns for the NSPs than for unregulated businesses whose future cash flows are highly uncertain. The NSPs are therefore insulated to a large degree from the factors that affect equity values during the current economic circumstances. In this context, arguments suggesting that returns provided to NSPs in a significantly more stable regulated environment should be comparable with higher expected returns for unregulated businesses due to the global financial crisis are unreasonable.

## I.3 Historically low nominal risk–free rate

CEG stated that the weight of the regulatory precedent from overseas and Australia supports a view that if the most recent averaging period overlaps with abnormal levels of the risk–free rate or periods of economic crisis then such a period should not be adopted.[767]

The AER notes that this is a continuation of the argument for a variable MRP given the alleged abnormally low CGS yields. However, given the dramatic changes in circumstances within the economic environment the AER has considered whether in fact the agreed averaging periods will result in an unreliable estimate of the risk–free rate such that it no longer reflects a reasonable forward looking estimate.

The AER's discretion in setting the nominal rate of return under clause 6.5.2 of the transitional chapter 6 rules and clause 6A.6.2 of the NER is limited to determining the reasonableness of the averaging period used to derive the nominal risk–free rate and the debt risk premium. The proxy for the risk–free rate—based on CGS yield—and the maturity period (10 years), including the requirement to average the observed rates are prescribed in the NER. The debt risk premium is defined in terms of a margin between the CGS yield and a benchmark corporate bond with a credit rating of BBB+. Given the level of prescription, the AER considers that the NER intended for

[767] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 64.

the WACC to vary over time in line with the interest rate cycle as opposed to being fixed.

The fact that CGS bond yields are at (or close to historical lows) does not of itself mean they cannot be used. Interest rates move all the time and reflect the market's assessment of the price of money at the time. Expectations about the prospect for prices and growth will influence this assessment. Brailsford, Handley and Maheswaran show that the nominal 10 year CGS yield averaged 5.7 per cent over 1883 to 2005 and 8.2 per cent over 1958 to 2005. In comparison the CGS yield rate based on February 2009 is close to 4.3 per cent being 1.4 per cent below the long–term average.[768]

The AER considers that the material provided by the NSPs in support of their revised regulatory proposals does not reasonably justify that, an averaging period prior to 5 September 2008 or an averaging period of 12 months ending on 20 March 2009 is better than a period that is as close as practically possible to the start of the next regulatory control period. Moreover, the agreed averaging periods do not exclude the downward movement of the CGS yields commensurate with an easing in monetary policy and a softening in economic growth. The AER considers that the agreed averaging periods are not abnormal and setting the risk–free rate using this period is also consistent with the NEL objective of efficient investment. The AER therefore considers that the agreed averaging periods do not represent an abnormal period in relation to the observed CGS yields.

Given that all WACC parameters are prescribed in the NER except for the risk–free rate and debt risk premium, the AER considers that the WACC commensurate with interest rate expectations in the economy—resulting from the agreed averaging periods—is consistent with the NER and the NEL objective.

Professor Grundy referenced a paper by Krishnamurthy and Vissing-Jorgenson and stated that US federal government securities are biased downwards due to unique collateral and liquidity features relative to other assets. In the US market this was estimated at 1 per cent pre–September 2008. EnergyAustralia stated that previously, the ACCC had referenced other industry and accounting practices when making a decision and noted that the Institute of Actuaries of Australia (IAA) noted that the CGS yields were not necessarily a perfect proxy for the risk–free rate. EnergyAustralia stated that if the CGS yields were to be used—given the current market conditions and the liquidity premium paid for CGS—the IAA recommended an upward adjustment.[769]

The paper by Krishnamurthy and Vissing-Jorgensen (2008) considers the most appropriate indicator of the risk–free rate. Similarly, the IAA also appears to be considering the appropriate proxy for the risk–free rate. The AER notes that it has no discretion on using a proxy other than the CGS for the risk–free rate as it has been specified in the NER and therefore considers this reference irrelevant.

