Final Distribution Determination

Aurora Energy Pty Ltd

2012–13 to 2016–17

April 2012

AUSTRALIAN ENERGY REGULATOR

Contents

Shortened forms

Shortened form	Full title
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	annual revenue requirement
Aurora	Aurora Energy Pty Ltd
capex	capital expenditure
CAM	cost allocation method
CPI	consumer price index
current regulatory period	1 January 2008 to 30 June 2012
DMIS	demand management incentive scheme
DNSP	distribution network service provider
DRP	debt risk premium
EBSS	efficiency benefit sharing scheme
GSL	guaranteed service level
GWh	gigawatt hour
MRP	market risk premium
MW	megawatt
MWh	megawatt hour
NEL	National Electricity Law
NEM	national electricity market
NEO	national electricity objective
NER	National Electricity Rules
forthcoming regulatory control period	1 July 2012 to 30 June 2017
opex	operating expenditure
OTTER	Office of the Tasmanian Economic Regulator
PTRM	post tax revenue model
RAB	regulatory asset base
RFM	roll forward model
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index

SRI	statement of regulatory intent
STPIS	service target performance incentive scheme
TEC	Tasmanian Electricity Code
TMR	trunk mobile radio
WACC	weighted average cost of capital

Background

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution services in the National Electricity Market (NEM). The AER's functions and powers are set out in the National Electricity Law (NEL) and the National Electricity Rules (NER).

Aurora Energy Pty Ltd (Aurora) is a Tasmanian Government owned fully integrated energy and network business, with complementary activities in telecommunications and energy related technologies.[1] Aurora operates as the distribution network service provider (DNSP) on mainland Tasmania, and services approximately 229,400 residential and 50,400 commercial distribution customers across the state.[2]

The NER requires the AER to make a final distribution determination for Aurora, which is predicated on several constituent decisions.[3] The AER must also provide reasons for its final determination, including the basis and rationale of the determination.[4] The AER's final distribution determination is set out in two documents.

The first document (called 'Constituent Decisions') sets out all the constituent decisions the AER is required to make.[5] The second document (this document, its attachments, and appendices, collectively called 'Final Distribution Determination') sets out the reasons for the final determination as required by the NER.[6]

The NEL requires the AER to make a distribution determination in a manner that will or is likely to contribute to the achievement of the national electricity objective (NEO).[7] The NEO promotes efficient investment in, and the efficient operation and use of, electricity services for the long term benefit of consumers.[8] The AER must also have regard to the revenue and pricing principles (RPP) set out in the NEL.[9] The RPP promote efficient provision of, and recovery of costs for providing, distribution services.[10] Chapter 6 of the NER sets out the framework for the economic regulation of distribution services. It provides that distribution determinations must include decisions on:

- how the AER will regulate distribution services
- the DNSP's revenue proposal
- how the AER will set prices for distribution services
- how the AER will apply incentive schemes to DNSPs.

1 Aurora, *Energy to the People: Aurora Energy Regulatory Proposal 2012–17*, 31 May 2011, p. 1 (Aurora, *Regulatory proposal*, May 2011).
2 Aurora, *Regulatory proposal*, May 2011, p. 1.
3 NER, clause 6.11.1 and clause 6.12.1.
4 NER, clause 6.12.2.
5 NER, clause 6.12.1.
6 This document, including its attachments and appendices satisfies the AER's obligations to produce a final determination and reasons for the determination under clauses 6.11.1 and 6.12.2 of the NER.
7 NEL, section 16.
8 The national electricity objective is set out in full in the NEL at section 7.
9 NEL, section 16(2)(a)(i).
10 The revenue and pricing principles are set out in the NEL at section 7A.

This is the first electricity distribution determination made by the AER that will apply to Aurora. The Office of the Tasmanian Economic Regulator (OTTER) made the previous determination, which applied for the period 1 July 2008 to 30 June. The AER's determination will take effect from 1 July 2012.

In making this final distribution determination, the AER has reviewed Aurora's regulatory proposal, revised regulatory proposal, proposed negotiating framework and submissions received in accordance with the process outlined in part E of chapter 6 of the NER. This process involved:

- framework and approach paper—the AER consulted with Aurora and interested stakeholders in developing the framework and approach paper. The framework and approach paper set out the AER's likely approach to the classification of services, control mechanisms and the application of the various incentive schemes. The AER published its framework and approach paper on 29 November 2010, as required under clause 6.8.1 of the NER.

- pre-lodgement consultation—the AER consulted with Aurora in developing the regulatory information notice (RIN) and regulatory templates. The purpose of the RIN was to obtain supporting information from Aurora to help the AER assess the regulatory proposal against the requirements of the NER.

- Aurora's regulatory proposals—Aurora submitted its regulatory proposal and proposed negotiating framework to the AER on 31 May 2011. Subsequent to the AER's draft determination, Aurora submitted a revised regulatory proposal on 16 January 2012.

- public consultation—the AER published Aurora's regulatory proposal and the AER's proposed negotiated distribution service criteria on 23 June 2011, and called for submissions from interested parties. The AER held a public forum in Hobart on Aurora's regulatory proposal on 19 July 2011. The AER received four submissions on Aurora's regulatory proposal.

  The AER published a draft determination on 29 November 2011, and held a pre-determination conference on the draft determination on 13 December 2011. The AER also invited interested parties to make submissions on the draft determination and on Aurora's revised regulatory proposal by 20 February 2012.

  The AER received five submissions in response to this invitation. The AER considered these submissions (and a late submission provided to the AER prior to the release of its draft determination) in making its final distribution determination.

- specialist advice—the AER engaged expert technical and engineering consultants and financial and economic experts to advise on key aspects of the regulatory proposal. The AER has considered this advice in making its draft distribution determination.

In response to the Aurora's initial regulatory proposal, a submission was received by a stakeholder who raised a concern that the efficiency and effectiveness of the Tasmanian electricity industry is constrained by the current business boundary between Transend and Aurora. This stakeholder considered that Tasmanian electricity customers are burdened both in a financial sense and in poor service delivery relative to elsewhere in Australia.[11] Transend provided the AER with a late submission that considered that there would be no material benefit

[11] DA Consulting, *Tasmanian electricity networks to suit the customer*, August 2011, p. 20.

to consumers from a change in the asset ownership boundaries between Aurora and Transend.[12] In making this final determination, The AER has considered that current operational boundary between Aurora and Transend's network as part of Aurora's operating circumstances.

[12] Transend, *Operational and ownership boundaries between Transend and Aurora*, October 2011, p. 3.

Summary

The NER require the AER to make a distribution determination on Aurora's regulatory proposal. The AER's determination sets the distribution component of electricity prices in Tasmania from 1 July 2012. The NEL requires the AER to make decisions in a manner that will, or is likely to, contribute to the achievement of the NEO. The NEO promotes efficient investment in, and operation and use of, electricity services for the long term benefit of consumers.

The AER's final determination and indicative price impacts

Aurora's revised regulatory proposal sought total revenue for the regulatory control period 1 July 2012 to 30 June 2017 of $1594.2 million ($nominal).[13] Aurora's revised regulatory proposal seeks a real increase in revenue (from its current allowance) of 3.1 per cent per annum (on average) over the 2012–17 regulatory control period.

The increase in Aurora's proposed revenue allowance is based on Aurora's expectations of the costs required to achieve its obligations under the NER. These obligations include:

- meeting and managing expected demand
- complying with regulatory obligations or requirements
- maintaining the quality, reliability and security of supply
- maintaining the reliability, safety and security of the distribution system.

The AER has accepted much of Aurora's revised regulatory proposal as being consistent with the requirements of the NER. However, the AER does not accept all elements of Aurora's revised regulatory proposal. The AER's final determination is for a total revenue requirement of $1410.4 million ($nominal) for the forthcoming regulatory control period. The AER's allowance is 11.5 per cent below Aurora's proposal.

The AER estimates its final determination will result in distribution prices increasing by 1.4 per cent per annum (on average) over the forthcoming regulatory control period. The AER's final determination should result in a $60 ($nominal) or 3 per cent increase in typical annual residential costs for 2012-13, and an increase of $2 ($nominal) or 0.1 per cent per annum (on average) over the remaining years of the forthcoming regulatory control period.

Differences between the AER's final determination and Aurora's revised regulatory proposal

The main drivers of the difference between the AER's final determination and Aurora's revised regulatory proposal are the rate of return, capital expenditure (capex) and operating expenditure (opex).

[13] This figure includes $52.5 million in under recoveries from prior years to be recovered in 2012-13. This amount was not included in Aurora's revised proposal, but was part of a subsequent submission. The AER has included it here to make its decision and the proposal comparable.

Rate of return

The rate of return is the most significant driver of the AER's lower revenue allowance. The AER accepts Aurora's revised method to estimate the debt risk premium. However, the AER does not accept Aurora's revised method to estimate the risk free rate using a long run averaging period. The AER considers there is no persuasive evidence justifying a departure from using the averaging period initially proposed by Aurora and agreed to by the AER, to estimate the risk free rate. The AER also considers Aurora's proposed market risk premium value is too high. If the AER was to accept Aurora's values for these two cost of capital parameters in combination with the AER's position on all other inputs, the final determination would have resulted in total revenue increasing by a further $149.8 million ($nominal) or 10.6 per cent over the forthcoming regulatory control period.

Operating expenditure

The AER considers Aurora's revised proposal opex is more than Aurora requires to achieve the opex objectives. The AER has substituted Aurora's revised proposal opex with its own forecast. The AER's considers that Aurora's forecast opex includes IT and demand management expenditure that is not required to meet the objectives, and was also constructed using unit rates that the NER did not permit Aurora to change.

If the AER were to accept Aurora's revised proposal opex in combination with the AER's position on all other inputs, the final determination would have resulted in total revenue increasing by a further $20.4 million ($nominal), or 1.5 per cent over the forthcoming regulatory control period.

Capital expenditure

The AER considers Aurora's revised proposal capex is more than Aurora requires to achieve the capex objectives. The AER has substituted Aurora's revised proposal capex with its own forecast. The AER considers Aurora's proposed capex forecast is too high given forecast demand for electricity and asset replacement needs. Aurora's capex proposal also includes projects and programs that are primarily driven by reliability improvements. Further, Aurora's forecast capex is based on revised unit rates that the NER does not permit Aurora to change.

If the AER was to accept Aurora's revised proposal capex in combination with the AER's position on all other inputs, the final determination would have resulted in total revenue increasing by a further $16.4 million ($nominal), 1.2 per cent over the forthcoming regulatory control period.

Under recovery of current regulatory period allowable revenues

The AER considers Aurora is entitled to recover the under recovery of allowable revenues from the current regulatory period in the forthcoming regulatory control period.

Aurora is expected to under recover $52.5 million ($nominal) of allowable revenues in the current regulatory period. The NER permits Aurora to recover these revenues by adding them as a 'building block' in determining the annual revenue requirement for the forthcoming regulatory control period.[14] The AER accepts this approach as it will smooth the recovery of these costs over the forthcoming regulatory control period, which mitigates price impacts on consumers.

[14] NER, clauses 6.4.3(a)(6) and (b)(6).

As this under recovery amount is an estimate, the AER will account for the difference between the estimate and the actual revenues received through the transitional parameter in the control mechanism for the forthcoming regulatory control period.

Alternative control services

The AER has classified metering, public lighting, fee based and quoted services as alternative control services.

The AER has not accepted Aurora’s revised proposal prices for these services. The AER has also decided to adjust prices for these services over the forthcoming regulatory control period by CPI and an X factor. The AER did not accept Aurora’s proposal to escalate alternative control services prices annually using a real labour escalator.

The AER’s review of the Aurora’s revised proposal prices for alternative control services has resulted in lower price caps for metering services and public lighting services than those proposed by Aurora by an average of 10.0 per cent and 3.9 per cent, respectively.

Outputs

Under the NER, accountability for delivering distribution services lies with Aurora. The AER, through its service target performance scheme and efficiency benefit sharing scheme, has strengthened the incentives on Aurora to improve distribution system reliability to all customers. This ensures that any cost savings achieved by Aurora during the forthcoming regulatory control period do not come at the expense of service standards. In addition, the AER’s demand management incentive scheme provides Aurora with additional incentives to undertake demand management.

Overview

1 Revenue

Aurora lodged its revised proposal for the regulatory control period 2012–13 to 2016–17 with the AER on 16 January 2012. Aurora proposed a total revenue requirement of $1541.64 million ($nominal). It also submitted that $52.5 million of under recoveries from prior years should be included in the assessment, for a total revenue requirement of $1594.15 million. Table 1.1 displays Aurora's revised total revenue allowance.

Table 1.1 Aurora's proposed revenue allowance ($million, nominal)

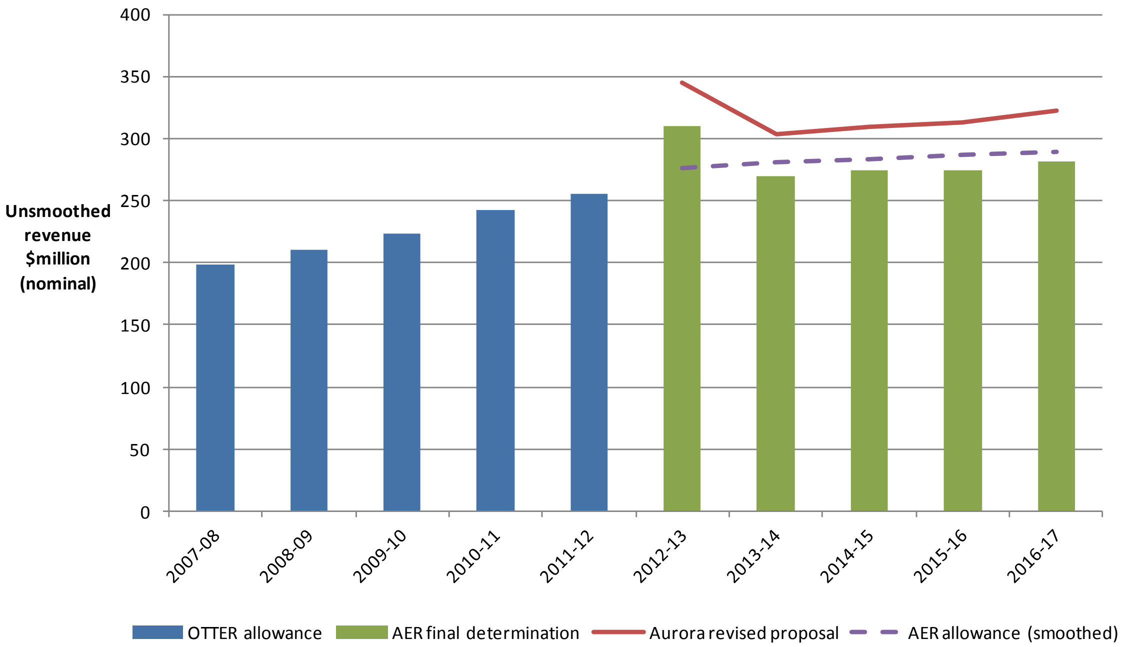
	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Aurora's revised proposal	292.24	303.00	309.83	313.51	323.06	1541.64
Under recovery adjustment	52.50[a]					
Total	344.74	303.00	309.83	313.51	323.06	1594.15

Source: Aurora's PTRM, AER analysis.
Notes: (a) The under recovery adjustment has been entered in 2012-13 revenues for comparability with the AER approach.

The AER has accepted much of Aurora's revised regulatory proposal as being consistent with the requirements of the NER. However, the AER does not accept all elements of Aurora's revised regulatory proposal. The AER's final determination is for a total revenue requirement of $1410.44 million ($nominal) over the forthcoming regulatory control period. The AER's adjustment of $183.8 million ($nominal) is 11.5 per cent below Aurora's proposal. Figure 1.1 demonstrates the difference between Aurora's revised proposal and the AER's final determination. The significant increase in revenues in 2012–13 is due to the addition of revenue under recoveries from previous years.[15]

[15] This money should have been recovered during the current regulatory control period and formed part of OTTER's revenue allowance.

Figure 1.1 The AER's final determination on Aurora's revenue allowance ($million, nominal)



Source: AER analysis, OTTER[16], Aurora's PTRM.
Notes: The under recovery adjustment has been entered in 2012-13 revenues for comparability with the AER approach.

The AER has calculated Aurora's total revenue allowance by summing a set of 'building blocks'. Table 1.2 displays the AER's final determination on these building blocks. This document discusses each building block throughout.

Table 1.2 The AER's final determination on Aurora's revenue cap for standard control services ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Return on capital	119.61	124.58	129.61	134.45	139.54	647.78
Regulatory depreciation	45.81	51.31	48.79	42.66	42.71	231.29
Operating expenditure	75.19	76.09	78.92	80.81	82.24	393.25
Corporate income tax	16.52	17.95	17.25	16.99	16.91	85.62
Under recovery adjustment	52.50					
Annual revenue requirement	309.62	269.92	274.57	274.92	281.40	1410.44

Source: AER analysis.

The AER's most significant change to Aurora's revenue proposal is a lower weighted average cost of capital (WACC). The AER has accepted Aurora's revised method to estimate the debt risk premium. However, the AER's final determination WACC value is lower than Aurora's revised proposal WACC as a result of adopting a lower nominal risk free rate and a lower market risk premium (MRP).

16 OTTER, model for *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: Final report and proposed maximum prices*, September 2007 (OTTER -Distribution 061108.xls).

The nominal risk free rate is determined by observing market determined Commonwealth Government bond rates over an averaging period.[17] For this final determination, the AER has used the averaging period agreed to by the AER. The AER considers there is no persuasive evidence justifying a departure from using the averaging period initially proposed by Aurora and accepted by the AER to estimate the risk free rate.

The AER also considers that Aurora's proposed MRP is too high. There is persuasive evidence that the AER's statement of regulatory intent (SRI) value for the MRP is inappropriate, and the AER has justified a departure from this value.[18].

Other key adjustments the AER has made to Aurora's proposed revenue allowance include:

- reducing Aurora's revised total forecast capex—Aurora has proposed to replace more assets than is necessary to maintain its network. Aurora also proposed capex for reliability improvement investment beyond that required to achieve the capex objectives. Further, some of Aurora's forecast capex to address growth in maximum demand is too extensive in scope, and more prudent solutions are available.

- reducing Aurora's revised total forecast opex— Aurora proposed an IT opex step change to support the capital costs associated with the roll out of its distribution network IT strategy. The AER considers some costs are already being funded internally, and others are not required to support the capex program. Aurora also resubmitted its initial demand management opex proposal despite the AER stating in the draft determination that it did not accept all of it. In its draft determination, the AER considered certain studies proposed by Aurora should be funded through the DMIA. The AER considers these elements of Aurora's revised forecast opex are not required to achieve the opex objectives.

- replacing revised unit rates with those in Aurora's initial regulatory proposal—the AER has set aside Aurora's revised unit rates as the AER considers Aurora was not permitted to change these under the NER. The AER's draft determination did not raise unit rates as a matter for Aurora to address.

- adjusting Aurora's revised labour cost escalators — Aurora's revised proposal included a new labour escalation methodology that the AER considers that the NER did not permit Aurora to submit. The AER has set this methodology aside, and considers that labour cost escalation using CPI is appropriate.

- adding Aurora's under recovered allowable revenues from the current regulatory period to the total revenue allowance for the forthcoming regulatory control period.

Further, the AER has made minor adjustments for Aurora's opening regulatory asset base and incentive schemes. Figure 1.2 displays the effect of the AER's adjustments on Aurora's proposed revenue allowance.

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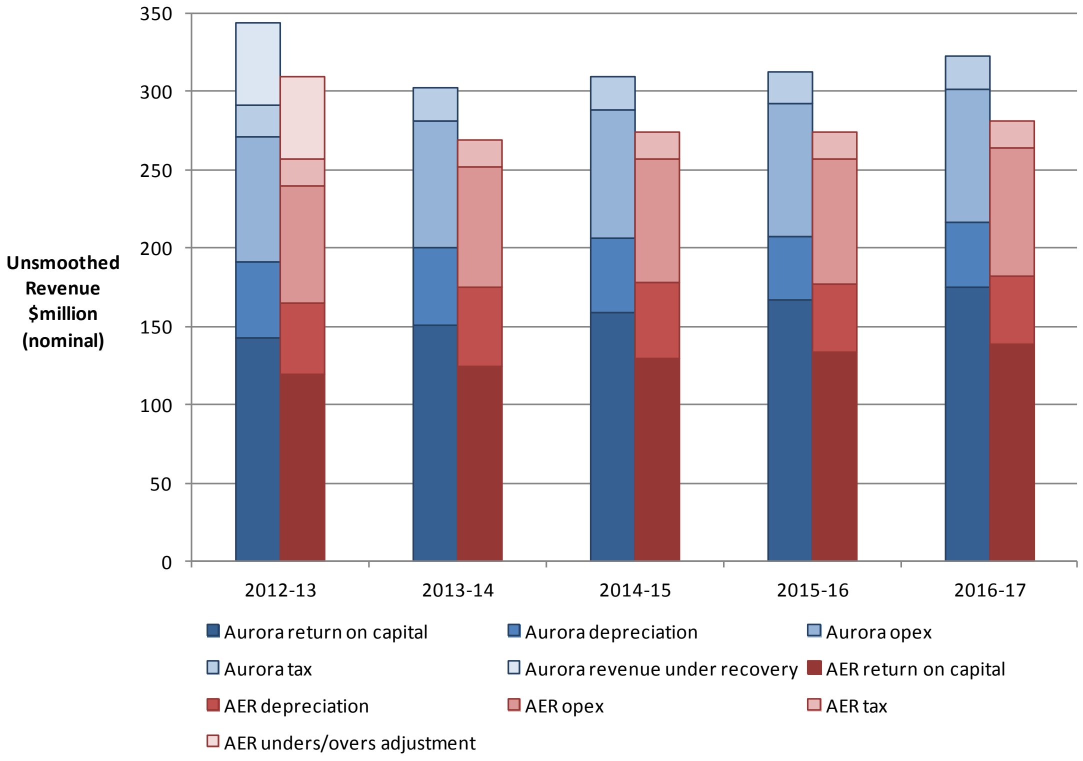
17 NER, clause 6.5.2(c).

18 NER, clause 6.5.4(g).

Figure 1.2 The AER's final determination adjustments to Aurora's revised proposal revenue allowance ($million, nominal)



Source: Aurora's PTRM, AER analysis.
Notes: The under recovery adjustment has been entered in 2012-13 revenues for comparability with the AER approach.

The AER has conducted sensitivity analysis of these adjustments on the final determination revenues. In particular, the AER has calculated the effect of applying Aurora's proposed cost of capital parameters, and opex and capex forecasts. Table 1.3 and Table 1.4 present this analysis.

Table 1.3 Changes to AER final determination in total over 5 years, if Aurora's cost of capital parameters are adopted

	Increased revenues ($million, nominal)	Increased revenues (per cent)
Risk free rate (Rf)	141.82	10.06
Debt risk premium (DRP)[a]	–6.15	–0.44
Market risk premium (MRP)	16.26	1.15
Nominal WACC	149.78	10.62

Source: AER analysis.
Notes: (a) The AER accepted Aurora's revised method to estimate the DRP. The change in the DRP estimate (negative sign) is due to the AER updating this parameter using the same averaging period applied to the risk free rate.

Table 1.4 Changes to AER final determination in total over 5 years, if Aurora's capex and opex forecasts are adopted

	Increased revenues ($million, nominal)	Increased revenues (per cent)
Opex	20.40	1.45
Capex	16.38	1.16

Source: AER analysis.

Table 1.5 displays the AER's X factors for each year of the forthcoming regulatory control period. The X factors represent the real revenue changes in each year over the regulatory control period. The AER has determined the X factors by smoothing the expected revenues over the regulatory control period so that in net present value terms they equal the revenue requirement set out in Table 1.2.

Table 1.5 The AER's final determination on Aurora's revised proposal X factors and expected revenue (per cent, real)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Aurora's proposal (X factors)	–12.09[a]	–2.00	–1.80	–1.60	2.10	n/a
AER final determination (X factors)	–4.56	1.00	1.50	1.50	1.50	n/a
AER expected revenue (smoothed) ($million, nominal)	276.40	280.75	283.73	286.74	289.78	1,417.40

Source: Aurora's PRTM, AER analysis.
Notes: (a) The P_0 for Aurora was recalculated to make it comparable to the AER's P_0 with the $52.5 million under recovery adjustment included in 2012-13.

The AER has smoothed the annual revenue requirement to determine the expected revenues as much as possible over the forthcoming regulatory control period, consistent with the requirements of the NER and NEL.[19]

The X factors equalise (in net present value terms) the expected revenue to be earned from the provision of standard control services with the annual revenue requirement attributable to those services for the entire regulatory control period.[20] The X factors are also designed to minimise the difference between the expected revenue and the annual revenue requirement for the last year of the regulatory control period.[21] In practice, the AER considers that a divergence of up to 3 per cent between the expected and annual revenue requirement for the last year is consistent with the NER, if this can achieve smoother price changes for users. This flexibility reflects the fact that the last year's revenues are based on forecasts that can diverge from what was expected (for example, CPI needs to be updated annually and is unlikely to be constant). In the present circumstances, based on the X factors determined by the AER, this divergence is 2.98 per cent.

Price impacts

Aurora's revenue allowance ultimately affects the prices consumers pay for electricity. Because the AER is regulating Aurora's standard control services under a revenue cap, the adjustments that the

19 See NER, clause 6.5.9(b)(2). NEL, clause 7.
20 NER, clause 6.5.9 (b)(3).
21 NER, clause 6.5.9 (b)(2)

AER has made to Aurora's annual revenue requirement do not directly translate to price impacts. This is because Aurora's revenue is fixed, so changes in the consumption of electricity will affect the price. However, Table 1.6 provides an indication of the price impacts of the AER's final determination. The impacts include the $52.5 million under recovery adjustment which has been smoothed over the forthcoming regulatory period, but still has a significant impact on prices in 2012-13.

With expected consumption growth of about 1.0 per cent per annum and a forecast inflation rate of 2.6 per cent per annum, the AER's draft determination X factors suggest that in nominal terms, distribution prices will increase by 1.4 per cent per annum (on average) over the forthcoming regulatory control period.

The AER expects a $60 ($nominal) or 3 per cent increase in typical annual residential costs for 2012-13, and an increase of $2 ($nominal) or 0.1 per cent per annum (on average) over the remaining years of the forthcoming regulatory control period. The AER has based this calculation on estimated annual costs of $2,000 for 2010–11[22], and an estimate that distribution costs make up 48 per cent[23] of the retail price (residential) of electricity.

This calculation assumes that a residential customer's annual level of consumption and all other possible influences on the retail prices (for example, wholesale prices) remain unchanged over the forthcoming regulatory control period.

22 This is based on a residential customer on tariffs 31 and 42 with medium level consumption. The tariffs are those approved by OTTER for 2010–11. The quantities are based on the typical customer profile for 2009–10, see OTTER, *Information Paper, Typical electricity customers*, September 2010, p.13. The estimated annual bill is exclusive of GST.

23 This figure is calculated by taking the distribution tariffs for 2010–11, multiplying these by the same quantities used to determine the estimate of the typical residential customer's annual bill and then dividing the resulting distribution charges by the estimated annual bill for 2010–11.

Table 1.6 Comparison of price impacts of Aurora's proposal and AER draft determination ($nominal)

	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	Average
Proposed by Aurora							
Residential bill (annual)	$2,000	$2,134	$2,174	$2,214	$2,252	$2,245	
Distribution charges	$968	$1,103	$1,143	$1,182	$1,220	$1,213	
Change in residential bill		$134	$40	$39	$38	–$6	$49
Percentage change in residential bill		6.72%	1.88%	1.80%	1.72%	–0.29%	2.4%
Percentage change in distribution prices		13.88%	3.63%	3.43%	3.23%	–0.53%	4.7%
AER draft determination							
Residential bill (annual)	$2,000	$2,060	$2,066	$2,067	$2,068	$2,069	
Distribution charges	$968	$1,028	$1,034	$1,035	$1,036	$1,037	
Change in residential bill		$60	$6	$1	$1	$1	$14
Percentage change in residential bill		3.02%	0.29%	0.04%	0.04%	0.04%	0.7%
Percentage change in distribution prices		6.23%	0.59%	0.08%	0.08%	0.08%	1.4%

Notes: Assumes a typical residential bill of $2,000, an inflation forecast of 2.6 per cent, consumption growth of 1.0 per cent and distribution proportion of 48 per cent.
Source: AER analysis.

The AER estimates its final determination will increase a typical residential bill by approximately 0.7 per cent per annum (on average) over the forthcoming regulatory control period. This compares to the increase of approximately 2.4 per cent per annum (on average) from Aurora's revised regulatory proposal (including the under recovery adjustment). The impact of the AER's determination on consumers will therefore be less than proposed by Aurora.

2 Aurora's outputs

As a distribution network service provider (DNSP), Aurora's primary output is to deliver electricity distribution services to its customers.

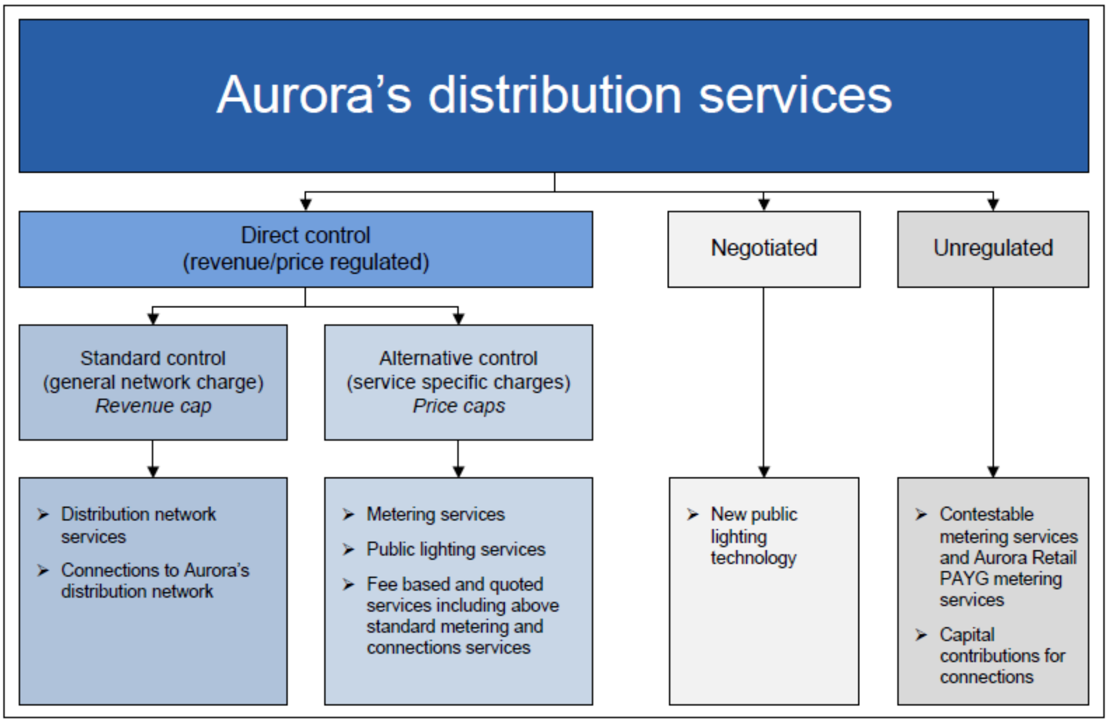
2.1 Aurora's distribution services

The AER has determined appropriate forms of regulation for the distribution services Aurora provides in this final determination (see attachment 1). The AER grouped Aurora's distribution services as those:

- recovered through general network charges (standard control services)
- recovered through individual prices (alternative control services)
- that are negotiated between Aurora and its customers
- not regulated by the AER.

Figure 2.1 displays Aurora's distribution services. The AER draft determination on service classification was not contested by Aurora. The AER's reasoning for service classification is set out in more detail in Attachment 1 of the draft determination.

Figure 2.1 Aurora's distribution services

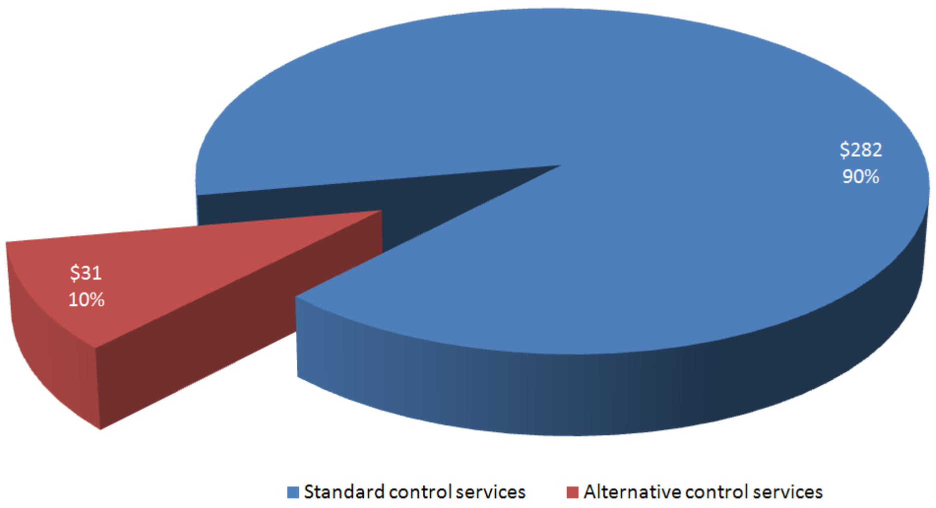


Source: AER, *Framework and approach paper*, November 2010, p. 61.

As shown in figure 2.2, in terms of revenue, the majority of the AER's final distribution determination concerns standard control services that are recovered through general network charges. The AER is regulating these services under a revenue cap, which means the amount of revenue Aurora can earn in each year of the forthcoming regulatory control period is limited to the amount the AER determines. The AER has not accepted Aurora's proposed revenue allowance for standard control services.

The AER has decided to regulate alternative control services by determining caps on the prices that Aurora can charge for them.[24] The AER has set out an overview of its reasoning for alternative control services in section 10, and in more detail in Attachments 15 to 19. Figure 2.2 compares the five year average of the AER's final determination revenue allowance for Aurora for 2012–17 for standard control services and alternative control services. The AER has also not accepted Aurora's proposed prices for alternative control services.

Figure 2.2 Comparison of average revenue requirements for standard control services and alternative control services for 2012–17 ($million, nominal)



Source: AER analysis.

2.2 NER objectives

The NER sets out certain objectives for Aurora's forecasts of total capital and operating expenditure (which are used in determining the revenue cap). These objectives are to:[25]

- meet or manage expected demand
- comply with regulatory obligations or requirements
- maintain the quality, reliability and security of supply
- maintain the reliability, safety and security of the distribution system.

The AER must determine whether Aurora's forecasts of capital and operating expenditure are required to achieve these objectives, and whether this expenditure reasonably reflects the efficient

[24] AER, *Framework and approach paper*, November 2010, pp. 84–85.
[25] NER, clauses 6.5.6(a) and 6.5.7(a).

costs that a prudent operator in Aurora's circumstances would need to incur, based on a realistic expectation of demand and cost inputs required to achieve these objectives.[26]

2.2.1 Meeting and managing expected demand

Aurora's network must be able to deliver electricity to its customers, and Aurora must build, operate and maintain its network to manage expected changes in the demand for electricity. Aurora therefore requires demand driven capex and opex so that its network can deliver a reliable supply of electricity when:

- the demand for electricity is at its peak (maximum demand)
- new customers connect to the network
- the overall consumption of electricity increases.

The AER has set out its reasoning for the forecast capex and opex it considers Aurora requires to meet and manage expected demand in more detail in Attachments 6 and 7.

Maximum demand

Maximum demand is a snapshot of the highest level of demand on Aurora's distribution system at a point in time. In its draft determination, the AER did not accept Aurora's initial maximum demand forecast, which the AER considered was too high. In its revised proposal, Aurora revised its maximum demand forecast to a level more comparable to the AER's draft determination. The AER accepts Aurora's revised demand forecast to be a realistic expectation of the demand forecast required to achieve the capex and opex objectives. Figure 2.3 compares Aurora's revised maximum demand forecasts with the AER's draft determination forecasts.

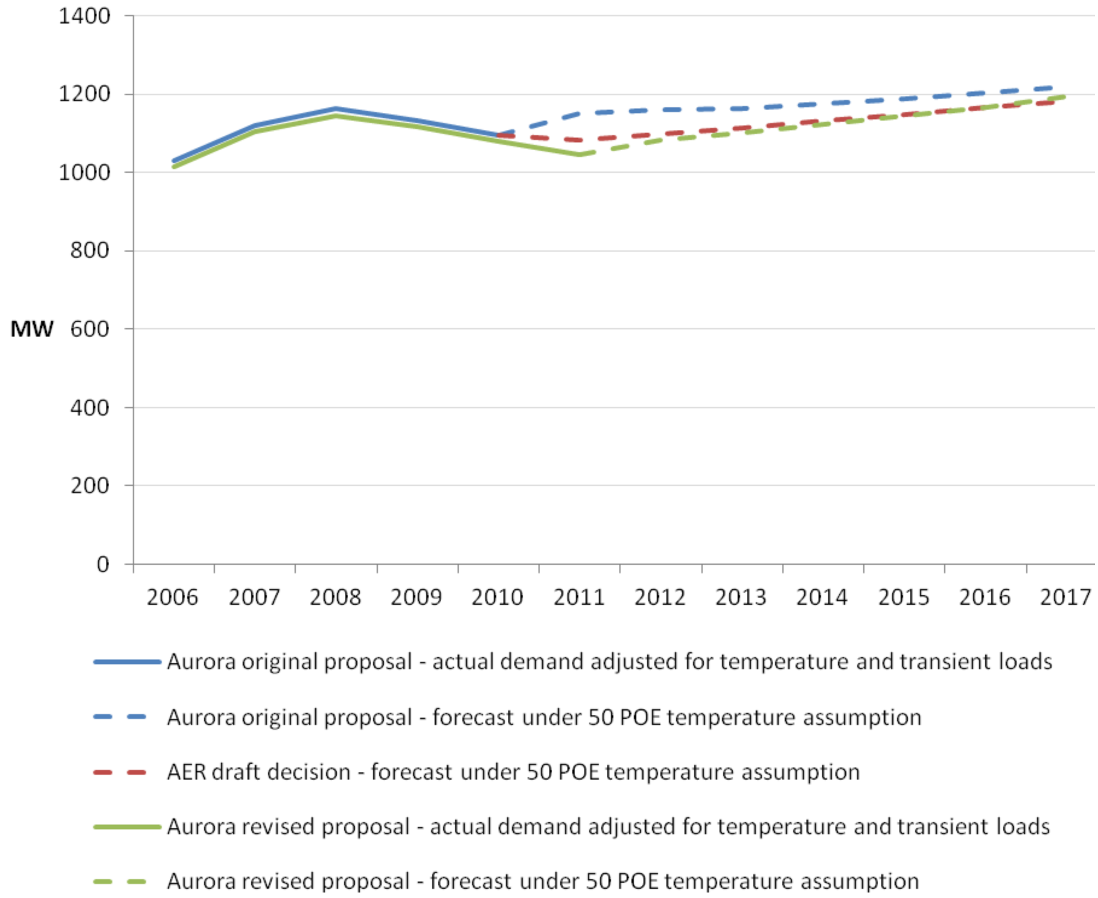
Aurora's revised maximum demand forecasts took into account: [27]

- adjustments to the forecasting method to address the issues raised in the AER draft determination and align the forecasting method with that used by the AER in developing a substitute forecast
- recent data on maximum demand, weather and other explanatory factors that have become available since the AER's draft determination.

[26] NER, clauses 6.5.6(c) and 6.5.7(c).

[27] Aurora, *Revised regulatory proposal 2012–17,* January 2012, p. 33.

Figure 2.3 Aurora's revised maximum demand and AER's draft determination forecasts



Source: AER analysis, Attachments to Aurora's revised regulatory proposal,[28] information provided by Aurora in response to AER's draft determination.[29]

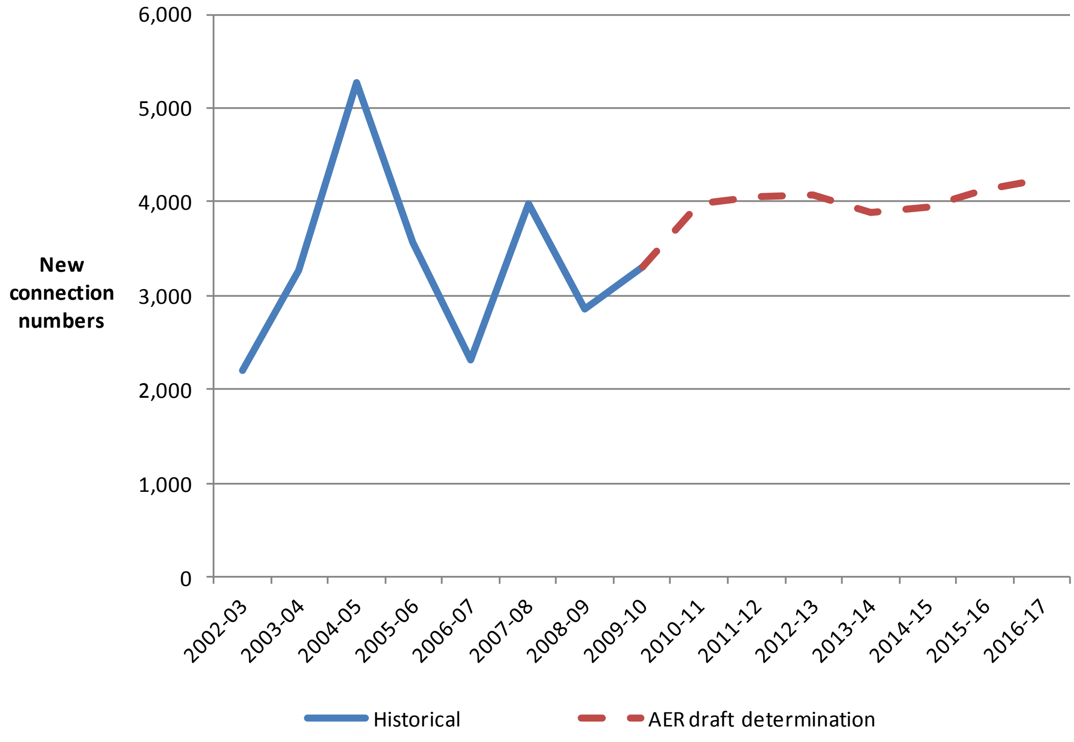
The consequence of Aurora's revised maximum demand forecast is a lower capex allowance for some categories of Aurora's demand-related capex, when compared to Aurora's initial regulatory proposal. The AER has set out its reasoning for peak demand in more detail in Attachment 5.

New customer connections

In its draft determination, the AER did not accept Aurora's forecasts of gross new customer connections as it did not reflect a realistic expectation of demand. Accordingly, the AER derived its own forecasts of new gross connections, using dwelling and demolition forecasts.

In its revised proposal, Aurora adopted the AER's forecasts of new gross customer connections for the purpose of calculating capex related to new customer connections. Figure 2.4 illustrates the growth in new gross customer connections over the forthcoming regulatory control period. The AER has set out its reasoning for new customer connections in more detail in Attachment 5.

Figure 2.4 Historical and AER forecast gross new customer connections



Source: AER analysis.

Electricity consumption

The AER is not required to make a decision on energy consumption forecasts because the AER is regulating Aurora's standard control services under a revenue cap.[30]

However, there are relationships between energy consumption, maximum demand and new customer connections. The AER did examine forecasts of energy consumption to ensure consistency with its forecasts of maximum demand and new customer connections. In its draft determination, the AER was concerned that Aurora's forecasts of economic growth used to develop its energy consumption forecasts differed from forecasts of economic growth used to develop the Transend state-wide maximum demand forecasts (to which Aurora reconciled its maximum demand forecasts).[31]

Electricity consumption forecasts are important for setting tariff levels, but the AER is not required to set tariffs in this determination. Aurora must submit its proposed prices for the first year of the forthcoming regulatory control period to the AER for approval within 15 business days of the AER publishing its final determination.[32] The AER considers Aurora's forecasts are appropriate for the purposes of illustrating indicative tariffs and pricing impacts of the AER's final determination.

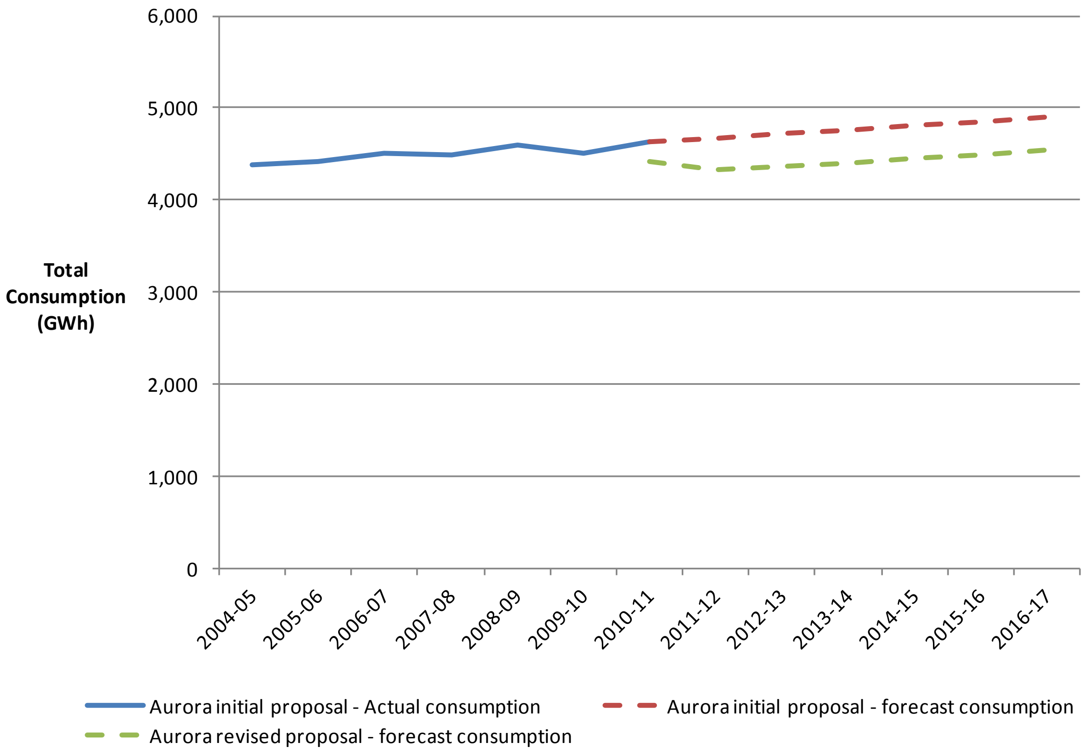
[30] AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 73.

[31] AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 87–88.

[32] NER, clause 6.18.2(a).

In its revised proposal, Aurora submitted a revised set of consumption forecasts that were updated from its initial proposal. The consumption forecasts provided by Aurora in its initial and revised proposals are depicted in Figure 2.5.

Figure 2.5 Historical and AER forecast total consumption (Gigawatt hours)



Source: ACIL Tasman, *Energy consumption forecasts 2011-12 to 2016-17*, January 2012, p. 56; ACIL Tasman, *Energy consumption forecasts 2010-11 to 2016-17*, June 2011, p. 6.

Demand management incentive scheme

To assist Aurora with meeting and managing expected demand, the AER in its draft determination, accepted and implemented a demand management incentive scheme for the forthcoming regulatory control period.[33] This scheme is designed to provide incentives for Aurora to pursue and implement innovative and efficient non-network solutions to address growing demand on its network. The AER will apply an annual demand management incentive allowance for Aurora of $379,799 ($2009–10) in accordance with the AER's framework and approach paper.[34] This equates to $1.9 million over the forthcoming regulatory control period. Aurora did not contest the AER's draft determination on the DMIS (see Attachment 1).

2.2.2 Complying with regulatory obligations

As a Tasmanian-based DNSP operating in the NEM, Aurora must comply with a number of statutory obligations at the national and state level.[35] These include:

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33 This is a constituent decision of a distribution determination under clause 6.12.1(9) of the NER.

34 AER, *Framework and approach paper*, November 2010, p. 136.

35 Aurora, *Regulatory proposal 2012–17,* May 2011, Attachment AE064.

- its Tasmanian Electricity Distribution Licence
- the requirements of the NEL and NER
- safety legislation such as the *Electricity Industry Safety and Administration Act 1997 (*Tas*)*
- Tasmanian electricity supply industry legislation and guidelines, such as the *Electricity Supply Industry Act 1995* and the *Tasmanian Electricity Code* (TEC)
- all relevant state and federal environmental, planning and cultural heritage legislation
- all statutory workplace health and safety requirements including the *Workplace Health & Safety Act 1995 (*Tas*)*.

In its initial regulatory proposal, Aurora did not anticipate any expenditure arising from new regulatory obligations for 2012–17,[36] and has maintained this position in its revised proposal.[37] However, during the forthcoming regulatory control period, Aurora will be subject to new requirements arising from the *National Energy Customer Framework*[38] and may be affected by outcomes arising from the review of the Tasmanian electricity supply industry.[39] The AER has taken Aurora's current obligations into consideration in developing substitute total capex and opex forecasts. Where appropriate, the AER will consider new obligations arising from legislative changes during the forthcoming regulatory control period as cost pass throughs.

2.2.3 Maintaining quality, reliability and security of supply

Aurora's network must supply reliable and secure electricity. As Aurora's network ages, or demand for electricity increases, Aurora may not be able to deliver electricity distribution services as required by the NER unless Aurora appropriately maintains its network. Many of the requirements in this objective overlap with regulatory obligations applying to Aurora. For example, Aurora is subject to power quality and reliability requirements under Tasmanian electricity supply industry legislation.

Service target performance incentive scheme

The AER's service target performance incentive scheme (STPIS) is applied to Aurora in the forthcoming regulatory control period.[40] This incentive scheme will financially reward Aurora for improving on its historical performance and penalise Aurora should its performance fall below historical levels. Maintaining quality, reliability and security of supply is therefore linked to STPIS targets, and this incentive scheme encourages Aurora to deliver efficient levels of reliability. In its draft determination, the AER applied an s-factor (STPIS) adjustment of ±5 per cent of Aurora's total revenue cap.[41] The AER maintains this approach in its final determination. Aurora will continue to be the subject of OTTER's jurisdictional guaranteed service level scheme in the forthcoming regulatory control period.

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36 Aurora has assumed its compliance obligations will remain unchanged for the forthcoming regulatory control period. Aurora, *Regulatory proposal 2012–17,* May 2011, p. 120.

37 Aurora, *Revised regulatory proposal 2012–2017*, January 2012, p. 23.

38 Aurora, *Regulatory proposal 2012–17,* May 2011, p. 61.

39 The Electricity Supply Industry Expert Panel has been established to conduct a review into the Tasmanian electricity supply industry. Aurora, *Regulatory proposal 2012–17,* May 2011, p. 61.

40 This is a constituent decision of a distribution determination under clause 6.12.1(9) of the NER.

41 NER, clauses 6.4.3(a)(5) and 6.4.3(b)(5).

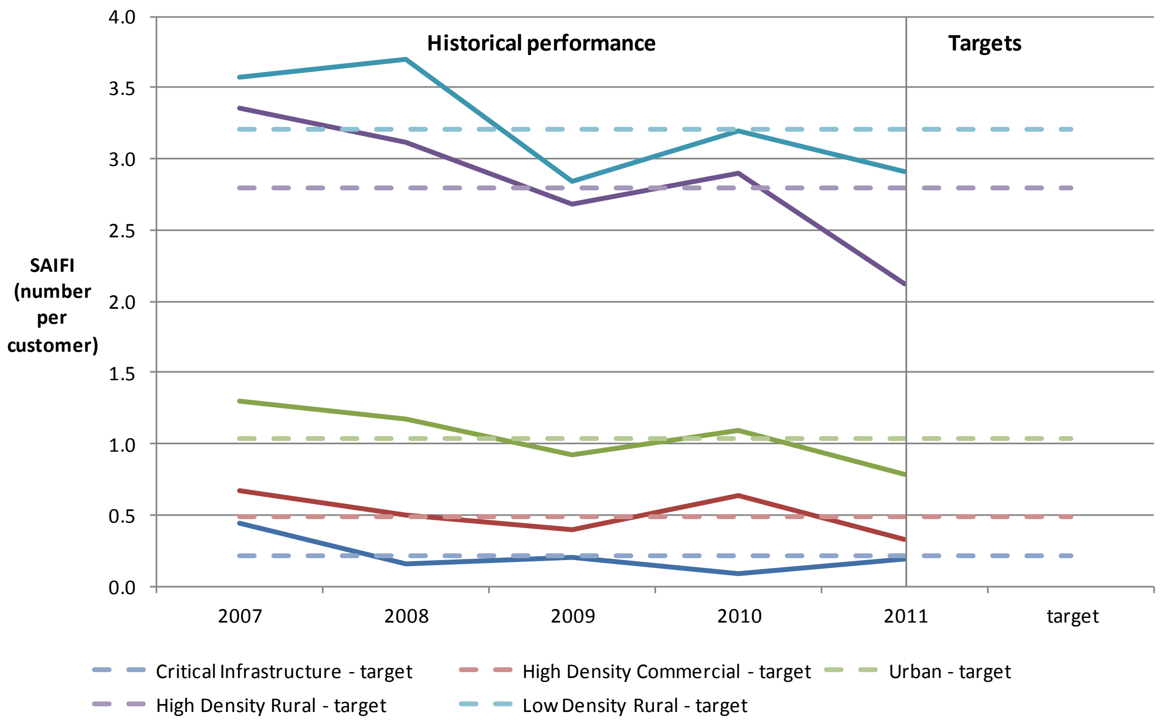
The AER's STPIS includes:

1. the system average interruption duration index (SAIDI) and system average interruption duration index (SAIFI) parameters and components,
2. revenue at risk which caps the risk of the STPIS to Aurora,
3. incentive rates outlining the penalty or reward that Aurora receives for a single unit variation in performance,
4. performance targets for Aurora's STPIS parameters,
5. transitional arrangements on Aurora's Momentary Interruption Frequency Index (MAIFI) performance and
6. the major event day boundary which excludes days in which SAIDI is more than 2.5 standard deviations greater than the mean of the log normal distribution of five regulatory year's SAIDI data.

In its revised regulatory proposal, Aurora highlighted a coding error in the AER's draft determination approach to adjusting Aurora's reliability targets to account for jurisdictional reliability targets. The AER noted the error and has revised its calculation of Aurora's reliability performance against the TEC reliability standards.

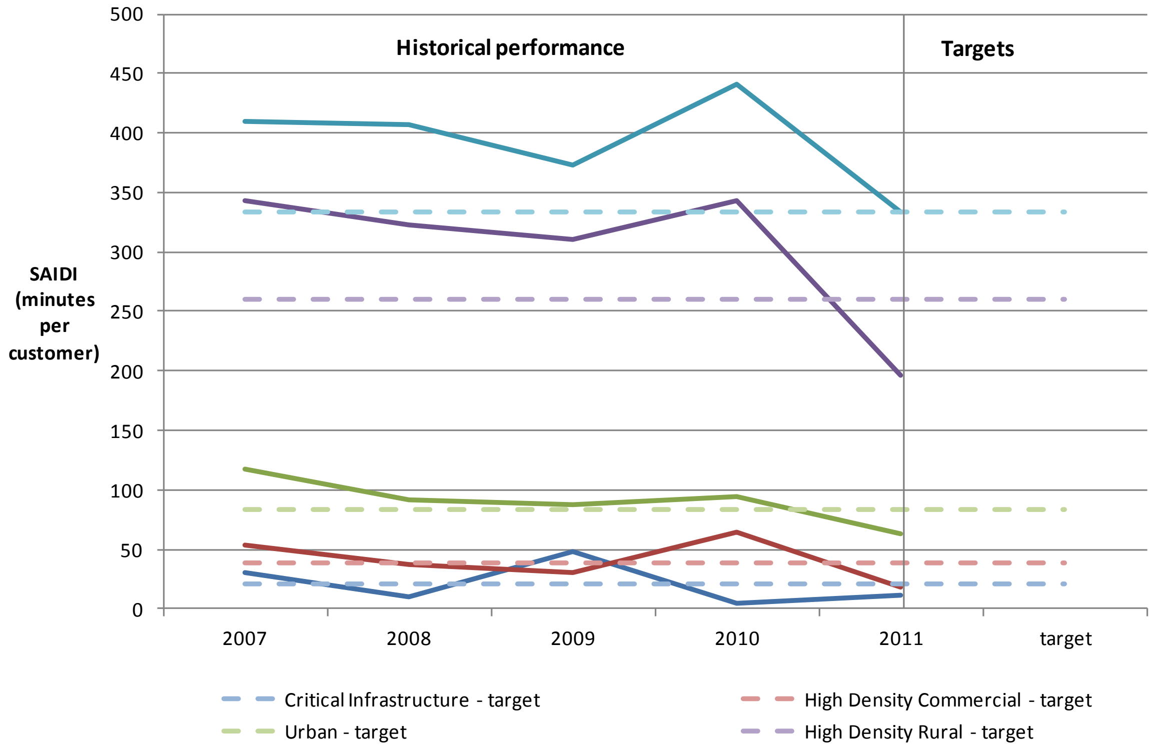
The final STPIS targets are presented in table 2.1 below. The AER considers that these targets better promote the reliability of supply experienced by Aurora's customers than the targets determined in the AER's draft determination and those proposed by Aurora in its revised proposal.

Figure 2.6 Aurora's historical SAIFI performance and AER targets



Source: AER analysis.

Figure 2.7 Aurora's Historical SAIDI performance and AER targets



Source: AER analysis.

The AER determines a telephone answering performance target for Aurora. Aurora's call centre is important as it is a key interface between Aurora and its customers. Aurora gathers network performance information through its call centre. In its draft determination, the AER set a target for Aurora to answer 73.6 per cent of calls to its call centre within 30 seconds of receiving the call. Aurora noted in its revised proposal that the AER's incentive rate for telephone answering differed from the incentive rate in the STPIS. The AER accepts Aurora's position and will apply an incentive rate of -0.040 per cent for the telephone answering parameter. The AER has set out its detailed reasoning for the STPIS in Attachment 12.

2.2.4 Maintaining reliability, safety and security of the system

Aurora's distribution system must also be reliable, safe and secure. Elements of this objective overlap with the requirement to maintain quality, reliability and security of supply. But in particular, this objective is to ensure Aurora's network does not pose safety risks to either its personnel or the public. Many of the requirements in this objective therefore also overlap with regulatory obligations. For example, Aurora must comply with electricity industry safety legislation such as the *Electricity Industry Safety and Administration Act 1997*, and workplace safety legislation such as the *Workplace Health & Safety Act 1995 (Tas)*.

Among other things, network reliability, safety and security may be affected by:

- asset replacement and maintenance
- older or poorer condition assets
- unsafe assets

- environmental factors.

In its initial regulatory proposal, Aurora identified many reliability, safety and security issues with its network, and forecast capex and opex to address them. In its draft determination, the AER did not accept all of Aurora's proposed capex and opex but agreed that Aurora's distribution network faces a number of safety and security issues that should be addressed in the forthcoming regulatory control period. In its revised regulatory proposal, Aurora did not accept the AER's draft determination capex and opex forecasts.[42] The AER considers in its final determination capex and opex forecasts reasonably reflects the efficient costs that a prudent operator in Aurora's circumstances requires to maintain reliability, safety and security of its distribution system.

The AER has set out its reasoning for the forecast capex and opex it considers Aurora requires in more detail in Attachments 6 and 7.

[42] Aurora, *Revised regulatory proposal 2012–2017*, January 2012, pp. 55, 64–65.

3 Regulatory asset base

The regulatory asset base (RAB) is used to calculate the return on, and return of, capital.[43] Aurora recovers the cost of this capital over the expected lives of the assets in its RAB. The AER must make a determination on Aurora's proposed opening RAB.[44] It does so by assessing Aurora's RAB at the start of the previous regulatory control period, and rolling it forward to the end of that period. The roll forward involves adding capital expenditure to, and subtracting depreciation and disposals from, the starting RAB value to arrive at a RAB as at 30 June 2012. This closing RAB forms the opening RAB for the forthcoming regulatory control period. From this opening RAB a forecast RAB for each year of the forthcoming regulatory control period is determined.

3.1 Determination

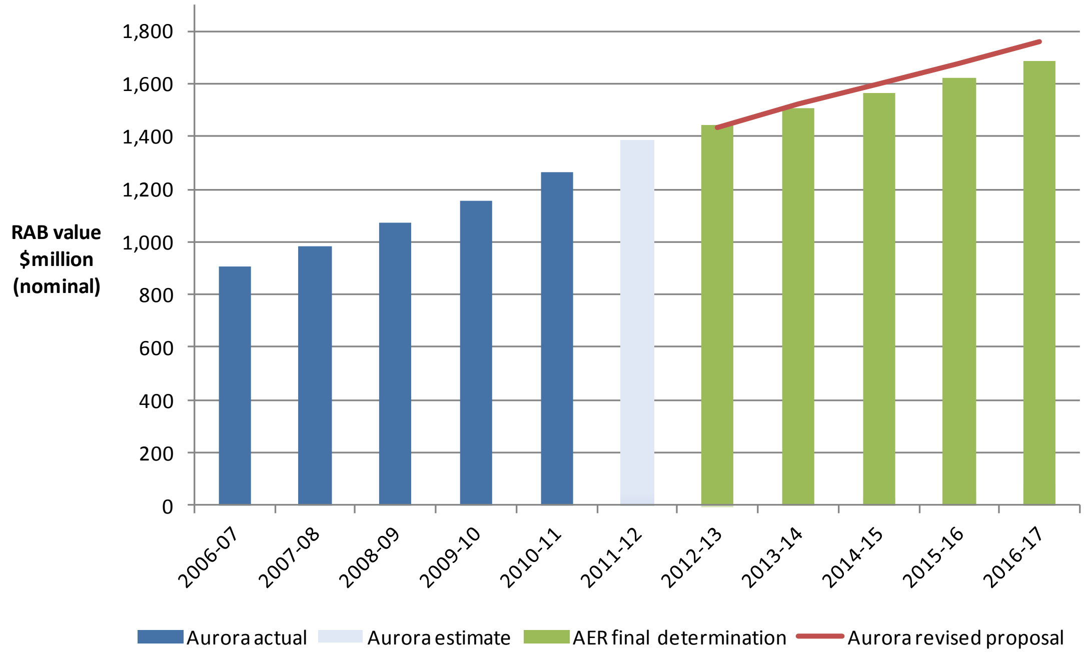
The AER does not accept Aurora’s revised opening RAB proposal of $1436.7 and instead determines the opening RAB as at 1 July 2012 to be $1445.2 million. The AER and Aurora’s opening RAB estimates differ as the AER has made input changes to Aurora’s revised roll forward model. These changes relate to the indexation adjustment for inflation and the treatment of spare parts assets.

The AER has forecast Aurora’s closing RAB as at 30 June 2017 to be $1750.4 million ($nominal), a 5.2 per cent reduction on Aurora’s proposed value of $1847.0 million ($nominal). The difference reflects the AER’s changes to the opening RAB as at 1 July 2012, the inflation forecast for the forthcoming regulatory control period, forecast capital expenditure, and forecast depreciation. Figure 3.1 displays Aurora's past actual opening RAB values compared to forecast values.

[43] The return on capital is Aurora's asset base multiplied by the rate of return, and return of capital is the depreciation of the asset base.

[44] NER, clause 6.12.1(6).

Figure 3.1 Aurora's past and forecast opening RAB values and the AER's final determination opening RAB values($million, nominal)



Source: AER analysis, Aurora's RFM, Aurora's PTRM.

Table 3.1 shows the AER's roll forward of Aurora's RAB from the final year of the previous regulatory period (2006–07) to the start of the forthcoming regulatory control period.

Table 3.1 AER final determination on Aurora's RAB for the current regulatory control period ($million, nominal)

	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12[a]
Opening RAB	908.2	984.1	1,066.0	1,176.2	1,276.4	1,379.5
Capital expenditure[b]	111.7	105.0	130.7	144.0	138.8	140.5
CPI indexation on opening RAB		29.1	39.3	24.8	33.8	42.8
Straight-line depreciation[c]	–35.8 [d]	–52.3	–59.8	–68.6	–69.5	–71.9
Closing RAB	984.1	1,066.0	1,176.2	1,276.4	1,379.5	1,490.8
Difference between forecast and actual capex (1 July 2006 to 30 June 2007)						–21.8
Return on difference for 2006–07 capex						–11.5
Adjustment for shared assets						–12.2
Opening RAB as at 1 July 2012						1,445.2

Source: AER analysis.
Notes: (a) Based on estimated capex. An update for actual capex will be made at the next reset.
(b) Net of disposals and capital contributions, and adjusted for actual CPI and WACC.
(c) Adjusted for actual CPI.
(d) Represents the forecast regulatory depreciation allowance from OTTER. Differences between forecast and actual depreciation are effectively picked up in the end of period adjustments.

Table 3.2 shows the AER's roll forward of Aurora's RAB over the forthcoming regulatory control period.

Table 3.2 AER final determination on Aurora's RAB for the forthcoming regulatory control period ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17
Opening RAB	1,445.2	1,505.3	1,566.0	1,624.6	1,686.1
Capital expenditure[a]	105.9	112.1	107.4	104.1	107.0
Inflation indexation on opening RAB	37.6	39.1	40.7	42.3	43.8
Straight line depreciation	–83.4	–90.5	–89.5	–84.9	–86.6
Closing RAB	1,505.3	1,566.0	1,624.6	1,686.1	1,750.4

Source: AER analysis.
Notes: (a) Net of disposals and capital contributions. In accordance with the timing assumptions of the PTRM, the capex includes a half-WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes.

3.2 Summary of analysis and reasons

The AER's final determination opening RAB for Aurora for 1 July 2012 is higher than Aurora's revised proposal due to the net effect of changes the AER has made to indexation for inflation (which reduces the RAB) and the treatment of spare parts assets (which increases the RAB).

3.2.1 Indexation approach

The AER maintains its position from the draft determination to use December-December CPI to index the RAB, instead of Aurora's revised proposal of June-June CPI indexation. In the draft determination, the AER used December-December CPI for indexation as it considered this was consistent with the existing control mechanism as required under clause 6.5.1(e)(3) of the NER.[45]

3.2.2 Treatment of spare parts

The AER determines that asset classes for 'spare parts' and 'emergency network spares' should not be depreciated when added to Aurora's opening RAB values. Aurora agrees with the AER's final determination.[46] Spare parts will be maintained as stock (similar in treatment to land and easements).

The effect of not depreciating spare parts asset categories will increase Aurora's RAB by $10.1 million as at the 30 June 2012.

3.2.3 Forecast closing RAB as at 30 June 2017

The AER determines Aurora's RAB to be $1750.4 million as at 30 June 2017. The AER's forecast results from changes the AER has made to Aurora's PTRM for the forthcoming regulatory control period. These changes are:

- Aurora's opening RAB as at 1 July 2012, as discussed in attachment 8
- the inflation forecast for the forthcoming regulatory control period, as discussed in attachment 10
- forecast capital expenditure, as discussed in attachment 6, and
- forecast depreciation, as discussed in attachment 9.

The AER has set out its detailed reasoning for Aurora's RAB in Attachment 8.

45 NER, clause 6.5.1(e)(3)

46 Aurora, *Response to information request AER/068 of 23 February 2012*, received 28 February 2012.

4 Regulatory depreciation

Regulatory depreciation is a building block in Aurora's annual revenue requirement. It is also used to model the change in Aurora's RAB over the forthcoming regulatory control period. Regulatory depreciation is the difference between Aurora's straight-line depreciation on its assets and the annual inflation indexation on its RAB. The AER must make a determination on Aurora's depreciation allowance (including schedules) for the forthcoming regulatory control period.[47]

4.1 Determination

The AER does not accept Aurora's revised regulatory proposal for a depreciation allowance of $227.5 million ($nominal) over the forthcoming regulatory control period. The AER's adjustments to Aurora's revised proposal for opening RAB, forecast capex, and forecast inflation will alter forecast regulatory depreciation under clause 6.5.5 of the NER. The AER has also determined that no depreciation will apply to the 'emergency network spares' and 'spare parts' asset categories. The AER's amendments result in a depreciation allowance of $231.3 million ($nominal), (a 1.7 per cent increase) as shown in Table 4.1. The increase is driven by the AER's marginally lower inflation forecast and revised remaining asset lives.

Table 4.1 AER final determination on Aurora's depreciation allowance ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Straight-line depreciation	83.4	90.5	89.5	84.9	86.6	434.8
Less: indexation of opening RAB	37.6	39.1	40.7	42.2	43.8	203.5
Regulatory depreciation	45.8	51.3	48.8	42.7	42.7	231.3

Source: AER analysis.

4.2 Summary of analysis and reasons

The AER does not accept Aurora's forecast depreciation allowance and has developed an alternative depreciation forecast for the forthcoming regulatory control period based upon changed remaining asset lives and no allowance for depreciation on the 'emergency network spares' and 'spare parts' asset categories.

4.2.1 Remaining asset lives

The AER does not accept Aurora's revised proposal for remaining asset lives as being consistent with clause 6.5.5(b)(1) of the NER. The AER considers that remaining asset lives should reflect the AER's amendments to actual capex, CPI indexation and the movement of provisions.

47 NER, clause 6.12.1(8).

4.2.2 Standard asset lives – ‘spares’

The AER determines that the asset classes ‘emergency network spares’ and ‘spare parts’ (collectively referred to as ‘spares’) should not be depreciated until they become an operational part of Aurora’s network.

The AER has set out its detailed reasoning for Aurora’s depreciation in Attachment 9.

5 Capital expenditure

Capex includes load driven network augmentation, connections, asset replacements and non-network expenditure such as IT, plant and equipment, motor vehicles and buildings. Aurora is required to submit a building block proposal to the AER that forecasts capex for the 2012–13 to 2016–17 regulatory control period.[48]

Aurora proposed a revised total forecast capex of $618.1 million ($2009–10) for the forthcoming regulatory control period. The AER must accept Aurora's revised total forecast capex if satisfied it reasonably reflects the capex criteria.[49] If not satisfied, the AER must give reasons for not accepting Aurora's proposal, and estimate the total required capex that reasonably reflects the capex criteria.[50] In doing so, the AER must have regard to the capex factors.[51]

5.1 Determination

The AER is not satisfied that Aurora's revised proposal capex reasonably reflects the capex criteria. The AER considers that a prudent operator in Aurora's circumstances (given a realistic expectation of the demand forecast and the cost inputs) could achieve the capex objectives with less capex than Aurora’s revised regulatory proposal.

The AER has estimated a substitute total capex for Aurora that the AER considers reasonably reflects the capex criteria, having regard to the capex factors. The AER’s estimate reduces Aurora's revised proposal of total forecast capex only to the extent necessary to comply with the NER.[52] Overall, the AER estimates a total forecast capex of $535.4 million ($2009–10) over the forthcoming regulatory control period. This equates to a reduction of approximately $82.7 million ($2009–10), or 13.4 per cent of Aurora’s revised total capex.

Table 5.1 displays the AER's estimate of the capex allowance required by Aurora for the forthcoming regulatory control period that reasonably reflects the capex criteria.[53]

Table 5.1 AER final determination on Aurora's total forecast capex ($million, 2009–10)

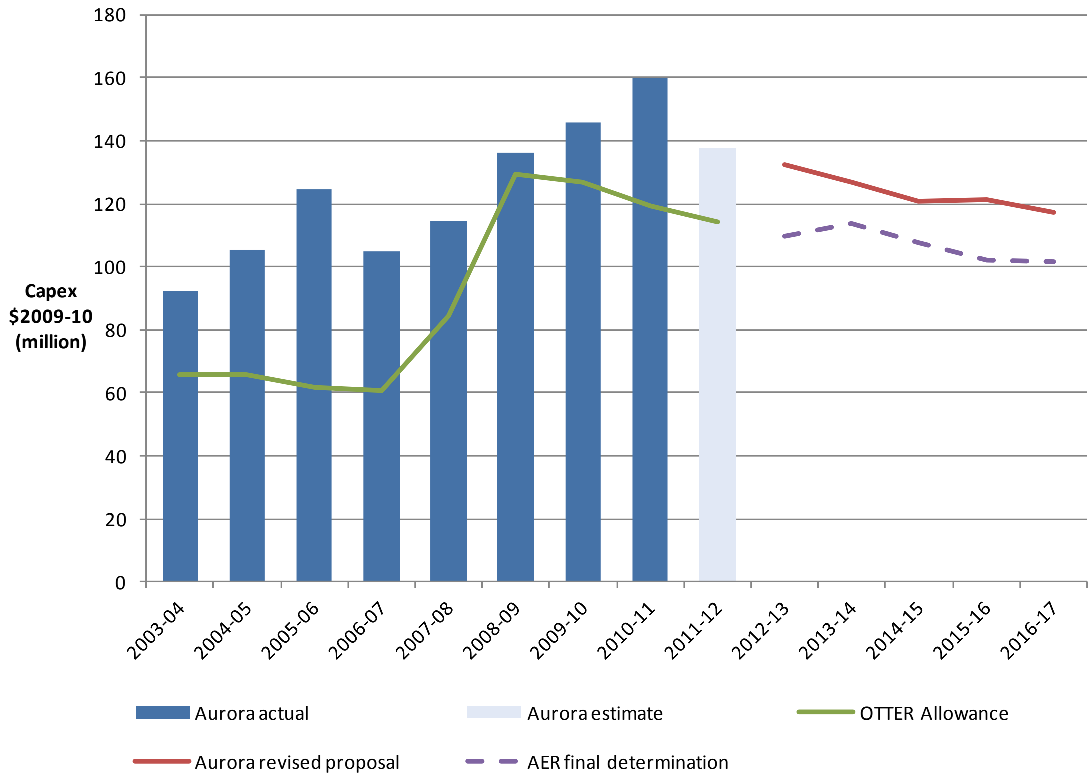
	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Aurora's revised proposal	132.4	126.7	120.7	121.1	117.2	618.1
Adjustment	22.5	12.8	12.9	19.2	15.3	82.7
AER final determination	109.9	113.9	107.8	102.0	101.8	535.4

Source: AER analysis.

Figure 5.1 compares Aurora's past and forecast total capex with the AER’s final determination.

48 NER, clause 6.8.2(c)(2).
49 NER, clauses 6.5.7(c) and 6.12.1(3)(i).
50 NER, clauses 6.5.7(d) and 6.12.1(3)(ii).
51 NER, clause 6.5.7(e).
52 NER, clause 6.12.3(f).
53 NER, clause 6.12.1(3)(ii).

Figure 5.1 Comparison of Aurora's past and forecast total capex and AER final determination ($million, 2009–10)



Source: AER analysis, Aurora's RIN template.

5.2 Summary of analysis and reasons

The AER is not satisfied that Aurora's total forecast capex reasonably reflects the capex criteria. The AER has come to this view based on a detailed review of Aurora's capex proposal and supporting documentation. The AER has considered historical costs and benchmarking to determine whether Aurora's total capex forecast reasonably reflects an efficient forecast,[54] and has considered the impact of Aurora's revised proposal estimate of maximum demand forecasts on Aurora's total capex. The AER has also used the following assessment techniques to assess whether Aurora's total capex is based on a realistic expectation of demand forecast and cost inputs:[55]

- unit cost comparative analysis
- age-based replacement modelling
- sampling analysis for demand driven capex
  - cash flow analysis for equity raising costs.

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54 NER, clause 6.5.7(c)(1) and (2).

55 NER, clause 6.5.7(c)(3).

The AER considers that much of the capex proposed by Aurora in its revised proposal is consistent with the requirements of the NER. However, the AER considers that several elements of Aurora's total forecast capex within its revised proposal are overstated. The AER's main concerns[56] with Aurora's revised proposal are:

- Aurora is proposing to replace more of its assets than necessary. Aurora can maintain its network with less expenditure. Aurora has not sufficiently justified an increase in the replacement volumes of some programs from historical levels. The AER considers a reduction of $28.8 million ($2009–10) 4.7 per cent of Aurora's total forecast capex proposal) is required to address this concern.

- $14.6 million ($2009–10) (2.4 per cent of Aurora's total forecast capex proposal) is for reliability improvement investment. The AER considers this expenditure is beyond that required for Aurora to achieve the capex objectives. Consistent with its draft decision, the AER has not allowed for this capex in its final determination.

- Some of Aurora's forecast capex to address growth in maximum demand is too extensive in scope, and more prudent solutions should be available. The AER considers that Aurora's revised proposal reflects a realistic expectation of demand but the AER does not accept Aurora's proposed capex to address demand-related issues is required to achieve the capex objectives in a manner that reasonably reflects the capex criteria. Accordingly, the AER has estimated an allowance of $26.3 million ($2009–10) for demand-related capex. This represents a 4.3 per cent reduction in the capex allowance, compared to Aurora's revised proposal.

- Aurora's constructed its revised capex forecast using revised unit rates that the AER considers the NER did not permit Aurora to change. The AER has set these aside, and applied the unit rates in Aurora's initial regulatory proposal. The impact of this adjustment is approximately $15.4 million ($2009–10).

- Aurora's revised proposal included a new labour escalation methodology that the AER considers that the NER did not permit Aurora to submit. The AER has set this methodology aside, and considers that labour cost escalation using CPI is appropriate.

In addition to making adjustments to account for these concerns, the AER has reallocated Aurora's shared costs across opex, capex and alternative control services using a methodology that closely reflects Aurora's CAM.[57]

Attachment 6 contains the AER's detailed reasons for its final determination on Aurora's total forecast capex.

56 The quantum of each concern excludes capitalised overheads and input price changes. The percentages also relate to unescalated total capex excluding capitalised overheads.

57 Aside from Aurora's direct labour hours allocator. The AER has used the previous proportion of direct costs as the allocator for these shared costs instead of the labour hours escalator.

6 Rate of return

The NER requires the AER to make a determination on the rate of return on Aurora's capital investment. In making this determination, the AER must consider whether to apply or depart from a value, method or credit rating level set out in the AER's statement of regulatory intent (SRI).[58] The SRI was issued by the AER following completion of its review of the parameters in the weighted average cost of capital (WACC review) in May 2009.[59] Under the NER, the rate of return the AER must apply is based on the nominal vanilla WACC formulation.[60] Aurora’s return on capital building block is calculated by multiplying the rate of return with the value of Aurora’s regulatory asset base (RAB).

6.1 Determination

The AER does not accept Aurora's revised proposal (indicative) WACC of 9.97 per cent. In this final determination, the AER determines a WACC of 8.28 per cent for Aurora as set out in Table 3.1. The nominal risk free rate and debt risk premium (DRP) were estimated over a 20 business day averaging period commencing on 9 January 2012 and ending on 6 February 2012.

Aurora's initial proposal submitted values for the equity beta (0.8), gearing (60 per cent), assumed utilisation of imputation credits (gamma)(0.25), and the credit rating level (BBB+) that were consistent with the values and credit rating set out in the WACC review.[61] The AER did not consider there was persuasive evidence justifying a departure from the WACC review position on these parameters. Accordingly, the AER accepted Aurora's proposed parameters in the draft determination.

The AER also agreed to Aurora's proposed averaging period to calculate the nominal risk free rate, which was consistent with the SRI methodology. However, the AER did not accept Aurora's proposed value for the market risk premium (6.5 per cent) (MRP) or its proposed method for setting the DRP.

In this final determination:

- the AER accepts Aurora's revised proposal methodology to estimate the DRP which is based on the Bloomberg 7 year BBB rated fair value curve (FVC) extrapolated to a 10 year term
- the AER does not accept Aurora's revised proposal to adopt the MRP value (6.5 per cent) from the SRI. The AER considers, consistent with its draft decision, that there is persuasive evidence justifying a departure from this value.
- the AER does not accept Aurora's revised proposal to depart from the SRI methodology to calculate the risk free rate with respect to:
    - amending the averaging period after it has been agreed or specified, and
    - using an averaging period which is not as close as practicably possible to the commencement of Aurora's regulatory control period

58 NER, clause 6.12.1(5).
59 NER, clause 6.5.4(c).
60 NER, clause 6.5.2(b).
61 The gamma parameter affects the corporate income tax building block, which is discussed in attachment 11.

The AER does not consider there is persuasive evidence justifying a departure from these or other elements of the SRI methodology on the risk free rate.

The AER adopts substitute values for the:

- MRP of 6 per cent,
- nominal risk free rate of 3.89 per cent (based on the 20 business day averaging period ending 6 February 2012 which is calculated in accordance with the SRI methodology)

By making these changes, the AER amends Aurora's proposed values for the MRP and risk free rate only to the extent necessary to enable those values to be approved in accordance with the NER.

In addition to bottom-up analysis on the parameter inputs, the AER also assesses the overall rate of return against market data to examine the overall WACC's appropriateness.[62]

Table 6.1 AER final determination on Aurora's WACC parameters

Parameter	AER draft determination	Aurora revised proposal	AER final determination
Nominal risk free rate	4.28%	5.50%	3.89%
Equity beta	0.80	0.80	0.80
Market risk premium	6.00%	6.50%	6.00%
Gearing level (debt/debt plus equity)	60%	60%	60%
Debt risk premium	3.14%	3.98%	4.11%
Assumed utilisation of imputation credits (gamma)[a]	0.25	0.25	0.25
Inflation forecast	2.62%	2.63%	2.60%
Cost of equity	9.08%	10.70%	8.69%
Cost of debt	7.42%	9.48%	8.00%
Nominal vanilla WACC	8.08%	9.97%	8.28%

6.2 Summary of analysis and reasons

The AER's final determination on Aurora's rate of return differs from Aurora's revised regulatory proposal primarily due to lower values for the nominal risk free rate and MRP.

The AER has applied the persuasive evidence test in the NER in making its final distribution determination on SRI values, methods and credit rating levels.[63] The AER considers there is persuasive evidence justifying a departure from the SRI value for the MRP.

62 NER, clause 6.5.2(b).
63 NER, clause 6.5.4(g).

6.2.1 Nominal risk free rate

The AER determines the nominal risk free rate on a moving average basis from the annualised yield on Commonwealth Government bonds over an averaging period that is as close as practicably possible to the commencement of the regulatory control period.[64]

The AER does not accept Aurora's revised proposal to depart from the SRI methodology, and specifically to adopt a long term historical average risk free rate, as:

- the prevailing 10 year Commonwealth Government Securities (CGS) yield is a forward looking 10 year risk free rate
- each WACC parameter should be estimated based on considerations relevant to that parameter, rather than to deal with issues relating to another parameter
- CGS bonds are efficiently priced in a liquid market, there is no persuasive evidence suggesting the CGS market is distorted
- CGS are low risk
- CGS yields are determined in a market, meaning the prevailing yield reflects the market's determination of the appropriate price at a particular time
- the averaging period method in the SRI is objective and unbiased
- there is no persuasive evidence justifying a departure from setting the risk free rate averaging period as close as possible to the start of the regulatory period.

6.2.2 Market risk premium

The AER considers there is persuasive evidence justifying a departure from the 6.5 per cent MRP set out in the SRI. In the AER's opinion, a value of 6.5 per cent is now inappropriate as:

- The AER's reasons for moving from the long term value of 6 to 6.5 per cent at the time of the WACC review appear less relevant now. Specifically, the AER is less convinced of the likelihood that the GFC led to a structural break in the market, and it appears that the heightening of market risk at the time has since eased.
- The AER's experts, Professor McKenzie and Associate Professor Partington from the University of Sydney, advised that the AER's reasons for moving to 6.5 per cent were not well justified in the WACC review.[65] McKenzie and Partington advised the AER to adopt a MRP of 6 per cent
- Historical excess returns and survey evidence support 6 per cent as a forward looking 10 year MRP estimate.
- In the recent Envestra matter, the Tribunal held that it was open for the AER to adopt 6 per cent for the MRP.

[64] NER, clause 6.5.2(c).

[65] McKenzie, M. and G. Partington, *Supplementary report on the equity market risk premium*, 22 February 2012, December 2011, pp.28-30.

For these reasons, the AER does not approve Aurora's revised proposal MRP value of 6.5 per cent. For these same reasons, the AER has substituted Aurora's proposal with a value of 6 per cent which is amended from Aurora's proposal only to the extent necessary to enable it to be approved in accordance with the NER.

6.2.3 Debt risk premium

The AER has changed its position on the DRP set out in the draft determination and accepts the methodology in Aurora's revised regulatory proposal. Following the release of the draft determination, the Australian Competition Tribunal (Tribunal) released its decisions relating to APT Allgas and Envestra's access arrangements and the Victorian electricity DNSPs. Among other issues, the Tribunal considered the AER's approach to estimating the DRP. The Tribunal found error in the AER's approach to estimating the DRP. It decided that for those regulatory decisions under review, 100 per cent weight would be placed on the extrapolated Bloomberg BBB rated FVC to estimate the DRP.[66] The Tribunal stated that if the AER wishes to adopt an alternative methodology to the extrapolated Bloomberg BBB rated FVC, it should develop the alternative approach through an industry wide consultation process.

The AER considers that there may be other preferable methodologies to estimate the DRP. Notwithstanding this, the AER acknowledges the Tribunal's views and agrees that it is desirable to consult widely on a new approach to estimate the DRP before it is used. The AER will begin an internal review of alternative methods to estimate the DRP and advise of a public consultation process in due course. For this final determination the AER has adopted the extrapolated Bloomberg BBB rated FVC to estimate the DRP, consistent with Aurora's revised regulatory proposal. Based on the same averaging period used to estimate the risk free rate, the AER has determined a benchmark DRP of 4.11 per cent (effective annual compounding rate).

The AER's final determination on Aurora's WACC results in the return on capital for each year of the forthcoming regulatory control period as set out in table 6.2. The AER has provided detailed reasons for its WACC determination in Attachment 10.

Table 6.2 AER final determination on Aurora's return on capital ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Aurora's revised proposal	143.2	151.5	159.3	166.9	175.5	796.5
Adjustment	23.6	27.0	29.7	32.5	36.0	148.7
AER final determination	119.6	124.6	129.6	134.5	139.5	647.8

Source: AER analysis.

66 Australian Competition Tribunal, *Application by Envestra Ltd (No 2) [2012] ACompT 3*, 11 January 2012, paragraph 120; Australian Competition Tribunal, *Application by APT Allgas Energy Ltd [2012] ACompT 5*, 11 January 2012, paragraph 117; and Australian Competition Tribunal, *Application by United Energy Distribution Pty Ltd (No 2) [2012] ACompT 1*, 6 January 2012, paragraph 462.

7 Operating expenditure

Operating expenditure (opex) is the operating, maintenance and other non-capital costs that Aurora incurs in providing standard control services.

Aurora proposed a revised total forecast opex of $360.4 million ($2009–10) over the forthcoming regulatory control period in its revised regulatory proposal. The AER must accept Aurora's revised total forecast opex if satisfied it reasonably reflects the opex criteria.[67] If not satisfied, the AER must give reasons for not accepting Aurora's proposal, and estimate the total required opex that reasonably reflects the opex criteria.[68] In doing so, the AER must have regard to the opex factors.[69]

7.1 Determination

The AER is not satisfied that Aurora's total forecast opex reasonably reflects the opex criteria. The AER considers that a prudent operator in Aurora's circumstances (given a realistic expectation of the demand forecast and the cost inputs) could achieve the opex objectives with less opex than Aurora’s proposal.[70]

The AER has estimated a substitute total opex for Aurora that the AER considers reasonably reflects the opex criteria, having regard to the opex factors. This estimate reduces Aurora's proposal of total forecast opex only to the extent necessary to comply with the NER.[71] Overall, the AER estimates a total forecast opex of $341.9 million ($2009–10) over the forthcoming regulatory control period. This equates to a reduction of approximately $18.5 million ($2009–10), or 5.1 per cent of Aurora’s proposed total opex.

Table 7.1 displays the AER's estimate of the opex allowance required by Aurora for the forthcoming regulatory control period that reasonably reflects the opex criteria.[72]

Table 7.1 AER final determination on Aurora's total forecast opex ($million, 2009–10)

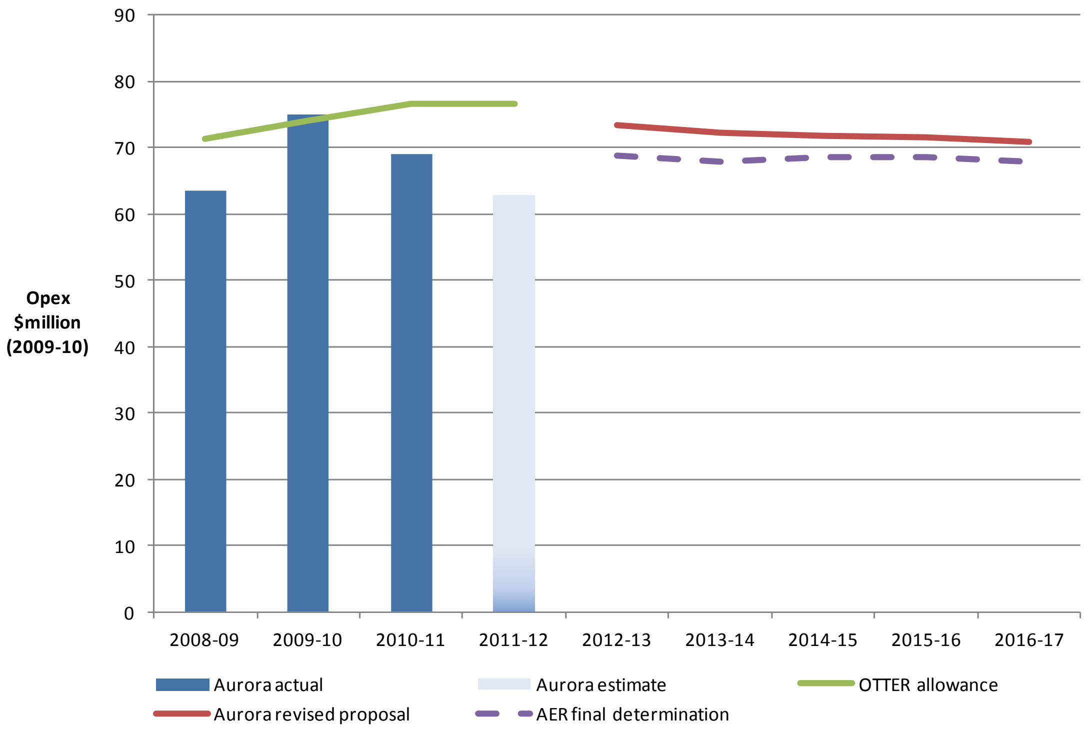
	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Aurora's revised proposal	73.5	72.4	71.9	71.7	71.0	360.4
Adjustment	4.6	4.5	3.3	3.2	3.0	18.5
AER final determination	68.9	67.9	68.7	68.5	68.0	341.9

Source: AER analysis.

Figure 7.1 compares Aurora's past and forecast total opex with proposed and approved opex.

67 NER, clauses 6.5.6(c) and 6.12.1(4)(i).
68 NER, clauses 6.5.6(d) and 6.12.1(4)(ii).
69 NER, clause 6.5.6(e).
70 NER, clause 6.5.6(c). Clause 6.5.6(a) specifies the opex objectives.
71 NER, clause 6.12.3(f).
72 NER, clause 6.12.1(4)(ii).

Figure 7.1 Comparison of Aurora's past and forecast total opex and AER final determination ($million, 2009–10)[73]



Source: AER analysis.

7.2 Summary of analysis and reasons

The AER considers that much of the opex proposed by Aurora in its revised proposal is consistent with the requirements of the NER. However, the AER considers that several elements of Aurora's total forecast opex within its revised proposal are overstated. The AER's main concerns with Aurora's revised proposal opex are:

- Aurora's proposed IT systems opex step change is more than the costs that reasonably reflect the efficient costs that a prudent DNSP in Aurora's circumstances would require to achieve the opex objectives over the forthcoming regulatory control period. Aurora proposed an opex step change to support the capital costs associated with the roll out of its distribution network IT strategy. The AER considers some costs are already being funded internally, and others are not required to support the capex program. The AER has therefore reduced Aurora's IT opex costs by $7.5 million ($2009–10).

- Aurora constructed its revised opex forecast using revised unit rates. Aurora removed the three per cent efficiency factor it originally proposed from these revised unit rates. The AER considers

[73] The AER's allowance and Aurora's actual, estimated and forecast opex are all presented in terms of Aurora's current cost allocation method (CAM). The OTTER allowance is presented in terms of Aurora's previous CAM. The AER could not present OTTER's allowance in terms of the current CAM as the CAM relies on Aurora's underlying business structure, which the OTTER allowance was not set against. This figure includes all historical and forecast opex including non-recurrent expenditures.

the NER did not permit Aurora to make this revision so the AER has applied the unit rates in Aurora's initial regulatory proposal. This change has reduced Aurora's total forecast opex by $3.9 million ($2009–10).

- Aurora's revised proposal included a new labour escalation forecasting methodology. The AER considers the NER do not permit Aurora to change its methodology, and maintains its draft determination approach to escalate Aurora's labour costs by CPI. This results in an increase to Aurora's total forecast opex of approximately $0.9 million ($2009–10).

- Aurora's proposed demand management opex is more than Aurora requires to achieve the opex objectives. Aurora resubmitted its initial proposal despite the AER stating in the draft determination that it did not accept all of Aurora's forecast. In its draft determination, the AER considered certain studies proposed by Aurora should be funded through the DMIA. The AER has maintained its position from the draft determination and considers that a reduction of $0.6 million ($2009–10) is required.

In addition to making adjustments to account for these concerns, the AER has reallocated Aurora's shared costs across opex, capex and alternative control services using a methodology the closely reflects Aurora's CAM.[74] Attachment 7 contains the AER's detailed reasons for its final determination on Aurora's total forecast opex.

7.2.1 Efficiency benefit sharing scheme

The AER will apply the electricity distribution EBSS to Aurora for the forthcoming regulatory control period in accordance with the AER's framework and approach paper.[75] In its revised regulatory proposal, Aurora accepted the AER's draft determination to apply an EBSS in the forthcoming regulatory period. However, Aurora disputed the categorisation of the Trunk Mobile Radio (TMR) cost as a controllable cost and considered that it should not be assessed under the EBSS. [76] The AER does not accept Aurora's revised proposal and maintains that the TMR cost be assessed as part of the EBSS. TMR is a cost that Aurora incurs as a result of its decision to use the TMR and therefore regarded as controllable.

Aurora does not currently operate under an EBSS, or similar jurisdictional scheme, but the AER considers the EBSS should apply to Aurora. The EBSS operates in conjunction with the ex ante incentive framework, to provide DNSPs with a continuous incentive to reduce opex. It provides this continuous incentive by allowing a DNSP to retain efficiency gains for five years before passing them to consumers. It also removes the incentive to overspend in the opex base year to receive a higher opex allowance in the following regulatory control period. The AER notes that Aurora's revenue requirements will not be affected by the EBSS until after the forthcoming regulatory control period.

The AER uses controllable opex forecasts to calculate efficiency gains and losses for the forthcoming regulatory control period. These forecasts are subject to adjustments required by the EBSS. Such adjustments include exclusion of cost categories from the EBSS. Attachment 13 provides the AER's detailed reasoning for the EBSS.

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[74] Aside from Aurora's direct labour hours allocator. The AER has used the previous proportion of direct costs as the allocator for these shared cost instead of the labour hours escalator.

[75] AER, *Framework and approach paper*, November 2010. This is a constituent decision of a distribution determination under clause 6.12.1(9) of the NER.

[76] Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 111–112.

8 Corporate income tax

The estimated cost of corporate income tax is one of the building blocks for Aurora's revenue cap for the forthcoming regulatory control period.[77] The NER requires the AER to publish a post-tax revenue model for Aurora for the forthcoming regulatory control period.[78] However, as Aurora is currently regulated under a pre-tax framework, Aurora must transition from a pre-tax to post-tax model. This involves establishing a tax asset base to determine tax depreciation which is offset against Aurora's forecast income.

8.1 Determination

The AER accepts Aurora’s proposed methodology to establish the opening tax asset base for the transition from the pre-tax to post-tax framework. The AER also accepts the standard tax asset lives and remaining tax asset lives used for tax depreciation purposes. The AER has determined the opening tax asset base as $995.9 million ($nominal) as at 1 July 2012. Consistent with the draft determination, the AER also accepts Aurora's proposal for the value of the assumed utilisation of imputation credits (gamma) of 0.25.

Table 8.1 AER final determination on corporate income tax allowance for Aurora ($million, nominal)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Tax payable	22.0	23.9	23.0	22.7	22.5	114.2
Less: value of imputation credits	-5.5	-6.0	-5.8	-5.7	-5.6	-28.5
Net corporate income tax allowance	16.5	17.9	17.3	17.0	16.9	85.6

Source: AER analysis.

8.2 Summary of analysis and reasons

The AER has assessed Aurora's methodology for establishing the opening tax asset base and considers that its methodology and the tax inputs are consistent with the NER.[79] Furthermore, the AER is satisfied that the proposed values for Aurora’s tax asset base reflect the values associated with its RAB assets and the tax lives for each asset class reflect the tax asset lives of its RAB assets.

Aurora proposed a gamma value of 0.25 based on the finding of the Australian Competition Tribunal (Tribunal).[80] The AER considers that the Tribunal's finding represents persuasive evidence justifying a departure from the value specified under the AER's SRI. The AER has no new evidence to cause it to vary from the Tribunal's finding. Attachment 11 of the AER’s final determination discusses the AER’s detailed reasoning for Aurora’s proposed tax.

77 NER, clause 6.4.3.
78 NER, clause 6.4.1(a).
79 NER, clause 6.5.3.
80 Australian Competition Tribunal, *Application by Energex Limmited (Gamma) (No. 5) [2011] ACompT 9*, 12 May 2011, paragraph 42.

9 Revenue cap control mechanism

The control mechanism for standard control services specifies how Aurora's total annual revenue requirement will change from year to year. In its framework and approach paper for Aurora, the AER decided a revenue cap control mechanism would apply to Aurora's standard control services in the forthcoming regulatory control period.[81]

The NER also provides for pass through events to allow DNSPs to recover legitimate costs that would otherwise be too uncertain to allow for in advance.[82] Pass through costs are added to a DNSP's allowable revenue during a regulatory control period rather than included in the allowance at the time of the AER's determination. The NER prescribes certain pass through events, but a DNSP may propose that the AER nominate additional pass through events.

9.1 Determination

The AER accepts Aurora's revised proposal to apply a revenue cap control mechanism for standard control services.[83] Aurora must demonstrate compliance with the control mechanism through an annual pricing proposal.[84] However, the AER considers some of Aurora's proposed revenue adjustment mechanisms should be excluded from the control mechanism or be modified on the basis they are not consistent with the NER.[85]

The AER accepts Aurora's revised proposal for revenue adjustments to account for the following costs:

- the electricity safety inspection levy (ESISC)
- the national electricity market levy (NEMC)
- under and over recovery of distribution use of system (DUOS) charges
- under and over recovery of transmission use of system (TUOS) charges.

The AER does not accept Aurora's revised proposal which relates to the following revenue adjustments for the forthcoming regulatory control period:

- trunk mobile radio (TMR) levy
- guaranteed service level (GSL) cap
- excess guaranteed service level (GSL) payments
- O-factor banking of revenues.

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81 AER, F*ramework and approach paper*, November 2010, pp. 62–85.
82 NER, clause 6.6.1.
83 NER, clause 6.12.1(11).
84 NER, clause 6.12.1(13).
85 NER, clause 6.2.5(c).

In addition, the AER has included a revenue adjustment mechanism to account for the difference between the estimate of under recoveries (from the current regulatory period) added to the forecast annual revenue requirement and the actual under recoveries incurred. This adjustment mechanism is in the transitional parameter in the control mechanism for the forthcoming regulatory control period.

For pass throughs, the AER has maintained its position from its draft determination, which Aurora did not contest.

9.2 Summary of analysis and reasons

TMR levy

The TMR adjustment is a continuation of a revenue adjustment mechanism relating to Aurora's involvement in the joint government departmental cost of running the TMR network within Tasmania for emergency services.[86]

The AER considers that the TMR levy is a controllable cost that can be forecast that Aurora will incur as a result of its decision to use the TMR. In light of the controllable nature of this cost, the AER does not accept the inclusion of the TMR revenue adjustment mechanism in the control mechanism for standard control services. As such, the AER considers that the TMR levy is appropriately considered as a component of operating expenditure and subject to the efficiency benefit sharing scheme.

GSL risk mitigation mechanisms

The AER does not accept the two GSL risk mitigation mechanisms provided in Aurora's revised proposal:

- GSL cap
- excess GSL payments.

The AER considers that these mechanisms insulate Aurora from the risk of making GSL payments for events that are within its control, and reduce the incentive for Aurora to improve its GSL performance. The AER considers that Aurora's exposure to major transmission and generation outages is limited, as it is already accounted for under the existing Tasmanian GSL scheme. The existing Tasmanian GSL scheme will be ongoing, with exemptions of GSL payments being regulated by OTTER under the Tasmanian Electricity Code.

O-factor banking of revenues

The AER does not accept Aurora's late proposal for the inclusion of an O-factor banking of revenues adjustment mechanism. The O-factor is a continuation of a revenue adjustment mechanism which enables Aurora to 'bank' revenues in one year when there is a prospect that an adjustment in the opposite direction is likely in the following years. This is done to achieve a smoothing of prices over the regulatory control period.

The AER considers the effectiveness of the O-factor is reliant on the ability to forecast demand with considerable accuracy. The AER notes that factors outside Aurora's control can have an unforeseen and considerable impact on its demand. The inability to predict these impacts, as demonstrated by

[86] Aurora, *Regulatory proposal 2012–17*, May 2011, p. 227.

Aurora's current regulatory period under recovery of revenues, can increase the probability of price shocks rather than mitigate them. Particularly later in the regulatory control period when early period banking of revenues are required to be returned before the end of the period. On balance, the AER considers it is not clear that the inclusion of the O-factor will result in smoother price changes over the forecast period.

Carryover adjustment

The AER has included an adjustment mechanism in the transitional parameter to account for the difference between the actual and estimated under recovery of revenues for 2011–12. The estimated under recovery of revenues as calculated by the current regulatory period control mechanism was added as a building block for the calculation of the annual revenue requirement for the forthcoming regulatory control period. This mechanism adjusts for the difference between the estimate and the actual under recovery incurred.

Attachment 2 of the AER’s final determination discusses the AER’s detailed reasoning on the control mechanism for standard control services.

10 Alternative control services

Alternative control services do not form part of Aurora's revenue cap. Rather, the prices of these services are set individually. In this final determination, the AER has classified the following services as alternative control services (see attachment 1[87]):

- metering services—providing, installing and maintaining standard meters and services provided to non-contestable customers to support the customer billing system
- public lighting services—repair, replacement and maintenance of existing public lighting assets and the provision of new public lighting assets
- fee based services—services provided for the benefit of a single customer rather than uniformly supplied to all network customers, which are generally homogenous in nature and scope. These include energisation, de-energisation, meter testing and renewable energy connections
- quoted services—non-standard services where the nature and scope of the service are specific to individual customers' needs. These include the removal or relocation of Aurora's assets at a customer's request, and above standard services.

10.1 Determination

In accordance with the AER's framework and approach paper, the AER has determined that the control mechanisms to apply to Aurora's alternative control services will be price caps.[88] The AER considers that Aurora should demonstrate compliance with the control mechanism through an annual pricing proposal.[89]

The basis of the control mechanism for alternative control services must be determined in the distribution determination.[90] The AER's determination on the basis of the control mechanism for each type of alternative control service is:

- metering services—the AER has determined that a limited building block based on the regulated asset base (RAB) roll forward approach should be used as the basis of the control mechanism for calculating the annual capital allowance for metering. In its revised regulatory proposal, Aurora accepted the AER's position to apply a limited building block model to determine the revenue requirement for metering services.[91]
- public lighting services—the AER has accepted Aurora's proposal to use an annuity approach to calculating the capital allowance, but substituted its forecast opex into Aurora's public lighting model. The AER has not been provided with enough data to develop a RAB roll forward model to determine public lighting prices. Public lighting services were previously unregulated in Tasmania.

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87 See also AER, F*ramework and approach paper*, November 2010, pp. 84–85 for further detail.
88 NER, clause 6.12.1(12).
89 NER, clause 6.12.1(13), clause 6.18.
90 NER, clause 6.2.6(b).
91 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 140.

- fee based services—the AER has accepted Aurora's proposed approach to setting prices based on a cost build-up approach, but made several minor adjustments to inputs to Aurora's fee based services model. Aurora's proposed cost reflective pricing structure has resulted in a rebalancing of individual charges for fee based services. Under the previous OTTER approach, not all fee based services were regulated under a price cap.

- quoted services—the AER has set price caps on the charge out rates of labour, and materials costs are to be charged at cost. Quoted services were previously unregulated.

Attachment 15 contains the AER's detailed reasoning for the control mechanism for alternative control services.

10.2 Summary of analysis and reasons

Metering services

Using the RAB roll forward approach, the AER has made the following adjustments to Aurora's metering model inputs to calculate efficient expenditure requirements:

- The AER accepts Aurora's revised proposal in respect of including timeclock assets into the initial metering RAB. Accordingly, the AER has altered initial meter volumes to reflect the number of timeclock assets that are used to calculate the initial metering RAB and capex requirements.

- The AER has updated purchase costs for single phase electronic meters to reflect the most efficient, up-to-date, competitive supply contract as an input into calculating the initial metering RAB.

- The AER has accepted Aurora's revised proposal to adjust the initial metering RAB to reflect the half-year change in the length of the regulatory year during 2007–08.

- The AER disagrees with Aurora's revised proposal in respect of meter volumes. The AER has calculated Aurora's capex requirement for metering services using its own revised estimates of new meter installation volumes. The AER's revised meter installation costs were forecast from historical trends, using new customer connections forecasts as the basis for the number of meters.

Attachment 16 contains the AER's detailed reasoning for Aurora's metering services.

Fee based services

Using the cost build-up approach, the AER has made the following adjustments to Aurora's fee-based services model inputs to calculate efficient expenditure requirements:

- The AER disagrees with Aurora's revised proposal that the time associated with undertaking de-energisation to be 20 minutes. In light of new material provided by Aurora, the AER considers that 15 minutes is an efficient time required to undertake de-energisation services.

Attachment 18 contains the AER's detailed reasoning for Aurora's fee based services.

Public lighting services

Using the annuity approach, the AER has made the following adjustments to Aurora's public lighting services model inputs to calculate efficient expenditure requirements:

- Aurora did not accept the AER's draft decision of opex requirements to provide public lighting services in its revised proposal. The AER now accepts that Aurora's revised proposal for opex requirements are efficient and consistent with other Australian DNSPs.