[768] Tim Brailsford, John C Handley, Krishnan Maheswaran, *Re-examination of the historical equity risk premium in Australia*, Accounting and Finance 48 (2008), pp. 73–97.

[769] EnergyAustralia, *Further submission on the AER's draft decision*, p. 9.

Professor Grundy noted that as the global financial crisis gathered, the gap between CGS and other zero beta debt securities has grown, as seen by the widening gap between NSW Treasury and CGS yields.[770] CEG also stated that the nominal CGS yields are depressed as evident by the high premium long–term state debt is attracting over the CGS yields and noted that this was due to the heightened demand for the liquidity of the CGS in a financial crisis.[771]

The AER understands CEG's argument as one suggesting that the CGS yield is an inappropriate proxy for the risk–free rate. The argument is based on the margin between CGS and state debt yields which is interpreted by CEG as evidence of the heightened demand for the liquidity of CGS.

The AER notes that Associate Professor Handley argues that it is unclear whether a premium should be paid for CGS or whether a discount should be applied to non–CGS assets due to their relative liquidity characteristics.[772] The AER therefore considers that it is unreasonable to conclude that the CGS yield is downwardly biased due to a heightened demand for the CGS liquidity.

The AER considers that the difference between the yields of state debt and the CGS does not diminish the suitability of the CGS as the best proxy for the risk–free rate. Moreover, the NER prescribes the use of the CGS as the risk–free rate. Additionally, the AER notes that the margin between state debt and CGS can also be attributed to a number of factors bearing on state government finances, including their debt servicing capacity.

## I.4 Inconsistency between nominal and indexed bond yields

CEG stated that the AER should address the issue that an averaging period post September 2008 is likely to result in the adoption of CGS yields depressed in absolute terms as well as relative to the indexed CGS yields.[773]

The AER acknowledges that CGS yields have declined post September 2008 but notes that, as discussed above, this decline is not abnormal but consistent with changes in economic conditions.

CEG stated that since the global financial crisis the 'flight to safety' has resulted in such a high liquidity premium being paid for CGS that this now exceeds the 'peace of mind' premium being paid for indexed CGS. Therefore, CEG considered that if the AER's inflation estimates are applied in the current circumstances then it will make the estimate of the real risk–free rate less accurate rather than more accurate.[774]

770 Grundy, pp. 10–11.
771 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 36–39.
772 John C. Handley, *Comments on the CEG report: establishing a proxy for the risk–free rate, Report prepared for the AER*, 12 November 2008, p. 4.
773 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 40–46.
774 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 42.

The AER maintains its view that indexed CGS yields are not set in a well functioning market and therefore do not reflect informed market opinion or can be relied upon for deriving the future expectations of inflation (section 12.5.3). This issue was previously considered by the AER in the 2008 SP AusNet transmission determination and also referred to in the 2008 ElectraNet transmission determination. No evidence has been provided to the AER that these inefficiencies have now been addressed. Given the inefficiencies of the indexed CGS market, the AER considers that very little weight (if any) can be placed on outcomes derived by comparing relative movements between nominal and indexed CGS yields.

The AER considers that CEG's conclusions based on relative movements between nominal and indexed CGS yields are unreasonable because any such conclusion will be tainted with the inefficiencies in the indexed CGS market.

## I.5 Cost of debt

CEG stated that the best averaging period to estimate the cost of debt is the period that results in the best estimate of the cost of debt obligations actually entered into by the NSPs (or alternatively, obligations entered into by an efficient benchmark firm). Therefore, it stated that the best estimate of the cost of debt should be analysed based on whether debt is refinanced/hedged during the agreed averaging period or outside the period. CEG's view is that cost of debt will never be determined by a single averaging period and therefore, efficiently incurred debt will reflect debt market conditions over an extended period of years.[775]