Attachment 17 contains the AER's detailed reasoning for Aurora's public lighting services.

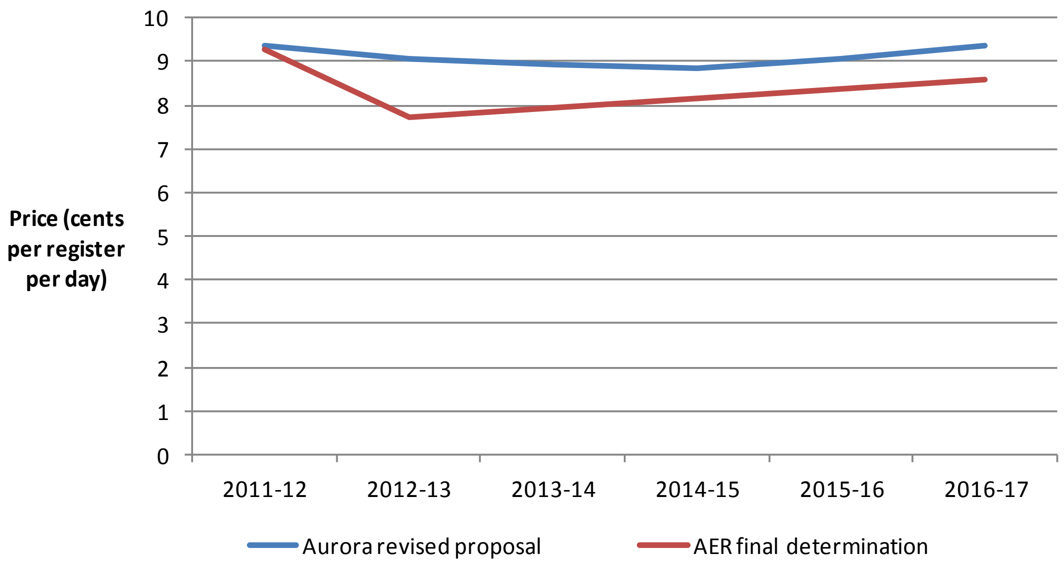
10.3 Prices

This section contains the AER's draft determination prices for some common metering and public lighting services.

10.3.1 Metering prices

The AER's final determination on metering services has resulted in price caps that are on average 10.0 per cent below those proposed by Aurora. The AER has determined smoothed prices to reduce the variability of the price path over the forthcoming regulatory period. Figure 10.1 shows the weighted average metering prices for meter types.

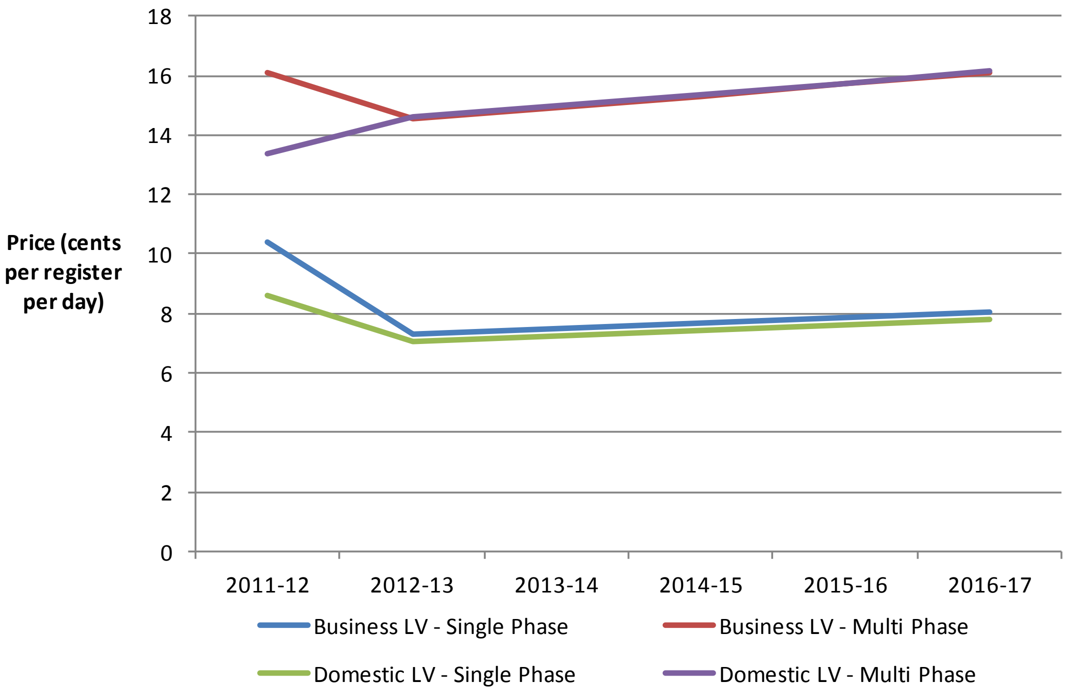
Figure 10.1 Weighted average metering prices for all meter types ($nominal)



Source: AER analysis.

Figure 10.2 shows the AER final determination prices for common metering services, and Table 10.1 lists the prices for these meter types.

Figure 10.2 AER final determination prices for common metering services ($nominal)



Source: AER analysis.

Table 10.1 AER final determination prices for common metering services ($2011-12, cents per register per day)

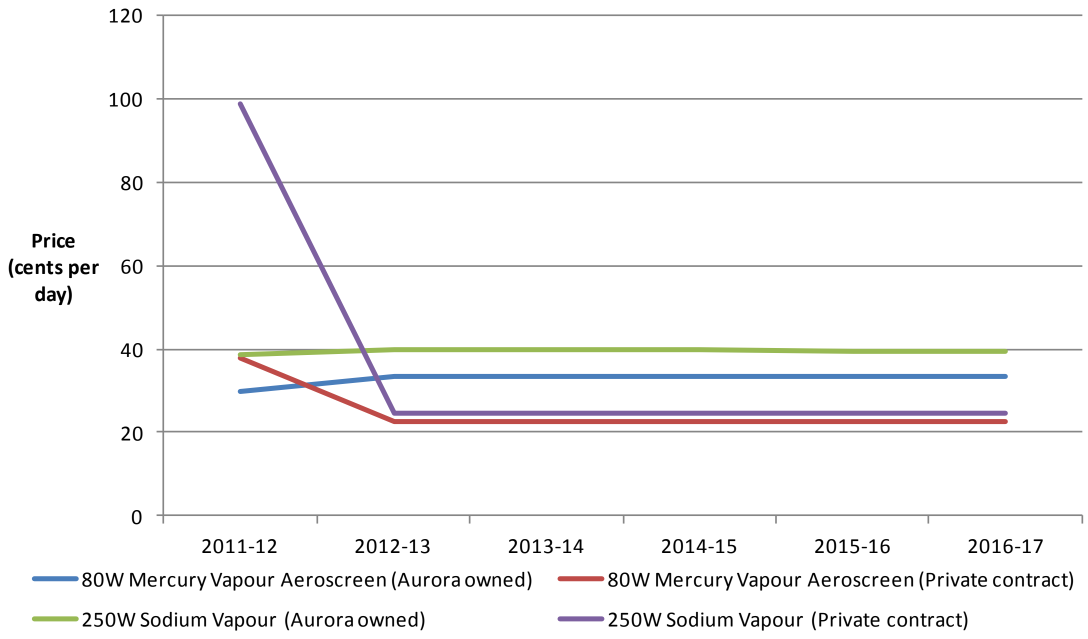
	2012-13
Business LV - Single Phase	7.088
Business LV - Multi Phase	14.179
Domestic LV – Single Phase	6.853
Domestic LV - Multi Phase	14.220

Notes: Prices are exclusive of GST. Nominal prices include forecast inflation rate. Actual prices approved by the AER through annual pricing process will reflect lagged actual CPI.
Source: Aurora's metering model, AER analysis.

10.3.2 Public lighting prices

The AER's final determination on public lighting services is likely to lead to more cost reflective prices because they are based on Aurora's actual and forecast costs. Figure 10.3 shows the AER final determination prices for common public lighting asset, and Table 10.2 lists the prices for these assets.

Figure 10.3 Current and AER final determination prices for common public lighting assets ($nominal)



Source: AER analysis.

Table 10.2 compares the AER's final determination price caps for 2012–13 with Aurora's proposed price caps for common public lighting assets. The AER's final determination on public lighting services has resulted in price caps that are on average 3.9 per cent below those proposed by Aurora.

Table 10.2 Comparison of AER final determination price caps and Aurora proposed price caps for 2012–13 for common public lighting assets ($nominal, cents per day)

	Aurora proposed price cap for 2012–13	AER final determination price cap for 2012–13	% difference between AER draft determination and Aurora proposal
80W Mercury Vapour Aeroscreen (Aurora owned)	35.050	33.397	-4.7%
80W Mercury Vapour Aeroscreen (Private contract)	22.791	22.803	0.1%
250W Sodium Vapour (Aurora owned)	42.366	39.729	-6.2%
250W Sodium Vapour (Private contract)	24.635	24.491	-0.6%

Notes: These light types represent 70 per cent of Aurora's public lighting population.
Source: AER analysis.

Final Distribution Determination

Aurora Energy Pty Ltd

2012–13 to 2016–17

Attachments

April 2012

AUSTRALIAN ENERGY REGULATOR

Contents

1 Uncontested issues

In its revised regulatory proposal, Aurora generally accepted the AER's draft determination on some issues, and does not substantively discuss those issues any further.[1] Aurora also accepted the AER's draft determination on some other issues, but provides some discussion in its revised regulatory proposal. Table 1.1 shows the substantive issues where the AER and Aurora are in agreement. For these issues, the AER has maintained its position from its draft determination, and they are not discussed further in this final determination.

Table 1.1 Substantive issues not discussed in the AER's final determination

Issue	Draft determination reference	Revised proposal reference
Classification of services	Attachment 1, pp. 48–50.	Chapter 1, p. 10.
Demand management incentive scheme	Attachment 13, pp. 281–282.	Chapter 1, p. 10.
Negotiating framework	Attachment 16, pp. 303–306.	Chapter 23, pp. 161–165.
Assigning customers to tariff classes	Appendix C	Chapter 18, p.131

Aurora also accepted several other elements of the AER's draft determination. However, these elements relate to broader issues contested by Aurora in its revised regulatory proposal. Therefore, the AER has considered these elements in the context of its discussion of the substantive issues in the attachments that follow.

1 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 10.

2 NER, clause 6.2.5(a).

2 Control mechanism for standard control services

The control mechanism imposes controls over the prices of direct control services, and/or the revenue to be derived from direct control services.[2] The AER will make constituent decisions on:

- the control mechanism (including the X factors) for standard control services[3]
- how the DNSP is to demonstrate compliance with the relevant control mechanism[4]
- how the DNSP is to report to the AER on its recovery of transmission use of system (TUOS) charges[5] for each regulatory year, and adjustments to be made in pricing proposals in subsequent years to account for TUOS over or under recoveries.[6]

2.1 Determination

The revenue cap control mechanism comprises the allowed revenue adjustments to annually update Aurora's maximum allowed revenue. The allowed revenue adjustments are:

- the electrical safety inspection levy (ESISC)
- the national energy market levy (NEMC)
- distribution use of system (DUOS) unders and overs
- TUOS unders and overs.

Aurora is to comply with the revenue cap control mechanism in its annual pricing proposal. Adjustments are to be made for the ESISC and NEMC revenue adjustments on a one year lagged basis and adjustments for DUOS and TUOS under and over recoveries on a one year lagged basis for estimates and a two year lagged basis for actual revenues.

The AER does not accept the revenue adjustments for the forthcoming regulatory control period in relation to:

- banking mechanism
- trunk mobile radio (TMR) levy
- GSL Cap
- Excess GSL Payments.

To close out the revenue adjustments from the current regulatory period, the AER has incorporated the carryover revenues (as calculated by the current control mechanism) as a building block into the

2 NER, clause 6.2.5(a).
3 NER, clause 6.12.1(11).
4 NER, clause 6.12.1(13).
5 Representing the avoided customer TUOS charges referred to in the designated pricing proposal charges definition under the NER, clause 6.12.1(19).
6 NER, clause 6.12.1(19).

annual revenue requirement for the forthcoming regulatory control period. Part of the carryover revenues are an estimate. Therefore, the AER has included a revenue adjustment mechanism in the transitional parameter of the revenue cap to account for the difference between the actual carryover revenues and the estimate.

The transitional parameter will also include revenue adjustment mechanisms to account for the outcome of current control mechanism adjustments that will not be known until 2012-13. The transitional parameter will extend no further than 2013-14.

The revenue cap formula is outlined in detail in section 2.3.3 below.

2.2 Assessment approach

The AER has not changed its assessment approach for Aurora's control mechanism since its draft determination, so it is not repeated here. See section 2.3 of attachment 2 of the AER's draft determination for this detail.[7]

However, two matters relevant to the AER's assessment of the control mechanism have arisen since the draft determination, and were not included in Aurora's revised regulatory proposal. These issues relate to how the AER should carryover the under recovery of revenue from the current regulatory period into the forthcoming regulatory control period and the proposed smoothing of revenues within the forthcoming regulatory control period. The AER's consideration of these issues is outlined in detail in section 2.3.2 below.

2.3 Reasons for determination

The AER's draft determination accepted Aurora's proposal that the control mechanism for standard control services be a revenue cap.[8] The AER also accepted Aurora's:[9]

- distribution use of system (DUOS) unders and overs mechanism
- national electricity market charge (NEMC) cost revenue adjustment mechanism
- electrical safety inspection levy (ESISC), in the event Aurora wins the tender to provide these services in the forthcoming regulatory control period.

The AER's draft determination did not however accept Aurora's proposed revenue adjustment mechanisms for:

- trunk mobile radio (TMR) levy
- full retail contestability charges (FRC)
- the mitigation of the risk of the GSL scheme
- unfunded shared network costs.

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7 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 53.
8 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 53.
9 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 51-53.

In addition, the AER did not accept Aurora's proposed TUOS unders and overs adjustment mechanism.[10] Instead the AER applied an unders and overs mechanism consistent with the DUOS unders and overs mechanism.[11] The AER also did not accept Aurora's proposal that side constraints not be applied.[12]

The AER's draft determination also stated the AER will use a transitional parameter to close out the revenue adjustments of the current regulatory period that would not be ongoing into the forthcoming regulatory control period.[13]

Aurora did not accept the AER's draft determination in relation to:[14]

- the ESISC revenue adjustment mechanism being contingent on Aurora winning the contract
- TMR levy revenue adjustment mechanism
- the GSL risk mitigation mechanisms.

Aurora also noted the AER's draft determination made no specific reference that the consumer price index (CPI) will be a component of the control mechanism.[15] Aurora assumed the AER will apply CPI to previous period adjustments as part of the control mechanism.

Subsequent to its revised regulatory proposal, Aurora made submissions that the AER should carryover the under and over recovery of revenue from the current regulatory period into the forthcoming regulatory control period.[16] Further, Aurora submitted that there should be a revenue adjustment mechanism to allow the smoothing of revenues within the regulatory control period.[17]

2.3.1 Uncontested issues

Aurora accepted the AER’s draft determination to not accept adjustments for; [18]

- unfunded shared network costs
- full retail contestability costs.

Aurora also accepted the AER’s method to calculate the DUOS unders and overs account and the TUOS unders and overs account.[19]

The AER's consideration of newly raised and contested issues is discussed in turn below.

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10 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 62-63.

11 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 62-63.

12 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 63.

13 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 52.

14 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 131.

15 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 131.

16 The following are attachments contained in the emails sent by Aurora which explain Aurora's reasoning for the AER to allow the smoothing of carryover amounts: Aurora, *Aurora distribution determination—Under/over revenue recovery*, 14 February 2012; Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012 and Allens Arthur Robinson, *Aurora energy distribution determination—Under/over revenue recovery*, 4 April 2012.

17 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012.

18 Aurora, *Revised regulatory proposal*, January 2012, p. 131.

19 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 131.

2.3.2 Revenue adjustment mechanisms

Smoothing

On 15 February 2012, 23 March 2012, and 4 April 2012 Aurora wrote to the AER stating that it considers clauses 6.4.3(a)(6) and (b)(6) of the NER permit the AER to smooth the carryover of under recovered allowed revenues ($49.4 million, $2012-13) from the current regulatory period over the forthcoming regulatory control period.[20] These under recovered allowed revenues are comprised of $-2.7 million ($2012-13) TUOS in 2010-11, $26.0 million (2012-13) DOUS in 2010-11 and $26 million (2012-13) DUOS in 2011-12.[21] In addition, Aurora submitted that its revenues should be smoothed within the forthcoming regulatory control period.[22] Aurora submitted a method to allow both the smoothing across and within regulatory control periods.[23]

The first part of Aurora's method was to apportion the carryover revenues from the current regulatory period in equal amounts over the five years of the forthcoming regulatory control period.[24] The apportionment resulted in the net present value (NPV) of the carryover revenues across the forthcoming regulatory control period being equal to the NPV if it were to be all recovered in the first year. Aurora submitted that the weighted average cost of capital (WACC) in the AER's final determination should be the appropriate discount rate for the NPV calculation. As the carryover revenues contain an estimate for the under recovery of allowed revenue in 2011-12, Aurora further submitted that the variation between the actual under recovery and estimate should be accounted for in the DUOS unders and overs account in 2012-13 as part of its pricing proposal for that year.[25]

In addition to smoothing the carryover revenues, Aurora submitted that the balance of the under recovered revenues from the application of the other additional revenue adjustment mechanisms should also be smoothed.[26] These additional mechanisms are:[27]

- electrical safety inspection levy (ESISC)
- national electricity market levy (NEMC)
- trunk mobile radio levy (TMR)
- national electricity market participation and retail contestability costs (NEM).

These additional carryover mechanisms would contribute an additional $3.1 million (nominal) the carryover revenues discussed above.[28]

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20 The following are attachments contained in the emails sent by Aurora on the respective dates above which explain Aurora's reasoning for the AER to allow the smoothing of carryover amounts: Aurora, *Aurora distribution determination—Under/over revenue recovery*, 14 February 2012; Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012 and Allens Arthur Robinson, *Aurora energy distribution determination—Under/over revenue recovery*, 4 April 2012.

21 Aurora, *Calculation of the transitional factors for distribution network services for the regulatory year 1 Jul 2012 to 30 Jun 2013*, provided to the AER by email on 13 April 2012.

22 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012, p. 2.

23 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012, Appendix A.

24 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012, p. 2.

25 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012, Appendix A, p. ii.

26 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012, Appendix A, p. ii.

27 Aurora, *Calculation of the transitional factors for distribution network services for the regulatory year 1 Jul 2012 to 30 Jun 2013*, provided to the AER by email on 13 April 2012.

The second part of Aurora's method is to include a banking mechanism to mitigate within regulatory control period price volatility.[29]

Smoothing of carryover revenue

The AER has decided to account for Aurora’s carryover revenues as a building block in the calculation of annual revenue requirements for the forthcoming regulatory control period.

The AER is satisfied Aurora has calculated the carryover revenues consistent with the current control mechanism. There is no disagreement between Aurora and the AER about the quantum of revenue to be recovered. However, the AER is not satisfied with Aurora's recovery profile. Aurora submitted a relatively even profile across the forthcoming regulatory control period but the AER does not consider it has the discretion to implement it. However, the AER's approach will deliver an outcome that is largely similar to the outcome sought by Aurora.

The carryover revenues include actual under recovery of revenues for 2010-11 and estimated under recovery revenues for 2011-12. Both amounts have been added as a building block. The AER notes the transitional parameter in the control mechanism for the forthcoming regulatory control period will account for any difference between the 2011-12 estimated and actual under recovery. This difference will be added (or subtracted) from maximum allowable revenues for the year 2013-14.

The under recovery is significant and, potentially, could have a substantial impact on prices in the forthcoming regulatory control period. Therefore, Aurora submitted that this amount should be added as an unsmoothed building block in the calculation of annual revenue requirements.[30] In particular, Aurora submitted that the under recovery should be included in allowable revenues equally over the forthcoming regulatory control period. The AER does not consider that it has discretion to include the under recovery in revenues equally over the forthcoming period. Instead, the under recovery should be incorporated into allowable revenues using the measures in the current regulatory period's control mechanism. Consistent with the operation of the current period's control mechanism, the AER considers that the under recovery should be included in allowable revenues in the first year of the forthcoming regulatory control period.

Notwithstanding this issue, the AER considers that it can achieve a smoother path of revenues using the X factors with the total under recovery allocated in the first year of the forthcoming regulatory control period. While clause 6.5.9(b)(2) constrains the extent to which the AER can defer revenue recovery, the AER has used the maximum flexibility available to it to defer the revenue increases resulting from the under recovery. This results in an expected price path that does not increase then decrease in nominal terms. In contrast, Aurora's submission would result in expected revenues significantly higher than allowable revenues in the final year (excluding the under recovery). This would result in a need to decrease revenues in the first year of the subsequent period.

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28 Aurora, *Calculation of the transitional factors for distribution network services for the regulatory year 1 Jul 2012 to 30 Jun 2013*, provided to the AER by email on 13 April 2012.

29 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012, p. 2.

30 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012.

Additional mechanisms

Aurora submitted that, should the AER consider the smoothing of the carryover revenues appropriate, it should also apply the same application to the additional mechanisms within the current regulatory period control mechanism.[31]

The AER's draft determination considered the closing out of the additional mechanisms. Specifically, it considered using the transitional parameter (for those revenue adjustment mechanisms ceasing at the end of the current regulatory period). It also considers individual revenue adjustment mechanisms in the forthcoming regulatory control period control mechanism. However, the under or over recovery of revenues from the additional mechanisms are actual and not estimated. Therefore, the AER considers it is administratively simpler to include these in the building block for carryover revenues. In doing so, the AER can remove these additional mechanisms from the transitional parameter in the control mechanism.

Banking mechanism

The AER does not accept Aurora's submission to include a banking mechanism (O-factor) as part of the control mechanism for the forthcoming regulatory control period. This is because it is not clear that a banking mechanism would reduce price volatility in the forthcoming regulatory control period. In fact, as discussed below, a banking mechanism may contribute to greater price volatility in the later years of the forthcoming regulatory control period.

Aurora submitted that the banking mechanism would operate the same way as the O-factor banking mechanism in the current control mechanism.[32] This mechanism allows Aurora to set the closing balance of the DUOS under and over recovery account at a value ± 2 per cent of its allowable revenues in any year. This is different to the zero balance in the AER's draft determination. Aurora also submitted that the balance of this account should be expected to be zero at the end of the regulatory control period to ensure no carryover of revenues to the following regulatory control period.[33] Aurora submitted that the banking mechanism would "accommodate fluctuations in pass through costs and other adjustments."[34] The AER notes a similar mechanism exists in the current control mechanism for the Queensland DNSPs.[35] However, the AER notes that this arose out of transitional provisions in the NER for the Queensland DNSPs rather than a decision of the AER.

In the current regulatory period Aurora under recovered revenues between the regulatory years 2008-09 and 2010-11. Aurora is estimated to under recover again in its final regulatory year (2011-12). The AER also notes the O-factor banking mechanism was available in the current regulatory period and Aurora applied it. However, Aurora's under recoveries have resulted in a $49 million carryover of under recovered revenues. Therefore, it is not apparent that the O-factor was an effective mechanism to reduce price volatility during the current regulatory period. The AER also notes that Aurora was required to return banked revenues in the last two years of the current regulatory period. This increased the allowed revenues in these years and contributed to this under

31 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012, Appendix A, p. ii.

32 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012, p. 2.

33 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012, Appendix A, p. v.

34 Aurora, *Aurora distribution determination—Under/over revenue recovery*, 22 March 2012, Appendix A, p. v.

35 AER, Draft decision, *Queensland Draft distribution determination 2010–11 to 2014–15,* November 2009, p. 31.

recovery.[36] Whilst the return of these banked revenues was not the driving factor of the large under recovery, its contribution compounded this effect.

As a result, the AER does not consider that a banking mechanism would be effective in reducing price volatility, and may contribute to greater price volatility in the later years of the forthcoming regulatory control period.

In deciding on the control mechanism for standard control services, the AER must consider the five factors under clause 6.2.5(c) of the NER. The AER considers the O-factor revenue adjustment mechanism should not be included in the control mechanism for standard control services. Consideration of these factors is outlined in table 2.1 below:

Table 2.1 NER factors and the O-factor revenue adjustment mechanism

NER Factor	AER consideration
Efficient tariff structures	The AER considers efficient tariff structures should reflect the efficient costs of providing services. Changes in tariffs should reflect changes in the underlying costs of providing services, rather than temporary fluctuations in demand. Smoothing should reduce the impact that temporary fluctuations in demand have on revenues and prices.
Administrative costs	There are no additional administrative costs to Aurora in implementing the O-factor mechanism as it exists in its current control mechanism. Also, the impact on the AER's administrative costs would be small.
Previous regulatory arrangements	The O-factor revenue adjustment mechanism is part of the control mechanism applied in the current regulatory period.
Desirability for a consistent regulatory approach	A similar adjustment mechanism is applied in the current control mechanism for the Queensland DNSPs. However, the AER notes this was due to transitional provisions in the NER for the Queensland DNSPs rather than a decision by the AER.
Any other relevant factor	A relevant factor for the inclusion of the O-factor is its effectiveness in smoothing revenues and prices It does not appear that the inclusion of the O-factor will result in smoother price changes over the forecast period, and may contribute to greater price volatility in the later years of the forthcoming regulatory control period.

Electrical safety inspection levy (ESISC)

The AER now considers the ESISC revenue adjustment mechanism should be included in the control mechanism for standard control services irrespective of whether Aurora wins Workplace Standards Tasmania's (WST) tender to conduct the electrical safety inspections.

The AER has provided an allowance in Aurora's opex forecast for the ESISC. The ESISC revenue adjustment mechanism will calculate the difference between the forecast allowance and the actual costs Aurora incurs. Where the amount Aurora incurs is lower than the forecast allowance provided by the AER, a negative revenue adjustment is made.

The AER's draft determination noted Aurora's contract to undertake electrical safety inspection services for WST expires on 30 June 2012. It also correctly recognised that:[37]

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36 Aurora, *Response to information request AER/053 dated 5 December 2011*, received 7 December 2011.

- the ESISC levied by the Minster is a legislative obligation and the provision of electrical safety inspections falls with the definition of standard control services
- the Minister has the ability to require Aurora to pay ESISC regardless of whether Aurora wins the tender to undertake these services.

The AER's draft determination however incorrectly interpreted the implications for Aurora of WST putting the service out to tender.[38] The AER has considered Aurora's revised regulatory proposal[39] and submission of 20 February 2012[40] and notes that:

- WST determines the amount of the levy and Aurora is obligated to pay the electrical service inspection charge regardless of who provides these services
- the ESISC levy in practical terms is likely to be determined via the contract WST enters into with the successful tender
- if Aurora does not win the contract, the ESISC levy paid by Aurora is a cost incurred by Aurora in providing standard control services and will reflect the costs determined in a tender process conducted by WST
- if Aurora wins the WST contract to provide electrical safety inspections post 1 July 2012 it will incur the costs of providing these electrical safety inspections and be paid the contracted amount by WST
- the ESISC revenue adjustment mechanism will not impact on Aurora's incentive to incur the costs associated with conducting the safety inspection services efficiently, as Aurora will not have any control over the ESISC determined by the Minister under the *Electrical Supply Industry Act 1995.*

The allowance in Aurora's forecast opex for the ESISC is presented in table 2.2 below.

Table 2.2 AER's final decision on ESISC forecast opex allowance ($million, 2009-10)

	2012-13	2013-14	2014-15	2015-16	2016-17
ESISC allowance	3.2	3.2	3.2	3.2	3.2

Source: AER analysis.

In deciding on the control mechanism for standard control services, the AER must consider the five factors under clause 6.2.5(c) of the NER. The AER considers that the ESISC revenue adjustment mechanism is consistent with all of the factors under this clause. Consideration of these factors is outlined in table 2.3 below:

37 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 60.

38 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 60.

39 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 132.

40 Aurora Submission, *AER's Draft Distribution Determination - Electrical Safety Inspection Service Charge Revenue Adjustment Mechanism*, 20 February 2012, p. 2.

Table 2.3 NER factors and the ESISC revenue adjustment mechanism

NER Factor	AER consideration
Efficient tariff structures	The inclusion of the ESISC revenue adjustment mechanism in the control mechanism for standard control services will not affect the efficiency of tariff structures. The inclusion of an adjustment will reflect actual costs incurred by Aurora.
Administrative costs	There are no additional administrative costs to Aurora in implementing the ESISC mechanism as it exists in its current control mechanism. Also, the impact on the AER's administrative costs would be small.
Previous regulatory arrangements	The ESISC revenue adjustment mechanism is part of the control mechanism applied in the current regulatory period.
Desirability for a consistent regulatory approach	The ESISC revenue adjustment mechanism is not present in the control mechanism established by the AER for any other DNSP in the NEM as the ESISC is unique to Tasmania.
Any other relevant factor	The National Electricity Objective (NEO) and RPP are relevant to the question of whether the ESISC should be in the control mechanism for standard control services. As Aurora has no control over the ESISC, the ESISC revenue adjustment mechanism will have no impact on Aurora's incentive to incur costs efficiently.

Trunk mobile radio (TMR) levy

The AER maintains the position it took in its draft determination. The TMR revenue adjustment mechanism should not be included in the control mechanism for standard control services.

The AER notes that TMR costs are set by the Police and Emergency Management Department on an annual basis[41] and Aurora has a contractual obligation to participate in the TMR as evidenced by the agreement provided.[42] This obligation does not however stem from a legislative obligation or Government directive but rather Aurora's decision to enter into this contract. The AER considers there is a clear distinction between Aurora's obligation stemming from a contract it freely entered into and legal obligations that are placed on Aurora by the Government, such as the ESISC. The AER considers its draft determination could have been clearer on this point. Based on the analysis in the confidential appendix, Aurora's costs under the TMR contract can be forecast and are controllable.

Aurora's decision to enter the TMR system was controllable. The AER considers that, like any other contract Aurora enters voluntarily, it should be subject to efficiency incentives provided under Chapter 6 of the NER. Aurora has a responsibility to forecast its efficient costs for all of its controllable expenditure. These controllable costs and their efficiency are best addressed through assessment under the opex and capex criteria in the NER and the incentives that exist under the regulatory framework (such as the EBSS). Since the AER considers TMR related costs are largely controllable and a cost Aurora has chosen to incur in the provision of network services, the AER considers the TMR costs should be subject to the same assessment as all other controllable costs.

TMR costs are included in Aurora's forecast opex and the AER will account for the carryover of TMR costs occurring in the last year of the current regulatory period by including these in the building block for carryover revenues.

41 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 135.

42 Agreement, *The Crown and Aurora Energy*, 2010 (confidential).

In deciding on the control mechanism for standard control services, the AER must consider the five factors under clause 6.2.5(c) of the NER. In deciding that the TMR revenue adjustment mechanism should not be included in the control mechanism, the AER considered that the desirability for a consistent regulatory approach across jurisdictions and the impact of the mechanism on Aurora's incentives outweighed maintaining consistency with Aurora's previous regulatory arrangements. Consideration of these factors is outlined in table 2.4 below:

Table 2.4 NER factors and the TMR revenue adjustment mechanism

NER Factor	AER consideration
Efficient tariff structures	The inclusion of the TMR mechanism into the control mechanism for standard control services may affect the efficiency of tariff structures. The inclusion of an adjustment may allow inefficient costs to be passed through to customers.
Administrative costs	There are no additional administrative costs to Aurora in implementing the TMR mechanism as it exists in its current control mechanism. Also, the impact on the AER's administrative costs would be small.
Previous regulatory arrangements	The TMR mechanism is part of the control mechanism applied in the current regulatory period.
Desirability for a consistent regulatory approach	A TMR revenue adjustment mechanism is not present in the control mechanism established by the AER for any other DNSP in the NEM. There is no TMR revenue adjustment mechanism in the control mechanism applied to Transend.
Any other relevant factor	The NEO and RPP are relevant to the question of whether the TMR should be in the control mechanism for standard control services. The TMR revenue adjustment mechanism eliminates Aurora's incentives to ensure that it incurs these costs efficiently. Removing this incentive would not promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers with respect to the price, quality and reliability of the supply of electricity.

Guaranteed service level (GSL) risk mitigation mechanisms

The two GSL risk mitigation mechanisms will not be incorporated into the control mechanism for standard control services in the forthcoming regulatory control period. These are:

- the GSL cap revenue adjustment mechanism, and
- single outage duration GSL payments revenue adjustment mechanism.

The GSL cap revenue adjustment mechanism limits the costs Aurora would bear under its GSL scheme to 2.5 times the allowance provided by OTTER in its 2007 determination. OTTER decided to apply this risk sharing mechanism to prevent poor weather from having a dramatic effect on Aurora's bottom line.[43] AER calculations indicate Aurora has not breached this cap during the current regulatory period.[44]

The single outage duration GSL payments revenue adjustment mechanism refunds a portion of Aurora's GSL payments if an outage affects more than 34,000 customers (or 12.5 per cent of the customer base at the time of OTTER's 2007 determination). Where an outage affected more than

43 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: Final report and proposed maximum prices*, September 2007, p. 232.

44 See attachment 12 covering the Service Target Performance Incentive Scheme, p. 8.

34,000 customers, this mechanism would calculate an increased threshold for the payment of outages. This increase would be used to then provide Aurora with a rebate for half of these GSL payments.[45] The remaining half contributes to calculations of whether Aurora has reached the cap for GSL payments over the period.[46]

The AER notes Aurora's view that without these mechanisms, Aurora may be exposed to the risk of events that are beyond its control.[47] However, the AER considers the risk events outside of Aurora's control are capped as Aurora can apply to OTTER to have any large events excluded under the GSL scheme.

Aurora's proposed revenue adjustment mechanisms would insulate Aurora from the risk of events that are within its control. This would weaken the incentive to reduce GSL payments. This is not consistent with the NEO.[48] The AER therefore considers that the continuation of the GSL adjustment mechanism would reduce Aurora's incentives improve its GSL performance in the forthcoming regulatory control period.[49]

The AER will account for the adjustment of GSL payments occurring from the application of these adjustment mechanisms for the second year of the current regulatory period by including these in the building block for carryover revenues. The GSL payments occurring in the last year of the current regulatory period will be accounted for in the transitional parameter. The AER's detailed reasoning for this view is provided below.

Exposure to major transmission and generation outages

In its revised regulatory proposal, Aurora stated that the Tasmanian GSL scheme requires Aurora to compensate its customers for all outages experienced by the customer no matter what the cause.[50] However, under the GSL scheme the calculation of GSL payments excludes exempted outages.[51] Exempted outages include:

- a planned outage requested by a customer
- an outage caused by customer installation faults
- an outage approved by OTTER on application from Aurora in relation to:
    - widespread interruptions to supply due to rare events

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45 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: Final report and proposed maximum prices*, September 2007, p. 182.

46 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: Final report and proposed maximum prices*, September 2007, p. 183.

47 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 134.

48 The NEO promotes the efficient provision of distribution services with respect to reliability:
The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-
(a) price, quality, safety, reliability and security of supply of electricity; and
(b) the reliability, safety and security of the national electricity system.

49 Specifically, by providing DNSPs with an allowance for forecast GSL payments in opex, the building block approach under Chapter 6 of the NER creates an incentive for DNSPs to minimise their GSL costs during the forthcoming regulatory period.

50 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 133.

51 OTTER, *Guideline - Guaranteed Service Level Scheme*, December 2007, p 6.

- load shedding due to a short fall in generation capacity.[52]

Indeed, Aurora has made three applications for exclusions under the GSL scheme in the current regulatory period, all relating to weather events. Two of these applications were rejected on the grounds that OTTER did not consider them to be rare events.[53] The other application was approved by OTTER for exclusion under the GSL scheme.[54]

In its revised regulatory proposal Aurora expressed the view that OTTER had assessed that an event will only be considered rare if it is akin to an act of terrorism.[55] However, this view is contrary to OTTER's most recent determination on an application from Aurora to have an event classified as a rare event.[56] OTTER ruled that "to give effect to the intent of the GSL scheme established as part of the 2007 Pricing Investigation, the Regulator will only grant a GSL exemption on the ground of ‘rare event’ if the widespread outages in question:

- will result in Aurora being liable to pay GSL payments (for these outages) amounting to more than 2.5 per cent of Aurora’s approved maximum AARR (for network services) for the relevant financial year
- are of such a scale that, in the opinion of the Regulator, Aurora is not reasonably able to mitigate against them."[57]

It is important to note that the Tasmanian Electricity Code (TEC) GSL scheme is outside of the AER's jurisdiction. OTTER is the regulator responsible for the TEC and hence is responsible for the administration of the TEC GSL scheme. Based upon OTTER's statement above it would appear that sufficiently large outages would be excluded.

Considering that Aurora has some protection from the financial effects of large scale transmission and generation events an adjustment in the control mechanism to protect Aurora from the risk of such events is unnecessary. The inclusion of such a revenue mechanism adjustment would duplicate the effect of the GSL rare event exclusion.

Further, the AER considers that it would be more efficient for Aurora to bear the costs of large transmission GSL payment event rather than recover the GSL costs from customers in the event that it was not exempted by OTTER. Aurora is better placed than consumers to forecast, insure against and manage the financial consequences of such an event. For this reason, even if OTTER decides not to exclude a large scale transmission outage it would be preferential for Aurora to bear the costs of GSL payments for such an event.

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52 OTTER, *Guideline - Guaranteed Service Level Scheme*, December 2007, pp 1–2.

53 OTTER, *Statement of Reasons - Application for relief of obligation for Single Outage Duration Guaranteed Service Level Payments arising from the windstorms on 15 April 2009*, January 2010.
OTTER, *Statement of Reasons - Application for relief of obligation for Single Outage Duration Guaranteed Service Level Payments arising from the windstorms on 22 January 2009*, August 2009.

54 OTTER, *Statement of Reasons - Application for relief of obligation for Single Outage Duration Guaranteed Service Level Payments arising from the windstorms on 2 and 3 April 2008*, July 2008.

55 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 134.

56 OTTER, *Statement of Reasons - Application for relief of obligation for Single Outage Duration Guaranteed Service Level Payments arising from the windstorm on 15 April 2009*, January 2010.

57 OTTER, *Statement of Reasons - Application for relief of obligation for Single Outage Duration Guaranteed Service Level Payments arising from the windstorm on 15 April 2009*, January 2010, p. 9.

Investment incentives

The AER does not accept Aurora's contention that the removal of the revenue adjustment mechanisms will not affect Aurora's incentive to invest. Aurora contends that the STPIS creates an incentive for Aurora to invest more heavily in the distribution network. This would offset the disincentive to invest imposed by the revenue adjustment mechanism.[58]

The AER does not agree with this view. The AER considers the GSL scheme provides an incentive for Aurora to invest because it penalises Aurora for not meeting minimum reliability standards. Where there is a financial penalty for not meeting an obligation, there is a financial incentive to meet that obligation. Any mechanism that removes or lowers the financial penalties of the GSL scheme will also weaken Aurora's incentives to invest to meet the minimum reliability standards.

The GSL scheme is unique

The AER does not accept Aurora's contention that the GSL scheme is unique and therefore warrants the proposed GSL risk mitigation mechanisms.[59] Although Aurora's GSL scheme requires Aurora to make payments on a rolling 12-monthy basis, other jurisdictional schemes have multiple GSL payment thresholds that impose a similar obligation.[60]

Intent of the GSL scheme

Aurora's states that it was not OTTER's initial intention for the GSL scheme to have uncapped liabilities when the scheme was developed.[61] However, OTTER has indicated "that it does not intend to codify in the GSL Guideline or the TEC the single event safety net or the risk sharing mechanism that currently applies".[62] Hence, the current application of the GSL scheme is OTTER's intended application.

In deciding on the control mechanism for standard control services, the AER must consider the five factors under clause 6.2.5(c) of the NER. In deciding that the excess GSL cost revenue adjustment mechanisms should not be included in the control mechanism, the AER considered that the desirability for a consistent regulatory approach across jurisdictions and the impact of the mechanism on Aurora‘s incentives outweighs maintaining consistency with Aurora‘s previous regulatory arrangements. Consideration of these factors is outlined in table 2.5 below.

58 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 133.
59 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 133.
60 Essential Services Commission of Victoria, *Electricity Distribution Code - Chapter 6*, January 2006.
61 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 134.
62 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 198.

Table 2.5 NER factors and the GSL revenue adjustment mechanism

NER Factor	AER consideration
Efficient tariff structures	The inclusion of these mechanisms into the control mechanism for standard control services will not affect the efficiency of tariff structures.
Administrative costs	The removal of these mechanisms may moderately reduce Aurora's administrative costs.
Previous regulatory arrangements	These mechanisms are part of the control mechanism applied in the current regulatory period.
Desirability for a consistent regulatory approach	GSL revenue adjustment mechanisms are not present in the control mechanism established by the AER for any other DNSP in the NEM.
Any other relevant factor	The NEO and revenue and pricing principles (RPP) are relevant to the question of whether these revenue adjustments should be in the control mechanism for standard control services. Weakening the incentives to minimise GSL payments and therefore reduce outages is not consistent with the NEO as it does not promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers with respect to the price, quality and reliability of the supply of electricity.

Consumer price index (CPI)

The AER's draft determination provided evidence that it may apply CPI in both its revenue cap control mechanism and side constraint formulas. However, the AER's draft determination did not explicitly state that it would apply CPI.

Aurora submitted the AER's draft determination had not specifically stated that CPI would be a component of the control mechanism.[63] Aurora's revised regulatory proposal assumed that the AER would apply CPI to previous period adjustments as part of the AER's final decision control mechanism.

The AER will apply CPI in both its revenue cap control mechanism and side constraint calculations as set out in the control mechanism formulas below.

The AER also notes that the maximum allowable revenue (MAR) for 2012-13 will be equal to the MAR in the PTRM. Subsequent years will use the actual March CPI to update the MAR.

2.3.3 Control mechanism formulas

Aurora as part of its pricing proposals must submit to the AER proposed tariffs and charging parameters.[64] Aurora's revenues must be consistent with the MAR formula set out below plus any unders and overs adjustment needed to move the balance of its DUOS unders and overs account to zero.

63 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 131.

64 NER, clauses 6.18.2(b)(2) and 6.18.2(b)(3).

Revenue cap formula

Figure 2.1 is the form of control for standard control services for Aurora to apply in the forthcoming regulatory control period.

Figure 2.1 AER's final decision revenue cap

$$MAR_t = AR_t \pm passthrough_t \pm ESISC_t \pm NEMC_t \pm transitional_t$$

where:

- t is the regulatory year
- MAR_t is the maximum allowed revenue for each year of the forthcoming regulatory control period
- AR_t is the allowed revenue for regulatory year t. For the first year of the forthcoming regulatory control period, this amount will be equal to the smoothed revenue requirement for 2012-13. The subsequent year's allowed revenue is determined by adjusting the previous year's allowed revenue for actual inflation, the X factor and the other following adjustments:

  $$AR_t = AR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + S_t)$$

  where:

  - CPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in year t–2 to March in year t–1[65]
  - X_t is the X factor for each year of the forthcoming regulatory control period as determined by the PTRM
  - S_t is the STPIS factor sum of the raw s-factors for all reliability of supply and customer service parameters (as applicable) to be applied in regulatory year t[66]

- $passthrough_t$ is the approved pass through amounts with respect to regulatory year t, as determined by the AER
- ESISC is the actual under or over recovery of revenues from the estimated ESISC costs in regulatory year t-1
- NEMC is the actual under or over of revenues from the estimated NEMC costs in regulatory year t-1
- $transitional_t$ is to account for revenue adjustments from the application of the current regulatory period control mechanism that were either estimates or not known at the time of the final determination.

[65] The AER considers the inflation measure used in the control mechanism should be as up to date as possible for the pricing proposal.

[66] In the formulas in the STPIS Draft Decision appendix C, the AR_{t+1} is equivalent to AR_t in this formula. Calculations of the S factor adjustment are to be made accordingly.

Side constraints

Aurora will be required to demonstrate in its pricing proposal that proposed DUOS prices for the next year (t) will meet the following side constraints formula (expressed in percentage terms) for each tariff class:

$$\frac{\sum_{j=1}^{m} d\frac{j}{t} \times q\frac{j}{t}}{\sum_{j=1}^{m} d\frac{j}{t-1} \times q\frac{j}{t}} \leq (1+\Delta CPI_t)\times(1-X_t)\times(1+2\%)\times(1+S_t) \pm passthrough_t \pm ESISC_t \pm NEMC_t \pm DUOS_t \pm transitional_t$$

where each tariff class 'j' has up to 'm' components, and where:

- $d\frac{j}{t}$ is the proposed price for component 'j' of the tariff class for year t
- $d\frac{j}{t-1}$ is the price charged by the DNSP for component 'j' of the tariff class in year t–1
- $q\frac{j}{t}$ is the forecast quantity of component 'j' of the tariff class in year t
- ΔCPI_t is the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in regulatory year t–2 to March in regulatory year t–1
- X_t is the X factor for each year of the regulatory control period. If X>0, then X will be set equal to zero for the purposes of the side constraint formula
- S_t is the STPIS factor sum of the raw s-factors for all reliability of supply and customer service parameters (as applicable) to be applied in regulatory year t
- $passthrough_t$ is an annual adjustment factor that reflects the pass through amounts approved by the AER with respect to regulatory year t
- ESISC is the actual under or over recovery from the estimated ESISC costs in regulatory year t-1
- NEMC is the actual under or over recovery from the estimated NEMC costs in regulatory year t-1
- $DUOS_t$ is an annual adjustment factor related to the balance of the DUOS unders and overs account with respect to regulatory year t
- $transitional_t$ is to account for revenue adjustments from the application of the current regulatory period control mechanism that were either estimates or not known at the time of the final determination.

With the exception of the CPI and X factors, the percentage for each of the other factors above can be calculated by dividing the incremental revenues (as used in the MAR formula) for each factor by the expected revenues for regulatory year t–1 (based on the prices in year t–1 multiplied by the forecast quantities for year t).

Electrical safety inspection service charge formula

The AER accepts Aurora's proposed formula to adjust for the difference between the actual ESISC and the forecast charge for the previous period ($ESISC_t$):[67]

$ESISC_t = (ESISCa_{t-1} - ESISCf_{t-1}) \times (1+WACC)$

where,

- $ESISCa_{t-1}$ is the actual charge for the period previous to the relevant period
- $ESISCf_{t-1}$ is the forecast charge for the period previous to the relevant period
- WACC is the Weighted Average Cost of Capital for a full year.

The AER's final decision on the opex allowance for the ESISC is presented in table 2.2 above.

National energy market charge formula

The AER accepts Aurora's proposed formula to adjust for the difference between the actual NEMC and the forecast charge for the previous period ($NEMC_t$):[68]

$NEMC_t = (NEMCa_{t-1} - NEMCf_{t-1})x(1+WACC)$

where,

- $NEMCa_{t-1}$ is the actual charge for the period previous to the relevant period
- $NEMCf_{t-1}$ is the forecast charge for the period previous to the relevant period
- WACC is the Weighted Average Cost of Capital for a full year.

The AER's final decision on the opex allowance for NEMC is presented in table 2.6 below.

Table 2.6 AER's final decision on NEMC forecast opex allowance ($million, 2009-10)

	2012-13	2013-14	2014-15	2015-16	2016-17
NEMC allowance	0.4	0.4	0.4	0.4	0.4

Source: AER analysis.

Transitional parameter

The transitional parameter will account for revenue adjustments from the application of the current regulatory period control mechanism that were either estimates or not known at the time of the final determination. The transitional parameter will extend no further than 2013-14.

Where required, the following illustrates how each individual adjustment will be calculated:

67 Aurora, *Regulatory proposal 2012–17*, May 2011, Attachment AE073, May 2011, p. 5.
68 Aurora, *Regulatory proposal 2012–17*, May 2011, Attachment AE073, May 2011, p. 6.

Carryover revenue adjustment

The adjustment for the difference between the actual carryover under recovery of revenues as calculated by the current control mechanism for 2011-12 and the estimated carryover under recovery of revenues added as a building block for the calculation of the annual revenue requirement.

$CR_t = (CRa_{t-1} - CRe_{t-1}) \times (1 + WACC)$

where,

- CRa_{t-1} is the actual under recovery of carryover revenues incurred in 2011-12
- CRe_{t-1} is the estimated under recovery of carryover revenues for 2011-12 added to the annual revenue requirement
- WACC is the Weighted Average Cost of Capital for a full year.

GSLse

The adjustment for making single duration outage GSL payments to customers where the threshold for payments has been subsequently altered using the approved methodology ($GSLse_t$) is calculated on the following basis:[69]

$GSLse_t = GSL_{t-1} \times (1 + WACC)$

where,

- GSL_{t-1} is the sum of the payments made to customers who experienced an outage shorter than the adjusted threshold for the period previous to the relevant period; and
- WACC is the Weighted Average Cost of Capital for a full year.
- GSL_{t-1} is calculated on the following basis:
- $GSL_{t-1} = \sum_{events} ({}^{P}/_{2} \times 80)$

where,

- P is the number of payments made to customers who experienced an outage shorter than the adjusted threshold.

GSLcap

$GSLCap_t$ is the adjustment to the transitional parameter calculated as follows:[70]

- If the sum of actual payments made for period 1 to period t (inclusive) is greater than the cumulative GSL threshold for period y given in table 6 of the 2007 Determination, then the adjustment is:

[69] Aurora, *Regulatory proposal 2012–17*, May 2011, Attachment AE073, p. 8.

[70] Aurora, *Regulatory proposal 2012–17*, May 2011, Attachment AE073, pp. 15–16.

- for period 1, the actual payments made for period 1 less the cumulative threshold for period 1
- for all other periods, the sum of actual payments made in periods 1 to t (inclusive), less the cumulative threshold for period t, less the sum of all adjustments made in periods 1 to t-1 (inclusive).

- Else, the adjustment for period 1 is zero and for all other periods the adjustment is zero less the sum of all adjustments made in periods 1 to t-1 (inclusive).

All calculations are to be done in $2006 and the final adjustment is then to be escalated by the prescribed inflationary factor and then multiplied by WACC.

NEM participation and retail contestability related costs (NEM)

The adjustment for the difference between the actual revenue allowance and the forecast revenue allowance in prior periods for costs attributable to NEM and retail contestability costs (but excluding full retail contestability costs) (NEM_t) is calculated on the following basis:[71]

$NEM_t = (NEMa_{t-2} - NEMf_{t-2}) \times (1+ WACC_{t-2}) \times (1+WACC_{t-1})$

where,

- $NEMa_{t-2}$ is the actual revenue in relation to NEM and retail contestability costs for the period prior to the previous period
- $NEMf_{t-2}$ is the forecast revenue in relation to NEM and retail contestability costs for the period prior to the previous period
- $WACC_{t-1}$ is the Weighted Average Cost of Capital in the period previous to the relevant period
- $WACC_{t-2}$ is the Weighted Average Cost of Capital in the period prior to the previous period
- $NEMf_{t-2}$ is calculated on the following basis:
  - $NEMf_{t-2} = RAB_f \times WACC + DEPN_f + OM_f$

2.3.4 DUOS over and under recovery

To demonstrate compliance with its distribution determination in the forthcoming regulatory control period, the AER requires Aurora to maintain a DUOS unders and overs account. Aurora must provide information on this account to the AER as part of its annual pricing proposal.[72]

Aurora must provide the amounts for the following entries in their DUOS unders and overs account for the most recently completed regulatory year (t–2), the current regulatory year (t-1) and the next regulatory year (t):

1. opening balance for year t–2, year t-1 and year t;[73]

71 Aurora, *Regulatory proposal 2012–17*, May 2011, Attachment AE073, May 2011, p. 12.
72 NER, clause 16.12.1(19) and 6.18.2(b)(7).
73 The opening balance for year t–2 should be indexed by WACC to the start of year t–2 before it is indexed by WACC for two years (under item 2 above) to be in year t dollars.

2. an interest charge for one year on the opening balance in year t–2 and an interest charge for one year on the opening balance in year t-1. These adjustments are to be calculated using the approved nominal WACC. No such interest charge applies to the opening balance for year t;
3. the amount of revenue recovered from DUOS charges in respect of that year, less any under/over adjustments approved by the regulator for year t–2 and year t-1, less the MAR for the year in question;
4. an interest charge for one year related to the net amounts in item 3 for year t–2 and an interest charge for one year for year t-1. These adjustments are to be calculated using the approved nominal WACC. No such charge applies to the net amount in item 2 for year t;
5. the total of items 1–4 to derive the closing balance for each year.

Aurora must provide details of calculations in the format set out in table 2.7. All of Aurora's approved revenue adjustments operate on a one year lag and are therefore to be entered in the DUOS unders and overs account inclusive of an interest charge of one year. Amounts provided for the most recently completed regulatory year (t–2) must be audited. Amounts provided for the current regulatory year (t-1) will be regarded as an estimate. Amounts provided for the next regulatory year (t) will be regarded as a forecast.

In proposing variations to the amount and structure of DUOS charges, Aurora must attempt to achieve an expected zero balance on their DUOS unders and overs accounts in each forecast year in its annual pricing proposals in the forthcoming regulatory control period.

The proposed prices for year t are based on the sum of the MAR for year t plus any adjustment for DUOS under or over recoveries.

Table 2.7 Example calculation of DUOS unders and overs account ($000, nominal)

	year t–2 (actual)	year t–1 (estimate)	year t (forecast)
Revenue from DUOS charges	37,021	43,761	49,982[a]
Less MAR for the relevant year	34,365	46,694	49,920
Allowed revenues (AR_t)	34,100	46,554	49,895
Transitional ($transitional_t$)	240[b]	100	0
Electrical safety inspection service adjustment ($ESISC_t$)[c]	–5[c]	4	10
National energy market charge adjustment ($NEMC_t$)[d]	30	36	15
Approved pass throughs ($passthrough_t$) [e]	0	0	0
Under/over recovery for regulatory year	2,656	-2,933	62
DUOS unders and overs account			
Nominal WACC	8.28%	8.28%	na
Opening balance	0[f]	2,876	-62
Interest on opening balance	0	238	na
Under/over recovery for regulatory year	2,656	-2,933	62
Interest on under/over recovery for regulatory year	215	-243	na
Closing balance	2,876[g]	-62	0[h]

Notes: (a) Forecast revenue from DUOS charges will be set to achieve an expected zero balance in the DUOS unders and overs account for year t.
(b) In this example, the DNSP has transitional adjustment amounts. The transitional parameter will lapse no later than 2013-14.
(c) In this example, the DNSP has received more electricity safety inspection service allowance in year t–3 and less in year t–2 than was forecast for these years. The electrical safety inspection service adjustment is based on the difference between the actual service charge collected and the forecast charge for the most recently completed year.
(d) The national energy market charge adjustment is based on the difference between the actual service charge collected and the forecast charge for the most recently completed year.
(e) Approved pass throughs have been set to zero in the above example and will be dependent on Aurora applying for pass throughs.
(f) The opening balance for year t–2 is set to zero to reflect the carryover of under recoveries from the current regulatory period to the forthcoming regulatory control period are accounted for in the PTRM and individual adjustment mechanisms including the transitional parameter.
(g) This figure will be the opening balance in the DUOS unders and overs account for year t–2 for the annual price approval process in one year's time.
(h) Aurora must attempt to achieve an expected zero balance on their DUOS unders and overs accounts in each forecast year in its annual pricing proposals in the forthcoming regulatory control period.

2.3.5 TUOS over and under recovery

To demonstrate compliance with its distribution determination in the forthcoming regulatory control period, the AER requires Aurora to maintain a TUOS unders and overs account. Aurora must provide information on this account to the AER as part of their annual pricing proposal.[74]

[74] NER, clause 16.12.1(19) and 6.18.2(b)(7).

Aurora accepted the AER's draft determination that a TUOS method similar to that of the DUOS method is appropriate. This method provides for consistency between treatment of DUOS and TUOS, and also results in less price volatility for customers. Aurora must provide the amounts for the following entries in their TUOS unders and overs account for the most recently completed regulatory year (t–2), the current regulatory year (t-1) and the next regulatory year (t):

1. opening balance for year t–2, year t–1 and year t;
2. an interest charge for one year on the opening balance in year t–2 and an interest charge for one year on the opening balance in year t-1. These adjustments are to be calculated using the approved nominal WACC. No such interest charge applies to the opening balance for year t;
3. the amount of revenue recovered from TUOS charges applied in respect of that year, less any under/over adjustment approved by the regulator for year t–2 (in relation to year t–3) and year t-1, less the amounts of all transmission related payments made by Aurora in respect of that year;
4. an interest charge for one year related to the net amounts in item 3 for year t–2 and an interest charge for one year for year t-1. These adjustments are to be calculated using the approved nominal WACC. No such interest charge applies to the net amount in item 2 for year t;
5. the total of items 1–4 to derive the closing balance for each year.

Aurora must provide details of calculations in the format set out in table 2.8. Amounts provided for the most recently completed regulatory year (t-2) must be audited. Amounts provided for the current regulatory year (t-1) will be regarded as an estimate. Amounts for the next regulatory year (t) will be regarded as a forecast.

In proposing variations to the amount and structure of TUOS charges, Aurora is to achieve a zero expected balance on its TUOS unders and overs account at the end of each of the forecast years in its annual pricing proposals in the forthcoming regulatory control period.

Table 2.8 Example calculation of TUOS unders and overs account ($000, nominal)

	year t–2 (actual)	year t-1 (estimate)	year t (forecast)
Revenue from TUOS charges	37,221	37,800	36,863 [a]
Less total transmission related payments	34,365	38,734	39,200
Transmission charges to be paid to TNSP	33,793	38,000	38,400
Avoided TUOS payments	572	734	800
Under/over recovery for regulatory year	2,856	-934	-2,327
TUOS unders and overs account			
Nominal WACC	8.28%	8.28%	na
Opening balance	0	3,092	2,337
Interest on opening balance	0	256	na
Under/over recovery for regulatory year	2,856	-934	-2,337
Interest on under/over recovery for regulatory year	236	-77	na
Closing balance	3,092 [b]	2,337	0

Notes: (a) Forecast revenue from TUOS charges will be set to achieve an expected zero balance in the DUOS unders and overs account for year t.
(b) This figure will be the opening balance in the TUOS unders and overs account for year t–2 for the annual price approval process in one year's time.

2.4 Revisions

Revision 2.1: The AER included a revenue adjustment mechanism in the transitional parameter to account for the difference between the actual carryover under recovery of revenues as calculated by the current control mechanism for 2011-12 and the estimated carryover under recovery of revenues added as a building block for the calculation of the annual revenue requirement.

Revision 2.2: The AER does not accept Aurora's proposed revenue adjustment for banking within regulatory control period revenues (O-factor).

Revision 2.3: The AER accepts Aurora's proposed revenue adjustment for ESISC.

Revision 2.4: The AER does not accept Aurora's proposed revenue adjustment for TMR.

Revision 2.5: The AER does not accept Aurora's proposed revenue adjustment for GSL risk mitigation mechanisms.

3 Unit rates

Aurora utilises unit rates as a key input to determining its capital and operating expenditure programs.[75] The unit rates comprise an aggregation of materials, labour and other costs required to complete required works.[76] Aurora has used unit rates currently incurred, and reflected in the current average cost of works as the basis to forecast its future unit rates.[77] Aurora applies forecast unit rates to specific tasks within work programs that are repetitive in nature and are contained within the operating and capital programs of work. Where there is more than one task within a work program, the unit rate is applied to the volume of tasks to determine the overall program cost.[78] Unit rates therefore form the basis of Aurora's capex, opex and alternative control services expenditure proposals.

In its regulatory proposal, Aurora applied an annual three per cent efficiency factor to the labour rates within its unit rates as a means of reducing total expenditure.[79] However, in its revised regulatory proposal, Aurora submitted that the AER's draft determination did not accept Aurora's efficiency factor.[80] On this assumption, Aurora submitted revised unit rates for all expenditure with the three per cent efficiency factor removed.[81]

3.1 Determination

The AER considers that Aurora's removal of the three per cent efficiency factor does not accord with the requirements of clause 6.10.3(b) of the National Electricity Rules (NER). Therefore, the AER considers that Aurora is unable to make this revision and has not accepted Aurora's revised unit rates.

3.2 Assessment approach

The AER has assessed Aurora's revised unit rates against the NER provisions in respect of revised regulatory proposals. The relevant provision of the NER is clause 6.10.3(b):

> A Distribution Network Service Provider may only make the revisions referred to in paragraph (a) 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.

The meaning of clause 6.10.3(b) was discussed by Justice Katzmann in the recent ActewAGL Federal Court matter.[82] Justice Katzmann stated:[83]

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75 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 167; Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 83.

76 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 75, Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 27.

77 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 167; Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 83.

78 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 167; Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 83.

79 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 167.

80 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 75, 80, 83.

81 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 83.

82 *ActewAGL Distribution v The Australian Energy Regulator* [2011] FCA 639, 8 June 2011.

> …even if it can be said that the AER considered or discussed the averaging period in the draft determination, in my opinion that is not the relevant meaning of “raised” in cl 6.10.3(b). Rather, the relevant meaning in this context is “brought up (a question, a point, etc.)” or “put forward (an objection, a difficulty, etc.)”: See *Oxford English Dictionary*. **The clear intention of the paragraph is to afford a distribution network service provider procedural fairness; to enable it to address concerns the AER has *before* it makes its decision, not to give the service provider the opportunity to reverse a decision already made** (emphasis added).

The AER considers the above extract indicates that the purpose of a revised regulatory proposal is to allow a DNSP to address matters or concerns the AER has 'brought up' or 'put forward' in its draft determination.

The AER also considers that clause 6.10.3(b) indicates a desire for the decision making process to go through stages of filtering issues. That is, a DNSP should raise all necessary issues in its regulatory proposal. The AER then assesses the regulatory proposal and makes a draft determination. All matters that the AER accepts in the draft determination are settled at that point and cannot be revisited. Only those matters which are still in contention continue to be considered. The final determination resolves these issues. Therefore, unless the AER has indicated in the draft determination that a revision is required, it follows that no matter has been raised.[84] Therefore, in the AER's view, Aurora is not able to submit, and the AER cannot accept, the revised unit rates.

For this final determination, the AER required Aurora to provide an updated revised program of work (POW) with capex and opex unit rates that included the originally proposed three per cent efficiency factor.[85] Aurora's first response to this request contained errors[86], so the AER issued a follow up request and received a follow up revised POW.[87]

For opex, the AER was satisfied that the relevant opex programs in the follow up revised POW accurately included the efficiency factor.[88] The AER has therefore used the follow up revised POW to assess Aurora's revised opex forecast.

However, for capex, the AER could not reconcile the relevant capex programs in the follow up revised POW with information from Aurora's initial and revised regulatory proposals. The AER was not satisfied the follow up revised POW accurately included the efficiency factor because the AER identified a reconciliation error of approximately $8 million. As a result, the AER has not relied on the updated revised POW to amend Aurora's revised capex forecast. Instead, the AER has relied on unit rates from Aurora's initial regulatory proposal wherever possible. Where this has not been possible, the AER has relied on cost information from Aurora's revised regulatory proposal and adjusted the underlying labour rates by three per cent per year.

3.3 Reasons for determination

The AER considers that Aurora has mischaracterised its draft determination and resubmitted matters that the AER's draft determination did not require Aurora to address. Therefore, any revisions Aurora

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83 *ActewAGL Distribution v The Australian Energy Regulator* [2011] FCA 639, 8 June 2011, at [64].

84 The AER took a similar 'filtering issues' view in the July 2011 NT Gas 2011-16 final access arrangement (see pp. 37-43). Although, this decision applies in the context of gas, the relevant National Gas Rule (rule 60(2)) is substantively similar to clause 6.10.3(b) of the NER.

85 AER, *Information request AER/066 of 22 February 2012*.

86 Aurora, *Response to follow up information request AER/066 of 13 March 2012*, received 15 March 2012.

87 AER, *Follow up information request AER/066 of 13 March 2012*.

88 The AER compared the follow up revised POW to Aurora's initial POW and was able to reconcile them.

proposes on this issue cannot be 'to incorporate the substance of any changes required to address matters raised by the draft distribution determination.'[89] Therefore, the AER considers that Aurora is unable to make this revision and has not accepted Aurora's revised unit rates.

Aurora developed its regulatory proposal with a clear aim to minimise the impact of further price increases to customers.[90] On this basis Aurora applied an annual three per cent efficiency factor to the labour rates within its unit rates as a means of reducing total expenditure.[91] Aurora adopted this top down approach because it is yet to fully substantiate the individual projects under a typical engineering solution.[92] Aurora used the unit rates as the basis for developing its capex, opex and alternative control services expenditure forecasts.

However, in its revised regulatory proposal, Aurora stated that the AER's draft determination did not accept Aurora's proposed three per cent efficiency factor for labour rates.[93] Aurora stated it accepts the AER's draft determination and removed the three per cent labour efficiency factor from all unit rates.[94]

However, the AER's draft determination did not reject Aurora's efficiency factor or unit rates pr require a revision so those unit rates. Aurora has not provided any supporting information for its contention that the AER rejected the originally proposed efficiency factor or unit rates other than its interpretation of the AER's draft determination. The AER considers Aurora has mischaracterised its draft determination. Aurora's removal of its efficiency factor has changed its expenditure forecasts, resulting in increased amounts for all categories of expenditure.

3.3.1 Unit rates for capex and alternative control services

In its draft determination, the AER clearly accepted Aurora’s unit rates for capex and alternative control services, which included the efficiency factor:[95]

> The AER has assessed the unit rates applied by Aurora to forecast its capex and alternative control expenditure and is satisfied that these reflect the efficient costs of a prudent DNSP.

The AER benchmarked a selection of Aurora's unit rates against similar unit rates of the Victorian DNSPs.[96] The AER also compared the results of its capex unit rate benchmarking with the results of a benchmarking report prepared for Aurora by Parsons Brinkerhoff (PB).[97] This report was provided as an attachment to Aurora's regulatory proposal to demonstrate that Aurora's capex and opex unit rates were comparable with other DNSPs.[98] Aurora did not provide any report with its revised regulatory proposal that demonstrated its revised unit rates were comparable with other DNSPs.

89 NER, clause 6.10.3(b).
90 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 14.
91 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 167.
92 Aurora, *Response to information request AER/046 of 5 October 2011, received 11 October 2011*, p. 3.
93 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 75, 80, 83.
94 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 83.
95 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 96.
96 AER, *Aurora 2012–17 draft distribution determination,* November 2011, pp. 112, 359-360.
97 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 112.
98 Parsons Brinkerhoff, *Capex and opex benchmarking study*, March 2011. Attachment AE061 to Aurora, *Regulatory proposal 2012—17*, May 2011.

The outcome of the AER's draft determination assessment was that Aurora's unit rates—which included the efficiency factor—benchmarked reasonably with other DNSPs.[99] The AER was therefore satisfied that Aurora's unit rates were appropriate as the starting point for Aurora's expenditure forecasts.

Therefore, for capex and alternative control services unit rates, the AER considers there was no 'matter raised' in the draft determination that the AER required Aurora to address. Therefore, the AER considers that Aurora's removal of the efficiency factor from its capex and alternative control services unit rates was not permitted under clause 6.10.3(b) of the NER.

3.3.2 Unit rates for opex

The AER's draft determination was silent on the issue of whether or not it accepted Aurora's unit rates for opex because it did not need to form a view on this issue. In the draft determination, the AER was not satisfied that the methodology adopted by Aurora provided a satisfactory total forecast as required by clause 6.5.6. The AER, instead, adopted a base year approach to determine an alternative opex forecast, which relies on historic expenditure.[100] Therefore, the AER did not utilise Aurora's forecast opex unit rates (and hence the efficiency factor) to determine its substitute forecast.

In the draft determination opex attachment, the AER did comment on Aurora's efficiency factor. Indeed, one of the reasons why the AER used a base year approach to assess Aurora's forecast was because the AER was unable to form a view about Aurora's efficiency factor:[101]

> While Aurora's application of labour efficiencies has reduced its total forecast opex it is not clear whether this adjustment is sufficient to result in a total forecast opex that reasonably reflects the opex criteria - it may be too high or too low. The AER is unable to form a view about this high level adjustment on the basis of Aurora's proposal alone as reasoning for the quantum of the adjustment has not been substantiated.

Similarly, in the context of labour cost escalation, the AER commented that Aurora's efficiency factor was not a robust forecast of labour productivity improvements. The AER considered it was best described as an aspirational target to reduce total expenditure.[102] However, this statement simply supported the AER's use of a productivity adjusted labour price index (LPI) to assess Aurora's labour cost escalation. Had the AER considered Aurora's efficiency factor to be a robust productivity improvement, it would not have been appropriate to use productivity adjusted LPI because productivity improvements would have been accounted for twice. Instead, the AER considered that the three per cent efficiency factor only had the effect of reducing Aurora's unit rates to an efficient level. It did not amount to a productivity improvement for the purposes of labour cost escalation.[103]

In any event, as noted in attachment 4, the AER accepted the amount of Aurora's labour cost escalation when compared to the AER's own escalation:[104]

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99 AER, *Aurora 2012–17 draft distribution determination,* November 2011, pp. 96, 359-360; Nuttall Consulting, *Aurora electricity distribution revenue review: A report to the AER*, April 2012, section 4.2.

100 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 96.

101 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 158.

102 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 99.

103 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 99.

104 AER, *Aurora 2012–17 draft distribution determination,* November 2011, pp. 96–97.

> On balance, the AER is satisfied that the impact of the real cost escalators applied by Aurora on forecast opex reasonably reflects a realistic expectation of labour and materials cost increases over the forthcoming regulatory control period.

Despite these comments, the AER did not raise Aurora's efficiency factor or opex unit rates as a matter for Aurora to address in its revised regulatory proposal, as it did on other issues. Nor did the AER propose any changes to Aurora's efficiency factor or opex unit rates. It appears Aurora considers that, because the AER mentioned the efficiency factor in connection with concerns about forecasting total opex, and did not accept Aurora's total forecast opex proposal, the AER rejected Aurora's efficiency factor. However, Aurora's view is incorrect, and the AER's broader actions in relation to Aurora's opex proposal as a whole do not constitute a rejection of Aurora's efficiency factor or other unit rates.

The AER is cognisant that Aurora's unit rates are a key input for determining its capex and its opex forecasts. Aurora's regulatory proposal and revised regulatory proposal both state this, and additionally explain that assumptions applicable to unit rates apply across Aurora's capex and opex forecasts.[105]

To argue that the AER did not accept Aurora's unit rates for opex when it clearly did so for capex and alternative control services implies that Aurora's opex and capex unit rates should be based on different methodologies. Aurora itself identified that this would be inconsistent, albeit under the mistaken assumption that the AER had erred:[106]

> The AER has been inconsistent in its application of escalators and unit rates between and within service classifications. The AER only applied its labour escalators to standard control services operating expenditure; Aurora considers that these escalators should be applied to all work categories and all forms of control.

The AER agrees that it would be inconsistent if Aurora's opex forecast was derived from different unit rates to those used for capex and alternative control services, given the statements in Aurora's regulatory proposal and revised regulatory proposal noted above.

Indeed, while the AER's draft determination did not explicitly state that it did accept Aurora's opex unit rates, it is a mischaracterisation of the AER's draft determination for Aurora to assume that the AER rejected them. Where the AER's draft determination did not accept an element of Aurora's opex proposal, it stated this expressly. For example, the AER did not agree with the amounts of some of Aurora's recurrent costs, non-recurrent costs and step change costs. The AER's draft determination stated where it had made reductions for these costs.[107]

Further, the AER did not accept Aurora's opex proposal in total on the basis that it was too high.[108] The revision the AER's draft determination required Aurora to make in its revised regulatory proposal was a lower total forecast opex.[109] Aurora's removal of its efficiency factor in its revised regulatory proposal has increased forecast opex (because unit rates are now higher). To argue that Aurora's revised opex unit rates are to address a matter raised in the AER's draft determination is not valid.

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105 Aurora, *Regulatory proposal 2012–17*, May 2011, pp. 75, 167; Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 27, 83.

106 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 76.

107 AER, *Aurora 2012–17 draft distribution determination,* November 2011, pp. 169-173, 178-180, 182-183.

108 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 153.

109 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 190.

The AER therefore considers there was no 'matter raised' in the draft determination in relation to opex unit rates that the AER required Aurora to address. The AER considers that Aurora's removal of the efficiency factor from its opex unit rates was not permitted under clause 6.10.3(b) of the NER.

3.3.3 Other matters

It appears Aurora has assumed that because the AER at times updates forecasts for currency of information between its draft and final determinations, Aurora could then update its forecasting methodologies. For example, in its revised regulatory proposal, Aurora revised its forecasting methodologies for:

- labour cost escalation (see attachment 4)
- unit rates
- the nominal risk free rate (see attachment 10).

Aurora's revisions to labour cost escalation, unit rates or nominal risk free rate are changes in approach, and not comparable with a forecast updated for currency of information. Clause 6.10.3(b) of the NER does not permit such revisions to the proposal as they are not made to incorporate the substance of changes required to address matters raised by the draft determination or the AER's reasons for it.

The AER stated in its draft determination when it will update information. For example, the AER stated that it would update *its* labour cost growth forecasts[110] and exchange rate forecasts.[111] However, the only matter raised on these issues was the currency of the forecasts. While it may have been appropriate and in accordance with clause 6.10.3(b) for Aurora to update its own forecasts in response, it was restricted to addressing the currency of its forecasts. New forecasting methodologies were beyond the scope of the matter raised in the AER's draft determination.

In contrast, the AER considered Aurora's maximum demand forecasts were based on out-dated information[112] but also explained how Aurora's methodology to forecast maximum demand was flawed.[113] It was therefore reasonable and in accordance with clause 6.10.3(b) for Aurora's revised regulatory proposal to address the AER's concerns by updating its methodology. However, this was not the case in relation to the methodologies to calculate labour cost escalation, unit rates or the nominal risk free rate.

For the avoidance of doubt, if the AER requires updated information, the AER will seek it and consider it in a procedurally fair manner. For example, the AER requested that Aurora provide audited actual data for 2010–11 opex amounts.[114]

110 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 101.
111 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 103.
112 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 86.
113 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 84.
114 AER, *Information request AER/055 of 21 January 2012*.

3.4 Revisions

Revision 3.1: The AER does not accept Aurora's removal of the annual three per cent efficiency factor from the labour rates within its revised capex, opex and alternative control services unit rates. The efficiency factor must be applied, as originally proposed by Aurora.

4 Real cost escalation

This attachment sets out the AER's determination of the growth in labour and materials prices over the forthcoming regulatory control period. The application of real cost increases is discussed in the capex, opex, and alternative control attachments (attachments 6, 7 and 15–19 respectively).

Movements in labour and materials prices will impact Aurora's opex and capex over the forthcoming regulatory control period. Due to market forces, labour and materials costs may not increase at the same rate as the consumer price index (CPI). In its draft determination, the AER was satisfied that the real cost increases included in Aurora's forecast opex, capex and alternative control expenditure reasonably reflected forecast cost increases.[115]

The AER also stated in its draft determination that it would update its labour and materials real cost forecasts for its final determination.[116] The AER has done this to ensure it remains satisfied that Aurora's proposed labour and materials real cost increases reasonably reflect a realistic expectation of cost increases over the forthcoming regulatory control period.

4.1 Determination

The AER is not satisfied the labour cost escalators, proposed by Aurora in its revised regulatory proposal (table 43) reasonably reflect a realistic expectation of labour costs for the forthcoming regulatory control period.[117] The AER considers labour costs should be escalated by CPI only, consistent with Aurora's initial regulatory proposal.

The AER is not satisfied the construction cost escalators proposed by Aurora in its revised regulatory proposal (table 44) reasonably reflect a realistic expectation of construction costs for the forthcoming regulatory control period.[118] The AER considers construction costs should be escalated by CPI only, consistent with Aurora's initial regulatory proposal.

The AER is satisfied the materials costs escalators proposed by Aurora in its revised regulatory proposal (tables 41 and 42) reasonably reflect a realistic expectation of materials costs for the forthcoming regulatory control period.[119]

4.2 Assessment approach

The AER has assessed Aurora's revised regulatory proposal using the same approach as used for its initial proposal, which is outlined in the AER's draft determination.[120] In undertaking this assessment the AER has considered information that was not available when making its draft determination, including:

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115 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 93.
116 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 101.
117 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).
118 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).
119 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).
120 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 95–96.

- Aurora's 2011 collective agreement
- revised labour cost forecasts from Deloitte Access Economics, reflecting updated economic data
- updated market data on materials prices and exchange rates.

4.3 Reasons

Clause 6.10.3(b) of the National Electricity Rules (NER) requires Aurora only make revisions to its regulatory proposal 'to incorporate the substance of any changes required to address matters raised by the draft distribution determination.'[121] The draft determination accepted the labour and materials escalators proposed by Aurora. It also stated the AER would update its forecasts of labour and materials real cost increases for the final decision.[122] The AER did this to ensure it remains satisfied the determined labour and materials cost escalation rates reasonably reflect a realistic expectation of the cost inputs required to achieve the capex and opex objectives. Given this, the AER considers clause 6.10.3(b) of the NER only allowed Aurora to revise its labour and materials cost escalators to the extent necessary to account for any changes in the economic outlook for labour and materials costs.

Deloitte Access Economics provided the AER with revised Tasmanian utilities sector wage forecasts. These revised forecasts are lower than the forecasts used by the AER in its draft determination. Given this, the AER remains satisfied labour cost increases equal to CPI increase reflect a realistic expectation of labour costs for the forthcoming regulatory control period. This is consistent with the AER's draft determination and Aurora's initial regulatory proposal. Further, the AER considers forecast LPI growth adjusted for labour productivity improvements represents a lower bound forecast of labour cost growth, and forecast LPI increases unadjusted for labour productivity represent an upper bound. Forecast labour cost increases of CPI are consistent with this because CPI increases, on average over the regulatory control period, lie between Deloitte Access Economics' forecasts of these two labour cost measures.

The AER did not raise issue with the contractor cost escalation rates proposed in Aurora's initial proposal and did not propose any change to Aurora's proposed contractor cost escalation rate of CPI. The AER considers no revision was required by Aurora 'to incorporate the substance of any changes required to address matters raised by the draft distribution determination.'[123]

The AER compared the materials cost escalators proposed by Aurora in its revised regulatory proposal against its own forecast materials cost increases. It is satisfied the materials costs escalators proposed by Aurora reasonably reflect a realistic expectation of materials costs for the forthcoming regulatory control period.

4.3.1 Currency of forecasts

In its draft determination, the AER was satisfied that, on balance, the real cost increases included in Aurora's forecast opex, capex and alternative control expenditure reasonably reflected forecast cost

121 NER, clause 6.10.3(b).
122 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 101.
123 NER, clause 6.10.3(b).

increases.[124] However, cost forecasts change as they are updated to reflect changing economic data. As stated in the draft determination, the AER considers that, if the available economic data has changed significantly, forecasts that do not reflect current economic data do not reasonably reflect a realistic expectation of cost inputs.[125] For this reason the draft determination stated that the AER would update its labour and materials costs forecasts for this final decision. Deloitte Access Economics provided the AER with updated labour cost forecasts produced in March 2012. The AER also updated its materials cost forecasts based on data available as at January 2012. The AER has used these revised labour and materials cost forecasts to assess whether the real cost escalators proposed by Aurora reasonably reflect a realistic expectation of labour and materials costs.[126]

4.3.2 Labour cost forecasts

Aurora stated in its revised regulatory proposal that the AER's draft determination did not accept Aurora's proposal of CPI-only escalation of labour costs.[127] It also stated:[128]

> The AER has been inconsistent in its application of escalators and units rates between and within the service classifications. The AER has only applied its labour escalators to Standard Control Services operating expenditure; Aurora considers that these escalators should be applied to all work categories and all forms of control.

The AER agrees that the same labour cost escalators should be applied to all work categories and all forms of control. The AER did this in its draft determination. In the draft determination the AER was satisfied the real cost increases included in Aurora's forecast opex, capex and alternative control expenditure reasonably reflected forecast cost increases.[129]

The AER notes that, prior to submitting its revised regulatory proposal, Aurora sought clarification from the AER on how labour cost escalation was applied in the opex, capex and alternative control services models used by the AER for its draft determination.[130] Regarding opex, the AER confirmed no labour cost escalation was applied, and demonstrated how this was applied in the opex model used by the AER.[131] The AER consistently applied labour cost escalation of CPI throughout its draft determination.

Treatment of labour productivity effects

As stated in the draft determination, to the extent that labour prices rise due to increased labour productivity, the increase in labour costs will be less than the increase in the labour price. Therefore, in order to determine the impact of labour price increases on the total labour cost, the price impacts of labour productivity effects should be removed from the labour price measure used.[132]

In its revised regulatory proposal, Aurora proposed the wage increases in its 2011 collective agreement be used to escalate labour costs through to the end of that agreement in 2014. For the last

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124 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 93.
125 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 101–102.
126 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).
127 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 80.
128 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 76.
129 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 93.
130 Aurora, *Information request AUR/007 of 12 December 2011*, p. 2.
131 AER, *Response to information request AUR/007 of 12 December 2011*, sent 15 December 2011. AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 96–97.
132 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 99.

three years of the forthcoming regulatory control period, Aurora proposed labour costs be escalated using Deloitte Access Economics forecast increases in the utilities LPI for Tasmania, adjusted for productivity.[133] Consequently Aurora's revised proposal inconsistently included a labour productivity adjustment for the years 2014–15 to 2016–17, but no labour productivity adjustment for the years prior.

The AER maintains the view that labour cost forecasts should be adjusted for labour productivity effects. However it also notes that if the LPI series is adjusted using forecast labour productivity increases based on the conventional labour productivity measure, the resulting labour cost series could understate labour cost changes.[134] This is because the conventional labour productivity measure includes composition productivity effects but the LPI does not. However, Deloitte Access Economics stated it considers the impact of compositional productivity on labour productivity to be small. Further, Deloitte Access Economics stated that, even if this were wrong, it would not affect its productivity adjusted forecasts because of its forecasting approach.[135] Given this, the AER considers Deloitte Access Economics' adjusted and unadjusted LPI forecasts to be lower and upper bound estimates of the annual increase in Aurora's efficient labour costs.

It is also worth noting Aurora removed the 3 per cent efficiency factor it proposed in its initial regulatory proposal from the labour component of all unit rates in its revised regulatory proposal.[136] As discussed in attachment 3, the AER does not consider the unit rates adjustment to be a productivity adjustment because benchmarking has shown the adjusted unit rates to be comparable to rates in other jurisdictions. That is, Aurora's proposed unit rates, including the 3 per cent efficiency improvement, are comparable to unadjusted rates in other jurisdictions.

Revised labour cost forecasts

Deloitte Access Economics provided revised labour cost forecasts to the AER in March 2012. As can be seen in table 4.1, LPI growth in the utilities sector in Tasmania is not expected to be as strong in the short term as previously projected because two speed economy issues have affected wage negotiations.[137]

Table 4.1 Deloitte Access Economics forecast average annual real labour cost changes, Tasmanian utilities sector, per cent

	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17
LPI—initial	2.2	2.8	2.3	0.7	0.5	–0.1	0.5
LPI—revised	1.0	1.0	0.6	–0.2	0.7	0.2	0.3
Productivity adjusted LPI—initial	3.1	1.7	0.8	–0.8	–1.2	–2.1	–1.5
Productivity adjusted LPI—revised	2.8	–0.9	–0.9	–1.9	–0.9	–1.7	–1.9

Source: Deloitte Access Economics

133 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 75.

134 Powerlink, *2013–2017 Powerlink Queensland: Revised revenue proposal*, pp. 35–36.
Electranet, *Submission on the Powerlink draft transmission determination 2012-13 to 2016-17*, 20 February 2012, p. 2.

135 Deloitte Access Economics, *Response to issues raised in the Powerlink regulatory proposal*, 2 March 2012, pp. 32–33.

136 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 83.

137 Deloitte Access Economics, *Forecast growth in labour costs: update of August 2011 report*, 9 March 2012, pp. 78–79.

Given Deloitte Access Economics' revised Tasmanian utilities sector wage forecasts are lower than its previous forecasts, the AER considers constraining wage increases to CPI should be more achievable under the revised forecasts compared to the forecasts used by the AER for its draft determination. Further, the AER considers Deloitte Access Economics' productivity adjusted and unadjusted LPI forecasts to be lower and upper bound estimates of the annual increase in Aurora's efficient labour costs. Forecast labour cost increases of CPI are consistent with this because CPI increases, on average over the regulatory control period, lie between the two forecasts.

In its revised regulatory proposal, Aurora proposed labour cost escalators for the first two years of the forthcoming regulatory control period based on the 2011 Aurora collective agreement. For the remaining three years, Aurora proposed labour cost escalators based on the Deloitte Access Economics report prepared for the AER's draft determination (table 4.2).[138]

Table 4.2 Aurora proposed average annual real labour cost changes, per cent, year on year

	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17
Real labour cost change	0.3	1.1	1.2	–1.2	–2.1	–1.5

Note: The real labour cost changes in Aurora's revised regulatory proposal were presented in cumulative terms. These have been converted to year on year terms.
Source: Aurora, *Revised regulatory proposal*, p. 80.

The AER was unable to reconcile the real wage increases proposed by Aurora with the nominal wage increases in the Aurora's 2011 collective agreement and the inflation rates proposed by Aurora. In deriving its labour cost escalator, Aurora did not apply the same inflation rate that it applied in its asset base roll forward model and its post tax revenue model. Further Aurora's 2011 collective agreement provides a competency payment equal to the difference between actual CPI and 2.5 per cent. Aurora did not include this in its labour cost escalator. Using the inflation rates in the asset base roll forward model and post tax revenue model, real wage increases associated with the 2011 collective agreement are lower than those proposed by Aurora for 2011–12 but higher for 2012–13 and 2013–14 (table 4.3).

Table 4.3 Aurora collective agreement wage increases, per cent

	2011–12	2012–13	2013–14
Collective agreement nominal wage increase	3.00	2.50	2.50
Collective agreement competency payments	0.00	1.42	1.42
Inflation	3.10	2.60	2.60
Collective agreement real wage increases (excluding competency payments)	–0.10	–0.10	–0.10
Collective agreement real wage increases (including competency payments)	–0.10	1.27	1.27
Proposed real wage increase	0.30	1.10	1.20

Note: The inflation rates are those in the roll forward model and post tax revenue model.
The collective agreement provides wage increases on 19 December 2011, 1 July 2012 and 1 July 2013.
Source: Aurora, *Aurora Energy Agreement 2011*, p. 106.

138 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 75.

Consequently, Aurora's new 2011 collective agreement, negotiated after it submitted its initial regulatory proposal, provides employees wage increases greater than CPI when competency payments are included. Similarly, Deloitte Access Economics' unadjusted LPI forecasts for the last three years of the forthcoming regulatory control period are also greater than CPI (0.7, 0.2 and 0.3 per cent). However, Aurora stated in response to an AER information request:[139]

> Given the uncertainty surrounding Aurora's wage negotiations, the base rates for Aurora's labour within its Regulatory Proposal have been held at the current levels and will increase by CPI only. Should Aurora's wages outcomes be in excess of CPI Aurora will find savings in other areas to offset any wages growth greater than CPI.

Further, Aurora's revised regulatory proposal is inconsistent with previous statements made by Aurora. Aurora stated in its initial regulatory proposal it was:[140]

> … confident of achieving efficiencies in its labour costs over the 2012–17 Regulatory Control Period and does not consider that an increase in labour costs over and above CPI is reflective of efficient costs.

Given these considerations, the AER is satisfied Aurora's initially proposed labour cost escalators of CPI, accepted by the AER in its draft determination, reasonably reflect a realistic expectation of the labour cost inputs required to achieve the opex and capex objectives.[141]

Contractor cost forecasts

The AER is not satisfied the contractor cost escalators proposed by Aurora in its revised regulatory proposal reflect a realistic expectation of contractor costs for the forthcoming regulatory control period.

Aurora applied the contractor cost escalation rates in table 4.4 to the portion of costs incurred by contractors within its revised capex and opex forecasts.[142] This approach is not consistent with Aurora's initial regulatory proposal in which it applied CPI cost increases (that is, no real cost escalation) to these costs.[143]

Table 4.4 Aurora proposed year on year real contractor cost changes, per cent.

	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17
Real contract cost change	0.59	–0.17	–1.18	–1.54	–0.61	–0.19	0.35

Note: The real contractor cost changes in Aurora's revised regulatory proposal were presented in cumulative terms. These have been converted to year on year terms.

Source: Aurora, *Revised regulatory proposal*, p. 81; SKM, *Annual material cost escalation factors 2013–17*, December 2011, p. 6.

The AER did not raise issue with the contractor cost escalation rates proposed in Aurora's initial proposal. In the draft determination the AER was satisfied that, on balance, the real cost increases included in Aurora's forecast opex, capex and alternative control expenditure reasonably reflected

139 Aurora, *Response to information request AER/042 of 27 September 2011*, received 4 October 2011, p. 10.
140 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 165.
141 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).
142 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 76.
143 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 165.

forecast cost increases.[144] The AER did not apply real cost escalation to contractor costs to determine its opex and capex forecasts in its draft determination.

Consistent with the reasons provided in attachment 3, the AER considers Aurora's inclusion of real cost escalation rates for contractor costs in its revised regulatory proposal does not accord with the requirements of clause 6.10.3(b) of the NER. The AER's draft determination did not raise the matter of contractor cost escalation, and did not require any revision to Aurora's proposed contractor cost escalation rate of CPI only. The AER considers no revision was required by Aurora 'to incorporate the substance of any changes required to address matters raised by the draft distribution determination.'[145] Therefore, the AER considers that Aurora is unable to make this revision, and therefore has not accepted Aurora's revised contractor cost escalation rates.

4.3.3 Materials cost forecasts

The AER is satisfied the materials costs escalators proposed by Aurora in its revised regulatory proposal reflect a realistic expectation of materials costs for the forthcoming regulatory control period.

Table 4.5 Forecast average annual real cost changes, per cent

	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17
Aluminium—Aurora	–12.4	2.1	4.5	3.9	3.7	3.2
Aluminium—AER	–13.0	2.4	6.7	8.6	1.3	0.5
Copper—Aurora	–12.6	–1.8	–0.1	–1.6	–2.0	–2.5
Copper—AER	–11.7	–0.7	0.6	–1.0	–5.1	–4.0
Steel—Aurora	2.6	4.3	1.0	0.9	1.3	0.9
Steel—AER	–6.9	5.6	2.6	2.0	–1.3	0.5
Oil—Aurora	1.9	1.9	–2.8	–1.6	0.7	4.5
Oil—AER	1.6	4.6	–2.4	–2.4	–1.5	–1.0
Construction costs—Aurora	–0.2	–1.2	–1.5	–0.6	–0.2	0.4
Construction costs—AER	–1.7	–0.7	–0.3	0.3	0.7	1.0
CPI—Aurora	2.00	3.25	2.50	2.50	2.50	2.50
CPI—AER	2.11	2.60	2.60	2.60	2.60	2.60

Source: Aurora, *Revised regulatory proposal*, p. 78; AER analysis.

Foreign exchange rate forecasts

Both the AER and Sinclair Knight Merz (SKM) forecast movements in aluminium, copper and steel prices from forward prices on the London metal exchange (LME) and Consensus Economics long term price forecasts. Both of these are denominated in US dollars and require forecast exchange rates to convert to Australian dollar terms.

[144] AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 93.
[145] NER, clause 6.10.3(b).

The draft determination stated monthly average forward exchange rates produce materials cost forecasts that reasonably reflect the opex and capex criteria[146] and that the AER would update these forecast exchange rates in its final determination to reflect the most current exchange rates available at that time.[147]

The AER is not satisfied the exchange rates forecast by SKM, and proposed by Aurora, reasonably reflect a realistic expectation of costs during the forthcoming regulatory control period (table 4.6).[148]

Table 4.6 AER's conclusion on USD/AUD foreign exchange forecasts

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17
SKM forecast	0.99	0.97	0.94	0.92	0.89	0.86	0.84
AER forecast	1.00	1.04	1.01	0.97	0.94	0.91	0.89

Source: AER analysis; Bloomberg; SKM.

In response to the draft determination, SKM updated its foreign exchange rate methodology. To derive the forecasts in table 4.6, SKM used forward prices from the Chicago Mercantile Exchange as available on 15 December 2011. The AER considers such an approach may not deliver foreign exchange rate forecasts that reasonably reflect a realistic expectation of costs because the timing of the forward rate data is not consistent with the timing of the commodity price data. As stated in the draft determination, commodity price forecasts and foreign exchange forecasts:[149]

> … should be derived at the same time because of the correlation between the two. Thus, if exchange rate forecasts were to be updated but not the US dollar materials costs forecasts (because long term forecasts had not been updated, for example), then the Australian dollar materials cost forecasts would be biased. If the Australian dollar had dropped, then the materials cost forecasts would be upwardly biased since commodity prices would likely have also dropped. Similarly, if the Australian dollar had risen, then the materials cost forecasts would be downwardly biased.

In this instance the Australian dollar has fallen from the time the commodity price forecasts were derived in October 2011 to when the foreign exchange forecasts were derived on 15 December 2011. As foreshadowed in the draft determination, this yielded upwardly biased commodity price forecasts, in Australian dollars. This is because SKM's forecast does not reflect the fact that aluminium, copper and steel prices, in US dollar terms, were lower on 15 December 2011 than the October average.[150]

Further, deriving foreign exchange forecasts from a singles day's forward rates is inconsistent with SKM's commodity price forecasting approach, which relies on a 30 day average or monthly data.[151] Using a single day's forward rates may not reasonably reflect a realistic expectation of foreign exchange rates since exchange rates are volatile. For example, the spot rate on 15 December 2011 (the date chosen by SKM) was 99.2 US cents. This was lower than the December average of 101.6 US cents (figure 4.1). Only one day in December 2012 (14 December) had a lower spot exchange rate.

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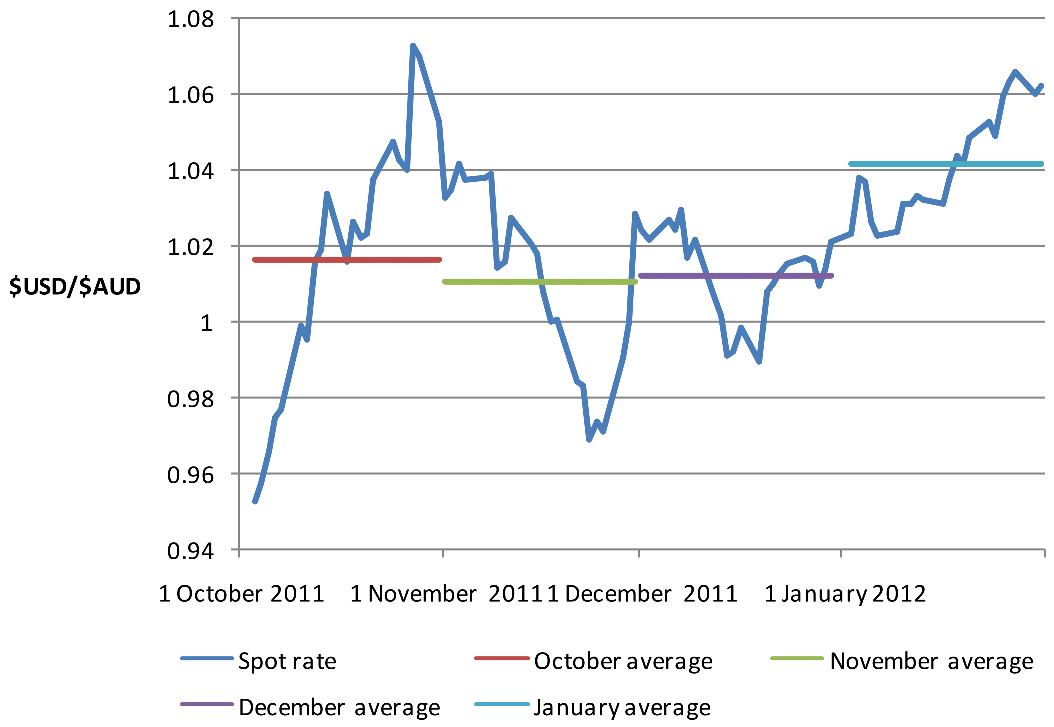
146 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).
147 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 103.
148 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).
149 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 102.
150 London metal exchange; Bloomberg.
151 SKM, *Aurora Energy annual material cost escalators 2013–17*, Draft Report, 22 December 2010.

Figure 4.1 US dollar spot exchange rates



Source: Bloomberg

Revised materials cost forecasts

The AER notes the materials cost escalators forecast by SKM were derived using a similar method to the AER's own forecasts. However, in the draft determination the AER was not satisfied the materials cost escalators forecast by SKM reflected the most current market data available at that time. SKM's revised forecasts were based on Consensus Economics' October 2011 forecasts, whereas the AER's forecasts were based on Consensus Economics' January 2012 forecasts. Between October and January the AER's cost forecasts went up for most materials. However, for the reasons discussed above, SKM's commodity price forecasts, in Australian dollar terms, are upwardly biased due to the foreign exchange rate forecasts used.

Table 4.7 Average cumulative real price impact over the forthcoming regulatory control period, per cent.

	AER	SKM
Aluminium	–0.6	–3.1
Copper	–14.8	–16.1
Steel	1.2	9.3
Oil	2.0	1.8
Construction costs	–2.0	–2.9

Source: AER analysis, SKM.

The impact of the differences in the AER's and SKM's forecasting methods, and the data used, is summarised in table 4.7, which outlines the average cumulative impact of real materials prices changes during the forthcoming regulatory control period compared to 2010-11. With the exception of steel, the AER's forecasts are higher. However, the difference between steel prices is greater, and a greater weighting is applied to steel. Therefore, on balance, the AER is satisfied the materials costs escalators proposed by Aurora reflect a realistic expectation of materials costs required to achieve the opex and capex objectives.[152]

4.4 Revisions

Revision 4.1: The AER has escalated forecast labour costs by CPI only, consistent with Aurora's initial regulatory proposal.

Revision 4.2: The AER has escalated forecast construction costs by CPI only, consistent with Aurora's initial regulatory proposal.

152 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).

5 Demand forecasts

In making its determinations on Aurora's forecast capex and opex for standard control services and alternative control metering services; the AER is required under the National Electricity Rules (NER) to have regard to a realistic expectation of demand.[153] This chapter outlines the AER's consideration of a realistic expectation of demand. This chapter does not outline the impact of these forecasts on Aurora's capex, opex or tariffs.

The AER considers there to be two main aspects to demand for Aurora's distribution services that are relevant to the determination of forecast capex and opex for standard control services and alternative control metering services:[154]

- Demand for new customer connections
- The maximum amount of power being supplied at any single point in time (maximum demand)

5.1 Determination

The AER accepts Aurora's forecasts of net new customer connections, gross new customer connections and maximum demand. Aurora's revised demand forecasts are shown in Table 5.1.

In its draft determination, the AER accepted Aurora's original forecasts of net new customer connections, but did not accept Aurora's forecasts of gross new customer connections or maximum demand. Aurora addressed the AER's concerns with its forecasts of gross new customer connections and maximum demand in developing its revised forecasts. The reasons for the AER's view are detailed in section 5.3 below.

Table 5.1 AER's forecasts of demand

	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17
Net new customer connections (#)	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Gross new customer connections (#)	3,150	3,133	3,133	3,142	3,152	3,160	3,171
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Maximum demand (MW)	1,047	1,082	1,101	1,124	1,145	1,168	1,196

Source: AER analysis using data from Aurora's original and revised regulatory proposals, data provided by Aurora in response to AER request, and data from the ABS.

Note: 1. Net new customer connections is the difference in connections measured as at 30 June of current year and 30 June of previous year.
2. Maximum demand measured in calendar years because Aurora experiences winter-peaking demand.

153 National Electricity Rules (NER), clause 6.5.7(c)(3), 6.6.6(c)(3)

154 Aurora also submitted forecasts of demand for energy consumption. However, the AER does not require electricity consumption forecasts to determine Aurora's revenue allowance because the AER is regulating Aurora's standard control services under a revenue cap. These forecasts are important for setting tariff levels, but the AER is not required to set tariffs in this determination. Aurora must submit its proposed prices for the first year of the forthcoming regulatory control period to the AER for approval within 15 business days of the AER publishing its final determination. [NER, clause 6.18.2(a)]. The AER has undertaken a review of Aurora's energy consumption forecasts and considers them to be appropriate for the purposes of illustrating indicative tariffs and indicative pricing impacts of the AER's draft and final determinations. Aurora may submit revised energy consumption forecasts with its pricing proposal.

5.2 Assessment approach

The AER has not changed its assessment approach for demand forecasts since its draft distribution determination, so it is not repeated here. See section 3.2 of attachment 3 for this detail.[155]

5.3 Reasons for determination

The AER outlined its realistic expectation of Aurora's demand in the AER's draft determination.[156] The AER considered its demand expectations to reflect the NER requirements as discussed in the AER's assessment approach outlined in section 5.2. The AER considered that Aurora's demand expectations were not realistic. The AER found that the general basis of Aurora's forecasting methods were appropriate but the application of Aurora's method in a number of areas resulted in unrealistic expectations of demand. In the draft determination the AER accepted Aurora's forecasts of net new customer connections, but developed substitute forecasts for gross new customer connections and maximum demand.

In its revised proposal, Aurora adjusted its forecasting methods to address all of the issues raised in the AER draft determination. Aurora also updated its forecasts for currency of input data. Aurora's revised proposal includes forecasts of net and gross new customer connections equal to the AER's forecasts. Aurora's revised proposal includes forecasts of maximum demand that are comparable to, though slightly divergent from, the AER's draft determination.

The AER accepts Aurora's revised demand expectations because:

- Aurora has revised its forecasting methods to address the concerns expressed in the AER's draft determination
- Aurora's has accepted the AER's demand expectations for new customer connections from the AER's draft determination, and
- Aurora's updated maximum demand forecasts were developed using revised methods that reflect a realistic expectation of demand and relieve the AER's concerns about forecasting method from the draft determination.

The AER's assessment of Aurora's revised demand expectations is discussed in more detail below.

5.3.1 New customer connections

New customer connections[157] can be measured in net or gross terms. Gross new connections are the number of new connections added to Aurora‘s network. Net new connections are the number of new connections added to Aurora‘s network minus existing connections removed from Aurora‘s network.

155 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 75-76.

156 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 73-92.

157 Note that the NER, at chapter 10, define a connection as "a physical link to or through a transmission network or distribution network". Therefore a new connection is used here to mean a new or altered physical connection, rather than changes to the owner/occupier of the premises that constitute the connection site. Aurora estimated the number of connections using national meter identifiers (NMIs) [see: Aurora, *Response to information request AER/017 of 27 July 2011*, received 3 August 2011]. Aurora considered that one NMI should reflect one connection, and assumed an average of one NMI per connection site [see: Aurora, *Response to information request AER/017 of 27 July 2011*, received 3 August 2011].

Gross new connections are an important driver of Aurora's capex as Aurora must provide each new connection and, if required, undertake network augmentation to facilitate the connection. Net new connections are considered a measure of overall change in network size, which is an important driver of Aurora's opex (see the discussion of opex in attachment 7).

In its draft determination, the AER considered that Aurora's forecasts of net new customer connections was realistic given historical trends and the range of appropriate growth expectations of various other institutions. However, the AER considered that Aurora's forecasts of gross new customer connections was not realistic as it was not consistent with Aurora's forecasts of net new customer connections and realistic expectations of existing connections that may be replaced, upgraded or otherwise removed.[158]

Aurora's original forecasts and the AER's draft determination forecasts are shown in Table 5.2.

Table 5.2 Forecasts of new customer connections

Aurora's original proposal	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17
Net [159]	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Gross [160]	3,984	4,051	4,068	3,896	3,942	4,129	4,233
AER draft determination	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17
Net	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Gross	3,150	3,133	3,133	3,142	3,152	3,160	3,171

Source: ACIL Tasman, Aurora.

In its revised proposal, Aurora submitted that it updated its forecasts of new customer connections to account for recent movements in economic growth and the current outlook for economic growth, a key driver of new customer connections. Aurora submitted that its revised forecasts are generally consistent with the AER's draft determination and that Aurora has therefore adopted the AER forecasts as the basis for new customer connections.[161]

"Given that the AER has found that the original forecast was at the higher end of the range, the EUAA asks if the revised customer number forecast, which is still higher than the AER proposed in its Draft Determination, is reflective of the growth expectations taking into account the acknowledgement by Aurora Energy that the outlook for the Tasmanian economy is weak and the statements by the Department of Treasury and Finance in Tasmania."

The Energy Users Association of Australia (EUAA) submitted that given the AER found Aurora's original forecasts were at the higher end of the range of realistic expectations, and that Aurora submits that the outlook for the Tasmanian economy is weak, the AER should review its draft determination forecasts.[162]

158 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 77–83.
159 Aurora, *Regulatory Information Notice*, template 6.7.
160 ACIL Tasman, *Aurora new customer connections forecasts*, Prepared for Aurora Energy, February 2011, pp. 24–25.
161 Aurora, *Revised regulatory proposal 2012–2017*, January 2012, p. 40.
162 EUAA, *Submission to the AER on its draft distribution for Aurora Energy, and Aurora's Energy's revised proposal*, February 2012, p. 8.

The AER acknowledges the argument put by the EUAA, but considers that changes in the outlook for Tasmanian economic growth since the AER made its draft determination have not been material and expectations of Tasmanian economic growth in Aurora's regulatory proposal remain realistic. The AER therefore maintains its expectation of Tasmanian economic growth from its draft determination and accepts Aurora's revised forecasts for net and gross new customer connections.

Customer number forecasts

The EUAA also submitted that the AER should review Aurora's customer number forecasts because the AER had assessed customer number forecasts in previous electricity distribution reviews, and because customer numbers are important inputs into forecasts of maximum demand and energy consumption.[163]

The AER understands the interactions between customer numbers, maximum demand and energy consumption. The AER has reviewed Aurora's forecasts of net and gross new customer connections because of the importance of growth in physical network connections as a driver of opex and capex. Measures of customer numbers may differ from measures of customer connections depending on the definition of a customer (which may be determined for billing purposes). The AER considers measures of physical connections to the network is a better indicator of forecast opex and capex than other measures that may be distorted by a DNSP's billing arrangements.[164] To the extent that both measures are driven predominately by population growth and economic activity, the AER has assessed these factors in its assessment of new customer connections and maximum demand.

5.3.2 Maximum demand

Maximum demand forecasts are important for identifying network capacity constraints and consequent investment needs to address those constraints. Accordingly, Aurora developed maximum demand forecasts for various network assets. Aurora's asset level forecasts were predominately developed by forecasting a growth rate in total distribution system maximum demand and applying this growth rate to current maximum demand levels for the various assets. The AER has therefore focused its review of demand forecasts largely on maximum demand forecasts at the total system level.