The AER considers that the expected cost of debt over the regulatory control period should equal an estimate of the cost of debt at the start of the regulatory control period (as this is what the market at that time is requiring to invest in debt securities over the regulatory control period). As a proxy for the expected cost of debt, the yield to maturity (YTM) on an efficient benchmark firm's debt (prescribed by the NER as BBB+) at the start of the regulatory control period is adopted, irrespective of when the NSP issued the debt or the YTM on the debt it issued. The debt financing strategies of the NSPs are not prescribed by the AER. Even if firms could not hedge over an averaging period this does not imply that an estimate based on an averaging period close to the start of the regulatory control period is not the best forward looking unbiased estimate of the cost of debt over the regulatory control period or that it will systematically under compensate the regulated firm. The AER does not agree with CEG's underlying assumption that the best estimate of the cost of debt under the NER is an estimate set in an averaging period that a regulated business (or efficient benchmark business) is able to hedge/refinance its debt.

On the basis that the best estimate should be used, Professor Grundy stated that although the return on debt is independent of the risk–free rate, an estimate of the cost of debt ending on 5 September 2008 is appropriate.[776]

As discussed before, the AER notes that interest rates have reduced since September 2008 consistent with current monetary policy and growth expectations in

[775] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 18–21.
[776] Grundy, p. 4.

the Australian economy. The AER therefore considers that an averaging period ending on 5 September 2008 is likely to result in expected over compensation of the regulated firm relative to the cost of the efficient benchmark. The RBA recently noted that average business lending costs on outstanding loans have declined by around 230 basis points since the start of the monetary policy easing cycle.[777]

The expected return on debt appears to have increased relative to the benchmark risk–free rate due to tightening in credit markets and the perception of increased risks in these markets. This could explain a narrowing of the difference between the required return on debt and the required return on equity. Debt is a fixed nominal cash flow claim while equity has a residual claim that is insulated against inflation. Therefore, the risks facing debt and equity are different and the required returns will be different. The AER considers that to the extent there is a narrowing of the difference between the required return on debt and equity, it is driven primarily by the increased debt risk premiums. Such a change is consistent with the current global financial crisis which is primarily driven by a crisis in credit markets.

Comments regarding the accuracy of the Bloomberg data for calculating the cost of debt are considered by the AER in section 12.5.2 of this final decision.

## I.6 Certainty and the averaging period

In its April 2008 report (prior to the draft decision), CEG noted that the main reason for the WACC parameters being set in the NER was the need for early certainty by the NSP about the rate of return to be earned and extending this logic to the averaging period would suggest an early period—even one that may be set before the AER's draft determination.[778] CEG reiterated the need for business certainty in its January 2009 report.

The AER does not agree that the main consideration for setting the WACC parameters was to provide the NSPs early rate of return certainty as interpreted by CEG. The AEMC's aim was to provide short–term stability regarding the WACC determination by reducing an important source of potential differences between regulatory decisions.[779] Contrary to CEG's interpretation, logically extending the AEMC's objective suggests that the averaging period should be consistent with the current AER practice as this would extend the intended regulatory certainty. Consistency with current regulatory practice is discussed in section I.7.

In the event that CEG's interpretation about early certainty is adopted, then it is akin to the regulator agreeing to set the regulated rate of return at whatever time the NSPs decide that is in their best interest to refinance debt/raise capital. This could create opportunities for 'gaming' the regulator. For example, an NSP can lock in an averaging period that it considers achieves the most advantageous rate of return early in the regulatory process based on its view of future interest rate movements but if its