In its draft determination the AER considered that Aurora's forecasts were too high and the AER developed substitute forecasts. The AER considered Aurora's forecasts were too high because of issues with Aurora's forecasting method in the following areas:

- reconciling to Transend's state-wide maximum demand forecasts
- measuring the impact of temperature on maximum demand
- adjusting demand to a level of demand consistent with a median temperature
- applying growth rates to 'base' demand for individual assets.

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163 EUAA, *Submission to the AER on its draft distribution for Aurora Energy, and Aurora's Energy's revised proposal*, February 2012, p. 10.

164 An entity may be recorded by Aurora as a single customer for billing purposes but that customer may have multiple premises connected to Aurora's distribution network, or a single premise with more than one connection to Aurora's distribution network. As each new connection causes Aurora to incur costs, the AER is more concerned with measures of connections than measures of customers in this instance.

Aurora submitted revised maximum demand forecasts in its revised proposal. Aurora's original and revised forecasts, and the AER's draft determination forecasts are shown in Table 5.3.

Table 5.3 Aurora's and AER's forecasts of maximum demand (MW)

	2011	2012	2013	2014	2015	2016	2017
Aurora original proposal [165]	1,152	1,159	1,165	1,177	1,189	1,203	1,218
AER draft determination	1,082	1,098	1,115	1,132	1,149	1,165	1,182
Aurora revised proposal	1,047	1,082	1,101	1,124	1,145	1,168	1,196

Source: ACIL Tasman; Aurora; AER analysis using data from Aurora's original and revised regulatory proposals, data provided by Aurora in response to AER request, and data from the ABS.

Aurora's revised maximum demand forecasts take into account:[166]

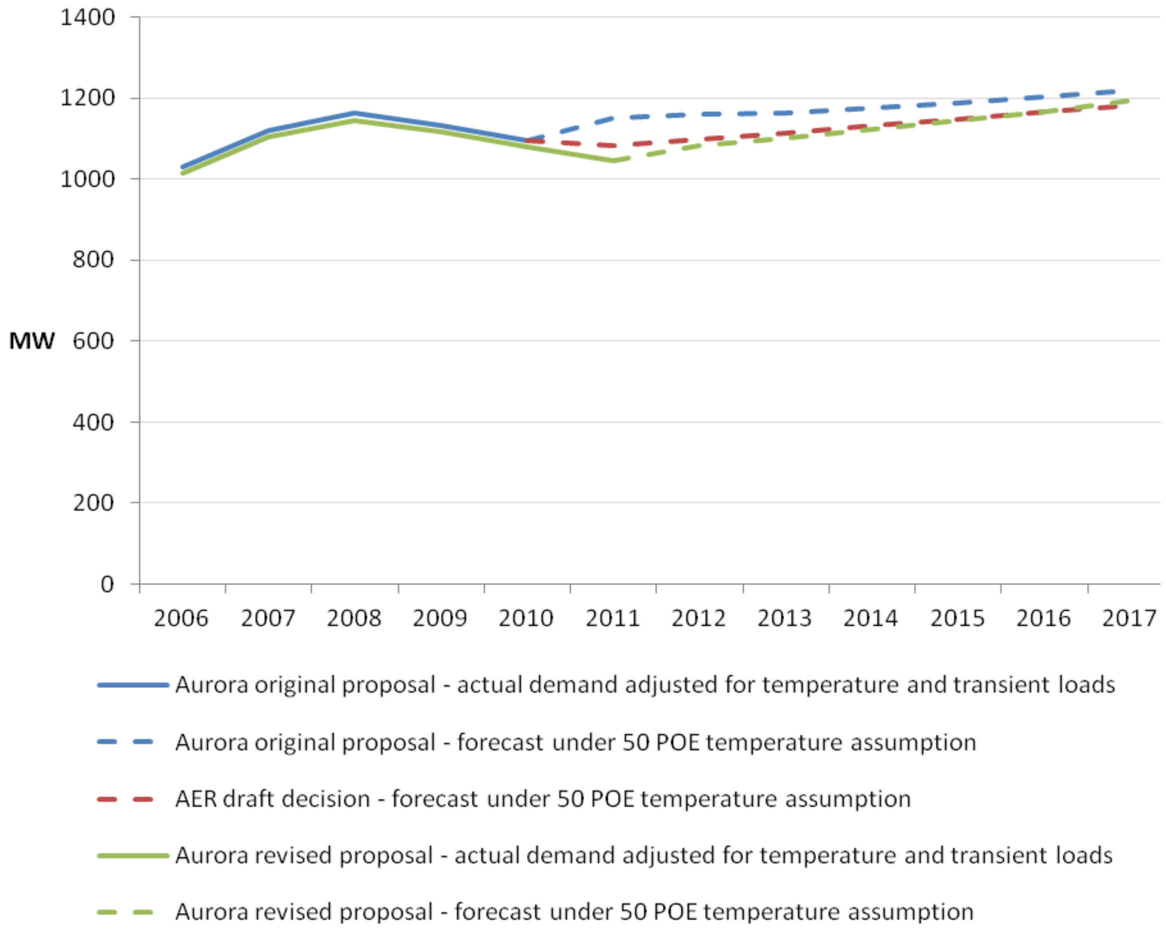
- Adjustments to the forecasting method to address the issues raised in the AER draft determination and align the forecasting method with that used by the AER in developing a substitute forecast.
- Recent data on maximum demand, weather and other explanatory factors that have become available since the AER's draft determination.

Figure 5.1 compares Aurora's revised maximum demand forecasts with the AER's draft determination forecasts.

165 Aurora, *Regulatory Information Notice*, template 6.3.

166 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 33.

Figure 5.1 Aurora’s and AER's forecasts of maximum demand



Source: AER analysis

Aurora's revised forecasting method addresses the concerns raised by the AER in its draft determination. In most cases, Aurora's revised forecasting method addresses the AER's concerns by adopting the alterations recommended by the AER in the draft determination. However, on the issue of reconciling to Transend's state-wide maximum demand forecasts, Aurora's revised forecasting method differed to that used by the AER in its draft determination.

In the draft determination, the AER raised concerns with the currency of the Transend state-wide maximum demand forecasts to which Aurora reconciled its forecasts. The AER acknowledged that reconciliation often allows for macroeconomic and demographic factors, which are typically better forecast at a higher (eg. state-wide) level, to be accounted for in the forecasts. However, given the concerns about Transend's forecasts, the AER considered a substitute forecast should include no such reconciliation. The AER did reconcile to a seven-year linear trend of weather-adjusted state-wide maximum demand, but this reconciliation was done to address the AER's concerns about weather adjustment rather than to account for macroeconomic factors.[167]

[167] The AER considered that, given its constraints of time and available information, that a computationally simpler adjustment at the state-wide demand level to address concerns about weather adjustment would be the most appropriate option.

Aurora's revised forecasting method retains the step of reconciling initial maximum demand forecasts with state-wide forecasts. But, these are new state-wide forecasts developed by Aurora to address the AER's concerns about currency. Aurora's state-wide maximum demand forecasts were developed via a multi-variate linear regression that assumes maximum demand to be driven by economic growth, weather fluctuations, and the use of air conditioners and electric heaters.[168]

The AER considers that Aurora's revised forecasting method is a reasonable means for incorporating macroeconomic and demographic factors (that is, patterns of air conditioning and heating usage). Since the AER's concerns from the draft determination have been addressed, the AER considers that Aurora's revised forecasting method is likely to result in realistic expectations of demand. As shown in Figure 5.1, Aurora's revised forecasts are comparable to the substitute forecasts from the AER's draft determination.

The AER accepts Aurora's revised maximum demand forecasts as a realistic expectation of demand.

Energy consumption forecasts

In its draft determination the AER stated that it did not require a decision on energy consumption forecasts because the AER is regulating Aurora's standard control services under a revenue cap.[169]

The EUAA submitted that the AER should review Aurora's forecasts of energy consumption because the AER had done so in previous reviews and to ensure the drivers of the inputs correlate with the maximum demand and customer number forecasts.[170]

There are relationships between energy consumption, maximum demand and new customer connections. Total energy consumption may increase as more customers connect to the network. Higher energy consumption may also be correlated with higher maximum demand. The AER did examine forecasts of energy consumption to ensure consistency with its forecasts of maximum demand and new customer connections. In its draft determination, the AER was concerned that Aurora's forecasts of economic growth used to develop its energy consumption forecasts differed from forecasts of economic growth used to develop the Transend state-wide maximum demand forecasts (to which Aurora reconciled its maximum demand forecasts).[171]

Issues arising from the AER's review of energy consumption forecasts have been mentioned in the AER's review of new customer connections or maximum demand wherever relevant. As the AER is regulating Aurora's standard control services under a revenue cap, the AER has not made a decision on Aurora's forecast of energy consumption.

5.4 Revisions

The AER accepts Aurora's revised demand forecasts as a realistic expectation of demand. The AER has made no revisions.

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168 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 35.
169 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 73.
170 EUAA, *Submission to the AER on its draft distribution for Aurora Energy, and Aurora's Energy's revised proposal*, February 2012, p. iii.
171 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 87-88.

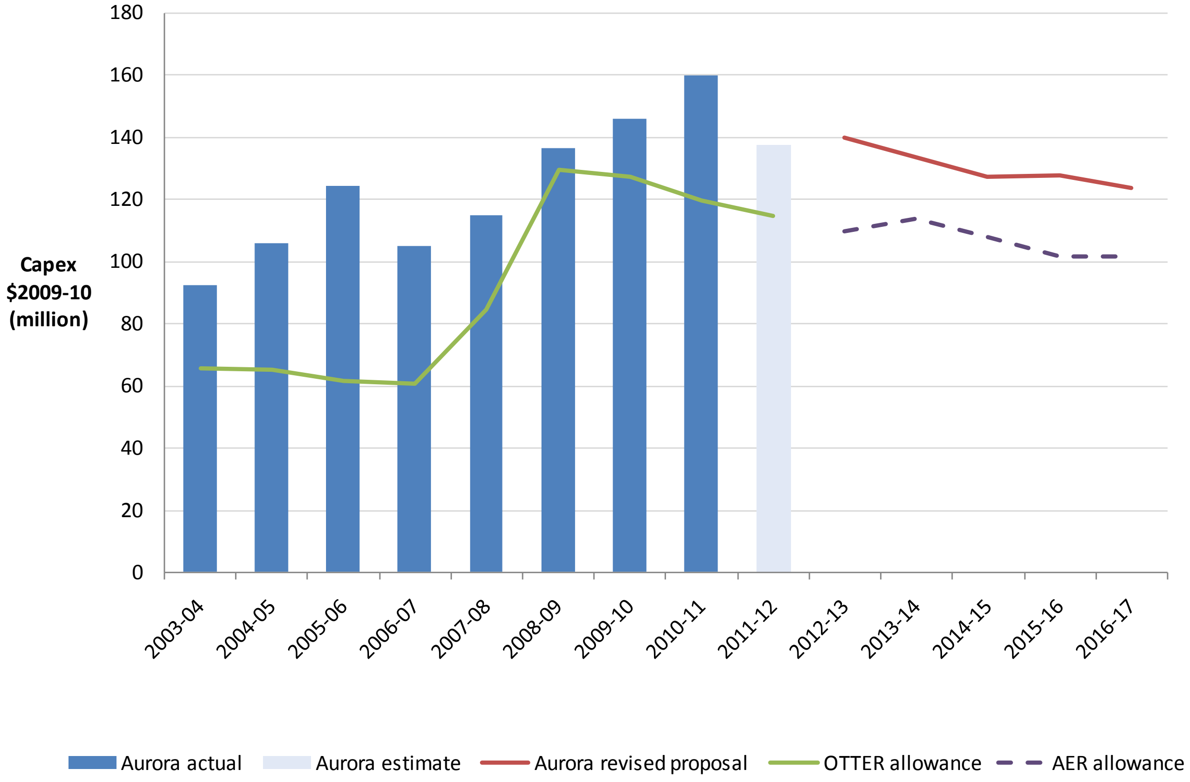
6 Capital expenditure

This attachment discusses the AER's assessment of Aurora's forecast capital expenditure for the forthcoming regulatory control period. Aurora proposed total forecast capex of $618.1 million ($2009–10) for 2012–13 to 2016–17.

6.1 AER determination

The AER is not satisfied that Aurora's total forecast capex reasonably reflects the capex criteria. The AER considers that a prudent operator in Aurora's circumstances (given a realistic expectation of the demand forecast and the cost inputs) could achieve the capex objectives with less capex than Aurora's proposal.[172] Figure 6.1 compares Aurora's past and forecast total capex with proposed and approved capex.

Figure 6.1 Comparison of Aurora's past and forecast total capex, and AER final and draft determinations ($million, 2009–10)



Source: AER analysis.

The AER has estimated a substitute total capex for Aurora that the AER considers reasonably reflects the capex criteria, having regard to the capex factors. This estimate is a reduction of Aurora's

172 NER, clause 6.5.7(c). Clause 6.5.7(a) specifies the capex objectives.

proposal of total forecast capex to the extent necessary to enable the AER to approve Aurora's total forecast capex in accordance with the NER.[173]

Overall, the AER is satisfied that its estimate of a total forecast capex of $535.4 million ($2009–10) reasonably reflects the capex criteria for the forthcoming regulatory control period. This equates to a reduction of approximately $82.7 million ($2009–10), or 13.4 per cent of Aurora's revised total forecast capex. This is set out in Table 6.1.[174]

Table 6.1 AER determination on Aurora's total forecast capex ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Aurora's proposal	139.9	138.5	134.7	130.3	131.9	675.3
AER's draft determination	109.4	112.6	109.3	102.2	102.3	535.8
Aurora's revised proposal	132.4	126.7	120.7	121.1	117.2	618.1
AER's final determination	109.9	113.9	107.8	102.0	101.8	535.4

Source: Aurora, Revised PTRM, submitted 30 June 2011; Aurora, revised proposal PTRM (AE141); AER analysis.

Much of the capex proposed by Aurora in its revised proposal is consistent with the requirements of the NER. However, there are still several elements of Aurora's total forecast capex proposal are overstated, excluding capitalised overheads and input price changes. The percentages also relate to unescalated total capex excluding capitalised overheads. The AER's main concerns with Aurora's proposal are:

- Aurora is proposing to replace more of its assets than necessary. Aurora can maintain its network with less expenditure. In particular, the AER does not consider that proposed increase in the replacement volumes of some programs from historical levels is justified. The AER considers a reduction of $28.8 million ($2009–10) (4.7 per cent of Aurora's revised total forecast capex proposal) is required to address this concern.

- $14.6 million ($2009–10) (2.4 per cent of Aurora's revised total forecast capex proposal) is for reliability improvement investment. This is beyond what is required for Aurora to achieve the capex objectives. The AER has not allowed for this capex in its revised forecast.

- Some of Aurora's forecast capex to address growth in maximum demand is too extensive in scope, and more prudent solutions are available. They are also based on a maximum demand forecast which is too high. The AER considers, using a more realistic demand forecast, an adjustment of $26.3 million ($2009–10) (4.3 per cent of Aurora's revised total forecast capex proposal) is required to address these concerns.

6.2 AER approach

The AER has not changed its assessment approach for capex since its draft distribution determination. See section 5.2 of attachment 5 for this detail.[175]

[173] NER, clause 6.12.3(f).
[174] NER, clause 6.12.1(3)(ii).
[175] AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 110-117.

In response to the AER's draft determination Aurora and the Energy Users Association of Australia (EUAA) raised issues about the AER's assessment approach. Aurora submitted a number of concerns about the AER's replacement expenditure (REPEX) model. Aurora also submitted that the AER should undertake line-by-line assessments of all proposed capex projects rather than a sample of projects. The EUAA questioned why the AER has not used benchmarking approaches to directly determine substitute capex amounts. The AER's assessment of these issues and the reasons why the AER has not altered its approach in response to them is outlined below.

Use of project sampling to assess demand-driven capex

In the draft determination the AER conducted a targeted review of a sample of projects and programs that underpin Aurora's capex forecast. The AER grouped maximum demand-driven projects (both those within the sample and those outside the sample) based on the issues uncovered from detailed review and the likely prevalence of the issues among the grouped projects. The AER then inferred the average finding of the sampled projects within a group to be the overall finding for the group.[176]

In its revised proposal Aurora submitted that the AER erred in not undertaking a 'line-by-line' assessment of each of Aurora's maximum demand-driven capex projects.[177] Aurora also noted in a submission that maximum demand-driven capex is less homogenous in nature than other capex programs such as those to maintain network condition. Aurora considered that sampling would only be appropriate if maximum demand-driven capex projects are similarly homogenous.[178] While the AER considers the degree of homogeneity of maximum demand-driven capex items is a relevant consideration, it also considers its grouping of projects addresses this concern.

Maximum demand-driven capex is to address issues arising from growth in peak demand and/or other changes in demand patterns.[179] This type of capex typically involves matters of network configuration (eg. re-configuring the network to relieve capacity limitations). Network configuration is typically driven by a diverse range of matters (such as forecast demand, service standards, topography, land use regulations) which complicate any assessment of projects to relieve demand-related issues. But more significantly, the preferred network reconfiguration option to address a demand issue will be heavily influenced by the configuration and condition of the existing network as well as the relationship between the proposed alteration and the existing network. That is, capex for network augmentation tends to be materially influenced by the direction in which the augmented parts of the network ‘face’ the existing network. As each asset constituting the network ‘faces’ the rest of the network from its own unique position, capex to relieve demand-related issues can be less homogenous than capex to maintain the condition of the network (for example: like-for-like replacement a pole).

For these reasons, it is impractical for the AER to review all the relevant details of each demand-driven capex project. Furthermore, the AER must consider the capex required to meet or manage expected demand over the forthcoming regulatory control period, and the precise measure of each matter relevant in such consideration may not be known so far in advance.

Instead, the AER has focussed its assessment on the processes used by Aurora to develop its forecast of maximum demand-driven capex. The AER categorised maximum demand-driven capex

176 AER, *Aurora 2012–17 draft distribution determination*, November 2011, sections 5.3.3 and 5.4.4.

177 Aurora, *Revised regulatory proposal 2012–17,*January 2012, AE128, pp. 15–17; Aurora, *Correspondence re proposed reinforcement capital expenditure*, 30 March 2012, p. 2.

178 Aurora, *Correspondence re proposed reinforcement capital expenditure*, 30 March 2012, p. 2.

179 Other than simply supplying new customer connections to the network.

projects based on similarities in forecasting processes,[180] and examined the relevant matters for a sample of projects from each category.[181] The AER then applied the average finding of the sampled projects in each category to the other projects within that category. The AER considers categorising projects in this manner means that the projects within each group are sufficiently similar such that any actual absence of of homogeneity is not material.

The AER considers that this sampling approach is consistent with the NER requirements to the extent that the matters raised by the AER on Aurora's forecasting processes are applicable to all projects within the relevant category. Where it can be reasonably expected that a matter is applicable to a project, the AER must then consider that matter in light of the capex factors.

In developing its categorisation of maximum demand-driven projects, the AER began with the categories used by Aurora in its capacity management plan.[182] This categorisation accounted for the work programs developed out of the various threads of distribution system capacity planning undertaken by Aurora.[183] The AER then further delineated substation augmentation (major system capacity risk management) projects to account for the additional and discrete demand management processes undertaken by Aurora and applicable to some substation projects.[184] The AER considers that this categorisation reasonably ensures consistency of planning process across projects of the same category. The AER's sample covered over 80 per cent of Aurora's total proposed maximum demand-driven capex.

The AER's review of the details of a sample of projects within each category[185] raised a number of matters of concern that were outlined in the AER's draft determination.[186] The AER considered that these matters highlighted a general concern that the scope of the sampled projects was significantly wider than required to achieve the capex objectives under current operating practices. The AER considered that a large portion of the proposed capex is primarily directed at achieving operational efficiencies and/or improving reliability beyond that which would reasonably reflect the capex criteria.

Aurora did not submit any additional information to indicate that the planning / forecasting processes for particular projects are materially different. Nor did Aurora provide any other reason to suggest that

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180 For the AER's categories, see table 5.6 and pages 141–142 of AER, *Aurora 2012–17 draft distribution determination*, November 2011; and tables 9 and 11 of Nuttall Consulting, *Aurora Electricity Distribution Revenue Review A report to the AER*, 11 November 2011.

181 Note that the AER did not categorise projects based on similarities of particular project details but based on forecasting process. There may be some aspects of a demand-driven capex project that can be found to be relevant to multiple other demand-driven capex projects — for example, both may involve the installation of a particular piece of equipment. In such a case, concerns raised by the AER about that aspect of a project may be inferred to be a relevant concern for the related projects. However, in many cases the details about the drivers of the project and the elements of the preferred solution may be too complex for this type of analysis. For example, it may be impractical to investigate all the elements of the preferred solution to identify projects that use similar pieces of equipment – finding areas of similarity at that level of detail may involve no less effort than simply reviewing each of the projects.

182 Aurora, *Capacity Management Plan 2011 (System Development Thread)*, July 2011; provided as attachment AE033 to: Aurora, *Regulatory Proposal 2012–2017*, May 2011.

183 Aurora's capacity management plan separately discusses major system capacity risk management, high voltage system capacity risk management, and low voltage system capacity risk management, with individual work programs outlined under each group. See: Aurora, *Capacity Management Plan 2011 (System Development Thread)*, July 2011; provided as attachment AE033 to: Aurora, *Regulatory Proposal 2012–2017*, May 2011.

184 For details of these demand management planning processes see: Aurora, *Management Plan 2011: Demand Management*, 23 February 2011; provided as attachment AE034 to: Aurora, *Regulatory Proposal 2012–2017*, May 2011.

185 Although for many categories of maximum demand-driven capex outlined in Aurora's capacity management plan the capex program had a general application and the AER was able to review the forecasting processes for the category as a whole. See table 7 of: Nuttall Consulting, *Aurora Electricity Distribution Revenue Review A report to the AER*, 11 November 2011.

186 AER, *Aurora 2012–17 draft distribution determination*, November 2011, section 5.4.4. For more detail, see sections 5.4 and B.2 of Nuttall Consulting, *Aurora Electricity Distribution Revenue Review A report to the AER*, 11 November 2011.

the general pattern of concern from the matters identified through sampling in the AER's draft determination could not be inferred across the project population.

Conversely, Aurora stated that its proposed maximum demand-driven capex in its revised regulatory proposal was developed by reference to the AER's method of developing a substitute allowance, which included the AER's sampling approach.[187] That is, Aurora revised downwards its proposed capex for some maximum demand-driven projects that were not subject to detailed review by the AER and for which no matter was directly raised (outside of sampling inference). Aurora did not provide properly justify[188] its approach to developing its revised regulatory proposal maximum demand-driven capex.[189] Nonetheless, the approach used by Aurora to calculate its revised proposal for maximum demand-driven capex implies that Aurora accepts the AER's substitute amounts.[190]

To determine a substitute capex allowance, the AER amended Aurora's proposal on a project-by-project basis. Where the AER considered that a matter of concern related to a particular maximum demand-driven project (either by direct detailed review of through sampling inference), the AER determined a substitute amount by amending the proposed capex for the project by the quantification of the matter of concern.

The AER therefore considers its approach to assessing maximum demand-driven capex, including the use of sampling, is on the basis of Aurora's proposal and amends it to the extent necessary. The AER has not altered this assessment approach in this final determination.

Use of benchmarking to assess proposed capex

In response to the draft determination the EUAA submitted that it was not clear why the AER did not use benchmarking to set Aurora's capex allowance.[191] The AER does not agree. In the draft determination, the AER did use benchmarking as part of assessing whether Aurora's proposed capex reasonably reflects the capex criteria, having regard to the capex factors.[192]

The AER's estimated substitute amount must be on the basis of the regulatory proposal and amend it from that basis to the extent necessary for it to be approved in accordance with the NER.[193] This does

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187 Aurora, *Response to information request AER/060 of 8 February 2012*, received 9 February 2012, pp. 3–4.

188 In explaining its approach to developing its revised proposal maximum demand-driven capex, Aurora stated that it examined the AER's substitute amount but "found a number of these reductions to be too large" but that the AER's substitute before reductions were applied to account for substitute demand forecasts "provided a better middle ground".

Aurora did not explain why its proposal maximum demand-driven capex provided a better middle ground than the AER's draft determination, or why a middle ground would more reasonably reflect the capex required to achieve the capex objectives, or why the AER's reductions to account for its substitute demand forecasts were not appropriate. The AER subsequently requested Aurora explain why it considered its revised proposal maximum demand-driven capex better reflects the forecast capex required to achieve the capex objectives. However, in response Aurora only stated that it does not consider that the AER's substitute amount before reductions to account for substitute demand forecasts (that is, Aurora's revised proposal) reflects a realistic forecast of efficient capex requirements, but rather a more realistic forecast than the AER's draft determination.

Aurora also stated in response that it considers it unclear why the AER preferred a substitute demand forecast over Aurora's demand forecasts in its original proposal. This is despite Aurora accepting the AER's substitute forecast of demand for new customer connections and submitting a revised maximum demand forecast developed under an approach consistent with the AER's substitute maximum demand forecast (see Attachment 5).

189 Aurora, *Response to information request AER/060 of 8 February 2012*, received 9 February 2012, pp. 3-4; and Aurora, *Response to information request AER/066 of 22 February 2012*, received 29 February 2012, p.4.

190 That is, before amendments due to the AER's substitute demand forecasts and amendments for projects otherwise contested by Aurora.

191 EUAA, *Submission to the AER on its draft distribution for Aurora Energy, and Aurora's Energy's revised proposal*, February 2012, p.13.

192 AER, *Aurora 2012-17 draft distribution determination*, November 2011, pp.121–122, 127–131, 138–139, 148, 151.

193 NER, clause 6.12.3(f).

not preclude the use of benchmarking, as the AER has used in the draft determination and this final determination, to determine what are the necessary amendments to Aurora's proposed capex to arrive at a substitute amount that reasonably reflects the capex criteria.

6.2.1 The AER's statistical replacement model

In the draft determination the AER used its REPEX model as a tool to analyse Aurora's likely required asset replacement expenditure.[194] The REPEX model is a high-level probability-based model that forecasts replacement needs for various asset categories based on the age and unit costs of a DNSP's asset base. The AER is able to use the REPEX model to benchmark both Aurora's proposed service lives and unit replacement costs for various assets against those that Aurora and other DNSPs have achieved in the past.

Replacement activities require engineering decisions that cannot be replicated by a theoretical replacement model

Aurora submitted that pole replacements are driven by a measurement of physical strength, and Aurora cannot ignore replacement or reinforcement activities without introducing unacceptable safety and legal consequences to the business. Aurora submitted that these are not the type of engineering decisions that can be undertaken by the AER based on a theoretical replacement expenditure model.[195]

The AER understands that DNSPs typically refer to the condition of assets as discovered during periodic inspections when making decisions on replacement or other remedial action. However, the AER does not determine appropriate courses of action that a DNSP is to take ex post to remedy particular situations. Rather, the AER is required to determine a total capex allowance that it is satisfied reasonably reflects the capex criteria. DNSPs are free to undertake any course of action they deem necessary in response to future events.

As part of its requirement to assess Aurora's proposed capex and, if necessary, determine a substitute amount, the AER must consider the extent to which Aurora will likely be required to replace assets to achieve the capex objectives. The AER must consider Aurora's likely future replacement needs up front; the AER cannot wait to review the outcomes of periodic assessments of asset condition. Accordingly, the AER must consider ways of predicting future physical asset strength with reasonable accuracy. This requirement to forecast necessarily involves the use of 'theoretical' models in place of ex post engineering judgment.

The AER's REPEX model uses asset age as a proxy for physical strength. Aurora did not propose any alternative means of forecasting asset strength and did not provide any information to suggest that age is not an appropriate proxy of physical asset strength. The condition of any individual asset may differ but, on average, age is a useful indicator.

The AER acknowledges that factors other than age may also influence an asset's physical strength (see below). For this reason, the AER did not rely solely on the results of the REPEX model to determine a substitute replacements capex amount; the AER considered all submissions from interested parties on matters that influence Aurora's capex requirements. That said, the AER considers that asset age has historically been a reasonable predictor of asset replacement needs.

194 AER, *Aurora 2012-17draft distribution determination,* November 2011, s.5.3.2.
195 Aurora, *Revised regulatory proposal 2012–2017*, January 2012, page 11.

Accordingly, the AER considers it appropriate to continue to use the REPEX model to assess whether a DNSP's proposed replacement capex reasonably reflects the expenditure required to achieve the capex objectives.

Accounting for differences in operating environments across DNSPs

In its revised proposal Aurora submitted that the REPEX model cannot be relied upon because it does not account for differences in operating environments across DNSPs.[196]

The AER acknowledges that differences in operating environments may influence differences in replacement costs across DNSPs. To the extent practicable, the AER takes into account the influence of differing operating environments in its REPEX modelling.

The REPEX model forecasts asset replacement needs based on the quantities and ages of Aurora's asset fleet. Assets are distinguished by various categories and expected lives and replacement costs may differ by asset category.[197] Differences in operating environments can be reflected to some degree through the categorisation of assets.[198] The AER must use its discretion to decide on the appropriate categorisation of assets in the REPEX model, balancing the greater accuracy in reflecting differences in operating environments with the predictive power of the model and the materiality of the differences in operating environments.

The AER considered other relevant and material differences in Aurora’s operating environment that may not be adequately addressed through the current REPEX model when reviewing in detail each non-demand-related capex project proposed by Aurora.[199] In addition, significant operational differences between Aurora and CitiPower led to the AER excluding CitiPower data from the benchmark REPEX model. That is, the AER considered the differences in operating environment between CitiPower and Aurora to be of an extent that would be better accounted for through CitiPower's exclusion from the model than through changes in asset categorisation.[200]

The AER also notes that its calibrated version of the REPEX model is calibrated to reflect Aurora's historical replacement activities, forecasting future replacement needs based on Aurora's historical performance. This calibrated model therefore reflects the characteristics of Aurora's operating environment.

The AER considers that the REPEX model as used in the draft determination sufficiently accounted for differences in operating environments for the purposes of highlighting areas of potential concern and further investigation by the AER. The AER has not changed its REPEX model analysis from the draft determination.

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196 Aurora, *Revised regulatory proposal 2012–17,* January 2012, Attachment AE121, p.4.

197 Nuttall Consulting, *Aurora Electricity Distribution Revenue Review A report to the AER*, 11 November 2011, p.72.

198 Differences in operating environments between DNSPs may to some extent be reflected in compositional differences in the DNSPs' asset fleets. Differences in operating environments between DNSPs may also result in differences in unit replacement costs across DNSPs, even for assets (or replacement procedures) that a physically identical between multiple DNSPs (for example, asset purchase prices may differ between DNSPs due to differing delivery costs, or installation costs may differ between DNSPs due to difference in labour markets). Differences in operating environments between DNSPs may also result in differences in asset service lives across DNSPs, even for assets (and replacement procedures) that a physically identical between multiple DNSPs (for example, humidity conditions may impact on service lives and may differ across DNSPs). However, physically identical assets can still be separated into multiple categories in the REPEX model to account for differences in asset lives and/or replacement costs.

199 AER, *Aurora 2012-17 draft distribution determination,* November 2011, pp. 122–123; and Nuttall Consulting, *Aurora Electricity Distribution Revenue Review A report to the AER*, 11 November 2011, pp. 78–119.

200 Nuttall Consulting, *Aurora Electricity Distribution Revenue Review A report to the AER*, 11 November 2011, p.74.

Use of the normal probability distribution in estimating asset lives

In the draft determination the AER used the normal distribution in its REPEX model, considering it to be a reasonable approximation of actual asset failure rates given the absence of a complete data set required to determine a more accurate distribution.[201] In its revised proposal Aurora submitted that the results of the REPEX model cannot be relied upon because the AER used a normal probability distribution which does not accurately reflect actual failure rates.[202] Aurora also provided analysis of the appropriateness of the Weibull probability distribution to the distribution of asset failures.[203]

The AER acknowledges that the Weibull distribution is often used in reliability analysis, including replacement modelling.[204] The AER compared Aurora's Weibull distribution to a normal distribution fitting the asset data provided in Aurora's Weibull analysis. This fitted normal distribution had a mean life comparable to that used in the REPEX model in the draft determination, however it had a materially different standard deviation. The AER then compared the use of Aurora's Weibull distribution and this fitted normal distribution in the REPEX model, finding consistent results between the two.[205] Aurora only provided Weibull data appropriate for one asset category used in the REPEX model, so the AER was only able to compare results for this single asset category. Nonetheless, the AER consider that the information provided by Aurora suggests that the use of a normal distribution instead of a Weibull distribution has not had a material impact on the AER's REPEX analysis.

The AER notes that the standard deviation derived from the normal distribution fitted to Aurora's Weibull data differs from the standard deviation used in the AER's REPEX model in the draft determination. Although Aurora provided Weibull data in support of its proposal about the appropriate probability distribution to use in the REPEX model, Aurora did not state whether or not it is proposing that the standard deviation from its Weibull data should be used in the REPEX model. Aurora did not provide any suggested probability distributions or standard deviation data in its original regulatory proposal or in response to the AER's regulatory information notice.[206] In the absence of any asset data or proposal from Aurora, the AER assumed standard deviation for asset categories to be the square root of the mean asset life. In any case, Aurora's Weibull data appears only applicable to one asset category, and assumed standard deviations would still be needed for the remaining categories.

The sensitivity of REPEX model outputs to asset life assumptions

In its revised proposal Aurora submitted that the REPEX model cannot be relied upon because the results are overly sensitive to input assumptions about asset lives. Aurora noted that, for the poles asset category, a 7 per cent increase in asset life resulted in a 40 per cent reduction in capex.[207]

The AER acknowledges the REPEX model used in the draft determination exhibits a sensitivity of forecast capex to changes in asset life. The AER considers that this sensitivity is reflective of the

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201 SP AusNet used a normal distribution in its replacement modelling provided in support of its regulatory proposal during the AER's distribution determination for the regulatory control period 2011 to 2016. Ofgem also appears to have used a normal distribution in its replacement modelling. See: Nuttall Consulting, *Report – Capital Expenditure: Victorian Electricity Distribution Revenue Review: Revised Proposals: A report to the AER*, 26 October 2010, p. 34.

202 Aurora, *Revised regulatory proposal 2012-17,* January 2012, Attachment AE121, pp. 4–5.

203 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE117 (confidential).

204 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, p.40.

205 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, p.41.

206 SP AusNet used a normal distribution in its replacement modelling provided in support of its regulatory proposal during the AER's distribution determination for the regulatory control period 2011 to 2016. Ofgem also appears to have used a normal distribution in its replacement modelling. See: Nuttall Consulting, *Report – Capital Expenditure: Victorian Electricity Distribution Revenue Review: Revised Proposal: A report to the AER*, 26 October 2010, page 34.

207 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE121, pp. 4–5.

asset age profile data provided by Aurora and the AER's assumptions about the standard deviation of asset replacement lives.

The AER does not consider that this sensitivity in itself can be viewed as evidence that the REPEX model as an assessment tool is not valid. It may suggest that a greater standard deviation should be considered (see the discussion of Aurora's Weibull data). This may be an area for further exploration, including consideration of greater DNSP data on asset failures and standard deviations. Nonetheless, the AER considers that the standard deviation assumption used in its REPEX model is appropriate given the available data provided by Aurora.

The REPEX model needs to be manipulated to replicate historical experience

In its revised proposal Aurora submitted that the REPEX model is unreliable because it needs to be arbitrarily manipulated to replicate historical experience. Aurora submitted that if the model output does not match historical data without manipulation then there can be little confidence that it would match future asset behaviour.[208]

The calibration process is simply one of estimating historical asset lives and unit replacement costs from historical replacement expenditures and volumes. This calibration process is undertaken so that forecasting replacement expenditure can be derived based on Aurora's asset age profile and asset lives that Aurora has historically achieved. This allows the AER to compare Aurora's proposed replacement capex to the forecast from the calibrated REPEX model and to the forecast from the REPEX model using benchmark asset lives and replacement costs achieved by other DNSPs.

The AER does not agree with Aurora's characterisation that the calibration process is an arbitrary manipulation. Adjustments, or calibrations, to the REPEX model are undertaken in a non-arbitrary way, with a transparent purpose and using data provided by Aurora. Also, the fact that the AER's calibrated REPEX model correlates well with Aurora’s replacement analysis based on a Weibull distribution (see above) supports the view that the AER's calibrations is not an arbitrary manipulation.

The REPEX model did not use CPI-indexed costs

In its revised proposal Aurora submitted that the results of the REPEX model cannot be relied upon because the AER did not use CPI-indexed costs.[209] The AER does not consider this to be correct. The AER used replacement cost data as inputs to the REPEX model from information provided by Aurora and which Aurora indicated were denominated in real terms ($2009–10). Indeed, such a denomination is corroborated by cost information provided by Aurora in other documents.[210]

6.3 Reasons for determination

This section outlines how the application of the AER’s assessment approach has led the AER to:

- not being satisfied that Aurora’s proposed forecast capex reasonably reflects the capex criteria, and

208 Aurora, *Revised regulatory proposal 2012-17,* January 2012, Attachment AE121, p. 4.
209 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE121, p. 4.
210 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, p.40.

- estimate a substitute forecast capex on the basis of Aurora's proposed forecast capex and amending it to the extent necessary so that it can be approved in accordance with the NER.

The AER has a number of concerns with Aurora's proposed total capex which are summarised in Table 6.2. Similar concerns were raised by the Energy Users Association of Australia (EUAA) in its submission on Aurora's regulatory proposal.[211] The AER's considerations of each issue in Table 6.2 are separately discussed in further detail in the sections that follow. The AER has quantified the impact of each concern based on amendments to Aurora's forecast capex.

Table 6.2 AER's adjustments to Aurora's proposed forecast capex ($million, 2009–10)

Issue	Amount
Replacement costs that are too high	28.8
Capex for reliability improvements that are not required to achieve the capex objectives	14.6
Capex projects to address maximum demand growth that are too extensive in scope, too high relative to benchmarks, and/or not required to acheive the capex objectives	26.3
Unit rates that are too high due to the removal of the efficiency factor*	15.4
Equity raising costs that are too high given realistic capital requirements	0.2
Capitalised overheads that are too high	2.4
Input price changes that are too high	1.4

Source: AER analysis.
Note: Amounts exclude capitalised overheads and input price changes
*The unit rates adjustment is already accounted for in the adjustments to other programs so the amount specified is not included in the total adjustment to Aurora's revised forecast.

The following sections outline the AER's review of issues raised by Aurora and other stakeholders.

6.3.2 Pole replacement

Aurora originally proposed capex of $40.0 million ($2009–10) over the forthcoming regulatory control period for pole replacement and maintenance.[212] In the draft determination the AER did not accept Aurora's proposal, considering that pole replacements in line with historical trends is more likely to be required than the unsubstantiated significant increase from historical trends proposed by Aurora. The AER provided a substitute allowance of $25.3 million based on a continuation of (increasing) historical trends for pole replacements capex. In its revised proposal Aurora raised a number of issues about the AER's analysis in addition to the REPEX issues addressed in section 6.2.1, and proposed the capex allowance from its original proposal be reinstated.[213]

The AER's final determination is for a substitute amount of pole replacement capex of $25.3 million over the forthcoming regulatory control period. The AER considers that its substitute reflects an efficient amount of capex required for Aurora to maintain the condition of its distribution system in order to maintain service quality and ensure compliance with regulatory obligations in accordance with the capex objectives. In coming to this consideration the AER had regard to the Aurora's current

211 EUAA, *Submission to the AER on its draft distribution for Aurora Energy, and Aurora's Energy's revised proposal,* February 2012, pp. i, 7–14.
212 Aurora, *Regulatory proposal 2012-17,* May 2011, Attachment AE083.
213 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE121.

network and its condition, current industry best-practice operating procedures, and realistic expectations of input costs.

The AER does not consider that the issues raised by Aurora in its revised proposal justify it in departing its position in the draft determination. The AER's analysis of each issue raised by Aurora is provided below.

Aurora's inspection and remediation process provides for predictable outcomes

Aurora submitted that its forecast pole replacement capex satisfies the requirements of the NER because Aurora "operates a stable pole inspection and remediation process, with predictable outcomes, both in terms of expenditure required and failure risk".[214]

But pole inspection and remediation is a reactive measure undertaken ex post. The AER is required under the NER to consider and satisfy itself as to whether Aurora's proposed capex reasonably reflects the capex criteria. This in part requires an ex ante consideration of activities likely to be required to achieve the capex objectives. Although current protocols for inspection and remediation of found faults may be appropriate, they provide little guidance on the likely future volume of faults and cost of remediation.

To the extent that operating procedures influence replacement costs, the AER has considered Aurora's current operating procedures when using Aurora's replacement costs in the calibrated REPEX model.

Aurora has not submitted any alternative forecasting models that it considers provides greater forecasting accuracy than the AER's REPEX model.

AER analysis of condemnation rates

Aurora considered that the AER did not account for "the fact that as wooden poles age their failure rate increases" when the AER analysed condemnation rates and pole service lives.[215] The AER accepts that the condition of an individual pole may deteriorate at a faster rate as the pole ages. However, given the large size of Aurora's pole fleet, in practice the AER must consider the age of Aurora's pole fleet more generally. The AER considers that information provided by Aurora indicates that the recent average age of Aurora's pole fleet has been stable in age.[216]

Further, the Weibull analysis of pole lives provided in Aurora's revised proposal suggest a historical condemnation rate of about 1.8 per cent per annum. This is consistent with the condemnation rate of 2 per cent per annum calculated from the AER's analysis of Aurora's historical data and on which the AER's substitute pole allowance was based, but inconsistent with a condemnation rate of about 4 to 5 per cent per annum implied by Aurora's proposed pole replacements capex.[217]

The AER therefore maintains its analysis of condemnation rates from its draft determination.

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214 Aurora, *Revised regulatory proposal 2012-2017*, January 2012, p.11.
215 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE121, p.3.
216 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp. 38–39.
217 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp. 38–39.

Treatment of 2009–10 data in AER analysis

Aurora submitted that the AER erred in omitting 2009–10 data from its historical trend analysis and calculation of a substitute amount for forecast pole replacements capex.[218]

The AER excluded 2009–10 data from its analysis because of the uncharacteristically high capex recorded in that year, and noted the influence of storm events in that year.[219] Aurora submitted that the storm events in that year did not materially impact pole replacement costs in that year, but rather that the increase in 2009–10 over previous years was more reflective of the aging of the asset base.[220]

Exclusion of 2009–10 data was done partly because the AER considered that costs in that year may have been impacted by very extreme storms. However, more importantly, the AER did not consider that the large increase in pole replacement capex in that year reflected the broader historical trend in condemnation rates. A linear trend in capex using 2009–10 would have resulted in a far greater rate of increase than historical condemnation rates suggested (including 2010–11).

The AER's substitute amount (via a linear trend) for pole replacement capex in the draft determination showed a growth rate in condemnations of nearly 3 per cent per year. Aurora's historical condemnations data indicates a much lower growth rate (via the linear trend): around 0.5% per annum. If 2009–10 data was included in the AER's analysis, the growth rate would increase to around 5% per annum. This is a 10-fold increase over the condemnation data figure.

For this reason, the AER does not consider that 2009–10 data should be included in the analysis and maintains its position in the draft determination.

Class of timber used by Aurora

Aurora submitted that the AER erred in comparing Aurora's historical pole lives to pole lives achieved by mainland DNSPs because Aurora uses a different type of timber pole to mainland DNSPs.[221]

In its draft determination the AER considered that the treatment of Aurora's timber poles should result in similar lives to the untreated mainland timber poles despite Aurora using a different timber class to mainland DNSPs.[222] Aurora submitted that the treatment process typically only impregnates the sapwood (outer layers) whilst the heartwood (inner core) remains untreated.[223] Aurora submitted that although treatment may extend pole life, there is no engineering reason to expect that it would result in a pole with the same life as the poles used on the mainland.[224]

The AER agrees that treatment only impregnates the outer layers of hardwood poles, but considers that this is true for all hardwood poles irrespective of the class of timber used. For softwood timber poles, the AER considers that the condition of the outer layers of a timber pole tends to be of greater significance to overall pole strength and ensuring adequate service lives than the condition of the inner core.[225] The AER notes the industry practice of applying preservatives to the outer surface of

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218 Aurora, *Revised regulatory proposal 2012-17,* January 2012, Attachment AE121, p.6.
219 AER, *Aurora 2012-17 draft distribution determination,* November 2011, pp.122–124.
220 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE 121, p.6.
221 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE121, pp. 5-6.
222 Nuttall Consulting, *Aurora electricity distribution revenue: A report to the AER*, 11 November 2011, p. 82.
223 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE121, pp. 5–6.
224 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE121, pp. 5–6.
225 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp. 25–26.

poles during the ground line maintenance process.[226] Further, the Weibull analysis provided in Aurora's revised proposal indicates that the average mean lives of Aurora's pole fleet is similar to those being achieved on the mainland.[227]

The AER therefore maintains its analysis from its draft determination.

Increased risks to public safety or of higher required maintenance

Aurora submitted that it can only accommodate a substitute amount of pole replacement capex lower than its proposed pole replacement capex by pushing back trigger points that are used to determine when a pole is replaced. Aurora submitted that this may increase required maintenance costs and/or risks to public safety.[228]

The AER's substitute pole replacement capex in the draft determination was developed to reflect the efficient expenditure associated with Aurora’s current operating practices. The AER's substitute amount is based upon the AER's view that Aurora’s proposed capex overstates the number of poles that are likely to need to be replaced based upon these practices.

The AER does not consider that Aurora's operating practices and associated risk levels need to change in response to the AER's draft determination. However, other events may transpire throughout the forthcoming regulatory control period that may influence Aurora's operating practices and the number of condemned poles may vary from the AER's (or Aurora's) forecast. The processes adopted to ensure the quality and security of supply, and compliance with regulatory obligations, remain the responsibility of Aurora over the forthcoming regulatory control period.

6.3.3 Other age or condition-based asset replacement

Aurora originally proposed capex of $119.6 million ($2009–10) over the forthcoming regulatory control period for replacement and maintenance of non-pole assets.[229] In the draft determination the AER developed a substitute capex of $113.9 million after raising concerns with 12 capex programs. In its revised proposal Aurora raised a number of issues, in addition to the REPEX issues discussed in section 6.2.1, about the AER's assessment for 10 of the 12 capex programs which the AER was concerned with. Aurora also provided new information indicating that 1 maximum demand-driven project and 1 reliability project were incorrectly classified, and are instead driven by the need to replace or maintain the condition of non-pole assets.

The AER has maintained its position in the draft determination because it considers that the arguments raised by Aurora in its revised proposal about the Gretna zone substation are not sustainable. On the other non-pole replacement matters, the AER accepts Aurora's arguments, but that the costs of Aurora's proposed solutions are too high. The AER's final determination is for a substitute amount of replacement capex for non-pole assets of $108.9 million over the forthcoming regulatory control period.

The AER's analysis of each issue raised by Aurora is provided below.

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226 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp. 25–26.
227 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp. 25–26.
228 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE121, p.6.
229 Aurora, *Regulatory proposal 2012-17,* May 2011, Attachment AE083.

Underground cables

Aurora originally proposed capex of $14.6 million ($2009–10) over the forthcoming regulatory control period for replacement of underground cables. Of this, Aurora proposed $2.3 million for high voltage (HV) cable replacement and $0.7 million for a new low voltage (LV) cable replacement program.[230]

In the draft determination the AER considered that Aurora's original proposal was unsubstantiated and significantly above historical experience. The AER substituted a lower amount for the HV cable replacement program and the LV cable replacement program reflective of historical trends. The new LV replacement program was removed completely and the existing HV replacement program was reduced to $0.3 million ($2009–10) over the forthcoming regulatory control period. The AER accepted the remainder of Aurora's proposed underground cable replacement capex.[231]

In its revised proposal Aurora submitted that it requires the full amount of its proposed underground cable replacement capex due to ageing of its asset base and recent incidents of asset failure. Aurora submitted new information on historical HV and LV cable failure rates.[232]

The AER considers that this new information does indicate deteriorating condition of Aurora's HV and LV underground cables, and that these assets may be at or approaching the end of their service lives.[233]

The AER considers that, based on the new fault information, Aurora’s forecast replacement volumes of 0.6 km of LV cables, or sections of LV cables, exhibiting multiple faults is reasonable. The AER has accepted Aurora's revised proposal of $0.7 million for the new LV cable replacement program.

However, while accepting the need for some HV underground cable replacement, the AER does not accept the volume of replacement proposed by Aurora. The AER does not consider that a proactive replacement program is justified as it is almost impossible to anticipate which sections of cable will experience faults. The AER also considers that Aurora has still not justified the need to spend over 7 times more than historical levels on HV cable replacements. Aurora has proposed $2.3 million ($2009–10) over the next regulatory period for the replacement of HV underground cables, based on the replacement of 3 underground cables and 1 submarine cable. However, historical actual expenditure over the last 5 years was only $0.3 million ($2009–10).

That said, the AER considers that its substitute capex amount of $0.3 million ($2009–10) over the forthcoming regulatory control period may be too low given the new information indicating that some assets may be reaching the end of their service life. The AER considers that a reasonable capex allowance for the replacement of HV cables would provide for the replacement of 1 submarine cable, as it appears this cable has been in service since 1914, and 1 underground cable. The AER has therefore substituted an amount for HV underground cable replacement capex of $1.3 million ($2009–10) over the forthcoming regulatory control period, which also allows for the higher costs associated with replacing submarine cables.

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230 Aurora, *Regulatory proposal 2012-17,* May 2011, Attachment AE083.
231 Nuttall Consulting, *Aurora electricity distribution revenue review: A report to the AER,* 11 November 2011, p.108.
232 Aurora, *Revised regulatory proposal 2012-17,* January 2012, Attachments AE114 and AE115.
233 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp. 29–30.

Zone transformers – provision for spares

Aurora originally proposed capex of $6.9 million ($2009–10) over the forthcoming regulatory control period for the replacement of 6 rural and 4 urban zone transformers.[234] In the draft determination the AER considered that the condition of the transformers did not indicate that any replacement was required, but included a substitute allowance of $1 million ($2009–10) over the forthcoming regulatory control period for "at least one spare". Increased opex of $0.3 million was also considered for increased asset inspection and conditioning.[235]

In its revised proposal Aurora accepted the AER's spare transformer option, but submitted that the AER did not consider the full costs and risks of this option and has submitted a revised costing. Aurora submitted a revised proposal of $6.81 million ($2009–10) over the forthcoming regulatory control period, constituting 4 rural spares at a cost of $2 million to purchase and $0.16 to house, and 4 urban spares at a cost of $4 million to purchase and $0.65 million to house.[236]

The AER considers that Aurora's revised proposal would result in a significant reduction in its risk profile and improve its ability to maintain the quality, reliability and security of supply of standard control services. The AER notes that Aurora is currently managing its power transformer fleet without any spares and that the AER's analysis of the condition of Aurora's transformer fleet indicated that the likelihood of transformer insulation failure in the forthcoming regulatory control period is low. The AER considers that a more reasonable forecast for zone transformer replacement to maintain the quality, reliability and security of supply of standard control services is for one spare 22/11 kV, 5 MVA transformer (estimated to cost of $0.5m for rural zone substations) and one spare 33/11 kV, 25 MVA transformer (estimated to cost $1.0m for urban zone substations).[237]

While the AER considers that a DNSP of Aurora's size should have sufficient existing space to store the AER's lower substitute volume of spares,[238] Aurora stated that it does not currently have existing space to house spares. The AER has accepted Aurora's proposed capex for housing spares, scaled down to reflect the lower volume of spares provided in the AER's substitute allowance.

The AER has therefore determined a substitute amount of $1.7 million ($2009–10) over the forthcoming regulatory control period for the purchase of spare zone transformers.

Zone transformers – Gretna

Aurora originally proposed $1.2 million ($2009–10) over the forthcoming regulatory control period for the conversion of part of the network to a different voltage as a demand-driven project.[239] In the draft determination the AER estimated a substitute amount for this project of $0.3 million based on its sampling method for assessing demand-driven capex (see section 6.3.5 for more detail on this method). In its revised proposal, Aurora submitted that it incorrectly classified this project as being

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234 Aurora, *Regulatory proposal 2012-17,* May 2011, Attachment AE083.

235 Nuttall Consulting, *Aurora electricity distribution revenue review: A report to the AER*, 11 November 2011, pp.115–116.

236 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE126, p.2 and Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE127, p.2.

237 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp. 35–37.

238 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp. 35–37.

239 Aurora, *Regulatory proposal 2012-17*, May 2011, Attachment AE083.

demand-driven instead of being a replacement capex project driven by the condition of the Gretna zone transformers.[240]

The AER has reviewed the additional information provided by Aurora on the condition of the Gretna zone transformers. The AER considers that the issues with current transformer condition can be addressed with some minor maintenance and that the network augmentation for voltage conversion is not required.[241] The AER therefore has re-classified this project as replacement capex and determined a substitute forecast capex without allowance for this project.