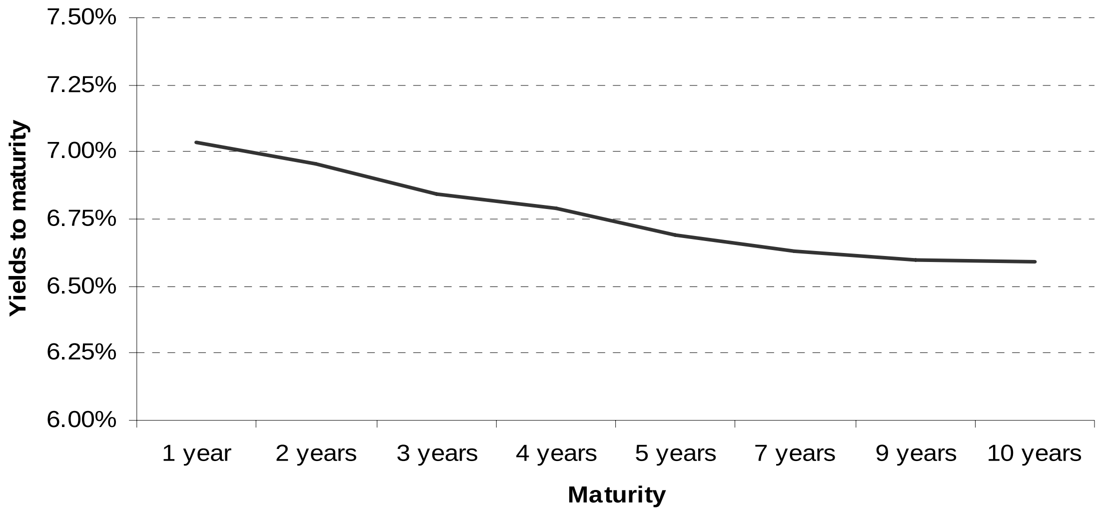
[777] RBA, *Statement on monetary policy*, February 2009. Available: http://www.rba.gov.au/PublicationsAndResearch/StatementsOnMonetaryPolicy/Feb2009/domestic_financial_markets.html, viewed 13 February 2009.

[778] CEG, *Nominal risk–free rate, debt risk premium and debt and equity raising costs*, April 2008, p. 5 and CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 27.

[779] AEMC, *Rule determination*, Rule No 2006 No. 18, p. 82.

view transpires to be disadvantageous, expect the regulator to accept a different period later on in the regulatory process. As shown in figure I.1, in June 2008 when the AER received the NSPs' regulatory proposals, the interest rate yield curve was downward sloping. The downward sloping yield curve at that time reflects market expectations of lower interest rates in the future. Therefore, setting the risk–free rate based on an averaging period at that time would have lead to systematic ex ante overcompensation of firms relative to the efficient cost of capital and inconsistent with the forward looking nature of CAPM—that is, it would not result in an unbiased risk–free rate.

**Figure I.1: June 2008 yield curve for CGS**




Source: Bloomberg data and AER analysis.
Note: Yield curve is based on a simple average of daily yields during June 2008.

EnergyAustralia argued that the AER did not specify proximity of the proposed averaging period to either the final determination or commencement of the regulatory control period in its 2007 Powerlink decision and that Powerlink's proposal was premised on the consideration of business certainty.[780]

The AER notes that the 2007 Powerlink final decision was originally targeted for completion in December 2006. On this basis, the averaging period proposed by Powerlink upfront at the start of the regulatory process was intended to be consistent with the AER/ACCC practice of setting the period as close as practicable to the start of the next regulatory control period.[781] However, the final decision was delayed to June 2007. As the averaging period was agreed early in the review process, consistent with standard practice, the AER did not change the averaging period to take account of the delay with the final decision date.

The AER considers that the additional material put forward by the NSPs does not support the view that its decision on the agreed averaging periods was inconsistent with the NER.

[780] EnergyAustralia, *Revised regulatory proposal*, attachment 8A, p. 4.
[781] Powerlink, letter to the AER – risk–free rate — confidential, 7 December 2005.