Distribution transformers – provision for spares

Aurora originally proposed capex of $20.3 million ($2009–10) over the forthcoming regulatory control period for replacement of distribution transformers, $1.7 million ($2009–10) of which was for replacement of 5 three-phase regulators.[242] In the draft determination the AER substituted an allowance of $0.7 million ($2009–10) for the replacement of 2 three-phase regulators over the forthcoming regulatory control period. The AER's substitute volume was based on historical trends, deviation from which Aurora had not substantiated. The AER accepted Aurora's implied average unit cost for replacing three-phase regulators. The AER accepted the remainder of Aurora's proposed distribution transformer replacement capex.[243]

Aurora accepted the AER’s draft determination for the volume of three-phase regulator replacement but submitted that it has concerns over the condition of its asset base. Aurora also submitted that it will need to carry spares to mitigate risks of asset failure and that it requires an increased capex allowance to account for the cost of carrying spares. Aurora has estimated that 8 spares are required and proposes capex to purchase and house the spares of $0.75 million ($2009–10) over the forthcoming regulatory control period ($0.55 million to purchase and $0.2 million to house).[244]

Given Aurora's historical risk profile and three-phase regulator failure rate, the AER accepts that some increased holding of spares are warranted for Aurora to maintain the quality, reliability and security of supply of standard control services. But the AER considers that Aurora's revised proposal would result in a significant improvement by materially reducing its risk profile.

Based on the cost information provided by Aurora, the AER considers an allowance of $70,000 ($2009–10) over the forthcoming regulatory control period for the purchase of an additional pair of 11 kV and 22 kV 200A and 300A tanks would reasonably reflect what is required to achieve the capex objectives.[245] While the AER considers that a DNSP of Aurora's size should have sufficient existing space to store the AER's lower substitute volume of spares,[246] Aurora stated that it does not currently have existing space to house spares. The AER has accepted Aurora's proposed capex for housing spares, scaled down to reflect the lower volume of spares provided in the AER's substitute allowance.

The AER has therefore substituted an amount for the replacement of three-phase regulators of $0.87m ($2009–10) over the forthcoming regulatory control period.

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240 Aurora, *Revised regulatory proposal 2012-17*, January 2012, p.48.
241 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp.11–12.
242 Aurora, *Regulatory proposal 2012-17*, May 2011, Attachment AE083.
243 Nuttall Consulting, *Aurora electricity distribution revenue review: A report to the AER,* 11 November 2011, pp. 93–94.
244 Aurora, *Revised regulatory proposal 2012-17)*, January 2012, Attachment AE116, p.2.
245 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp. 31–32.
246 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp. 31–32.

Distribution switchgear – EDO fuses

Aurora originally proposed capex of $25.3 million ($2009–10) over the forthcoming regulatory control period for replacement of distribution switchgear, $4.8 million of which is for replacement related to EDO fuses.[247]

EDO fuses expel hot plasma and particles when they operate and have the potential to start fires. In addition to this risk, the tube casing of an EDO fuse can weather and then not operate as designed, causing the tube to catch fire and drop to the ground.

To address these issues, Aurora's original proposal included replacement of the whole fuse for some EDO fuses with Boric Acid fuses, as well as replacement of just the fuse tubes for some EDO fuses. Aurora's original proposal also delineated its EDO fuse tube replacements into replacement in high fire risk areas ($2.7 million proposed capex) and replacement outside high fire risk areas ($2.1 million proposed capex).

In the draft determination the AER accepted Aurora's proposed capex for EDO fuse replacement in high fire risk areas. The AER also noted that the replacement of just the fuse tube for EDO fuses in high fire risk areas does not alleviate the risk of fire starts resulting from the correct operation of the EDO fuse.[248] In its revised proposal Aurora altered its proposed capex to reflect the additional cost of replacing with Boric Acid fuses those EDO fuses that were originally intended for just fuse tube replacement.[249]

The AER accepts that it is prudent to replace all EDO fuses in high fire areas with Boric Acid fuses rather than simply replacing the fuse tube. However, the AER considers that Aurora should be able to undertake less fuse tube replacements and more whole fuse replacements within its original capex proposal and achieve the same risk profile targeted under its original capex proposal. Aurora's original proposal included retaining some EDO fuses in high fire risk areas, despite the risk of fire starts from correct fuse operation. Replacing all these EDO fuses with Boric Acid fuses would result in an improvement in Aurora's risk profile above a level that Aurora originally proposed. That said, the AER nonetheless considers that the improved risk profile reflected in Aurora's revised proposal is consistent with the capex objectives.

In the draft determination the AER did not accept Aurora's proposed capex for EDO fuse replacement outside high fire risk areas. For replacement outside of high fire risk areas, the AER accepted Aurora's proposed program of replacement with Boric Acid fuses but did not accept Aurora's proposed program of EDO fuse tube replacement. The AER considered that replacement of EDO fuse tubes outside high fire risk areas should continue in a ‘business-as-usual’ manner in the absence of service life data to support a change in the risk profile. The AER therefore substituted an amount of $0.3 million ($2009–10 over the forthcoming regulatory control period) for EDO fuse replacement outside high fire risk areas, excluding the $1.8 million proactive program to replace EDO fuse tubes.

Aurora’s submitted in its revised proposal that it requires its original forecast capex for EDO fuse tube replacement outside of high fire risk areas. Aurora submitted that this capex is required to replace

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247 Aurora, *Regulatory proposal 2012-17*, May 2011, Attachment AE083.

248 Nuttall Consulting, *Aurora electricity distribution revenue review-revised proposal: A report to the AER*, 11 November 2011, pp. 99–101.

249 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE123, p.2.

switchgear at sites with a service life exceeding 10 years to manage the risk to public safety and mitigation of fire starts.[250]

The AER notes that an approach based on Aurora's current protocols for replacing EDO fuse tubes identified as defective either by malfunction, Aurora's current inspection programs or analysis of specific manufacturer's performance will result in the current risk profile accepted by Aurora over the previous 9 years being maintained.[251] However, the AER again considers that the improved risk profile reflected in Aurora's revised proposal is consistent with the capex objectives.

The AER therefore accepts the need to replace EDO fuses to achieve the capex objectives, and accepts Aurora's revised proposal for the 'replace overhead switchgear' sub-category.

Distribution switchgear – fuse reach program

Aurora originally proposed $0.5 million ($2009–10) over the forthcoming regulatory control period to rectify sites where the protection on the LV circuit does not adequately protect the circuits, usually because of the length of the circuits.[252] In the draft determination the AER classified Aurora's fuse reach program as being primarily directed at addressing reliability issues and considered that the allowance provided for replacements was sufficient to address these issues. For this reason, the AER did not consider it was necessary that a capex allowance be provided in respect of Aurora's fuse reach program.[253] In its revised proposal, Aurora submitted that the AER erred in providing no forecast capex allowance for the fuse reach program, submitting that it requires the full amount of its proposed capex to address risks of fire and public safety.[254]

The AER has examined Aurora's proposed fuse reach program and concurs that the program appears primarily directed at addressing fire and public safety risks. The AER accepts there is likely a need for the proposed fuse reach program, and notes that Aurora's proposed program is targeted towards high fire danger areas. [255] The AER also notes that the proposed fuse reach capex is modest compared to historical expenditure for this program. The AER therefore accepts Aurora's revised proposal.

6.3.4 Capex to address reliability issues

Aurora originally proposed capex of $22.2 million ($2009–10) over the forthcoming regulatory control period for programs to address reliability issues.[256] In the draft determination the AER did not accept Aurora's proposal, considering that the remaining capex allowance determined (particularly replacement capex) should be sufficient to allow Aurora to achieve the capex objectives[257]. The AER provided no allowance for the reliability projects proposed by Aurora.[258] In its revised proposal Aurora disputed the AER's analysis for most (but not all) of its proposed projects, proposing that $14.6 million ($2009–10) of reliability-driven capex would be required over the forthcoming regulatory control period to achieve the capex objectives.[259] In its revised proposal Aurora also provided new information to

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250 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE122, p.2.
251 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp.33–35.
252 Aurora, *Regulatory proposal 2012-17*, May 2011, Attachment AE083.
253 AER, *Aurora 2012-17 draft distribution determination*, November 2011, section 5.4.3.
254 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE119, p.2.
255 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE119, p.2.
256 Aurora, *Regulatory proposal 2012-17*, May 2011, Attachment AE083.
257 Particularly the maintenance of the quality, reliability and security of supply of standard control services.
258 AER, Aurora 2012-17 d*raft distribution determination*, November 2011, section 5.4.3.
259 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE125, p.2.

indicate that its $0.5 million fuse reach program previously classified as reliability-driven capex is actually driven by the need to ensure the safe condition of non-pole assets (see section 6.3.3).

In the draft determination the AER separated Aurora's proposed reliability capex into three broad categories:[260]

- local reliability programs aimed at specific areas where customers were considered to be affected by poor performance
- protection and control programs aimed at ensuring good industry practice with regard to protection and control, and
- other discrete projects (access tracks, wildlife protection, and lightning arrestors) directed at addressing reliability issues.

The AER's assessment of Aurora's revised proposal for each of these categories is outlined below. In conclusion, the AER considers that the arguments in Aurora's revised proposal are not valid, and for this reason has maintained its position in the draft determination for reliability-driven capex.

Local reliability programs

Aurora originally proposed $6.5 million ($2009–10) over the forthcoming regulatory control period for 5 local reliability programs.[261] In its revised proposal, Aurora removed 1 of its local reliability programs but proposed the original amounts for the remaining 4, adding to $6.7 million ($2009–10) over the forthcoming regulatory control period (higher than its original proposal due to higher proposed labour rates).[262]

Aurora's description of these programs indicates that they are designed to improve performance above levels that would exist in the absence of these programs. The AER considered that these programs are not driven by asset replacement / maintenance needs or changes in demand patterns. The AER then considered whether the increase in reliability expected from these programs is likely to be required to achieve the capex objectives.

In the current regulatory period, annual reliability data suggest that Aurora has improved its reliability considerably from the previous regulatory period.[263] At the same time, Aurora's replacement capex in the current regulatory period approximately doubled from levels in the previous regulatory period, while targeted reliability improvement programs[264] and the other reliability programs were also implemented. The AER considers that this step up in capex levels from the previous regulatory period to the current regulatory period is likely to have had a material positive impact on Aurora's reliability. While targeted reliability programs are likely to have had an influence,[265] the AER also considers that the replacements capex have also had a material impact, irrespective of whether the primary purpose of replacements capex is to address asset ageing or safety issues.

Since the AER's final determination provides for a further modest increase in replacement expenditure, the AER considers it likely that this capex allowance is sufficient to at least maintain

[260] Nuttall Consulting, *Aurora electricity distribution revenue review-revised proposal: A report to the AER,* 11 November 2011, p. 125.
[261] Aurora, *Regulatory proposal 2012-17*, May 2011, Attachment AE083.
[262] Aurora, *Regulatory proposal 2012-17,* May 2011, Attachment AE083.
[263] In terms of SAIFI.
[264] TRIPS, which are set to conclude in the current regulatory period.
[265] See Attachment 12.

reliability levels from the current regulatory period. Aurora has not provided any information to indicate that its current reliability levels are resulting in non-compliance with regulatory obligations or requirements. Therefore the AER considers that Aurora's proposed local reliability programs are not likely to be required to achieve the capex objectives. The AER's final determination includes a substitute total capex allowance that excludes these proposed programs.

Protection and control programs

Aurora originally proposed $9 million ($2009–10) over the forthcoming regulatory control period for 7 protection and control programs.[266] In its revised proposal, Aurora removed 5 of its protection and control programs but proposed the original amounts for the remaining 2, adding to $1.6 million[267] ($2009–10) over the forthcoming regulatory control period.[268]

Aurora submitted that these programs are required for compliance with regulatory obligations about the time for protection systems to clear faults on the network.[269] The regulatory obligations provide that faults should be cleared in sufficient time to avoid consequential equipment damage, with appropriate clearance times largely based on capabilities as at the date Aurora joined the National Electricity Market (NEM).

Aurora has undertaken a review of its distribution system and detailed assets that require work to address protection and control issues. However, the AER considers that Aurora has not evidenced that these issues are strictly compliance issues given the relevant clearance time thresholds in protection and control obligations. Aurora would need to demonstrate material risks to safety or damage to other parties' assets if these programs were not implemented, and that these programs reflect Aurora's capabilities as at the date of entry to the NEM. From the information provided by Aurora, the AER considers that these programs are predominately driven by Aurora's current priorities and operating protocols, with the intention to improve Aurora's reliability performance and operational efficiency.[270]

Further, the AER considers that Aurora would currently be undertaking action to mitigate risks of non-compliance, including actions that would incur costs associated with:

- restoration via the improved protection of Aurora's network
- investigating protection mal-operations, or damage to Aurora’s or other parties assets
- repairing damaged assets
- capitalised fault-related asset replacements.

The AER considers it would be appropriate for Aurora to undertake capex to improve reliability only if it resulted in future cost reductions. Otherwise Aurora could maintain its current reliability performance and risk profile by simply rectifying protection and control issues as they occur. Should Aurora later discover cost efficiencies resulting from a protection and control program, it may still undertake the program and realise efficiency gains under the AER's efficiency benefit sharing scheme. Since Aurora

266 Aurora, *Regulatory proposal 2012-17,* May 2011, Attachment AE083.
267 Higher than its original proposal due to higher proposed labour rates.
268 Aurora, *Regulatory proposal 2012-17,* May 2011, Attachment AE083.
269 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE125, p.4.
270 Aurora, *Response to Information request AER/066*, Attachment: Procedural Guideline - Additional Protection For Heavily Loaded Spurs, 15 February 2012, page 1.

has not demonstrated any future cost reductions that would result from its proposed protection and control programs, the AER maintains the substitute amount estimated in its draft determination.

Lightning arrestors

Aurora originally proposed $0.8 million ($2009–10) over the forthcoming regulatory control period for installation of lightning arrestors on high-value assets.[271] In its revised proposal, Aurora submitted that the AER erred in providing no forecast capex allowance for lightning arrestors and that it requires the full amount of its proposed capex to prevent ground mounted substation outages.[272]

Aurora did not provide any information to indicate that installation of lightning arrestors is required to ensure compliance with regulatory obligations or requirements or that failure to undertake the proposed works can reasonably be expected to result in non-compliance with a regulatory obligation.[273]

Clearly, the installation of lightning arrestors will prevent outages to Aurora's assets and improve Aurora's reliability.[274] The AER considers it would be appropriate for Aurora to undertake capex to improve reliability only if it resulted in future cost reductions—otherwise Aurora could maintain its current reliability performance and risk profile by simply rectifying outages as they occur. Should Aurora later discover cost efficiencies resulting from a lightning arrestors program, it may still undertake the program and realise efficiency gains under the AER's efficiency benefit sharing scheme. Since Aurora has not demonstrated any future cost reductions that would result from its proposed lightning arrestors program, the AER maintains the substitute amount in its draft determination.

Wildlife protection

Aurora originally proposed $0.2 million ($2009–10) over the forthcoming regulatory control period for installation of bird perches and other wildlife protection measures not requested by the Tasmanian Government. Aurora also proposed $0.7 ($2009–10) over the forthcoming regulatory control period million for wildlife protection measures required under a memorandum of understanding with the Tasmanian government.[275] In the draft determination the AER accepted Aurora's proposed wildlife protection capex required under a memorandum of understanding, but did not accept Aurora's proposed wildlife protection capex not requested by the Tasmanian government. In its revised proposal, Aurora submitted that the AER erred in providing no forecast capex allowance for wildlife protection not requested by the Tasmanian government and that it requires the full amount of its proposed capex to mitigate legal risks to Aurora from its network causing harm to endangered wildlife.[276]

The AER considers that the documentation provided by Aurora detailing its wildlife protection program not requested by the Tasmanian government indicates that the program is directed at improving reliability by reducing the impact of wildlife on Aurora's assets. The documentation discusses wildlife

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271 Aurora, *Regulatory proposal 2012-17,* May 2011, Attachment AE083.
272 Aurora, *AE120 Revised regulatory proposal 2012-17*, January 2012, Attachment AE120, p.2.
273 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE119, pp.6–9.
274 Aurora submitted that it loses about 1 ground mounted substation every second year as a result of a lightning strike to the overhead system, and that it proposed the lightning arrestors program to protect high value assets such as ground mounted substations and submarine cables. Aurora, *Revised Regulatory Proposal*, January 2012, Attachment AE120, p. 2.
275 Aurora, *Regulatory proposal 2012-17,* May 2011, Attachment AE083.
276 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE124, p. 2.

contact in terms of the impact on assets and supply rather than injury to wildlife, and the quantification of the issue is based on the number of wildlife-related outages.[277]

Even if legal risks are present, the AER considers that Aurora has not substantiated why the amount of its proposed capex is required to mitigate these risks. The AER notes that Aurora's average annual capex for this program from 2003–04 to 2010–11 has been less than half of the $0.04 million average annual capex proposed over the forthcoming regulatory control period.

Furthermore, the capex accepted by the AER for wildlife protection under the memorandum of understanding with the Tasmanian government is about 350 per cent higher than the other wildlife protection capex proposed by Aurora and accepted by the AER. The AER considers that the residual risks, if any, that may not be alleviated by the AER's capex allowance are likely to be immaterial.

The AER therefore considers that Aurora is not likely to require any additional capex for wildlife protection above that amount estimated in the AER's draft determination.

Access tracks

Aurora originally proposed $5.2 million ($2009–10) over the forthcoming regulatory control period for re-building access tracks for safe employee access to Aurora's network.[278] In its revised proposal, Aurora submitted that the AER erred in providing no forecast capex allowance for access tracks, submitting that it requires the full amount of its proposed capex to address safety issues.[279]

Aurora did not provide any information to indicate that rebuilding of access tracks is required to ensure compliance with regulatory obligations or requirements, to maintain performance, or to otherwise achieve the capex objectives. Aurora stated that the current condition of its access tracks is such that they may present risks of:[280]

- unsafe environments for Aurora's employees working on Aurora's network
- environmental degradation (spread of weeds and disease)
- reduced fault response and customer outages

The AER agrees that poorly conditioned access tracks may present these risks. But the AER considers that Aurora is likely to have in place measures and operating procedures to address these risks since:

- Aurora states that the access tracks are currently in this condition,
- Aurora has not provided information to suggest that its access tracks are causing non-compliance with regulatory obligations, and
- Aurora's reliability performance has been increasing over the current regulatory period (see Attachment 12).

277 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp.52–53.

278 Aurora, *Regulatory proposal 2012-17,* May 2011, Attachment AE083.

279 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE118, p.2.

280 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE118, p.2.

The AER considers that the costs[281] to address safety risks associated with the current condition of access tracks should be reflected in Aurora's current operating practices, which are reflected in the AER's forecast opex allowance (see Attachment 7). For these reasons the AER considered in the draft determination that Aurora's proposed access tracks program is designed to improve Aurora's performance and is not otherwise required to achieve the capex objectives.

In its revised regulatory proposal Aurora re-stated that the current condition of its access tracks is poor and that this condition may present safety, environmental and/or reliability risks. However, Aurora provided no information in its revised proposal to indicate that safety risks associated with access tracks are likely to materially increase over the forthcoming regulatory control period. Rather, Aurora proposed that this capex program is designed to improve access tracks from their current condition. In addition, Aurora did not provide any information to indicate that it is not currently adequately addressing risks caused by poorly conditioned access tracks or that access track condition is currently resulting in an inability to achieve the capex objectives.

The AER considers that it has provided an opex allowance sufficient for Aurora to maintain its current operating procedures which should allow Aurora to achieve the capex objectives (considering the capex factors, particularly trade-offs between capex and opex). Since there is no indication that improving access tracks is required under a compliance obligation; and since rebuilding access tracks is likely to improve the reliability, quality or security of supply of standard control services; the AER considers it would be efficient for Aurora to undertake this capex only if it results in future cost reductions. Since Aurora has not demonstrated any future cost reductions that would result from its proposed access track program, the AER maintains the substitute amount estimated in its draft determination.

6.3.5 Maximum demand-driven capex

Aurora originally proposed $87.1 million ($2009–10) over the forthcoming regulatory control period for capex to address growth in maximum demand.[282] In the draft determination the AER considered Aurora's proposal to be too high, based on the AER forecasting lower growth in maximum demand than Aurora, as well as the AER's consideration that Aurora systematically over-estimated the scope of the projects required to address growth in maximum demand. The AER developed a substitute capex allowance of $43.0 million.

In its revised proposal Aurora proposed maximum demand-driven capex of $71.1 million ($2009–10) over the forthcoming regulatory control period. In its revised proposal, Aurora submitted that its Gretna zone substation project previously classified as maximum demand-driven is actually driven by the need to maintain the condition of non-pole assets. On the remaining maximum demand-driven capex, Aurora submitted:

- revised maximum demand forecasts,
- that the AER had erred in its sampling approach used to assess Aurora's proposal and determine a substitute allowance, and

281 Such as instructing field staff on appropriate safety measures or increased maintenance costs associated with enhanced crew sizes and/or vehicle requirements.

282 Aurora, *Regulatory proposal 2012-17,* May 2011, Attachment AE083.

- revised project scopes for a number of maximum demand-driven projects in response to revised demand forecasts and concerns raised in the draft determination.

The AER has maintained its assessment approach as used in the draft determination (see section 6.2). Therefore, consistent with this approach, the AER:

- revised its detailed review of those projects within its sample and for which Aurora has provided additional information (Sandford and Geilston Bay), and
- inferred the results of the sample across the population where appropriate, without review of detail additional information provided by Aurora on projects outside of the AER's sample (St Leonards and Kingston).

The AER has assessed whether Aurora's revised demand forecasts represent a realistic expectation of demand in Attachment 5. The AER accepts Aurora's revised demand forecasts (the AER's assessment approach is discussed in section 6.2). The AER's assessment of the remaining issues raised in Aurora's revised proposal are outlined below.

In conclusion, the AER considers that:

- the revised project scope submitted by Aurora for the Sandford and Geilston Bay projects are appropriate,
- revised project scopes submitted by Aurora for other projects subject to detailed review by the AER in the draft determination have not been justified, and
- Aurora has not adequately addressed the impact of its revised demand forecast on its maximum demand-driven capex proposal.

The AER has re-done its analysis using its assessment approach from the draft determination (see section 6.2) and has estimated that an appropriate substitute amount of maximum demand-driven capex is $46.6 million over the forthcoming regulatory control period.

Treatment of capex that is directed at achieving operational efficiencies

In its revised proposal Aurora submitted:[283]

> ... in arriving at its substitute forecast, the AER has reduced the capex forecasts for projects in the category by a series of factors, with the factors being based on the proportion of project capex assessed to be demand-related...Aurora contends that this approach does not “reflect the efficient costs of achieving the capex objectives”. Rather it reflects the portion of costs in the Reinforcements RIN [maximum demand-driven capex] category that should have been reclassified to another RIN category.

The AER considers that Aurora has mischaracterised the AER's draft determination. In the draft determination, the AER stated:[284]

> ...it seems that only small components of most projects the AER has reviewed have a direct correlation with the need to meet or manage expected demand. The AER considers the remaining capex is beyond what is required for Aurora to achieve the capex objectives because it is driven by operational efficiencies and/or improvements in reliability. The AER also considers that in some

283 Aurora, *Revised regulatory proposal 2012-17,* January 2012, Attachment AE128, p.18.
284 AER, *Aurora 2012-17 draft distribution determination,* November 2011, pp.137–138.

cases Aurora has not adequately demonstrated that its proposed solution to address demand growth reasonably reflects the efficient costs of achieving the capex objectives.

The AER considers it clearly stated in the draft determination that the downwards amendment to Aurora's proposed maximum demand-driven capex to determine a substitute amount was because many of the projects proposed by Aurora were not required to achieve the capex objectives.[285] This consideration was made in light of all the capex objectives, not just the objective to meet or manage expected demand.

Sandford conductor augmentation

Aurora originally proposed $6.6 million ($2009–10) over the forthcoming regulatory control period for a Sandford conductor augmentation. In the draft determination the AER considered (in addition to concerns over a lower demand forecasts) that the scope of the project was too extensive and that a less costly option would likely be available. In the draft determination the AER developed a substitute allowance of $0.7 million.

In its revised proposal Aurora submitted that it reviewed the Sandford conductor augmentation project in light of the AER's concerns, and developed an alternative option. Aurora costed its alternative option at $1.6 million ($2009–10) over the forthcoming regulatory control period. However, Aurora's revised proposal indicates proposed capex of $6.7 million. Aurora did not provide any justification for costing the Sandford conductor augmentation project above its $1.6 million alternative option.

The AER notes that Aurora's alternative option represents a significant cost reduction from its original proposal, and considers it now unlikely that additional material cost reductions could be found through further development of the project scope closer to the project implementation date. The AER therefore accepts Aurora's alternative Sandford conductor augmentation project at $1.6 million.

Geilston Bay conductor augmentation

Aurora originally proposed $0.2 million ($2009–10) over the forthcoming regulatory control period for a Geilston Bay conductor augmentation project. In the draft determination, the AER considered that the scope of the project was more extensive than necessary to address the maximum demand issues and achieve the capex objectives. In the draft determination the AER developed a substitute allowance of $0.07 million, which also reflected the AER's concerns in the draft determination about Aurora's maximum demand forecasts. Without the reduction to reflect the AER's substitute demand forecasts, the AER's substitute allowance is $0.20 million.

In its revised proposal Aurora submitted that the full amount of its original proposal for the Geilston Bay project is required to relieve old and overloaded transformers.[286] However, Aurora also proposed capex amounts for the Geilston Bay conductor augmentation project of $0.15 million over the forthcoming regulatory control period, significantly lower than Aurora's original proposal for this project.[287]

Nonetheless, despite apparent inconsistencies in the information provided by Aurora, the AER accepts Aurora's revised maximum demand forecasts (see Attachment 5) and therefore accepts demand-related needs to undertake the Geilston Bay conductor augmentation.

285 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 137–138.
286 Aurora, *Revised regulatory proposal 2012-17,* January 2012, Attachment AE132, p.5.
287 Aurora, *Response to follow up information request AER/060 of 13 February 2012*, received 15 February 2012.

However, on the age or condition of the relieved transformers, the AER considered that the age or condition of the transformers can be addressed by the holding of spares. Aurora agreed with position in its revised proposal (see section 6.3.3). The AER considers that Aurora has not provided any additional information to indicate that the age or condition of the transformers is a material driver of the Geilston Bay conductor augmentation project.

The AER therefore maintains its assessment from the draft determination of the project scope, but considers that reductions applied to account for a substitute demand forecasts should be removed.

St Leonards and Kingston substation augmentations

Aurora originally proposed $1.3 million ($2009–10) over the forthcoming regulatory control period for St Leonards substation augmentation. The AER did not review this project in detail but developed a substitute amount ($0.6 million) based on the AER's findings of its review of other substation augmentation projects not involving deferral. In its revised proposal Aurora submitted that the AER erred in substituting a lower amount for this project and that it requires the full amount of its originally proposed capex.

In its revised proposal Aurora also submitted that it requires a new zone substation in Kingston as a result of its revised maximum demand forecasts. Aurora did not propose capex for a new Kingston zone substation in its original proposal, but rather capex and opex for demand management intended to defer the need to build the new substation.

As the AER did not review the St Leonards or Kingston substation projects in detail in the draft determination, the AER has not reviewed these projects in detail in the final determination. These projects were therefore treated as out-of-sample projects in the substation augmentations not involving deferral category. The AER has therefore applied its findings for substation augmentations not involving deferral category to the proposed St Leonards and Kingston substation projects. The AER arrived at a substitute amount of $0.6 million ($2009–10) over the forthcoming regulatory control period for the St Leonards project and $2.3 million ($2009–10) over the forthcoming regulatory control period for the Kingston project.

In addition, Aurora submitted that the Kingston zone substation project will defer the need for the nearby Blackman's Bay zone substation project. Aurora originally proposed $0.53 million ($2009–10) over the forthcoming regulatory control period for demand management capex to defer the Blackman's Bay substation project. However, it appears that Aurora has not removed this demand management expenditure from its revised capex proposal. As Aurora has submitted that it now requires the Kingston substation project, the AER has removed the demand management capex associated with the Blackman's Bay substation from its substitute capex allowance.

Other unsubstantiated changes to project scope

Aurora's revised proposal included revised proposed capex amounts for the following maximum demand-driven capex projects:

- demand management (additional processes)
- development - LGA works
- system fault level - Trevallyn
- mobile generation

- substation augmentations - Rosny

In its revised proposal Aurora proposed capex totalling $15.6 million ($2009–10) over the forthcoming regulatory control period for these projects. Aurora's revised proposal capex for these projects is higher than its original proposal of $13.8 million and higher than the AER's draft determination of $4.6 million.

Aurora did not provide further supporting information justifying its revised proposal for each of these other projects as it had done for the Sandford, Geilston Bay, St Leonards and Kingston projects.

Aurora explained the general method it used to develop its revised maximum demand-driven capex proposal.[288] However, Aurora also stated that this general method was only applied "for projects where Aurora agreed with [the AER to] a reduction" from its original proposal. It appears that the projects listed above were not subject to this method, but Aurora did not provide any other explanation of why its proposed capex is required to achieve the capex objectives or how these amounts were developed other than its arguments about the AER's sampling approach (addressed in section 6.2).

The AER therefore does not accept Aurora's revised proposal for the projects listed above. The AER maintained the assessment approach from the draft determination and its detailed review findings from the draft determination for the projects listed above. The AER revised its sample findings for other issues raised by Aurora in its revised proposal, resulting in a revised inference of the sample findings to some of the projects listed above from that used in the draft determination. The AER has also reviewed Aurora's revised maximum demand forecasts, which has also resulted in amendments to these projects. The AER's final determination then results in a downwards amendment to Aurora's revised proposal of approximately $11.0 million.

Commitment to projects via a public consultation process

In its revised proposal Aurora stated that it has completed a public consultation process jointly with the electricity transmission network operator Transend for Aurora's proposed Geilston Bay conductor augmentation, St Leonards substation augmentation, and Kingston substation augmentation projects. Aurora submitted that these projects are already committed because of the finalisation of these consultation processes.

The AER does not consider that completion of a public consultation process for a project is sufficient evidence that the associated expenditure reasonably reflects the capex criteria. Rather, the AER would need to consider the public consultation process in light of the capex factors, in particular the extent to which Aurora's circumstances are influenced by contractual obligations relating to the project. Aurora provided no information indicating that Aurora is contractually obliged to incurring the proposed expenditure associated with the Geilston Bay, St Leonards, or Kingston projects.

Impact of revised demand forecasts on required capex

In the draft determination the AER did not accept Aurora's original maximum demand forecasts and developed lower substitute forecasts.[289] Based on these forecasts, the AER developed reductions

[288] Aurora, *Response to AER information request AER/060 of 7 February 2012*, received 9 February 2012, pp.3–4.
[289] AER, Aurora 2012-17d*raft distribution determination,* November 2011, p.73.

from Aurora's original proposed capex to come to a substitute allowance (in addition to reductions from Aurora's proposed capex for concerns over project scope).

Aurora submitted revised forecasts of maximum demand in its revised proposal as well as revised maximum-demand driven capex projects. Aurora's revised maximum demand forecasts are significantly lower than its original forecasts and more comparable to the AER's draft determination forecast (at least at the total network level, variations may appear at more localised levels).

However, the approach used by Aurora to calculate its revised proposal for maximum demand-driven capex has the effect of reversing the reduction to Aurora's original proposal that was made in the AER's draft determination to account for the AER's lower demand forecasts while accepting all other reductions made in the draft determination (except those for projects otherwise contested by Aurora).[290] Aurora did not explain why it considered this method to be appropriate or why the results of the method—its proposed capex—are required to achieve the capex objectives, but simply stated:[291]

> Aurora considered it prudent (especially given that Aurora had already imposed efficiencies in its forecasting process) not to alter the timing of its projects to accommodate the AER’s revised demand forecast so as to mitigate the effects of having a regulatory allowance below that required in the event that the AER’s forecast was overly conservative.

Aurora did not provide any justification to support its reversal of the draft determination amendment to account for lower demand forecasts. Aurora also stated that its revised proposal is below that required to achieve the capex objectives and that it does not consider its revised maximum demand-driven capex proposal is a realistic forecast of efficient capex requirements.[292] The AER therefore does not accept the method used by Aurora to derive its revised regulatory proposal for maximum demand-driven capex.

As outlined in Attachment 5, the AER accepts Aurora's revised maximum demand forecasts. The AER has then examined the impact of Aurora's revised demand forecasts on the sample of maximum demand-projects selected for detailed review by the AER. The AER considers that Aurora's revised proposal maximum demand-driven capex is too high given Aurora's revised maximum demand forecasts.[293] The AER considers that an amendment of $4.4 million ($2009–10) over the forthcoming regulatory control period is required to ensure a substitute capex amount that reasonably reflects the capex criteria.

6.3.6 Unit rates

Since the draft determination, Aurora has changed its capex forecast approaches in relation to labour cost escalation and unit rates. For the reasons that follow, the AER does not accept these changed approaches.

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290 Aurora, *Response to AER information request AER/060 of 7 February 2012*, received 9 February 2012, p.4. The AER notes that some projects or programs—development (LGA works), system fault level (Trevallyn), zone substation (Rosny)—do not consistent with the AER's demand forecast-based reduction for each year of the forthcoming regulatory control period. However, no issues about project scope were raised by Aurora, nor any other substantiation of the changes for these projects from Aurora's original regulatory proposal.

291 Aurora, *Response to AER information request AER/066 of 22 February 2012*, received 29 February 2012, p.4.

292 Aurora, *Response to AER information request AER/066 of 22 February 2012*, received 29 February 2012, p.4.

293 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER,* April 2012, pp. 16–18.

Aurora stated in its revised regulatory proposal that the AER rejected Aurora's CPI-only escalation of labour costs, and Aurora's proposed three per cent efficiency adjustment to labour rates within its unit rates.[294] On this assumption, Aurora revised its labour cost escalation approach and removed the three per cent efficiency factor from its unit rates. The AER did not require these revisions and considers they amount to more than 'amending to reflect more up-to-date data sets'.[295]

In the draft determination, the AER considered it was unable to form a view about Aurora's three per cent efficiency factor due to a lack of substantiation.[296] However, the AER did not reject Aurora's unit rates or the efficiency factor. Indeed, the AER explicitly accepted Aurora's capex unit rates.[297] For this final determination, the AER has maintained its position from the draft determination and assessed Aurora's capex with the three per cent efficiency factor included in the unit rates. This has resulted in a reduction of approximately $15.4 million to Aurora's revised total forecast capex. This reduction is not additional to the other adjustments the AER has made to Aurora's revised capex forecast. Unit rates are discussed in further detail in attachment 3. Labour cost escalation is discussed below in section 6.3.9.

6.3.7 Capitalised maintenance

In its original proposal Aurora proposed $10.3 million ($2009–10) over the forthcoming regulatory control period for capitalised emergency maintenance. In the draft determination the AER reviewed these costs in line with the AER's assessment of expensed emergency maintenance (opex). The AER considered that Aurora's proposal was too high, and determined a substitute amount of $9.4 million. In its revised proposal Aurora proposed $11.2 million for capitalised maintenance.

The AER has assessed capitalised emergency maintenance under the same approach used to assess opex. For the reasons outlined in the Attachment 7, the AER accpets Aurora's proposed capitalised emergency response maintenance.

6.3.8 Capitalised overheads

In its original proposal Aurora proposed to capitalise $98.5 million ($2009–10) of overheads over the forthcoming regulatory control period. In the draft determination the AER accepted Aurora's proposed capitalised overheads. In its revised proposal Aurora proposed to capitalise $91.1 million of overheads, reducing its proposed capitalised overheads to reflect its lower overall capex and opex proposals and therefore lower allocation of overheads to standard control services.

The AER has reallocated Aurora's shared costs across Aurora's distribution services in accordance with Aurora's CAM (see section 1.3.7). The AER has accepted Aurora's forecast of shared costs for opex in its revised proposal. Although the AER accepts the total amount of shared costs, it has reallocated these shared costs across service classifications. This is in accordance with the approach applied by Aurora in its revised regulatory proposal.[298] The AER's substitute (reallocated) amount of capitalised overheads is $88.7 million over the forthcoming regulatory control period.

294 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 75, 80, 83.
295 Aurora, *Revised regulatory proposal 2012-17*, p. 52.
296 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 158.
297 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 96.
298 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 47.

6.3.9 Real input price changes

In its original proposal Aurora propose capex of $5.3 million ($2009–10) to account for changes to real input prices over the forthcoming regulatory control period. In the draft determination the AER accepted Aurora's forecast rate of change in real input prices[299], but substituted a lower amount of capex of $5.1 million to account for the AER's lower draft decision capex allowance. In its revised proposal Aurora proposed capex of $5.3 million for real input price changes, which accounted for Aurora's revised forecasts for the rate of change in real input prices, as well as Aurora's revised total capex proposal being lower than its original proposal.

The AER accepts Aurora's revised forecast for the rate of change in capex materials inputs over the forthcoming regulatory control period. The AER does not accept Aurora's revised forecast for the rate of change in capex labour inputs over the forthcoming regulatory control period, and considers that no real labour price increases is a more realistic forecast. The AER amended Aurora's proposed capex to account for these forecasts and developed a substitute capex amount of $3.9 million. Real input price changes are discussed further in attachment 4.

6.3.10 Equity raising costs

Aurora originally proposed $3.0 million ($2009–10) over the forthcoming regulatory control period for equity raising costs. In the draft determination, the AER accepted Aurora's method for forecasting equity raising costs. However, this method relies on inputs of Aurora forecast cash flows which in turn depend on the AER's capex allowance. The AER accordingly revised the analysis to account for its draft determination and determined that no allowance was required for equity raising costs. In its revised proposal Aurora proposed $0.16 million for equity raising costs, determined under an unchanged forecasting method but reflecting the forecast cash flows expected from Aurora's revised regulatory proposal.

The AER has revised its forecast of equity raising costs to take account of its final determination on Aurora's capex and other building block components. The revised cash-flow analysis indicates that no equity raising costs will be required by Aurora over the forthcoming regulatory control period.

6.4 Revisions

Revision 6.1: The AER has revised Aurora’s total forecast capex for the forthcoming regulatory control period by $82.7 million. The AER’s substituted forecast is $535.4 million.

[299] AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 97.

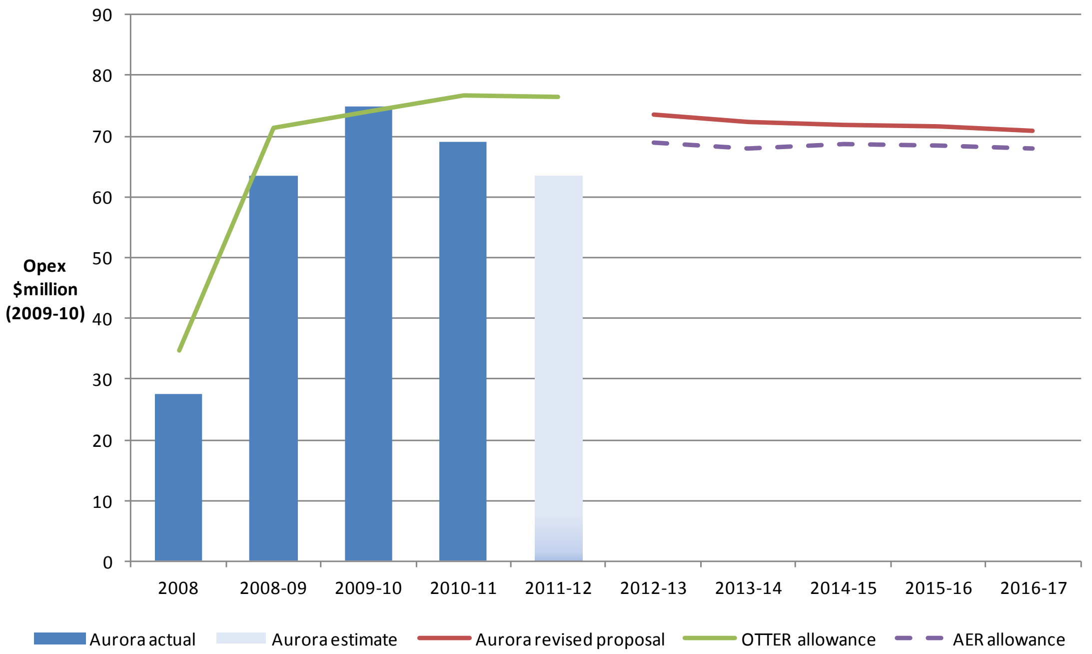
7 Operating expenditure

This attachment sets out the AER's determination on Aurora's proposed total forecast operating expenditure (opex). Opex refers to the operating, maintenance and other non-capital costs that Aurora incurs in providing standard control services.

7.1 Determination

The AER is not satisfied Aurora's revised total forecast opex reasonably reflects the opex criteria and accordingly, does not accept it.[300] The AER has estimated a total forecast opex for Aurora that it considers reasonably reflects the opex criteria, having regard to the opex factors.[301] Figure 7.1 compares Aurora's revised forecast total opex with the AER's final determination allowance.

Figure 7.1 Comparison of Aurora's past and revised forecast total opex and the AER final determination ($million, 2009-10)[302]



Source: Aurora proposal, Aurora revised proposal, AER analysis.[303]

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[300] NER, clauses 6.5.6(c), (d), (e).

[301] NER, clause 6.12.1(4)(ii).

[302] The first period (2008) in the current regulatory period extended for only six months, which, explains the significant increase in opex from 2008 to 2008-09. The AER's allowance and Aurora's actual, estimated and forecast opex are presented in terms of Aurora's current cost allocation method (CAM). The Office of the Tasmanian Economic Regulator's (OTTER) allowance is presented in terms of Aurora's previous CAM. The AER could not present OTTER's allowance in terms of the current CAM because the CAM relies on Aurora's underlying business structure, which the OTTER allowance was not set against. This figure includes all historical and forecast opex including non-recurrent expenditures.

[303] Aurora, *Regulatory proposal 2012–17*,May 2011, pp. 129–145, Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 65–73.

The AER's estimate is a reduction of Aurora's revised proposal total forecast opex to the extent necessary to enable the AER to approve it in accordance with the NER.[304] In this final determination the AER has amended Aurora's revised regulatory proposal rather than entirely substituting Aurora's forecast with the AER's base year estimate.

Overall, the AER is satisfied that its estimate of a total forecast opex for Aurora of $341.9 million ($2009-–10) for the forthcoming regulatory control period reasonably reflects the opex criteria. This forecast represents an $18.5 million (5.1 per cent) reduction (in real terms) from Aurora's revised total opex forecast and a $2.3 million (0.7 per cent) reduction (in real terms) from Aurora's initial forecast.

Table 7.1 AER final determination on Aurora's operating and maintenance expenditure ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Aurora revised **proposal**	73.5	72.4	71.9	71.7	71.0	360.4
Revisions	4.6	4.5	3.3	3.2	3.0	18.5
AER **final determination**	68.9	67.9	68.7	68.5	68.0	341.9

Source: AER analysis.

7.2 Assessment approach

Aurora's revised regulatory proposal raised several concerns in response to the base, step and trend assessment approach (base year approach). The AER used this approach in its draft determination in determining whether it was satisfied Aurora's proposal reasonably reflected the opex criteria, and in determining a substitute. The AER has considered Aurora's concerns with the base year approach in section 7.2.2.

Aurora also stated that it has updated its demand and economic forecasts for its revised opex proposal. Aurora considers its forecasting approaches are consistent with the AER's approaches and does not expect any changes from the AER.[305] The AER has considered Aurora's statement in section 7.3.4.

7.2.1 Review approach for the final determination

Aurora submitted that by applying the base year approach in determining a substitute forecast opex allowance, the AER did not properly apply clause 6.12.3(f) of the NER.[306] This clause requires the AER to determine a substitute opex forecast on the basis of Aurora's regulatory proposal, and to amend it only to the extent necessary to enable it to be approved in accordance with the NER.[307] In support of this submission, Aurora referred to comments the AER made in its recent chapter 6/6A rule change proposal.[308]

304 NER, clause 6.12.3(f).
305 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 65.
306 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 62.
307 NER, clause 6.12.3(f).
308 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 62.

In the draft determination the AER developed a base year estimate (using information provided in and accompanying Aurora's regulatory proposal) to first determine whether it was satisfied Aurora's opex forecast reasonably reflected the opex criteria, having regard to the opex factors.[309] The AER concluded that it was not satisfied that Aurora's forecast reasonably reflected the opex criteria because it was higher than the forecast the AER estimated by applying its base year approach.[310]

As is required by clause 6.5.6(d) and 6.12.1(4)(ii), the AER then determined an estimate of the total opex that it was satisfied reasonably reflects the opex criteria, based on Aurora's regulatory proposal, and amended to the extent necessary to be approved in accordance with the NER.[311] On the information available at the time of the draft determination, the AER had a number of concerns with Aurora's regulatory proposal which ultimately did not make it possible for the AER to amend Aurora's forecast. These concerns were identified and discussed in the draft determination.[312] They are reiterated below in addition to some further concerns identified by the AER in this final determination.

The significant concerns that the AER identified with Aurora's proposal meant that in preparing the draft determination, it was not practically possible for the AER to amend it as required by clause 6.12.3(f). In these circumstances, the only option available to the AER in order to estimate a substitute forecast in accordance with the NER was to wholly substitute Aurora's proposal with its own estimate.[313]

To the extent this approach was not evident in the AER's reasoning in the draft determination, the AER accepts that Aurora could have perceived the AER's draft determination did not comply with clause 6.12.3(f).

In this final determination, the AER has explained its concerns with Aurora's forecasting approach, and the assessment approach it has applied.

AER concerns with Aurora's forecasting approach

The AER explained Aurora's forecasting approach in the draft determination.[314] In summary, Aurora calculated its opex forecast using a program of work that sums each of the operating and maintenance projects Aurora considers will occur in the forthcoming regulatory control period—a bottom up build. Aurora calculated the forecasts for this bottom up build by multiplying estimated volumes and unit rates for each project. The forecast unit rates are based on unit rates currently incurred by Aurora and reflected in the current average cost of works. Aurora then applied an annual three per cent efficiency factor to the labour rates within the unit rates.[315]

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309 NER, clause 6.5.6(c), (d) and (e).

310 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 161-163.

311 NER, clauses 6.12.1(4)(ii), 6.12.3(f)(2).

312 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 157-158, 164-166.

313 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 157-161. The AER has previously wholly substituted its own estimate in the cases of United Energy's opex forecast in the Victorian electricity distribution determination and EnergyAustralia's proposed forecast maintenance expenditure in 2009. In both these cases there were significant concerns with the proposed forecasts such that it was not possible for the AER to estimate a substitute by amending the proposed forecasts. In the case of EnergyAustralia, the AER's decision to substitute EnergyAustralia's maintenance expenditure with its own estimate was upheld by the Australian Competition Tribunal. See AER, *Victorian 2011–15 distribution determination – Appendices*, November 2010, p. 157; *Application by Energy Australia and Others* [2009] ACompT8, 12 November 2009 at [253] – [257].

314 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 154-156.

315 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 167.

In the program of work, Aurora classified the projects into the categories, which form the basis of its total opex forecast. Aurora allocated corporate and shared services costs using its indirect cost allocation model (ICAM) between Aurora's divisions and subsidiaries. Aurora then used its AER-approved cost allocation method (CAM) to allocate costs between various classifications within the distribution business.[316] Finally, Aurora escalated the expenditure for input cost changes.[317]

The AER considers Aurora's use of historical expenditure and volumes, adjusted for factors specific to the forthcoming regulatory control period, is appropriate. However, there are other elements that are concern the AER.

First (as noted in the draft determination[318]), Aurora is not currently subject to an EBSS and is expected to spend close to its allowance for the current period. This means that while Aurora's forecasting approach may be based on actual costs, it does not necessarily mean it is based on efficient costs.

Second, (also noted in the draft determination[319]), Aurora's annual three per cent efficiency factor is a high level adjustment based on an aspirational objective of ensuring minimal increase to customer prices. While this adjustment reduced Aurora’s total forecast opex, it was not clear to the AER whether it would result in a total forecast opex that reasonably reflected the opex criteria—it could have been too high or too low.

Third, while Aurora's CAM explains how shared costs are allocated to expenditure categories, the approach Aurora uses to develop its shared costs forecasts, and the appropriateness of the costs, were not transparent to, or verifiable by, the AER. Aurora has stated that it generally develops forecasts of shared costs outside of its thread management framework, using its budgeting and forecasting tool.[320] However, Aurora's regulatory proposal and supporting information did not provide any proper insight into this tool. Therefore the basis of a significant part of Aurora's opex forecast is unclear.

Fourth, where Aurora has forecast an increase in costs, it has not necessarily been able to explain why the increase is efficient. For example, Aurora has proposed a step increase in IT opex for the forthcoming regulatory control period due to the proposed implementation of a new IT system. Although Aurora has provided documentation supporting the need for, and associated benefits of, this new system, Aurora has been unable to provide a cost benefit analysis.[321] This also casts doubt over Aurora's forecasting approach, and makes it difficult for the AER to satisfy itself that Aurora's forecast reasonably reflects the opex criteria.

Final determination approach

For the reasons discussed above, the AER considers it is open for it to apply the same approach to determining Aurora’s opex forecast that it did in the draft determination. That is, due to the concerns identified, the only amendment to Aurora's proposed forecast available to the AER is to entirely substitute Aurora’s forecast with the AER’s estimate. In these circumstances, the AER considers that

316 Aurora, *Regulatory proposal 2012–17*, May 2011, pp. 156-157.

317 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 161.

318 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 164–166.

319 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 157-158.

320 Aurora, *Regulatory proposal 2012–17*, May 2011, pp. 134-137; Aurora, *Response to information request AER/015 of 22 July 2011*, received 29 July 2011.

321 Aurora, *Response to information request AER/065 of 17 February 2012*, received 24 February 2012.

it is appropriate that the substitute be determined using a base year estimate as the starting point because it results in a forecast the AER is satisfied reasonably reflects the opex criteria.

However, in light of information provided in Aurora's revised regulatory proposal, the AER has modified the approach it applied in the draft determination. Specifically, in this final determination, the AER has:

- identified each relevant opex category in Aurora's regulatory proposal and split its base year forecast into these categories
- compared its base year forecast with Aurora's proposed expenditure in these categories to identify any areas of divergence
- conducted a detailed review of any divergences
- made adjustments to Aurora's forecast where appropriate.

This approach enables the AER to continue to rely on revealed costs and to determine an estimate that amends Aurora's forecast to the minimum extent necessary. This analysis is presented in section 7.3. Table 7.2 presents a summary of the AER's assessment approaches for the draft and final determinations.

Table 7.2 Summary of AER assessment approaches

Stage	AER Approach	Compliance with the NER
Draft determination	The AER assessed Aurora's proposal by developing an estimate using the base year approach. The AER was unable to amend Aurora's forecast due to concerns with Aurora's proposal, so wholly substituted Aurora's forecast with the base year estimate.	The AER determined its estimate in accordance with clauses 6.5.6(d) and 6.12.1(4)(ii). The AER considers it complied with clause 6.12.3(f) given it was not possible to amend Aurora's proposal due to the concerns it identified.[322]
Final determination	The AER identified each relevant opex category in Aurora's proposal and developed a base year estimate split into these categories. Using this estimate, the AER identified divergences, and then conducted a detailed review of any divergences. The AER has amended Aurora's revised proposal based on detailed review.	The AER has amended Aurora's revised proposal to determine an estimate in accordance with clauses 6.5.6(d) and 6.12.1(4)(ii) and 6.12.3(f)(2). This estimate is based on Aurora's revised proposal so is consistent with clause 6.12.3(f)(1).

7.2.2 Aurora's concerns with the base year approach

In its revised regulatory proposal, Aurora raised concerns that the base year approach:[323]

- is inappropriate at a time when Aurora is undergoing significant structural changes
- is not a full review of Aurora's detailed opex program

322 *Application by Energy Australia and Others [2009] ACompT8*, 12 November 2009 at [253] – [257].

323 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 63–64.

- does not recognise the shared services overheads that must be allocated in accordance with Aurora's CAM..

Aurora also stated that although it did not agree with using the base year approach, if the AER continues to use the base year approach for the final determination, it should use 2010-11 as the base year, rather than 2009-10.[324]

The AER has considered each of these issues below.

Significant structural changes in operating environment

In its revised regulatory proposal, Aurora submitted that the base year approach is not an appropriate method to forecast opex when the operating environment of a distribution business is in a period of substantial change.[325] However, Aurora also notes that, provided restructuring is taken into account, the base year approach would be appropriate if the AER used 2010-11 as its base year rather than 2009-10.[326]

In 2009-10 Aurora restructured its distribution business, and in 2010-11 further restructuring resulted in a number of redundancies. These redundancies caused Aurora to draw down on its provision accounts.[327] Aurora considers the movement in provisions was significantly different in 2010-11 compared to 2009-10 and demonstrated that had the AER used 2010-11 as its base year, it would have resulted in higher opex for the forthcoming regulatory control period.[328] Aurora also considers the restructuring has meant that it has had to limit its opex during the current period. However, such levels of opex are not achievable on an ongoing basis and would impact on reliability and safety outcomes if carried forward to the forthcoming regulatory control period.[329]

Aurora considers its opex will increase in the forthcoming regulatory control period due to implementation of its distribution network ISG strategy, changes in capex programs and demand management. Aurora considers these costs amount to 'volatility' in year on year expenditure and are therefore not captured in the base year.[330]

The AER considers Aurora has not provided evidence to support its contention that current levels of opex are unsustainable. Indeed Aurora’s regulatory proposal states that significant investment in recent years has resulted in a strong and resilient distribution network, delivering a level of reliability and system security commensurate with the needs of the Tasmanian community.[331] While Aurora may have spent less than initially forecast for 2010-11 due to the distribution business restructure, it has still spent close to its opex allowance for the current regulatory period. This suggests Aurora has not significantly limited its current period opex spend.

Notwithstanding this, the AER remains unconvinced that ‘volatility’ in Aurora's operating environment renders the base year approach inappropriate. The AER uses Aurora's revealed recurrent costs as the starting point to determine the base year. However, the AER also makes adjustments for non-

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324 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.
325 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 63.
326 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.
327 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.
328 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.
329 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.
330 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.
331 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 14.

recurrent costs and new costs arising from regulatory obligations, changes in the operating environment or otherwise unaccounted for costs by adding step changes to the base year amount. The AER required Aurora to identify any step changes in its regulatory information notice (RIN) prior to lodgement of Aurora's regulatory proposal. The purpose of this is to ensure Aurora's circumstances in the forthcoming regulatory control period are appropriately reflected in the AER's base year estimate.

To this end, Aurora proposed distribution restructure costs as a step change in the current regulatory period, which the AER has factored into its base year estimate.

Further, one of the reasons that the AER's draft determination opex estimate was lower than Aurora's forecast was because Aurora failed to accurately complete its RIN template. Aurora did not identify IT system maintenance costs and software charges (resulting from the implementation of its distribution network ISG strategy) as a step change as it was required to do. The AER therefore did not fail to recognise this step change, as Aurora suggests.[332] Aurora also did not raise movements in provisions or 'volatility' in its operating environment in its regulatory proposal.

The AER considers that the base year approach is appropriate whether or not Aurora's operating environment is in a period of change, but it is reliant on Aurora providing complete and accurate information. The AER therefore sought further information from Aurora regarding its step changes and movement in provisions to estimate the appropriate opex amounts to be carried forward.

Aurora has itself based its forecast on historical information. Aurora's proposed unit rates, which form the basis of its opex forecast, are based on the unit rates Aurora currently incurs, and reflected in the current average cost of works.[333] Even though Aurora subsequently applied the three per cent efficiency factor to its unit rates, the starting point is its historical information. Although the AER's estimate is based on one year of historical costs, the AER considers the subsequent escalation of this base year and addition of step changes appropriately accounts for additional costs arising from changes in Aurora's operating environment. The approaches used by Aurora and the AER are not significantly different.

Lack of detailed review

Aurora considers that by conducting a detailed review of the 2009-10 year only, the AER's base year approach does not adequately review Aurora's detailed five year opex program.[334] The AER's approach in this final determination has been to conduct additional detailed review of categories of Aurora's opex where there are significant divergences between Aurora's forecast and the AER's base year estimate.

Shared costs

In its revised regulatory proposal, Aurora stated that the AER's base year approach fails to recognise the shared services overheads that must be allocated in accordance with the AER-approved Aurora

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332 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 63.

333 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 83.

334 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 63.

CAM.[335] For this final determination, the AER has reallocated Aurora's shared costs across its distribution services in accordance with its CAM. Shared costs are discussed further in section 7.3.7.

Choice of base year

Aurora considered that should the AER continue to utilise a base year approach to setting forecast operating expenditure, it is appropriate to use the most recent year (2010-11) as the starting position, rather than 2009-10.[336] Whilst Aurora did not explicitly reason why it was more appropriate to use 2010–11, it appears that the difference in the movements in Aurora's provision accounts in 2010-11 compared to 2009-10 is the main driver.[337] Aurora has indicated that, due to restructuring, the AER's draft determination adjustment for movement in provisions will not provide Aurora with sufficient opex to meet its provisions obligations in the forthcoming regulatory control period.[338]

The AER used 2009-10 as the base year in the draft determination primarily because Aurora did not provide audited actual data for 2010-11 in time for the AER's draft determination.[339] For this final determination, the AER has used a base year approach to identify divergences between the AER and Aurora. The AER has decided to use 2010-11 as the base year to do this for the following reasons:

1. Aurora has since provided the AER with audited actual 2010-11 data.
2. The closest year to end of the current period with actual data is likely to be the most reflective of Aurora's circumstances in the forthcoming regulatory control period.
3. In the draft determination, the AER noted that while Aurora benchmarked above its peers, it was within their range.[340] Aurora also outperformed the NSW DNSPs and Ergon Energy.[341] The subsequent detailed review of 2009-10 expenditure therefore resulted in reasonably minor adjustments to the 2009-10 base year for the AER to rely on it as a starting point. Aurora has incorporated most of the AER's findings from its draft determination detailed review of 2009-10 opex into its 2010-11 base year model and revised opex forecast. The AER has found that (excluding the impact of movement in provisions) the total base year amounts for both 2009-10 and 2010-11 are very similar.
4. Aurora has indicated that the provisions opex amount for 2010-11 is more reflective of the amount Aurora will require to meet its obligations in the forthcoming regulatory control period than the amount in 2009-10.[342]

The AER's 2010–11 base year estimate is discussed in section 7.3.3.

7.3 Reasons for determination

This section outlines how applying the assessment approach outlined above has led the AER to:

- not being satisfied that Aurora's revised forecast opex reasonably reflects the opex criteria, and

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335 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.
336 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.
337 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.
338 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64; Aurora, *Response to information request AER/059 of 7 February 2012*, received 16 February 2012.
339 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 168.
340 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 166.
341 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 328.
342 Aurora, *Response to information request AER/059 of 7 February 2012*, received 16 February 2012.

- estimate a substitute forecast opex on the basis of Aurora's revised forecast opex, and amending it to the extent necessary to approve it in accordance with the NER.

The primary concern the AER has with Aurora's revised total forecast opex is that it is higher than its initial opex forecast. The Energy Users Association of Australia (EUAA) raised the same concern in its submission on Aurora's revised regulatory proposal.[343] To identify the cause of the increase, the AER has reviewed Aurora's revised regulatory proposal and developed a 2010–11 base year estimate to compare with Aurora's revised opex forecast. The AER has identified the issues in Table 7.3, which form the basis of its amendments to Aurora's forecast. Section 7.3.3 contains further detail of this review. The AER has considered each issue in Table 7.3 in the sections that follow.

Table 7.3 AER adjustments to Aurora's revised forecast opex ($million, 2009–10)

Issue	Amount
Unit rates—removal of three per cent efficiency factor	-3.9
Labour cost escalation—change in approach to calculating forecast	0.9
IT systems opex	-7.5
Demand management opex	-0.6
Reallocation of shared costs	1.7

Note: Amendments arising from escalation and shared cost reallocation are dependent on other modelling. They are therefore approximate only.

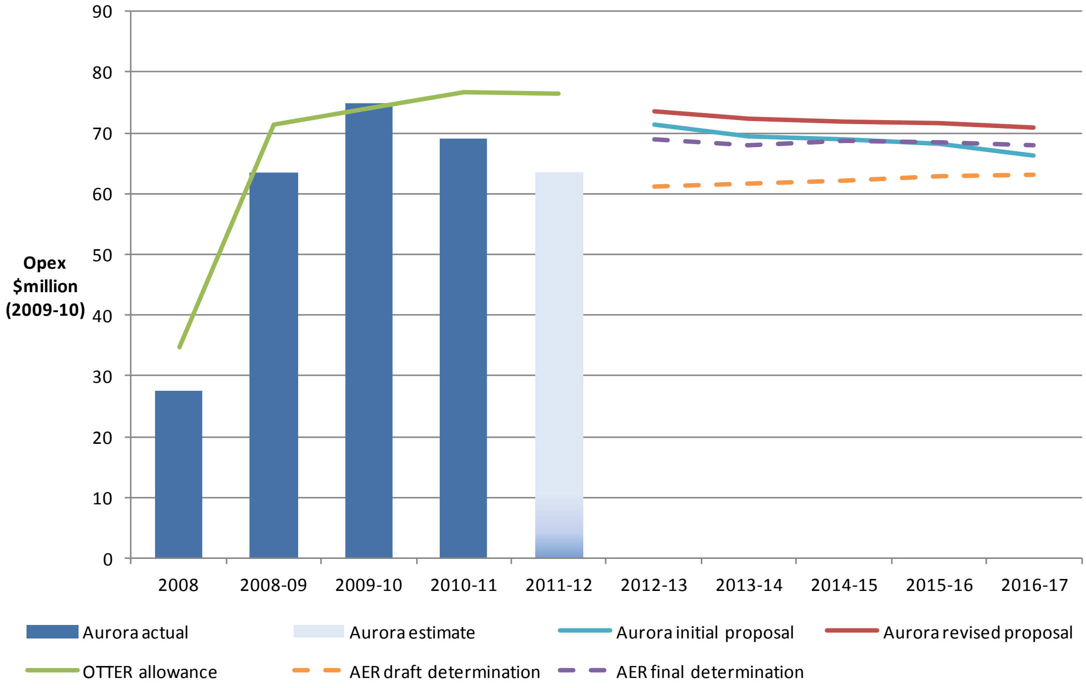
In addition to the AER's amendments, Aurora made some of its own adjustments since it submitted its revised regulatory proposal. These adjustments are for:

- revised IT opex requirements[344]
- correction of errors relating to vegetation management opex.[345]

Aurora's adjustments have resulted in further reductions to its revised total forecast opex of $8.7 million ($2009–10). Figure 7.2 compares the difference in opex forecasts from Aurora's initial regulatory proposal through to the AER's final determination.

343 EUAA, *Submission to the AER on its draft distribution for Aurora Energy, and Aurora's Energy's revised proposal*, February 2012, pp. iii, 17–18.
344 Aurora, *Email response to follow up request to AER/065 of 29 February 2012*, received 29 February 2012.
345 Aurora, *Response to information request AER/059 of 7 February 2012*, received 16 February 2012.

Figure 7.2 Comparison of Aurora's opex forecasts and the AER's estimates ($million, 2009–10)



Source: AER analysis.

Aurora did not contest all aspects of the AER's draft determination in relation to the opex forecast. The uncontested issues are summarised below.

7.3.2 Uncontested issues

Whilst Aurora did not accept the AER's draft determination in respect of the total opex forecast:

- Aurora accepted the AER's methodology to calculate a benchmark debt raising cost allowance.[346] Debt raising costs are discussed in section 7.3.8.
- Aurora did not raise any concern with the AER's use of real cost escalation and scale escalation to adjust the base year for changes in inputs and network growth. The AER has therefore continued to apply real cost escalation and scale escalation using the same approaches as the draft determination.[347]
- Aurora also did not raise any concern with the AER's treatment of non-recurrent costs, with the exception of movement in provisions. Movement in provisions is discussed in section 7.3.3.[348]

Aurora also stated that it had factored some of the AER's draft determination detailed review findings into its revised opex forecast.[349] The AER has confirmed that Aurora's revised opex forecast has incorporated the AER's findings for:[350]

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[346] Aurora, *Response to information request AER/056 of 31 January 2012*, received 1 February 2012, p. 3.
[347] Aurora, *Revised regulatory proposal 2012-17*, January 2012, p. 64.
[348] Aurora, *Revised regulatory proposal 2012-17*, January 2012, p. 64.
[349] Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.

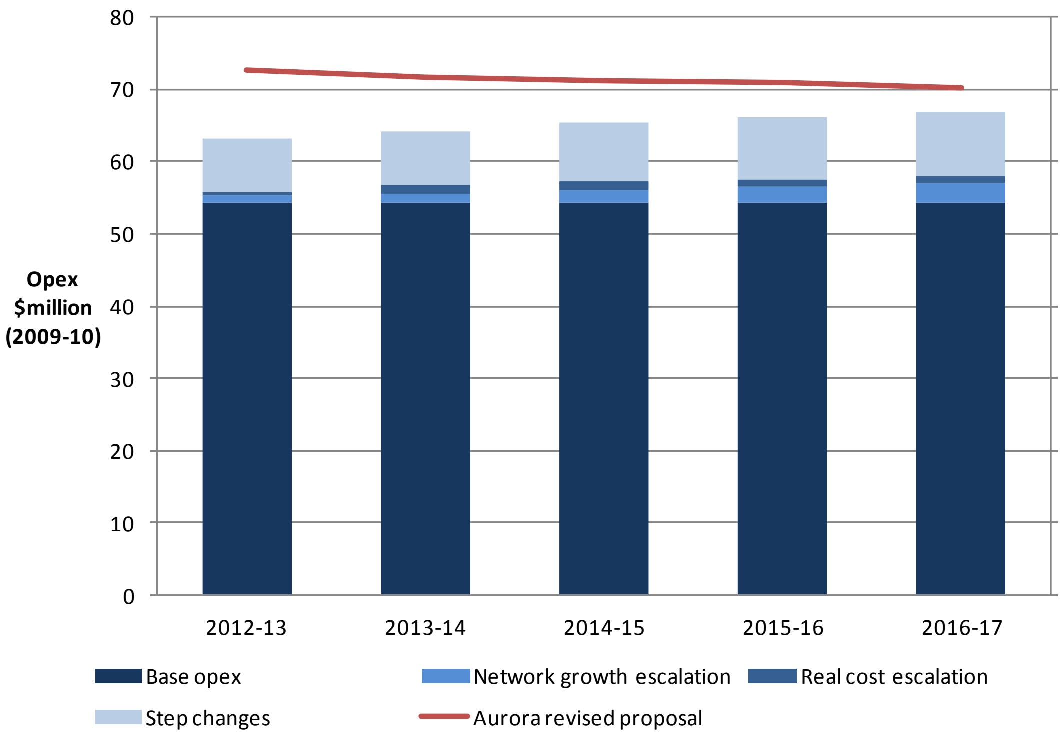
- GSL payments
- emergency and unscheduled power system response and repair
- vegetation management.

The AER considers the vegetation management allowance provided in its draft determination is appropriate in Aurora's current circumstances. However, the AER expects that Aurora's regulatory proposal for the 2017–24 regulatory control period will reflect lower cost best practice vegetation management as has been adopted by DNSPs in other jurisdictions.

7.3.3 Identification of areas of divergence between the AER and Aurora

As the starting point for its review, the AER developed a base year estimate, using 2010–11 as the base year. The AER's base year estimate is displayed in Figure 7.3.

Figure 7.3 AER's 2010–11 base year estimate ($million, 2009–10)



Source: AER analysis.

The AER calculated its 2010–11 base year estimate using the same approach as in the draft determination.[351] That is, it removed non-recurrent costs from the base year, escalated the base year for network growth and real cost escalation, and then added step changes. In this final determination, the AER has therefore discussed its base year estimate only to the extent that it differs from the draft determination. The differences are that the AER:

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[350] Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 68–71.

[351] AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 158–160.

- used 2010–11 as the base year rather than 2009–10
- accepted Aurora's 2010–11 movement in provisions as the base line opex requirement
- accepted most of Aurora's incorporation of the AER's draft determination detailed review findings
- accepted Aurora's revised scale escalation drivers
- removed the effect of changes in approach to real cost escalation and unit rates.

The AER developed the base year estimate using 2010–11 as the base year as a means of identifying areas of divergence with Aurora's revised opex forecast. The AER considers that at the total level, ignoring the impact of movement in provisions, the AER's 2010–11 base year is comparable to its draft determination 2009–10 base year estimate. The differences between the AER's draft determination 2009–10 base year estimate and its 2010–11 final determination estimate are discussed below.

Movement in provisions

The AER has accepted Aurora's 2010–11 movement in provisions as the opex required in each year of the forthcoming regulatory control period, and incorporated this amount into its 2010–11 base year estimate.

Movement in provisions was a key issue raised by Aurora in its revised regulatory proposal. The AER's base year approach impacts the movement in provisions and the amount of opex that Aurora receives as a result.[352]

In the draft determination, the AER reversed the movement in provisions for 2009–10 to estimate the base amount of opex Aurora would incur in each year of the forthcoming regulatory control period.[353] The AER considered this approach produced a base level of expenditure suitable for regulatory purposes.[354] However, the reversal resulted in decreased base year opex because Aurora increased the amount in its provision accounts in 2009–10 due to its energy and distribution businesses restructure.[355]

Aurora's revised regulatory proposal explained that if the AER used 2010–11 as the base year (rather than 2009–10), Aurora's opex would increase as a result of movements in provisions.[356] In 2010–11, separation of staff meant Aurora had to 'call on' the provisions, reducing the amount in its provision accounts. To demonstrate, Aurora replicated the AER's 2009–10 base year forecast using 2010–11 as the base year.[357]

The AER requested Aurora clarify whether the provisions amount in Aurora’s 2010–11 base year forecast reflected the best estimate of the opex that Aurora is seeking to recover in each year of the forthcoming regulatory control period. Aurora confirmed its 2010–11 amount reflects the recurring amount. Due to its ageing workforce, Aurora anticipates accelerated separation and provision

352 Aurora, *Revised regulatory proposal 2012-17*, January 2012, p. 64.
353 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 180.
354 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 180.
355 Aurora, *Revised regulatory proposal 2012-17*, January 2012, p. 64.
356 Aurora, *Revised regulatory proposal 2012-17*, January 2012, p. 64.
357 Aurora, *Revised regulatory proposal 2012-17*, January 2012, p. 63; Attachment AE147 (confidential).

drawdown to occur over the period.[358] Aurora pointed to its most recent annual report to support this statement, which the AER has verified.[359]

The AER acknowledges the movement in provisions has been volatile in the current regulatory period, given Aurora's recent restructuring. So, an historical average of such data may not reflect Aurora's requirements in the forthcoming regulatory control period. The AER also recognises the high proportion of Aurora's workforce aged over 51 years is likely to result in Aurora having to draw down on provisions (and incur opex) to pay out entitlements when staff separate from the business.

Incorporation of draft determination detailed review

Aurora provided its own 2010–11 base year estimate as an attachment to its revised regulatory proposal.[360] This estimate mostly incorporated the AER's findings from its draft determination detailed review of categories of Aurora's 2009–10 opex that showed material increases compared to the historical average.[361] Aurora's estimate did not wholly incorporate the AER's findings for network management expenditure. However, for the reasons below, the AER is largely satisfied that Aurora's changes to network management expenditure can be incorporated into the AER's 2010–11 base year estimate.

In the draft determination, the AER considered a reduction to Aurora's 2009–10 actual costs for network management expenditure was required to reflect the restructuring of network management services staff in 2010–11.[362] This reduction was to scale the 2009–10 actual opex by the ratio of staffing levels before and after the restructure.

Aurora's 2010–11 base year model adopted these findings to the extent Aurora considered it necessary to adjust actual 2010–11 costs to reflect recurrent levels of opex.[363] Aurora used the same approach as the AER to further proportionately reduce the 2010–11 actual costs of by the number of additional staff who separated from the business between 2010–11 and 2011–12. This reduction is lower than the AER's adjustment to 2009–10 actual costs because the change in staffing levels in 2011–12 was significantly less than in 2010–11.[364] The AER considers this approach is reasonable.

However, Aurora split its adjustment between capex and opex. The AER considers Aurora has erred in doing so, because the draft determination adjustment was to opex only. The AER has therefore incorporated Aurora's adjustment in its 2010–11 base year estimate, but has applied the whole adjustment to opex.

Aurora also did not incorporate the AER's draft determination adjustment for the subcontractor component of network management expenditure. The AER has not accepted this change as it considers its draft determination findings are the recurrent levels. Aurora has not explained why it did not incorporate these findings or what concerns it had with them.

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358 Aurora, *Response to information request AER/059 of 7 February 2012*, received 16 February 2012; Aurora, *Response to information request AER/066 of 22 February 2012*, received 29 February 2012.

359 Aurora, *2010-11 Aurora Energy Annual Report*, p. 56.

360 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE147 (confidential).

361 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 168.

362 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 169.

363 Aurora, *Response to information request AER/059 of 7 February 2012*, received 16 February 2012.

364 In 2010–11, 16 staff separated from Aurora, and in 2011–12 a further four staff separated.

Updated scale escalation drivers

In attachment AE147 to its revised regulatory proposal, Aurora updated forecast values for the line length and distribution transformers network growth drivers to provide more accurate data.[365] Aurora identified an error in its actual 2009–10 line length data, and the correction resulted in a slight decrease in forecast line length in each year.[366] Aurora also updated its distribution transformer forecasts to reflect ACIL Tasman's 2012 forecast of customer numbers.[367] Aurora forecast distribution transformers based on customer growth due to a strong correlation between them. Aurora's initial forecast of distribution transformer numbers was based on ACIL Tasman's 2011 customer number forecast, which the AER did not accept in its draft determination.[368] Aurora accepted the AER's draft determination customer number forecasts (see attachment 5).

Having considered Aurora's justification documentation[369], the AER is satisfied that Aurora's revised network growth drivers reasonably reflect a realistic expectation of Aurora's demand forecasts, and has incorporated them into its base year estimate.[370] However, the AER considers that Aurora should have submitted this justification documentation with its revised regulatory proposal. Although Aurora did not propose a base year forecast, it provided a base year model as an attachment to its revised proposal to demonstrate its concerns with the AER's draft determination.[371] The network growth drivers are inputs to this model, and Aurora did not explain why they had changed.

Real cost escalation and unit rates

For its revised opex forecast, Aurora removed the three per cent efficiency factor from its unit rates and changed its approach to forecast labour cost escalation. The AER has not accepted these revisions because clause 6.10.3(b) of the NER does not allow them. Therefore, for comparative purposes, the AER has:

- applied Aurora's revised proposal real cost escalation to its base year estimate
- required Aurora to provide an updated revised total forecast opex that included the three percent efficiency factor in its unit rates.[372] The result is that the amounts in Table 7.4 under 'Aurora revised proposal' include the three per cent efficiency factor.

This negates the impact of Aurora's revisions to its unit rates and labour cost escalation. Section 7.3.4 contains further detail of the AER's reasons for not allowing Aurora's changes to labour cost escalation and unit rates.

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365 Aurora, *Scale estimation forecast update justification*, Attachment to *Response to information request AER/069 of 28 February 2012*, received 29 February 2012.

366 Aurora, *Scale estimation forecast update justification*, Attachment to *Response to information request AER/069 of 28 February 2012*, received 29 February 2012.

367 Aurora, *Scale estimation forecast update justification*, Attachment to *Response to information request AER/069 of 28 February 2012*, received 29 February 2012.

368 Aurora, *Scale estimation forecast update justification*, Attachment to *Response to information request AER/069 of 28 February 2012*, received 29 February 2012.

369 Aurora, *Scale estimation forecast update justification*, Attachment to *Response to information request AER/069 of 28 February 2012*, received 29 February 2012.

370 NER, clause 6.5.6(c)(3).

371 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE147 (confidential).

372 AER, *Information request AER/066 of 22 February 2012* and follow up request of 13 March 2012. Aurora's response of 29 February 2012 contained errors so the AER issued the follow up request.

Areas of divergence

To identify the areas of divergence the AER split its 2010–11 base year estimate into Aurora's proposed opex categories. The AER then compared this split base year estimate with Aurora's revised opex. Table 7.4 summarises this comparison.

Table 7.4 Comparison of Aurora's forecast and AER's 2010–11 base year estimate by opex category ($million, 2009–10)

	Aurora revised proposal	AER base year	Difference
Operating costs			
Network management	83.3	80.6	2.7
Non-network management	58.0	62.5	-4.5
Operating costs-other	18.5	4.5	14.0
Maintenance costs			
Routine maintenance	84.1	79.1	4.9
Non-routine maintenance	99.3	96.2	3.0
Demand management			
Demand management	3.3	2.7	0.6
Total	**346.5**	**325.7**	**20.7**

Source: AER analysis.

Table 7.4 demonstrates that (excluding unit rates and labour cost escalation), the key area of divergence between the AER's 2010–11 base year estimate and Aurora's revised regulatory proposal is in the category of 'operating costs–other'. Therefore, the AER conducted a detailed review of this category and has discussed its findings in section 7.3.5.

The AER has not reviewed the demand management category in detail because its position has not changed from the draft determination. The impact of demand management on Aurora's revised regulatory proposal is discussed in section 7.3.6.

The AER is not concerned with the differences in the other categories as they have an immaterial impact on the total forecast opex. Aurora also explained that minor changes to some expenditure categories have resulted from overhead reallocation.[373] The AER has not undertaken further detailed review of these categories.

Aurora's revised unit costs and labour cost escalation are the other two key areas of divergence between the AER and Aurora. Table 7.4 does not capture these divergences because the AER removed their impact for comparative purposes. They are discussed below.

373 Aurora, *Response to information request AER/076 of 14 March 2012*, received 15 March 2012.

7.3.4 Aurora's revised labour cost escalation and unit rates

Since the draft determination, Aurora has changed its opex forecast approaches in relation to labour cost escalation and unit rates. For the reasons that follow, the AER does not accept these changed approaches.

Aurora stated in its revised regulatory proposal that the AER rejected Aurora's CPI-only escalation of labour costs, and Aurora's proposed three per cent efficiency adjustment to labour rates within its unit rates.[374] On this assumption, Aurora revised its labour cost escalation approach and removed the three per cent efficiency factor from its unit rates. The AER did not require these revisions and considers they amount to more than 'amending to reflect more up-to-date data sets'.[375]

In the draft determination, the AER did observe that Aurora's labour cost escalation approach was not the AER's preferred approach.[376] However, the AER accepted Aurora's real cost escalation for opex. The AER was satisfied that on balance, the impact of real cost escalators applied by Aurora on forecast opex reasonably reflected a realistic expectation of labour and materials cost increases over the forthcoming regulatory control period.[377] Therefore, for this final determination, the AER has continued to escalate Aurora's labour costs by CPI. This has resulted in a slight increase to Aurora's revised total forecast opex of approximately $0.9 million. Real cost escalation is discussed further in attachment 4.

For unit rates, in the draft determination, the AER considered it was unable to form a view about Aurora's three per cent efficiency factor due to a lack of substantiation.[378] However, the AER did not reject Aurora's unit rates or the efficiency factor. The AER applied a base year approach to estimate its substitute opex forecast which did not involve applying Aurora's unit rates. The AER recognises that it explicitly stated that it accepted Aurora's unit rates for capex and alternative control services, but did not state this for Aurora's opex unit rates.[379] However, to assume that the AER also rejected Aurora's opex unit rates is incorrect. For this final determination, the AER has assessed Aurora's opex with the three per cent efficiency factor included in the unit rates. This has resulted in a reduction of $3.9 million to Aurora's revised total forecast opex. Unit rates are discussed in further detail in attachment 3.

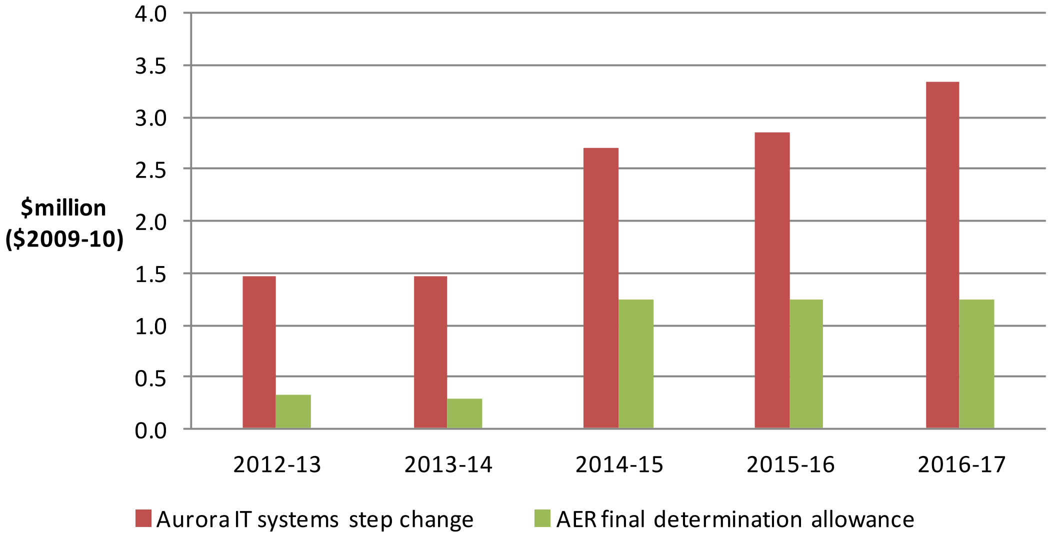
7.3.5 Detailed review of the Operating costs–other category

In its revised regulatory proposal, Aurora submitted that the AER's draft determination had not recognised a step change relating to IT system maintenance and software fees.[380] The AER notes that Aurora did not properly identify this opex as a step change in the RIN templates it was required to provide to the AER as part of its regulatory proposal. As such the AER did not review it for its draft

374 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 75, 80, 83.
375 Aurora, *Revised regulatory proposal 2012-17*, p. 65.
376 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 96.
377 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 96–97.
378 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 158.
379 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 96.
380 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 63.

determination. Aurora's revised forecast amount for its IT systems step change is $11.8 million.[381] Figure 7.4 compares the AER's final determination allowance with Aurora's revised forecast.

Figure 7.4 AER final determination allowance for Aurora's IT systems step change ($million, 2009–10)



Source: AER analysis.

The AER has subsequently reviewed Aurora's proposed opex step change for IT system maintenance and software fees (IT systems) and considers $4.3 million reasonably reflects the efficient costs that a prudent DNSP in Aurora's circumstances would require to achieve the opex objectives over the forthcoming regulatory control period. Table 7.5 presents the AER's final determination on Aurora's IT systems allowance.

Table 7.5 AER's final determination on IT systems allowance ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
IT Systems	0.3	0.3	1.2	1.2	1.2	4.3

Source: AER analysis.

The AER's amendments to Aurora's IT systems opex results in a reduction of $7.5 million to Aurora's revised total forecast opex.

The proposed IT systems step change relates to the implementation of Aurora's Network IT Strategy to deliver future benefits.[382] Aurora's current IT system consists of a large number of relatively discrete

[381] Aurora's revised program of work initially forecast an amount of $15.9 million for this step change, but Aurora subsequently submitted the revised figure. Aurora, *Email response to follow up request to AER/065 of 29 February 2012*, received 29 February 2012.

[382] Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 63.

systems.[383] The AER considers it reasonable to move to a more unified new generation information system platform (tier one platform) to deliver these future benefits.

The AER reviewed each component of the IT systems step change. A number of projects within the IT systems proposal are for expenditure already being incurred.[384] If this expenditure is considered to continue at a recurrent level, it has not been considered as a step change. These costs are already considered to be part of Aurora's recurrent opex. Therefore the AER has only reviewed new or increased expenditures. In summary, the AER does not accept Aurora's proposal for expenditures relating to:

- market interfaces
- tariff modelling
- customer case management
- SMS Hub.

The AER accepts an increase in forecast expenditure relating to the following, but at a reduced level:

- backend systems
- network modelling and simulation tool.

The AER accepts Aurora's proposal for expenditure relating to demand management systems (DMS) and systems control and data acquisition (SCADA).

The AER does not accept the proposed step changes for market interfaces, tariff modelling and customer case management on the same basis. Aurora proposed these opex costs as a proportion of its IT capital program for software and licence fees.[385] However, the AER's review of the IT capital program identified that the program development is being undertaken with internal labour (and a small amount of external labour), and not through the purchase of external software. As such, there are no additional software costs associated with these activities. In the absence of these software purchase costs, it is not reasonable to apply a software licencing cost as there is no software to licence.[386] This finding is supported by information in Aurora's technology roadmap cost model.[387] The AER considers these proposed costs do not reasonably reflect the efficient costs that a prudent DNSP in Aurora's circumstances would require to achieve the opex objectives over the forthcoming regulatory control period. The AER therefore does not accept them.

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383 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 56–57.

384 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 55-56.

385 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 61–63, 64–66.

386 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 61–63, 64–66.

387 Aurora, *Technology roadmap cost model* (confidential).

The AER also does not accept the proposed SMS Hub component of this step change. The SMS Hub costs relate to IT system functionality for the purposes of distribution customer messaging.[388] The AER considers that although Aurora has identified some potential benefit associated with the proposed SMS hub, it has not reasonably shown that the benefits outweigh the proposed costs.[389] In particular the AER considers: [390]

- the SMS Hub is supplementary to the current system functionality
- the type of functionality proposed is beyond that implemented by DNSPs in other jurisdictions
- it is not necessary for the move to a tier one platform.

The AER therefore considers this expenditure does not reasonably reflect the efficient costs that a prudent DNSP in Aurora's circumstances would require to achieve the opex objectives over the forthcoming regulatory control period.

The AER accepts an increase in forecast expenditure on the backend systems component of this step change. But it does not accept Aurora's proposed forecast amount, and subsequently provided a reduced allowance. These costs relate to software and licence fees for a software package that collects, displays and reports time series data.[391] The AER recognises this is consistent with a move to a tier one platform. It considers that the proposed administration and support costs reasonably reflect the efficient costs that a prudent DNSP in Aurora's circumstances would require to achieve the opex objectives over the forthcoming regulatory control period.[392] However, the AER does not consider all of the licence fees are reasonable so has not accepted a minor portion of these costs.[393]

The AER also accepts an increase in forecast expenditure for Aurora's proposed network modelling and simulation tool.[394] The proposed costs are to replace the current network modelling and simulation tool (DINIS) that is being retired. However, Aurora did not remove the existing costs of DINIS from its forecast. Since this product is being retired, these costs will no longer be required. The AER has therefore adjusted Aurora's forecast accordingly, but allowed DINIS costs for the first year of the forthcoming regulatory control period. This will enable Aurora to transition from DINIS to the new tool.[395] The AER considers these reduced costs reasonably reflect the efficient costs a prudent DNSP in Aurora's circumstances would require to achieve the opex objectives over the forthcoming regulatory control period.

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388 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 59–60.

389 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 59–60.

390 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 59–60.

391 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 60–61.

392 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 60–61.

393 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 60–61.

394 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 57–58.

395 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 57–58.

The AER accepts the additional cost components relating to DMS and SCADA for the IT systems step change. These costs relate to upgrades required for the real time management, monitoring and control of an electrical distribution network. The AER considers the proposed costs are reasonable and required for a move to a tier one platform.[396] Based on its review, the AER considers these costs reasonably reflect the efficient costs that a prudent DNSP in Aurora's circumstances would require to achieve the opex objectives over the forthcoming regulatory control period.

7.3.6 Demand management opex

Aurora's revised regulatory proposal did not respond to the AER's draft determination for demand management opex. Instead, Aurora resubmitted its initial proposal of $3.3 million.[397] In its draft determination, the AER considered certain studies proposed by Aurora should be funded through the DMIA. Since Aurora did not provide any explanation or additional material to explain its departure from the AER's draft determination, the AER maintains the conclusion it arrived at in the draft determination. This results in a reduction to Aurora's revised total forecast opex of $0.6 million. Demand management opex is discussed in section 6.4.3 of attachment 6 to the AER's draft determination.[398]

7.3.7 Reallocation of shared costs

The AER has reallocated Aurora's shared costs across Aurora's distribution services in accordance with Aurora's CAM. Table 7.6 presents the final allocation of shared costs.

Table 7.6 AER final determination of shared costs, escalated ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Standard control - capex	30.7	31.7	29.3	26.6	26.5	144.8
Standard control - opex	38	37.4	37.6	37.6	37.2	187.8
Alternative control - metering	5.2	4.9	5.0	5.0	5.0	25.1
Alternative control - public lighting	3.1	3.0	3.0	2.7	2.6	14.4
Alternative control - fee based services	5.0	5.0	5.0	5.0	4.9	24.9
Alternative control - quoted services	1.6	1.5	1.5	1.4	1.5	7.5

Source: AER analysis.

In its draft determination, the AER did not separate shared costs for opex from its base year forecast.[399] This was because shared costs were included in its build up of base year costs.

Aurora did not adjust the total quantum of shared costs in its revised regulatory proposal, but it did reallocate these costs. Aurora submitted that the AER's inclusion of shared costs in its base year approach for standard control opex is inappropriate. Aurora considered this treatment assumes the

396 Nuttall Consulting, *Aurora electricity distribution revenue review–revised proposal: A report to the AER*, April 2012, pp. 63–64.

397 Aurora, *Revised regulatory proposal 2012-17*, January 2012, p. 72, Aurora, *Response to information request AER/055 of 25 January 2012*, received 1 February 2012.

398 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 181-183.

399 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 186.

allocation of these costs occur in the 'same quantum' year on year and does not accurately account for the expenditure that is required over the forecast.[400] Aurora considered this treatment created a misallocation of these costs across all of Aurora's services.[401] Aurora reallocated its shared costs in accordance with its revised expenditure programs.[402]

The AER accepted the amount of shared costs for Alternative Control Services and Capex in its draft determination. This was not contested by Aurora or other stakeholders. Consequently, the AER has upheld this in its final determination.

The AER has accepted Aurora's forecast of shared costs for opex in its revised proposal. These costs were incorporated into Aurora's forecast opex costs covered in the AER's detailed review. Aurora did not remove any of the efficiency adjustment to labour rates from these costs. Further, these shared costs were not included as part of its IT step change cost that the AER amended.

Although the AER accepts the total amount of shared costs, it has reallocated these shared costs across service classifications. This is in accordance with the approach applied by Aurora in its revised regulatory proposal.[403] The AER has used all of the allocators from Aurora's CAM apart from Aurora's direct labour hours allocator. The AER has used the previous proportion of direct costs as the allocator for these shared costs instead of the labour hours escalator. The labour hours for projects will not have changed. As such, the direct costs will reflect the allocation of shared costs across services based upon the labour hours.

The AER's reallocation of shared costs has resulted in a moderate increase to Aurora's total forecast opex of approximately $1.7 million over the forthcoming regulatory control period.

7.3.8 Debt raising costs

The AER has determined a benchmark debt raising cost allowance of $3.9 million for Aurora. Table 7.7 shows the annual allowance.

Table 7.7 AER's final determination on debt raising costs ($million, 2009–10)

Unit rate	2012-13	2013-14	2014-15	2015-16	2016-17	Total
9.6 basis points per year	0.8	0.8	0.8	0.8	0.8	3.9

Source: AER analysis

The AER's draft determination applied updated unit cost inputs to its method for determining benchmark debt raising costs and determined the total debt raising cost allowance for Aurora based on the debt component of the RAB. Some of the unit costs depend on the WACC. The AER updated those unit costs to reflect the WACC for this final determination. The AER has also adjusted Aurora's RAB value since the draft determination (see attachment 8). As a result, while the debt component of the RAB has changed, Aurora is still required to raise four standard sized bond issues. Table 7.8 shows the unit costs and the resulting total unit cost of 9.6 basis points per year based on the required four bond issues for this final determination.

400 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.
401 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 64.
402 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 47, 64.
403 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 47.

Table 7.8 AER's (unit) debt raising cost for Aurora based on a nominal WACC of 8.28 per cent

Fee	Explanation	One issue	Two issues	Four issues
Amount raised ($million, 2011-12)	Multiples of median MTN ($250 million)	250	500	1000
Gross underwriting fee	Median gross underwriting spread upfront per issue amortised	6.79	6.79	6.79
Legal and road show	$195,000 upfront per issue, amortised	1.18	1.18	1.18
Company credit rating	$55,000 per year	2.20	1.10	0.55
Issue credit rating	4.5 basis points upfront per issue, amortised	0.68	0.68	0.68
Registry fees (initial)	$4,000 upfront per issue, amortised	0.02	0.02	0.02
Registry fees (annual) (previously labelled Paying Fees)	$9,000 per issue per year	0.36	0.36	0.36
Total	Basis points per year	11.2	10.1	9.6

Source: AER analysis

The AER provides for a forecast benchmark of debt raising costs for Aurora. To avoid double counting of debt raising costs in the forthcoming regulatory control period, the AER made an adjustment to remove actual costs from its opex base year when forecasting opex.

The AER considers the benchmark debt raising unit cost of 9.6 basis points per year reflects efficient and prudent costs for current market conditions and it applied this value when estimating Aurora's allowance for debt raising costs. This benchmark multiplied by the debt component of Aurora's RAB results in a total allowance of $3.9 million (2009–10) for debt raising costs.

7.4 Revisions

Revision 7.1: The AER has revised Aurora's total forecast opex for the forthcoming regulatory control period by $18.5 million. The AER's estimate is $341.9 million.

8 Regulatory asset base

The AER is required to make a decision on Aurora's opening regulatory asset base (RAB) at the commencement of the forthcoming regulatory control period.[404] This attachment presents the determination of the opening RAB as at 1 July 2012 and the treatment of depreciation to roll forward the RAB over the forthcoming regulatory control period.[405]

8.1 Determination

The AER has determined the opening RAB as at 1 July 2012 to be $1445.2 million ($nominal). This differs from Aurora's revised proposal due to differences in indexation and treatment of spares. Also, the forecast roll forward of the RAB over the forthcoming regulatory control period differs from Aurora's due to differences in indexation, depreciation and forecast capex.[406] The AER forecasts the RAB to be $1,750.4 million by 30 June 2017.

The AER's roll forward of the RAB from the final year (2006–07) of the previous regulatory control period through to the end of the current regulatory control period, which establishes the opening RAB value for the forthcoming regulatory control period, is shown in table 8.1. The AER's forecast roll forward of the RAB during the forthcoming regulatory control period is shown in table 8.2.

Table 8.1 AER conclusion on Aurora's RAB for the current regulatory control period ($million, nominal)

	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12[a]
Opening RAB	908.2	984.1	1,066.0	1,176.2	1,276.4	1,379.5
Capital expenditure[b]	111.7	105.0	130.7	144.0	138.8	140.5
CPI indexation on opening RAB		29.1	39.3	24.8	33.8	42.8
Straight-line depreciation[c]	–35.8[d]	–52.3	–59.8	–68.6	–69.5	–71.9
Closing RAB	984.1	1,066.0	1,176.2	1,276.4	1,379.5	1,490.8
Difference between forecast and actual capex (1 July 2006 to 30 June 2007)						–21.8
Return on difference for 2006–07 capex						–11.5
Adjustment for shared assets						–12.2
Opening RAB as at 1 July 2012						1,445.2

Source: AER analysis.
(a) Based on estimated capex. An update for actual capex will be made at the next reset.
(b) Net of disposals and capital contributions, and adjusted for actual CPI and WACC.
(c) Adjusted for actual CPI.
(d) Represents the forecast regulatory depreciation allowance from OTTER. Differences between forecast and actual depreciation are effectively picked up in the end of period adjustments.

404 NER, clause 6.12.1(6).
405 NER, clause 6.12.1(18).
406 The treatment of spare parts also has a marginal impact.

Table 8.2 AER conclusion on Aurora's RAB for the forthcoming regulatory control period ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17
Opening RAB	1,445.2	1,505.3	1,566.0	1,624.6	1,686.1
Capital expenditure[a]	105.9	112.1	107.4	104.1	107.0
Inflation indexation on opening RAB	37.6	39.1	40.7	42.2	43.8
Straight-line depreciation	–83.4	–90.5	–89.5	–84.9	–86.6
Closing RAB	1,505.3	1,566.0	1,624.6	1,686.1	1,750.4

(a) Net of disposals and capital contributions. In accordance with the timing assumptions of the PTRM, the capex includes a half-WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes.

The AER accepted Aurora's proposed approach to use depreciation based on actual capex for the purpose of rolling forward the RAB to establish the opening RAB at the beginning of the 2017–22 regulatory control period. However, due to timing, a forecast capex amount is to be used for the final year of the next regulatory control period.

8.2 Assessment approach

There have been no changes to the assessment approach from that outlined in the draft determination.[407] Accordingly, that discussion is not repeated here.

8.3 Reasons

This section sets out the AER's final decision on Aurora's opening RAB as at 1 July 2012. The AER provides its consideration of issues raised in Aurora's revised proposal, which include the treatments of provisions, CPI indexation in the RAB roll forward and the depreciation approach to roll forward the RAB for the 2017–22 regulatory control period. The AER identifies an issue with the treatment of spares, which impact on the RAB roll forward. The AER also sets out its forecast of Aurora's closing RAB as at 30 June 2017resulting from input changes to the post-tax revenue model (PTRM) for the forthcoming regulatory control period, as outlined below.

8.3.1 Opening RAB as at 1 July 2012

The AER does not accept Aurora's revised proposed opening RAB as at 1 July 2012 and has determined the RAB to be $1445.2 million. The AER has made input changes to the revised Roll Forward Model (RFM) submitted by Aurora. These changes relate to the indexation approach to account for inflation and the treatment of spare parts. The indexation adjustment is discussed in section 8.3.3, and the treatment of spares is discussed in section 8.3.4.

The AER accepted Aurora's proposed RAB as at 1 July 2006 of $908.2 million in the draft determination. However, the AER made various adjustments in its draft determination to the roll forward for differences in indexation and the treatment of provisions. The AER also noted that the

[407] AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp.195-196.

forecast capex amounts for 2010–11 and 2011–12 would need to be updated for the final determination.

In its revised proposal, Aurora updated its forecast capex for 2010–11 with actual capex in the RFM. However, Aurora did not revise the forecast capex for 2011–12 in the RFM. Aurora also rejected the AER's adjustment for indexation and made adjustments to its provisions accounts.

The AER accepts Aurora's actual capex for 2010–11. These figures were checked against accounting information supplied by Aurora. It also accepts Aurora's revised proposal not to revise the forecast capex for 2011–12. In this regard, the AER considers the forecast capex amounts appear reasonable.[408] The financial impact of any difference between actual and forecast capex for 2011–12 will be accounted for at the next reset.

The AER also accepts the revisions made by Aurora to the treatment of provision, although this matter does provide Aurora with a benefit. This issue is discussed in section 8.3.2.

8.3.2 Treatment of provisions

The AER accepts Aurora's proposed adjustment to the RAB for net movement in capitalised provisions. This has the effect of adding $2.2 million to Aurora's opening RAB.

The AER removed the net movement in capitalised provisions from the RAB in the draft determination. The AER's reasons for doing this were explained in that determination.[409]

Aurora has agreed to the AER's approach to adjusting the RAB for provisions.[410] However, it stated that only half a year's movement in provisions needs to be removed for the first year, as the regulatory year was only half a year. Aurora also identified an error in the allocation of its provision accounts for the current regulatory control period.[411] The revised net movement in capitalised provisions are set out in table 8.3.[412] Aurora calculated the net movement in provisions, rather than reducing the RAB, would increase it by $2.2 million.[413]

Table 8.3 Movement in provisions – capex ($million, nominal)

	2007–08	2008–09	2009–10	2010–11	2011–12
Net movement in provisions – capex	0.1	0.1	0.5	–0.8	–1.9

Source: Aurora, *Updated AE148–Provision model,* January 2012.

The AER agrees with Aurora that only half a year's movement in provisions needs to be applied to the 2007–08 regulatory year, given that year commenced on 1 January 2008 (not 1 July 2007) and finished on 30 June 2008. The AER also accepts the correction (and update) made by Aurora for the error it identified in the allocation of its provisions accounts.

408 Similarly, the AER accepts the revised disposals and capital contributions for 2010–11 that have been updated for actuals. Forecast disposals for 2011-12 were also revised and appear reasonable.

409 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp.197-201.

410 Aurora, *Revised regulatory proposal* 2012–17, January 2012, p.86.

411 Aurora, *Revised regulatory proposal*, January 2012, p.86.

412 Figures based on updated provision model. Aurora, Response to AER 062 - Provisions and shared assets allocation, 20 February 2012.

413 Aurora, *Revised regulatory proposal* 2012–17, January 2012, p.90

In the present circumstances, the AER accepts the adjustment as proposed by Aurora, which results in a small increase to Aurora's opening RAB. Based on information supplied by Aurora, there was approximately $9 million of capitalised provisions included in the RAB as at 1 January 2008. Under an accounting approach, the provisions account would fall below $9 million. The RAB would also decrease due to a negative capex adjustment for the change in provisions. However, as discussed in the draft determination, the AER considers that the roll forward of the RAB should be conducted on an 'as incurred' basis, consistent with clause S6.2.1(e)(1) of the NER.[414] The negative movement in the provisions account over the current regulatory control period suggest that on balance cash was paid out during this period to settle expenses for certain provisions. To recognise these expenses on an 'as incurred' basis (as a capitalised item), the amount should be included in the RAB.

In the present circumstances, the adjustment appears to result in an unusual outcome as $9 million in provisions is already included in the RAB as at 1 January 2008. Rather than allowing the amount of provisions in the RAB to fall below $9 million, this adjustment will effectively maintain the provisions at that level.[415] The AER considers it has no option but to allow the adjustment as it cannot revisit the RAB value as at 1 January 2008.[416] Accordingly, the AER has included this adjustment in its revised RFM using the updated data supplied by Aurora.[417]

8.3.3 Indexation of the RAB

The AER maintains its position in the draft determination and has adjusted Aurora's revised RFM to be indexed by December-December CPI, rather than June-June CPI.[418]

The inflation (CPI) factor used by the control mechanism changed for Aurora at the last reset. The CPI factor changed from a June-June CPI to a December-December CPI, reflecting that the first regulatory year was not a full year, only half a year. In the draft determination, the AER revised the actual inflation inputs in the RFM to reflect this change by basing them on December-December CPI, consistent with the control mechanism, as clause 6.5.1(e)(3) of the NER requires.

In its revised proposal, Aurora disagreed with the AER's approach. It stated that June-June CPI was consistent with the control mechanism.[419] Aurora also referred to correspondence from the Office of the Tasmanian Economic Regulator (OTTER) that indicated that for regulatory accounting purposes OTTER agreed for June-June CPI to be used to index asset values in the 2007–08 regulatory accounts.[420]

414 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p.198.

415 Ideally, all provisions should be removed from the RAB. However, as discussed in the draft determination, the AER considers a certain amount to have been effectively locked in the RAB schedule established in the NER.

416 The value of the RAB in schedule 6.2 of the NER is set as at 1 January 2008.

417 Should future net movements in capitalised provisions be positive (as was indicated in the AER's draft determination based on information from Aurora's original proposal) then such a movement in provisions would be subtracted from the RAB at the next reset.

418 The December 2011 CPI was not available at the time of the draft determination. However, it has subsequently become available and therefore the December CPI for 2011–12 is incorporated in the RFM.

419 Aurora, *Revised regulatory proposal* 2012–17, January 2012, p. 88.

420 Aurora, *Revised regulatory proposal* 2012–17, January 2012, p. 86.

The AER does not accept that June-June CPI was used in the control mechanism during the current regulatory control period. The most recent calculation of the maximum annual revenues for 2011-12 shows the CPIs that have been applied historically as being:[421]

> The weighted average of all capital cities CPI index number for the December quarter of 2007 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 160.10.
>
> The weighted average of all capital cities CPI index number for the December quarter of 2008 as obtained from the Australian Bureau of Statistics website, www.abs.gov.au, is 166.00.
>
> The weighted average of all capital cities CPI index number for the December quarter of 2009 as obtained from the Australian Bureau of Statistics website, www.abs.gov.au, is 169.50.
>
> The weighted average of all capital cities CPI index number for the December quarter of 2010 as obtained from the Australian Bureau of Statistics website, www.abs.gov.au, is 174.00.

OTTER’s in its correspondence on the use of CPI in the regulatory accounts concedes that it had not considered the effect changing CPI may have on the regulatory accounts. To maintain consistency with past regulatory accounts, OTTER agreed that Aurora could continue to index the asset base for regulatory accounting purposes using June-June CPI for 2007–08. The AER acknowledges that maintaining consistency in the regulatory accounts is generally desirable. However, these regulatory accounts do not determine how the AER must roll forward the RAB. Clause 6.5.1(e)(3) requires the AER to adopt an inflation indexation method that is consistent with the indexation of the previous control mechanism for standard control services. The AER considers that the previous control mechanism's method for indexation was based on December-December CPI. OTTER’s decision on Aurora’s 2007–08 regulatory accounts is a separate matter and does not change this.

For presentation purposes, the AER considers that the indexation in the regulatory accounts should be consistent with that used in the annual price control mechanism and therefore the RAB roll forward. The AER will develop regulatory accounts for Aurora going forward and the indexation will be consistent with the control mechanism. Also, the regulatory accounts the AER prepared for the ACT, NSW, Qld and SA DNSPs for 2010 to 2012, used an inflation adjustment consistent with their respective control mechanisms.

8.3.4 Treatment of spare parts

Aurora's RAB includes asset classes for 'spare parts' and 'emergency spare parts' (spares). The opening values of these assets were depreciated in Aurora's roll forward over the current regulatory control period. As discussed in attachment 9, the AER considers spares should not be depreciated.[422] This approach is also consistent with OTTER's previous approach. Instead, spares should be maintained as stock (like land and easements). Also, the level of spares will only change through additions and disposals, when the spares are used and form part of an asset.

421 Aurora, *Calculation of the Maximum Annual Revenue for Distribution Network Services for the period from 1 Jul 2011 to 30 Jun 2012*, p.3.

422 The standard and remaining asset lives inputs for these spares asset classes are assigned "n/a" for modelling purposes.

Aurora agreed that spares should not be depreciated.[423] This has the effect of increasing Aurora's RAB by $10.1 million as at 30 June 2012.

Going forward Aurora will only earn a return on these assets and no depreciation. This approach is also adopted for the roll forward of the RAB to 30 June 2017.

8.3.5 Forecast closing RAB as at 30 June 2017

The AER has determined *the forecast RAB to be* $1,750.4 m*illion as at 30 June 2017.* The forecast of Aurora's closing RAB as at 30 June 2017 is impacted by input changes for the forthcoming regulatory control period made by the AER to the PTRM. These changes are:

- The opening RAB as at 1 July 2012, as discussed in section 8.3.1
- The inflation forecast for the forthcoming regulatory control period, as discussed in attachment 10
- Forecast capital expenditure, as discussed in attachment 6
- Forecast depreciation, as discussed in attachment 9.

8.3.6 Depreciation approach to roll forward the RAB

In the draft determination, the AER accepted Aurora's proposal to use depreciation based on actual capex for the purposes of rolling forward the RAB to establish the opening RAB at the beginning of the 2017–22 regulatory control period. In explaining how this is to be done Aurora proposed that forecast capex be used for the final two years of the forthcoming regulatory control period in the RAB roll forward.[424]

The AER accepts forecast capex will need to be used for the final year of the forthcoming regulatory control period in the RAB roll forward. However, actual capex for the fourth year of the forthcoming next regulatory control period will be available for the final determination of the next reset. Therefore it is the actual capex amounts that should be used for that fourth year.