## I.7 Consistency with regulatory practice

The AER considers that given the evidence at the time, the additional material contained in the revised regulatory proposals do not justify a conclusion that the AER's decision to withhold agreement to the proposed averaging periods and consequently the agreed averaging periods were inconsistent with regulatory precedent. The AER notes the following:

- The approach is consistent with recent transmission determinations made under chapter 6A of the NER for ElectraNet and SP AusNet.[782]
- The AEMC's National Electricity Amendment (*Economic regulation of transmission services*), Rule 2006 No 18, rule determination recognised the need for consistency with the ACCC's WACC methodology and parameters contained in the ACCC's 2004 Statement of Regulatory Principles.[783]
- The AEMC's transmission rule (noted above) was adopted by the Standing Committee of Officials of the Ministerial Council on Energy for the WACC in the transitional chapter 6 rules.[784]
- The AER's approach was recently enunciated in its WACC review issues paper released in August 2008.[785] It was noted that:

> The AER's current approach is to accept a proposed starting date to the averaging period which is as close as practically possible to the commencement of the regulatory control period, to ensure an unbiased estimate of the risk–free rate (and the corporate bond rate).[786]

- In the WACC review issues paper, the AER specifically asked whether the practice of accepting any averaging period of between 5 and 40 days and commencing as close as possible to the start of the regulatory control period should be reconsidered. In response, the Joint Industry Associations (JIA) consisting of the Energy Networks Association, Australian Pipeline Industry Association and Grid Australia stated that:

> The businesses are of the view that the current regulatory practice of averaging contained in the NER is acceptable.[787]

782 AER, *ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008 and AER, *SP Ausnet transmission determination 2008–09 to 2013–14*, January 2008.

783 AEMC, *National Electricity Amendment (Economic regulation of transmission services) Rule 2006 No 18, Rule determination*, November 2006, pp. 85–86 and AEMC, *Draft rule determination, Draft national Electricity Amendment (Economic regulation of transmission services)*, 26 July 2006, pp. 56–57.

784 SCO, *Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution*, Explanatory Material, p. 44.
Available: www.ret.gov.au/Documents/mce/emr/governance.
EnergyAustralia, *Supplementary submission on NER exposure draft*, 31 May 2007, attachment 1.
Available: www.ret.gov.au/Documents/mce/emr/governance

785 AER, *Issues paper, Review of the WACC parameters for electricity transmission and distribution*, August 2008.

786 AER, *Issues paper, Review of the WACC parameters for electricity transmission and distribution,* p. 36.

787 JIA, *Network Industry Submission, AER issues paper–Review of the WACC parameters for electricity transmission and distribution*, September 2008, pp. 76–77.

- JIA also submitted that the regulated businesses should have the discretion to select the start date and noted that continuing the current practice:[788]
  - provides consistency with regulatory precedent thereby minimising regulatory risk
  - provides consistency with existing practices arising from this in tapping and accessing debt and equity markets
  - provides regulated electricity transmission and distribution businesses with an opportunity, but not an obligation, to raise a portion of the debt during the averaging period
  - allows regulated electricity transmission and distribution businesses to build a debt profile of multiple debt financing to minimise risks.
- The AER's WACC review draft decision formalised its current approach and proposed to retain the current NER methodology subject to only accepting an averaging period commencing as close as practically possible to the start of the regulatory control period.[789] This formalisation of the current approach was not objected to by JIA in its submissions on the WACC review draft decision.

## I.8 NEL revenue and pricing principles

Revenue and pricing principles in the NEL state that an NSP should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control services and complying with a regulatory obligation or making a regulatory payment.[790]

The NSPs submitted that the AER should have regard to whether the selection of the averaging period in determining the rate of return provides a reasonable opportunity to recover at least the efficient costs.[791]

Clause 6.5.2(b) of the transitional chapter 6 rules and clause 6A.6.2(b) of the NER prescribe the WACC methodology (including the CAPM) for calculating the regulated rate of return. The AER considers that the agreed averaging periods are consistent with finance theory. Moreover, the determined WACC is consistent with the NER and as intended moves commensurate with interest rate changes in the Australian economy which is also consistent with the NEL objective of promoting efficient investment. The fact that the risk–free rate is at (or close to) historical lows does not by itself mean that the resulting WACC does not provide a reasonable opportunity to recover the efficient costs of capital.

The AER notes that the WACC parameters are based on benchmarks and are part of the incentive framework. Therefore, the NSPs have an opportunity to achieve a higher rate of return by better managing their operating costs.

788 JIA, pp. 76–77.
789 AER, *Explanatory statement, Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters*, December 2008, p. 133.
790 NEL, clause 7A(2).
791 EnergyAustralia, *Revised regulatory proposal*, p. 58.

Under incentive regulation, firms generally receive the benefits and incur the cost of deviating from the efficient benchmark. Rewarding firms for losses incurred when they deviate from the efficient benchmark may encourage firms to act in this manner as they will expect to incur any upside from taking on risk and not suffer from the downside. An incentive mechanism with such expectations built in may encourage excessive risk taking inconsistent with the revenue and pricing principles in the NEL that require incentives to promote economic efficiency.[792]

Given the significant future capex programs and the evolving changes in the Australian economy in 2009, the AER requested confirmation from the NSPs on whether they are able to fund their respective capital programs. In response, the NSPs confirmed their ability to fund the capital programs for the next regulatory control period.[793]

Generally, the AER does not place much weight on WACC comparisons across regulatory control periods. However, in the absence of information supporting the NSPs' assertion that the agreed averaging period for setting the risk–free rate will result in inconsistency with the NEL revenue and pricing principles, a comparison was undertaken.

The IPART and the ICRC determined a pre–tax real WACC of 7.0 per cent applicable to the NSW DNSPs and ActewAGL respectively for the current regulatory control period.[794] This compares with an equivalent pre–tax real WACC of about 6.8–6.9 per cent for the next regulatory control period under this final decision.[795] For TransGrid's/EnergyAustralia's (transmission) and Transend's current regulatory control period the ACCC determined a nominal vanilla WACC of 9.08 and 8.80 per cent respectively and these compare with a nominal vanilla WACC of 8.79 per cent and 8.80 per cent for the next regulatory control period.[796] The AER notes that during the period December 2003 to March 2005 the RBA's cash rate was between 5.00–5.25 per cent whereas during the agreed averaging period it was at 3.25 per cent.[797] Noting this reduction in the cash rate commensurate with a softening in economic growth, the AER considers that the NSPs' WACC for the next regulatory control period (although lower) is reasonable compared to the WACC in the current regulatory control period.[798]

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792 NEL, clause 7A(3).

793 Country Energy, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 18 February 2009; EnergyAustralia, letter to the AER - *Deliverability of capital expenditure program*, 17 February 2009; Integral Energy, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 18 February 2009; TransGrid, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 27 February 2009; and Transend, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 17 February 2009.

794 IPART, *NSW electricity distribution pricing 2004/05 to 2008/09, final report*, June 2004, pp. 217–218 and ICRC, *Investigation into prices for electricity distribution services in the ACT, final decision*, March 2004, p. 70.

795 This varies depending on the effective tax rate modelled for each NSP.

796 ACCC, *Tasmanian transmission network revenue cap, 2004 – 2008/09, final decision*, December 2003 and ACCC, *NSW & ACT transmission revenue cap TransGrid 2004–05 to 2008–09, final decision*, April 2005.

797 RBA, Cash rate target, viewed 23 March 2009. Available: <http://www.rba.gov.au/Statistics/cashrate_target.html>

798 On 7 April 2009 the RBA further reduced the cash rate to 3.0 per cent.

Overall, the AER considers that the NSPs are not being deprived of a reasonable opportunity to recover their efficient cost of capital.

## I.9 Conclusion

Based on the above reasons the AER considers that its decision to withhold agreement to the averaging periods nominated in the NSPs' regulatory proposals was reasonable and that its agreed averaging periods are consistent with finance theory, regulatory practice, the NER and NEL.