8.4 Revisions

The AER requires the following revisions to Aurora's revised proposal in relation to its RAB.

Revision 8.1: The AER has determined Aurora's opening RAB as at 1 July 2012 to be $1,445.2 million as set out in table 8.1.

Revision 8.2: The AER has determined Aurora's forecast RAB as at 30 June 2017 to be $1,750.4 million as set out in table 8.2.

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[423] Aurora, *Response to follow up request to AER/068 of 24 February 2012*, received 28 February 2012.

[424] Aurora, *Revised regulatory proposal* 2012–17, January 2012, p. 103.

9 Depreciation

The AER is required to make a decision in relation to the depreciation schedules submitted by a DNSP.[425] Regulatory depreciation is used to model the nominal asset values over the regulatory control period and the depreciation allowance in the annual revenue requirement. This attachment sets out the annual allowances for regulatory depreciation—that is, the sum of the straight-line depreciation (negative) and the annual inflation indexation (positive) on the regulatory asset base (RAB). The attachment also analyses Aurora's proposed depreciation schedule, including an assessment of the standard asset lives and remaining asset lives used for depreciation purposes over the forthcoming regulatory control period.

9.1 Determination

The AER does not accept Aurora's revised proposed regulatory depreciation allowance of $227.5 million ($nominal) for the forthcoming regulatory control period. The AER's adjustments to Aurora's revised proposed opening RAB, forecast capex, and forecast inflation impact the forecast regulatory depreciation allowance under clause 6.5.5 of the NER. The AER also made changes to Aurora's proposed depreciation treatment in relation to the 'Emergency network spares' and 'Spare parts' asset classes. The AER's amendments result in a regulatory depreciation allowance of $231.3 million ($nominal) (a 1.7 per cent increase), as shown in table 9.1.

Table 9.1 AER's determination on Aurora's depreciation allowance ($m, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Straight-line depreciation	83.4	90.5	89.5	84.9	86.6	434.8
Less: indexation of opening RAB	37.6	39.1	40.7	42.2	43.8	203.5
Regulatory depreciation	45.8	51.3	48.8	42.7	42.7	231.3

Source: AER analysis.

9.2 Assessment approach

There have been no changes to the assessment approach from that outlined in the draft determination.[426] Accordingly, that discussion is not repeated here.

9.3 Reasons

This section sets out the AER's consideration of issues raised in Aurora's revised proposal. These issues include whether 'Emergency network spares' and 'Spare parts' asset classes should be depreciated, and whether the remaining asset lives of all asset classes for the purposes of depreciating existing assets in the opening RAB conform to clause 6.5.5(b) of the NER .

[425] NER, clause 6.12.1(8).

[426] AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 203–204.

The AER also sets out its final decision on Aurora's regulatory depreciation allowance resulting from changes to other components of Aurora's revised proposal, as outlined below.

9.3.1 Regulatory depreciation allowance

The AER's final decision on Aurora's regulatory depreciation allowance is $ 231.3 million ($nominal). This represents an increase of $3.8 million ($nominal) or 1.7 per cent of Aurora's revised proposal.

The AER does not accept Aurora's proposed regulatory depreciation allowance of $227.5 million ($nominal) for the next regulatory control period.[427] This is because the AER's determinations regarding other components of Aurora's revised proposal impact the proposed regulatory depreciation allowance. These are discussed in other attachments and include:

- the opening RAB (attachment 8)
- forecast capex (attachment 6)
- forecast inflation (attachment 10).

The AER's final decision on the depreciation treatment of the 'Emergency network spares' and 'Spare parts' asset classes, and the remaining asset lives, as discussed below, also affect the estimate of regulatory depreciation.

9.3.2 Standard asset lives – Spares

The AER considers that the asset classes of 'Emergency network spares' and 'Spare parts' (collectively referred to as 'spares') should not be subject to depreciation until they are used and become an operational part of the network. The AER recognises that carrying spares is necessary to minimise the response time to replace failed equipment. Further, the inclusion of spares in the RAB is considered efficient because it allows the NSP to earn a return on these assets to compensate for the opportunity cost of holding these assets.

Aurora's proposal was not clear in its intention to depreciate the spares asset classes. However, in Aurora's revised asset base roll forward model and post-tax revenue model these asset classes were assigned a life and therefore subject to depreciation. In response to an inquiry by the AER, Aurora confirmed that the regulator for its current regulatory control period, the Office of the Tasmanian Economic Regulator (OTTER), had not depreciated spares.[428] Aurora also stated in its response it did not intend to depreciate spares. The AER accepts that spares should not be depreciated.

The AER considers Aurora's depreciation schedule must reflect the nature of the asset over its economic life as required under clause 6.5.5(b)(1) of the NER. To depreciate spares before they have become part of the network does not do so because the economic life would not reflect the intended use of the assets. The AER also considers the following issues are relevant to the treatment of spares as non-depreciating assets:

427 NER, clause 6.12.1(8).

428 Aurora, *Email response to follow up request to AER/068 - Spares asset class of 24 February*, received 28 February 2012, p. 3.

- to depreciate the asset before it is in use, could create an incentive to remove the useful asset from service prior to the end of its economic life

- the depreciation of spares would result in customers paying for depreciation on an asset that is effectively not in service, as the reason for carrying spares is to minimise the interruption to such services.

- The AER considers that spares should not be depreciated until they are used and become an operational part of the network.[429] The asset is then depreciated according to the standard asset life of the asset class for which it has been installed.[430] Therefore, the AER considers that correcting this aspect of Aurora's depreciation schedules would conform to clause 6.5.5(b)(1) of the NER.

9.3.3 Remaining asset lives

The AER does not accept Aurora's proposed remaining asset lives as being consistent with clause 6.5.5(b)(1) of the NER. This is because the AER considers the remaining asset lives do not reflect the AER's adjustments to the opening RAB. These include changes to actual capex, CPI indexation and the movement of provisions. The AER has recalculated the remaining asset lives to account for these changes, but otherwise employs the same method Aurora used to calculate its proposed remaining asset lives. The AER approved Aurora's use of the depreciation method[431] to calculate the remaining asset lives in the draft determination.[432]

In addition, the remaining asset lives for the asset classes of 'Emergency network spares' and 'Spare parts' have been changed to 'n/a' to reflect that these asset classes are not subject to depreciation, for the reasons as discussed above. The AER's determination on Aurora's remaining asset lives by asset class is shown in table 9.2.

Table 9.2 AER's final determination on standard and remaining asset lives (years)

Asset classes	Standard asset life	Aurora's proposed remaining asset life	AER's approved remaining asset life
Overhead subtransmission lines (urban)	50	29.4	29.1
Underground subtransmission lines (Urban)	60	38.2	37.9
Urban zone substations	40	31.1	30.8
Rural zone substations	40	29.6	29.4
SCADA	10	2.6	2.6
Distribution switching stations (ground)	40	32.4	32.3
Overhead high voltage lines urban	35	24.0	23.9

429 For modelling purposes, the AER has assigned a standard life of 'n/a' for these asset classes in the models.

430 NER, clause 6.5.5(b)(1).

431 The depreciation method of calculating the remaining asset lives involves dividing the closing RAB values for each asset class, by an estimate of depreciation for that asset class. In Aurora's case the estimate of depreciation was a forecast of depreciation for 2012-13 from Aurora's roll forward model.

432 The AER noted it would require a further recalculation of Aurora's remaining asset lives to reflect the updated opening RAB for its final determination. See AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 209.

Overhead high voltage lines rural	35	20.9	20.7
Voltage regulators on distribution feeders	40	23.2	23.0
Underground high voltage lines	60	42.2	41.9
Underground high voltage lines SWER	60	48.0	47.5
Distribution substations HV (pole)	40	33.5	33.3
Distributions substations HV (ground)	40	17.0	16.9
Distribution substations LV (pole)	40	23.0	22.8
Distribution substations LV (ground)	40	24.6	24.5
Overhead low voltage underbuilt urban	35	23.9	23.7
Overhead low voltage underbuilt rural	35	17.7	17.5
Overhead low voltage lines urbana	35	24.4	17.6
Overhead low voltage lines rural	35	25.9	25.8
Underground low voltage lines	60	38.1	37.8
Underground low voltage common trench	60	47.2	46.9
HVST service connections	40	2.1	2.0
HV service connections	40	28.3	28.1
HV metering CA service connections	40	11.1	11.0
HV/LV service connections	40	27.2	26.9
Business LV service connections	35	13.1	13.0
Business LV metering CA service connections	25	6.4	6.3
Domestic LV service connections	35	22.0	21.8
Domestic LV metering CA service connections	20	3.9	3.9
Emergency network spares	n/a	n/a	n/a
Motor vehicles	6	3.5	3.5
Minor assets	5	2.6	2.6
Non-system property	40	17.3	17.0
Spare parts	n/a	n/a	n/a
NEM assets	5	1.8	1.8
Land	n/a	n/a	n/a
Easements	n/a	n/a	n/a

Source: Aurora,[433] AER analysis.

[433] Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 100.

(a) Aurora’s revised proposed remaining asset life for the ‘Overhead low voltage lines urban’ asset class was calculated based upon an incorrect cell reference in Aurora’s model. The calculation error resulted in a longer remaining asset life and understated Aurora’s revised proposed regulatory depreciation allowance for this asset class.

9.4 Revisions

The AER determines the following revisions to Aurora's proposal in relation to its forecast regulatory depreciation allowance.

Revision 9.1: The AER determined Aurora's forecast regulatory depreciation allowance to be $231.3 million ($nominal) over the forthcoming regulatory control period as set out in table 9.1.

Revision 9.2: The AER determined that the asset classes of 'Emergency network spares' and 'Spare parts' should not be subject to depreciation. The AER has assigned the standard asset life of 'n/a' for these asset classes.

Revision 9.3: The AER has determined Aurora's remaining asset lives as at the beginning of the forthcoming regulatory control period to be those set out in table 9.2.

10 Cost of capital

The AER is required to make a decision in relation to the rate of return (or cost of capital). This attachment sets out the AER’s determination of the cost of capital to apply over Aurora's forthcoming regulatory control period. In making its determination, the AER must make a decision on whether to apply or depart from a value, method or credit rating level set out in its statement of regulatory intent (SRI).[434] When the rate of return is applied to the value of the regulatory asset base (RAB) it results in the return on capital building block. Under the NER, the rate of return to be applied by the AER is based on the nominal vanilla weighted average cost of capital (WACC) formulation.[435] The NER also requires the AER to apply the capital asset pricing model (CAPM)[436] to calculate the return on equity for DNSPs.[437]

10.1 Determination

The AER does not accept Aurora's revised proposal (indicative) WACC of 9.97 per cent. In this final determination, the AER determines a WACC of 8.28 per cent for Aurora as set out in Table 8.1. The nominal risk free rate and debt risk premium (DRP) were estimated over a 20 business day averaging period commencing on 9 January 2012 and ending on 6 February 2012.

Aurora's initial proposal submitted values for the equity beta (0.8), gearing (60 per cent) and the credit rating level (BBB+) that were consistent with the values and credit rating set out in the WACC review.[438] The AER did not consider there was persuasive evidence justifying a departure from the WACC review position on these parameters. Aurora also submitted a value assumed utilisation of imputation credits (gamma)(0.25). This was inconsistent with the value in the WACC review (0.65), but consistent with the Australian Competition Tribunal's (Tribunal) decision.[439] The AER considered that the Tribunal's decision was persuasive evidence justifying a departure from the WACC review position on this parameter. Accordingly, the AER accepted Aurora's proposed parameters in the draft determination.

The AER also agreed to Aurora's proposed averaging period to calculate the nominal risk free rate, which was consistent with the SRI methodology. However, the AER did not accept Aurora's proposed value for the market risk premium (6.5 per cent) (MRP) or its proposed method for setting the DRP.

In this final determination, the AER:

- accepts Aurora's revised proposal methodology to estimate the DRP which is based on the Bloomberg 7 year BBB rated fair value curve (FVC) extrapolated to a 10 year term

434 NER, clause 6.12.1(5).
435 NER, clause 6.5.2(b).
436 The CAPM is a well known and widely used model. It specifies a relationship between the expected return of a risky (in terms of uncertainty over future outcomes) asset and the level of systematic (non-diversifiable) risk.
437 NER, clause 6.5.2(b).
438 The gamma parameter affects the corporate income tax building block, which is discussed in attachment 11.
439 Australian Competition Tribunal, Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, 12 May 2011.

- does not accept Aurora's revised proposal to adopt the MRP value (6.5 per cent) from the SRI. The AER considers, consistent with its draft decision, that there is persuasive evidence justifying a departure from this value
- does not accept Aurora's revised proposal to depart from the SRI methodology to calculate the risk free rate with respect to:
  - amending the averaging period after it has been agreed or specified, and
  - using an averaging period which is not as close as practicably possible to the commencement of Aurora's regulatory control period

The AER does not consider there is persuasive evidence justifying a departure from these or other elements of the SRI methodology on the risk free rate.

The AER adopts substitute values for:

- the MRP of 6 per cent,
- the nominal risk free rate of 3.89 per cent (based on the 20 business day averaging period ending 6 February 2012 which is calculated in accordance with the SRI methodology)

By making these changes, the AER amends Aurora's proposed values for the MRP and risk free rate only to the extent necessary to enable those values to be approved in accordance with the NER.

In addition to bottom-up analysis on the parameter inputs, the AER also assesses the overall rate of return against market data to examine the overall WACC's appropriateness.[440]

Table 10.1 AER determination on Aurora's WACC parameters

Parameter	AER draft determination	Aurora revised proposal	AER final determination
Nominal risk free rate	4.28%	5.50%	3.89%
Equity beta	0.80	0.80	0.80
Market risk premium	6.00%	6.50%	6.00%
Gearing level (debt/debt plus equity)	60%	60%	60%
Debt risk premium	3.14%	3.98%	4.11%
Assumed utilisation of imputation credits (gamma)[a]	0.25	0.25	0.25
Inflation forecast	2.62%	2.63%	2.60%
Cost of equity	9.08%	10.70%	8.69%
Cost of debt	7.42%	9.48%	8.00%
Nominal vanilla WACC	8.08%	9.97%	8.28%

440 NER, clause 6.5.2(b).

10.2 Assessment approach

10.2.1 Requirements of the law and rules relevant to the rate of return

The AER completed its review of the WACC parameters for DNSPs (the 'WACC review') as required under the NER in May 2009.[441] As a consequence of the review, the AER issued the SRI, which set out WACC parameter values, methods and a credit rating level for DNSPs.[442] The WACC parameter values, methods and credit rating level determined by the AER in the SRI are outlined in Table 10.2.

Table 10.2 AER WACC parameters in the SRI

Parameter	Value, method or credit rating level
Nominal risk free rate	Annualised yield on 10 year CGS based on agreed averaging period as close as practically possible to the commencement of regulatory control period[a]
Equity beta	0.80
Market risk premium	6.50%
Gearing level (debt/debt plus equity)	60%
Debt risk premium credit rating level	BBB+
Assumed utilisation of imputation credits (gamma)[b]	0.65

Source: AER.[443]
Notes: (a) Full specification of the SRI risk free rate methodology is set out in section A.1.1.
(b) The gamma parameter affects the corporate income tax allowance, which is discussed in attachment 11.

The SRI applies to Aurora's distribution determination because Aurora's initial proposal was submitted after the publication of the SRI.[444] The AER's distribution determination for Aurora must be consistent with the SRI unless there is persuasive evidence justifying a departure from a value, method or credit rating level set out in the SRI.[445]

In deciding whether a departure from a value, method or credit rating level set in the SRI is justified, the AER must consider:[446]

- the criteria on which the value, method or credit rating level was set in the SRI (the 'underlying criteria'); and
- whether, in light of the underlying criteria, a material change in circumstances since the date of the SRI, or any other relevant factor, now makes a value, method or credit rating level set in the SRI inappropriate.

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441 NER, clause 6.5.4(b).
442 NER, clause 6.5.4(c).
443 AER, Electricity transmission and distribution network service providers—Statement of the revised WACC parameters (transmission)—Statement of regulatory intent on the revised WACC parameters (distribution), May 2009, p. 7.
444 NER, clause 6.5.4(f).
445 NER, clause 6.5.4(g).
446 NER, clause 6.5.4(h).

Further, where Aurora's revised proposal is consistent with the applicable criteria in the NER the AER must accept it. If the AER refuses to approve an amount or value for a WACC parameter that has been proposed by Aurora, the AER's substitute amount or value on which the distribution determination is based must be:

- determined on the basis of the current regulatory proposal, and
- amended from that basis only to the extent necessary to enable it to be approved in accordance with the NER.[447]

Meaning of persuasive evidence

There are similar, though slightly different, persuasive evidence tests that apply at the time of the WACC review and at the time of a distribution determination.[448] Both require an understanding of the notion of 'persuasive evidence'.

In the WACC review, the AER stated:

> Persuasive evidence is likely to include objective and verifiable empirical market evidence, and theoretical reasons, so long as they are well founded. The AER's view is that persuasive evidence refers to material which is of sufficient substance to justify a departure from the previously adopted value, method or credit rating. In order to form a view as to whether persuasive evidence exists the AER has considered all the relevant material before it.[449]

It is also useful to consider the meaning of persuasive evidence from the perspective of what it is not. During the WACC review there were a number of views on the meaning of persuasive evidence raised by stakeholders. Interpretations the AER did not accept were that:

- persuasive evidence is limited to evidence that proves the previously adopted parameter was 'incorrect' at the time it was determined
- unanimous evidence is required among experts before the evidence can be considered persuasive
- persuasive evidence is limited to 'new' evidence, or
- the upper or lower 95 per cent confidence interval (depending on if the empirical estimates are below or above the previously adopted parameter) is the threshold that determines whether empirical evidence is persuasive or not.[450]

Additionally, Aurora in its revised proposal states:

> Aurora considers that it is not appropriate for the AER to introduce new refinements to the theory of estimating the MRP in the context of an individual DNSP's determination. The periodic, industry-wide review is the appropriate forum for such innovation to be raised and properly tested by all stakeholders.[451]

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447 NER, clause 6.12.3(f).

448 NER, clauses 6.5.4(e)(4)(ii) and 6.5.4(g).

449 AER, Final decision—Electricity transmission and distribution network service providers—Review of the WACC parameters, May 2009, pp. 91-92.

450 AER, Final decision—WACC review, May 2009, pp. 88–89.

451 Aurora, Revised proposal—Supporting information: Return on capital, January 2012, pp. 21-22.

While not explicitly stated, it would appear that Aurora considers changes in theoretical views cannot count towards the establishment of persuasive evidence. If this is Aurora's position, the AER finds nothing in the NER that would lend support to this interpretation. The AER's positions in the WACC review were variously based on both theoretical and empirical considerations. There might be new theoretical and empirical evidence since the WACC review, or there might be changed assessments on theoretical or empirical evidence that existed at the time of the WACC review. Both types of evidence could be capable of persuading the AER that a position taken in the WACC review is now inappropriate. Accordingly both types of evidence appear capable of counting towards the establishment of persuasive evidence.

The AER also makes the following comments on the views regarding the 'incorrectness' of a parameter. During the WACC review, some stakeholders considered that the proper interpretation of the persuasive evidence test is one that requires demonstrating a previously adopted parameter is ‘incorrect’ before the parameter may be departed from. This was a position held by a number of stakeholders including the Joint Industry Association, Gilbert and Tobin and NSW Treasury.[452] A requirement that previous parameters must be ‘incorrect’ results in a high threshold before a departure is permitted. The AER did not, in the WACC review, accept that the threshold was this high.[453]

Overall the AER considers that the persuasive evidence test requires the AER to:

- have regard to the value or methodology for each parameter in the WACC review
- have regard to the underlying criteria or considerations that led to that value or methodology in the WACC review, and
- justify any departures from the WACC review values or parameters in the context of the underlying criteria or considerations.

There may be circumstances where a departure from the WACC review would better promote the NEO, better reflect the revenue and pricing principles, or better reflect a forward looking rate of return commensurate with prevailing conditions in the market for funds (and the other NER criteria). So long as the AER has stepped through the process outlined in the dots points above, the AER does not consider the threshold to meeting persuasive evidence to be so high such that it would act as a barrier in preventing the accomplishment of such a parameter estimate.

Finally, throughout this attachment and the appendix, the AER makes comments about whether there is "persuasive evidence justifying a departure." A finding that there is not "persuasive evidence justifying a departure" means that the AER considers that this test has not been met. It should not be interpreted as the AER finding that there is no evidence available on the particular issue.

Meaning of underlying criteria

The underlying criteria the AER relied on in setting the value, method or credit rating level in the SRI included:[454]

452 AER, Final decision—WACC review, May 2009, pp. 87–89.
453 AER, Final decision—WACC review, May 2009, p. 89.
454 AER, Final decision—WACC review, May 2009, pp. 175–176.

- the need for the rate of return to be a forward looking rate of return
- the need for a rate of return that reflects the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the relevant service provider
- the need to achieve an outcome that is consistent with the NEO
- the need for persuasive evidence before adopting a value or method that differs from the value or method that has previously been adopted for it
- providing a service provider with a reasonable opportunity to recover at least the efficient costs
- providing a service provider with effective incentives in order to promote efficient investment, and
- having regard to the economic costs and risks of the potential for under and over investment.

10.2.2 Bottom-up determination with reasonableness check on overall rate of return

As required by the NER, the AER must determine an estimate for each individual WACC parameter. Consistent with recent AER decisions, the AER first assesses each WACC parameter based on considerations relevant to that parameter.[455] As part of this parameter by parameter assessment, the AER also has appropriate regard for economic interdependencies (i.e. internal consistency) between the various WACC calculation inputs (e.g. between the MRP and gamma). In addition, the AER compares the resultant WACC against a series of reasonableness checks on the overall rate of return based on:

- The rate of return used by equity analysts in valuation analysis of listed companies operating regulated energy networks or pipelines in Australia, as set out in recent brokers' reports.
- The multiple of market value to book value (as reflected in the regulated asset base) both when an asset is sold and over time for companies operating regulated energy networks or pipelines in Australia.
- The rates of return recently provided by other Australian economic regulators in comparable industries.

10.2.3 Advice from Professor McKenzie and Associate Professor Partington (risk free rate and market risk premium)

In the context of the Tribunal's review of the MRP in the Envestra SA and Envestra QLD access arrangements, the AER commissioned (through Corrs Chambers Westgarth) an independent report on the MRP from Professor McKenzie and Associate Professor Partington (the 'December 2011 MRP report').[456]

Among other matters, the AER sought advice on the strengths and weaknesses of the following measures of the MRP:

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455 As discussed in section 10.3.1 the AER has consistently held a position that each parameter should be estimated based on considerations relevant to that parameter, rather than to deal with issues relating to another parameter.

456 McKenzie, M. and G. Partington, Equity market risk premium, 21 December 2011.

- historical excess returns (including the use of arithmetic and geometric averages)
- dividend growth model estimates
- survey evidence
- market commentary, and
- implied volatility (and the 'glide path' approach).

Based on this evidence, and any other evidence considered appropriate, the AER sought McKenzie and Partington to make a recommendation on the value of the MRP. McKenzie and Partington advised:

> On balance, our view is that there is little compelling evidence to deviate from the long standing regulatory consensus of an equity market risk premium of 6%. If anything, the risk with this estimate is that it may prove to be an overstatement and it is possible to argue in favour of a downward adjustment.[457]

The AER received this report after it had published its draft determination for Aurora. Therefore the December 2011 MRP report was not referenced or relied upon in the draft determination, though the report's conclusion of a 6 per cent MRP is consistent with the draft determination.

On 21 December 2011, the AER provided the December 2011 MRP report to Aurora. The AER advised Aurora that the report contained matters relevant to the MRP that the AER would consider in Aurora's final determination. The AER requested Aurora provide any comments on the December 2011 MRP report as part of its revised proposal.[458]

Aurora did not make any specific comments on the report in its revised proposal, however Aurora's submission on the draft determination and its revised proposal commented on the scope of the report, among other matters.[459] Aurora stated:

> The most pertinent question in today's market is whether, if a long term MRP is applied in the CAPM formula to derive a return on equity, it is appropriate to pair a long term MRP with a 'spot' risk free rate.
>
> …
>
> The fact that McKenzie and Partington were not instructed by the AER to examine this issue is, in Aurora's view, an important scope limitation that reduces the relevance of the report findings in the current circumstances.[460]

In response to Aurora's revised proposal, the AER commissioned and received a supplementary report from McKenzie and Partington on the MRP (the 'February 2012 supplementary MRP report'). The AER requested McKenzie and Partington to review the findings of their previous report in light of:

- Comments on the MRP made by the Tribunal in the Envestra matter
- The material presented by Aurora in its revised proposal

457 McKenzie, M. and G. Partington, Equity market risk premium, 21 December 2011, pp.36-37.
458 Yap, K (AER) to L Mayne (Aurora), Expert report on MRP—Opportunity for comment, Email, 21 December 2011.
459 Aurora, AER's draft distribution determination—Return on capital, Submission, 20 February 2012.
460 Aurora, AER's draft distribution determination—Return on capital, Submission, 20 February 2012, p.2.

- A report by SFG on the MRP commissioned by APTPPL and submitted with its access arrangement proposal

The AER requested that McKenzie and Partington explain whether and why, in light of the above new information, their advice and conclusions were changed or unchanged from the December 2011 MRP report. The terms of reference specifically directed McKenzie and Partington to review the material presented by Aurora in its revised proposal on the relationship between the risk free rate and MRP.

In the February 2012 supplementary MRP report, McKenzie and Partington concluded both that:

- there are good reasons for the AER to depart from a 6.5 per cent MRP and adopt a 6 per cent MRP,[461] and
- they see no reason to switch from using the current 10 year CGS yield as the proxy for the risk free rate.[462]

The AER publishes both reports from McKenzie and Partington with this final determination. The content and advice from both reports are referred to and relied upon in this attachment 10 and in appendix A.

10.2.4 Approach to the determination of specific parameters

Risk free rate

The risk free rate, as with other WACC parameters, needs to be a forward looking rate that is commensurate with prevailing conditions in the market for funds and the risk involved in providing standard control services.[463] The rate of return for a DNSP for a regulatory control period is 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 as that faced by the distribution business of the provider and must be calculated as a nominal post-tax WACC in accordance with the following formula:

$$WACC = k_e \frac{E}{V} + k_d \frac{D}{V}$$

The AER is also required under clause 6.5.2(b) of the NER to determine the return on equity using the Capital Asset Pricing Model (CAPM) and separately determine each of its inputs such as the risk free rate and MRP.

In the WACC review, the AER considered evidence before it and concluded the appropriate methodology for estimating the risk free rate is using the yield on CGS bonds with a 10 year term and an averaging period commencing as close as practically possible to the start of the regulatory control period. In addition, the AER provided further guidance that it would accept proposed averaging periods that were between 10 and 40 business days in length.

The AER’s approach for this decision is consistent with that set out in the WACC review. The AER has considered evidence from the Treasury and the RBA. The AER has also considered submissions in favour of an upward adjustment to the CGS yield to compensate for an otherwise ‘low’ return on

461 McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012, pp.9-12.

462 McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012, pp.28-30.

463 NER, c. 6.5.4 (e)(1)

equity. In forming the view of the methodology to estimate the risk free rate, the AER has had regard to legal, economic and policy considerations (where relevant) in respect of:

- the ability to depart from the WACC review
- setting a forward looking prevailing rate
- ensuring 'integrity' in the estimation of each parameter
- the economic interdependencies between parameters
- the appropriateness of using the CGS yield when the rate is 'low'
- unbiasedness in the method to determining the averaging period

Following this approach the AER concludes that the current approach to setting the risk free rate should be continued. This position is supported by advice from Professor McKenzie and Associate Professor Partington in their February 2012 MRP report.[464] The AER does not agree with Aurora's proposal to change the methodology for calculating the risk free rate to use the long term risk free rate (Aurora calculates that this would result in a 5.5 per cent risk free rate).

Market risk premium

The MRP is the expected return over the risk free rate that investors require to invest in a well diversified portfolio of risky assets.[465] The MRP represents the risk premium that investors who invest in such a portfolio can expect to earn for bearing only non-diversifiable (systematic) risk. The MRP is common to all assets in the economy and is not specific to an individual asset or business.

The MRP is not observable because it is a forward looking value. In addition to this, the available evidence that can be used to estimate the MRP is imprecise and subject to varied interpretation, a point that is well recognised in academic literature[466] as well as in reports put forward by regulated entities.[467] As a result, a degree of judgment is required to determine the MRP value that is the best estimate in the circumstances and commensurate with prevailing conditions in the market for funds.

Consistent with previous AER decisions, the AER assesses the MRP by considering a range of evidence, assessing the relative strengths and weaknesses of that evidence, and applying its judgement to the evidence before it in determining an appropriate value. In the context of the NER, this leads to the AER's consideration of whether the 6.5 per cent MRP from the SRI remains appropriate or whether there is persuasive evidence justifying a departure from this value. If there is persuasive evidence justifying a departure, the AER's considerations involve determining an appropriate substitute value.

In undertaking this process, the AER has considered the following evidence:

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464 McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012, pp. 9-12.

465 All assets other than the risk free asset have the potential to provide a negative return and are therefore classified as risky assets.

466 See for example Mehra R. and Prescott E.C., 'The equity premium, A puzzle', *Journal of Monetary Economics*, 15, 1985, pp. 145–161; Damodoran A., *Equity Risk Premiums (ERP), Determinants, Estimation and Implications*, September 2008, p. 1; Doran J.S., Ronn E.I. and Goldberg R.S., *A simple model for time-varying expected returns on the S&P 500 Index*, August 2005, pp. 2–3.

467 See for example Officer and Bishop, *Market risk premium, a review paper*, August 2008, pp. 3–4.

- Historical excess returns—These returns represent the additional return that investors could have earned in the past by investing in a diversified portfolio of shares, including appropriate adjustments for any imputation credits earned on this portfolio. Historical excess return estimates are taken into account on the basis that investors' expectations of the forward looking MRP are informed by past experience.

- Survey based estimates—Surveys of market practitioners and academics provide information on the expected forward looking MRP and their application in practice.

- Dividend growth model (DGM) estimates—Cash flow based measures of the MRP generally employ a dividend discount model. One such model is the DGM which values a stock by estimating the next dividend to be paid and then assumes dividends per share will increase in perpetuity by a constant growth rate. By rearranging the equation the implied cost of equity can be derived from the current share price. Replacing individual stock parameters for market parameters implies that the MRP equals the next period's market dividend yield plus expected market growth rate in dividends per share minus the risk free rate.[468]

- Implied volatility analysis—This method uses a number of assumptions to infer a required short term rate of return based on option prices in derivative markets, which reflect short term expectations of future prices and volatility. Further assumptions can then be used to extrapolate from the short term rate of return to a longer horizon.

- Market commentary and economic outlook—Market commentary from respected economic and financial commentators, such as the Reserve Bank of Australia (RBA), the Organisation for Economic Cooperation and Development (OECD) and International Monetary Fund (IMF), provides information on their assessment of economic and financial conditions.

The AER has interpreted the information available with regard to the advantages and limitations of each type of evidence.

For the reasons set out in section 10.3.2 and appendix A, the AER places limited emphasis, in a determinative sense, on DGM estimates, implied volatility and market commentary in estimating the value of the 10 year forward looking MRP.

However, each type of evidence is useful to some degree, in an informative sense, to assess whether the AER's reasons for moving to a 6.5 per cent MRP in the WACC review are still applicable. Those reasons were that the AER considered the GFC may have caused a possible structural break in the market or a possible prolonged heightening of market risk (but no structural break).

The AER's approach involves the exercise of appropriate regulatory judgement in the context of complex and sometimes conflicting evidence.

Debt risk premium

The AER estimates the DRP using:

- an appropriate benchmark—the AER specified in the SRI that the benchmark term for the risk free rate, and therefore the term for the DRP, is 10 years, and that the benchmark credit rating is BBB+.[469]

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468 AER, Final decision—WACC review, May 2009, pp. 216–217.
469 AER, *Statement of regulatory intent*, May 2009, p. 7.

- a method for estimating the DRP that conforms to these benchmark parameters as discussed below.

Method used to estimate the DRP

In assessing Aurora's revised proposal, the AER has considered:

- previous Australian Competition Tribunal (Tribunal) decisions on estimation of the DRP
- the use of the Bloomberg 7 year BBB FVC to estimate a 7 year (base) DRP[470]
- the method used to extrapolate the base DRP estimate from 7 to 10 years, consistent with the benchmark term.

In its draft determination for Aurora, the AER estimated the DRP based on a sample of observed bond market data and placed no weight on the Bloomberg BBB rated FVC.

Following the draft determination, the Tribunal released its decisions relating to APT Allgas and Envestra's access arrangements (the APT Allgas and Envestra decision) and the Victorian electricity DNSPs. Among other issues, the Tribunal considered the AER's approach to estimating the DRP. The Tribunal found error in the AER's DRP approach. It decided that for those regulatory decisions under review, 100 per cent weight would be placed on the extrapolated Bloomberg BBB rated FVC to estimate the DRP.[471] The Tribunal stated that if the AER wishes to adopt an alternative methodology to the extrapolated Bloomberg BBB rated FVC, it should develop the alternative approach through an industry wide consultation process.[472]

In those decisions, the use of the Bloomberg BBB rated FVC to estimate the DRP was in contention. The method for extrapolating the Bloomberg BBB rated FVC was not contested. However, the Tribunal stated that:

> If the AER were to decide that the **EBV**[473] was an unreliable indicator for the purposes of deciding that DRP, it would be desirable in the longer term to develop an alternative coherent and consistent methodology, in consultation with the relevant regulated entities and other interested parties. Although the DRP must be determined at a particular point in time, the use of a consistent and acceptable methodology would ensure regulatory consistency, and in relation to particular matters would also facilitate efficient decision making and in turn reduce the number of reviews of the DRP decisions by the AER brought to the Tribunal. While such a task would be a complex and lengthy one, it is one the Tribunal commends to the AER.[474] (AER's emphasis)
>
> …
>
> The Tribunal, of course, accepts that in the first instance it is for the AER to determine whether to rely upon the Bloomberg curve, **or to accept the extrapolation of that curve in the manner done in the past**. It is not obliged to do so, although given the past regulatory decisions it may be

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470 While the benchmark credit rating is BBB+, Bloomberg's BBB rated FVC is based on a composite of BBB–, BBB, BBB+ and A– rated bonds.

471 Australian Competition Tribunal, Application by Envestra Ltd (No 2) [2012] ACompT 3, 11 January 2012, paragraph 120; Australian Competition Tribunal, Application by APT Allgas Energy Ltd [2012] ACompT 5, 11 January 2012, paragraph 117; and Australian Competition Tribunal, Application by United Energy Distribution Pty Ltd (No 2) [2012] ACompT 1, 6 January 2012, paragraph 462.

472 Australian Competition Tribunal, Application by Envestra Ltd (No 2) [2012] ACompT, 11 January 2012, paragraphs 98, 120 and 121.

473 The Tribunal used EBV as the acronym for the extrapolated Bloomberg fair value curve.

474 Australian Competition Tribunal, Application by Envestra Ltd (No 2) [2012] ACompT, 11 January 2012, paragraph 98.

> expected to do so unless there were sound reasons to depart from that practice. For the future, that is a matter for the AER.[475] (AER's emphasis)

In light of the Tribunal's statements, the AER understands that in discussing the extrapolated Bloomberg BBB rated FVC the Tribunal is referring to:

- the Bloomberg BBB rated FVC to estimate the DRP at 7 years
- the last historical spread[476] between the Bloomberg 7 and 10 year AAA rated FVCs to extrapolate the 7 year DRP estimate to 10 years.

The AER considers that there may be other preferable methodologies to estimate the DRP. Notwithstanding this, the AER acknowledges the Tribunal's views and agrees that it is desirable to widely consult on a new approach to estimate the DRP before it is used. Prior to undertaking this consultation, and taking account of recent Tribunal decisions, the AER will assess Aurora's revised proposal against the following method to estimate the 10 year DRP:

- the Bloomberg BBB rated FVC to estimate the (base) 7 year DRP
- the last historical spread between the Bloomberg 7 and 10 year AAA rated FVCs, to extrapolate the 7 year DRP estimate to 10 years.

The AER will begin an internal review of alternative methods to estimate the DRP and advise of a public consultation process in due course.

10.2.5 Submissions from stakeholders and material from contemporaneous AER decision processes

In response to the AER's draft determination and Aurora's revised proposal, the AER received four consultant reports from the Victorian DNSPs (CitiPower, Jemena, Powercor, SP AusNet, United Energy). Those reports were:

- A report from NERA on the MRP—This report covered the issues of the use of arithmetic and geometric averages of historical excess returns, the volatility of historical excess returns, DGM estimates and survey evidence.[477]
- A report from SFG on the MRP—This report was an update of a previous SFG report submitted by APTPPL to the AER on the derivation of conditional and unconditional estimates of the MRP.[478]
- A report from Capital Research—This report presented DGM estimates of the MRP.[479]
- A report from CEG on the cost of equity—This report focused on the interaction between the risk free rate and MRP.[480]

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475 Australian Competition Tribunal, Application by Envestra Ltd (No 2) [2012] ACompT, 11 January 2012, paragraph 120.

476 Specifically, it is based on the last published 20 days prior to 22 June 2010.

477 NERA, The market risk premium, 20 February 2012.

478 SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, 20 February 2012.

479 Capital Research, Forward estimate of the market risk premium: Update, February 2012.

480 CEG, A report on the cost of equity in Aurora's revised regulatory proposal, February 2012.

The AER has considered each of these reports in making this final determination.

The last report was received after the time for making submissions had expired. In submitting the late consultant report, United Energy submitted that the AER should accept this late submission as the AER considered a late submission in its final decision on Envestra SA's access arrangement.[481]

The acceptance of a particular late submission during a previous determination should not lead stakeholders to assume that the AER will accept late submissions in all circumstances. Under the NER, the AER has a discretion to consider or not consider late submissions.[482] There may be occasions where the AER exercises its discretion to not consider a late submission. On this occasion, the factors the AER considered in deciding whether or not to accept the late submission included:

- the materiality of the matter
- the magnitude and complexity of the additional material presented
- how long after the due date the submission was made
- whether the party presenting the submission is directly affected by the outcome of the decision

These factors are not necessarily either definitive or exhaustive. The AER provides them principally to emphasise that its consideration of whether to accept a late submission is made on a case-by-case basis and is based on the particular circumstances at the time.

As part of the Roma to Brisbane pipeline gas access arrangement proposal, APTPPL submitted a report from SFG on the MRP with its access arrangement proposal. The AER's draft decision on APTPPL's access arrangement has been released at the same time as the AER released Aurora's final distribution determination. The AER has also considered the SFG report submitted by APTPPL in the context of assessing the MRP for the purposes of this determination.

Also, the AER has considered DRP material submitted in relation to concurrent assessments for the Powerlink final transmission determination and the Roma to Brisbane gas access arrangement review. Specifically, the AER has considered consultant reports from:

- PricewaterhouseCoopers (PwC)[483]
- SFG[484]
- CEG[485]

and submissions from stakeholders including:

- Queensland Treasury Corporation (QTC)[486]

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481 Rothfield, J (United Energy and Multinet Gas) to W. Anderson (AER), RE: response to AER draft distribution determination for Aurora Energy, Email, 29 February 2012.

482 NER, clause 6.14(a).

483 PricewaterhouseCoopers, *Debt risk premium and equity raising costs*, January 2012.

484 SFG, *Issues relating to Draft Decision (DRP and Equity Raising Costs)*, December 2011.

485 CEG, *Estimating the regulatory debt premium for the Roma to Brisbane pipeline—A report for APT Petroleum Pipelines*, October 2011.

- TransGrid[487]
- ElectraNet[488]
- Transend[489]
- The Energy Users Association of Australia (EUAA)[490]
- The Energy Users Group[491]
- Powerlines Action Group Eumundi (PAGE).[492]

10.3 Reasons

This section sets out the AER's consideration of issues raised in Aurora's revised proposal and submissions. These issues include the determination of the risk free rate, MRP and DRP. The AER has also assessed the overall rate of return against market data.

Aurora's revised proposal accepted the AER's approach to calculating the inflation forecast. The AER has updated the inflation forecast using that approach for the purposes of this final determination.

10.3.1 Risk free rate

In its initial proposal, Aurora proposed an averaging period that was consistent with the SRI methodology. It did not request the AER to depart from the SRI methodology for calculating the risk free rate.

In its letter dated 23 June 2011, the AER accepted Aurora's proposed averaging period. As a result, the AER did not raise any issues in respect of the risk free rate. Therefore, there were no changes required to address matters raised in the draft determination. In turn, this means that Aurora's revised proposal could not raise these matters.[493] Therefore, the AER considers that Aurora's revised proposal to use a long term estimate of the risk free rate is outside what clause 6.10.3(b) allows. Accordingly, the AER rejects that aspect of the proposal.[494]

However, the AER notes that aspects of Aurora's initial proposal may be viewed as an implicit request for the AER to depart from the SRI methodology. The AER does not agree with this characterisation. However, in case that is found to be the correct characterisation, the AER has assessed the merits of Aurora's revised proposal.

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486 QTC, *Debt risk premium analysis*, January 2012.

487 TransGrid, *Submission on the Powerlink draft decision*, February 2012.

488 ElectraNet, *re: Powerlink draft transmission determination 2012–13 to 2016–17*, February 2012.

489 Transend, *Submission to AER's draft decision for Powerlink*, February 2012, p. 10.

490 EUAA, *Submission to the Australian Energy Regulator (AER) on its Draft Decision on Aurora Energy's Regulatory Proposal 2012-2017 and Aurora Energy's Revised Proposal*, February 2012.

491 Energy Users Group, *AER 2011 review of Queensland electricity transmission—Response to Draft Decision*, February 2012.

492 Powerlines Action Group Eumundi, *Submission to the AER draft determination & Powerlink revised revenue reset application for 2012 to 2017*, February 2012.

493 NER, clause 6.10.2(c).

494 The AER's reasons for forming this conclusion are discussed further in section A.1.2.

The AER does not consider there is persuasive evidence justifying a departure from the SRI methodology in determining the appropriate risk free rate. The AER does not agree with Aurora's proposed process of nominating a multiple year averaging period that takes place in the past. Specifically, the AER considers:

- The prevailing 10 year CGS yield is a forward looking 10 year risk free rate
- Each WACC parameter should be estimated based on considerations relevant to that parameter, rather than to deal with issues relating to another parameter
- CGS appear to be efficiently priced in a liquid market, and there is not persuasive evidence suggesting the CGS market is distorted.
- CGS are low risk
- CGS yields are determined in a market, meaning the prevailing yield reflects the market's determination of the appropriate price at a particular time
- The averaging period method in the SRI is objective and unbiased, in that it is not susceptible to 'gaming'.
- In the Telstra matter, the Tribunal held that CGS yields remained an appropriate proxy of the risk free rate during the global financial crisis (specifically, during Telstra's averaging period of March to April 2009). The Tribunal's reasons why CGS yields remained an appropriate proxy of the risk free rate during Telstra's averaging period continue to apply during Aurora's initially proposed averaging period (of January to February 2012). [495]
- Following from the above reasons, there is not persuasive evidence justifying a departure from setting the risk free rate averaging period as close as practically possible to the commencement of the regulatory control period.

A key element of Aurora's submission appears to be that the prevailing CGS yields are lower than the past and therefore does not reflect an appropriate rate to be used as a forward looking rate. The AER considers that the current CGS pricing is the outcome of a well functioning efficiently priced market for these securities. There is no evidence presented to the contrary which is persuasive and shows other than an appearance of an unfavourable outcome for Aurora relative to the past.

The AER is cognisant of the NEL pricing principles which require the AER to provide 'a reasonable opportunity to recover at least the efficient costs'. The key question that has to be answered is whether the pricing principles have been met.

The AER's position is that the best method for ensuring that the pricing principles are achieved in relation to the WACC is to derive the individual WACC components based on the SRI and to the extent permitted by the NER, changed if there is persuasive evidence. That is, the AER considers that maintaining the 'integrity' of each parameter to achieve the best and most robust values taking account of relevant considerations including financial theory and regulatory practice would result in a WACC that satisfies the pricing principles. The starting point is the SRI.

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495 Australian Competition Tribunal, *Telstra Corporation Limited ABN 33 051 775 556 [2010] ACompT 1*, 10 May 2010, paragraphs 415-417. This matter is considered further in section A.1.5.

In the context of the methodology for setting the risk free rate, the issue before the AER is essentially one of identifying the method to determine the risk free rate that maintains that WACC parameter's 'integrity'. Both Associate Professor Lally and Greg Houston of NERA, in their expert evidence to the Federal Court agreed on the best approach that is consistent with CAPM theory:

> There was no dispute between the experts that the CAPM theory suggests that, ideally, the nominal risk-free rate input will be calculated on the day of the final determination. The AER believed that applying an averaging period that is closely aligned to the date of the final determination provides an unbiased rate of return that is consistent with the market conditions at the time of the final determination.[496]

Under clause 6.5.4(g), the AER is required to consider whether there is persuasive evidence justifying a departure from the SRI. The specific arguments raised by Aurora in the context of 'persuasive evidence' are unclear. Further, it is unclear whether the NER permits Aurora to raise this issue as part of its revised proposal given that it was not raised in its initial regulatory proposal or the AER's draft decision.

Nevertheless, the AER sets out its considerations that demonstrate why the SRI method is the most robust approach and the lack of 'persuasive evidence' to depart from it. The AER's reasons are set out below with further discussion in appendix A.

SRI risk free rate methodology

During the WACC review, there was substantial debate over the appropriate term and proxy of the risk free rate. In the end, the AER determined to maintain the previous adopted approach of a 10 year term and adopting CGS yields as the proxy for the risk free asset. Aurora appears to accept both the 10 year term and CGS proxy for the risk free rate.

During the WACC review, the appropriate averaging period to measure the risk free rate was not a contentious issue. Through the WACC review the AER formalised its existing approach to the averaging period. No objections from stakeholders were made on this approach at the time. It is this approach to the timing and length of the averaging period which Aurora now contests and proposes a departure from.

The key aspects of the SRI methodology in respect of the averaging period are that the period is:

- As close as practicably possible to the commencement of the regulatory control period
- Short run (10 to 40 days)
- Set in advance
- Once the period has been agreed or specified it cannot be changed.[497]

Ability to depart from the SRI risk free rate methodology

There has been some disagreement between the AER and Aurora on whether the averaging period the AER agreed with Aurora in June 2011 can subsequently be amended.

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496 Federal Court of Australia, ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639, 8 June 2011, paragraph 119.

497 The SRI methodology is further explained in section A.1.1.

The AER's position is that if the SRI methodology is applied then the agreed period cannot be amended. This is consistent with the view of the Federal Court in *ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639* (the 'ActewAGL matter') which involved the application of an analogous methodology.[498]

Accordingly the only way the agreed period can be amended is if there is persuasive evidence to depart from the SRI methodology.

A recount of the correspondence between the AER and Aurora on this matter and the development of the AER's view is set out in section A.1.2.

Prevailing 10 year CGS yield is a forward looking 10 year rate

In the ActewAGL matter before the Federal Court, both experts (Gregory Houston for ActewAGL and Associate Professor Martin Lally for the AER) agreed that the relevant required rate of return is the forward looking rate estimated as at the commencement of the regulatory control period.[499]

The AER agrees with Aurora that the prevailing 10 year CGS yield changes over time. However, contrary to Aurora's submission, it is incorrect to interpret these changes as indicating that the CGS yield is a short term rate. At any point in time, the yield on 10 year CGS bonds incorporates the market's expectation of financial and economic conditions over the next 10 years. This position is supported both theoretically and empirically:

- One of the main theories used to explain the term structure of debt is the 'expectations theory', which is generally regarded as an important part of the explanation of the term structure of debt.[500]
- The expectations theory implies that the current 10 year risk free rate is determined by the market expectation of the series of 10 consecutive one year risk free rates over the next 10 years—that is, the prevailing 10 year risk free rate does not reflect market expectations over the short term but rather over the next 10 years.
- It follows that the 10 year rate does not move in lock-step with the 1 year rate (which is a measure of short term expectations)—this is shown in Figure 10.1, which also shows the 10 year rate to be somewhat less volatile.

The fact that the AER measures this forward looking risk free rate over a relatively short averaging period does not change this conclusion.

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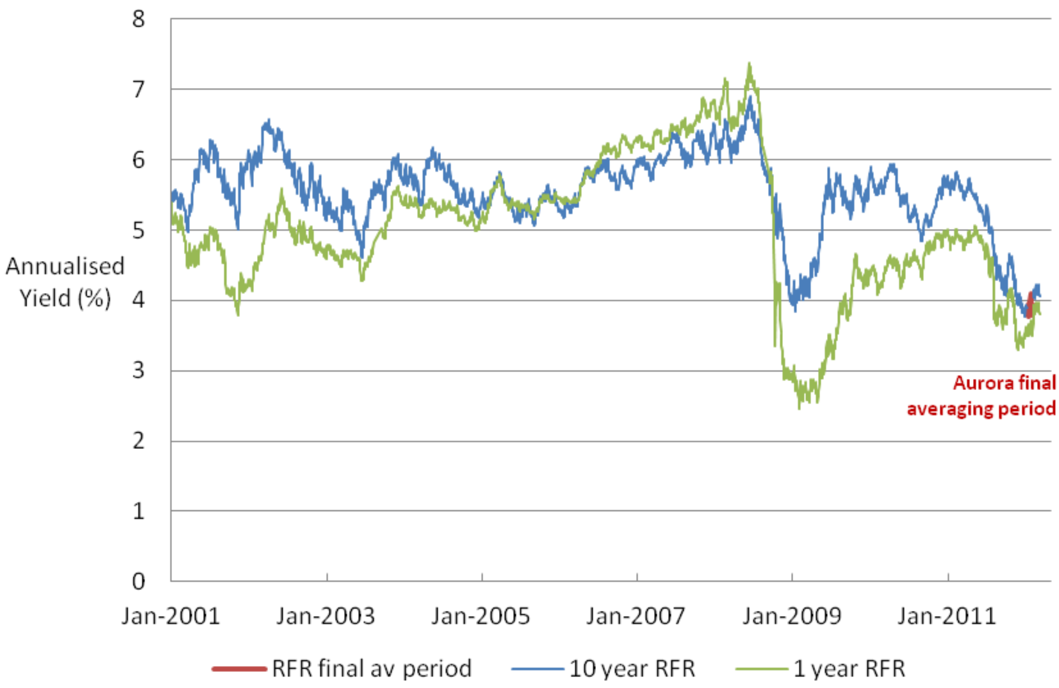
498 Federal Court of Australia, ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639, 8 June 2011, paragraph 85.

499 Federal Court of Australia, ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639, 8 June 2011, paragraph 145.

500 The 'liquidity premium theory' and the 'preferred habitat theory' identify other important determinant of the term structure of debt. Elton et al. *Modern Portfolio Theory and Investment Analysis* 8th ed. (2010), pp. 516 – 21. While the expectations theory is not generally considered to be sufficient, by itself, to explain reality, it continues to provide an important foundational understanding of the term structure of interest rates. The liquidity premium theory, which in a sense builds upon the expectations theory, is a more sophisticated and more likely explanation of the term structure.

Figure 10.1 Comparison of one and ten year CGS yields over time



Source: RBA, AER calculations.

Maintaining 'integrity' in the estimation of each parameter

The AER has consistently held a position that each parameter should be estimated based on considerations relevant to that parameter, rather than to deal with issues relating to another parameter.

In the WACC review, CEG considered the downward trend in the regulatory return on equity since mid-2008 might be a result of the MRP moving in the opposite direction to the yield on CGS. However, CEG did not provide a solution to address this issue through the MRP. Instead, it argued this was a reason why the AER should not lower the equity beta from the previously adopted value. The AER considered in the WACC review that a good regulatory principle was to preserve the integrity of each of the WACC parameters:

> However, the AER considers that the integrity in the estimation of each individual WACC parameter is important. This integrity includes that the MRP is a measure of market-wide non-diversifiable risk, whereas the equity beta is a measure of the benchmark efficient NSP's exposure to non-diversifiable risk relative to that of the market. To the extent that the prevailing MRP (and the MRP into the foreseeable future) is above the long term MRP, the AER does not agree that it is appropriate to address this issue via the equity beta.[501]

In the ActewAGL matter, ActewAGL submitted that the risk-free rate should be adjusted to take into account the variations in the MRP. This was because the NER fixed the MRP at 6 per cent. In that matter, Justice Katzmann held that:

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501 AER, Final decision—WACC review, May 2009, p. 190.

> The AER rejected the argument, not because it was blindly adhering to a rule or policy but for multiple reasons explained in the Final Decision at 264-265. It suffices to refer to one: adjusting the risk-free rate to make up for a higher MRP was an attempt to circumvent the legislation and would undermine the intended certainty provided under the regulatory regime.[502]

Maintaining the ‘integrity’ of each parameter promotes rigour and robustness in the estimation of each parameter. Addressing an ‘MRP issue’ through the estimation of the risk free rate introduces subjectivity and lacks rigour. Besides, the AER is unaware of any well accepted method for making these kinds of adjustments without introducing subjectivity or greater regulatory risk. Arguably, considering the NER sets parameter-by-parameter requirements, the AER’s approach is also required by the NER.

The AER has considered the argument that there is an inverse relationship between the CGS yield and the MRP as part of its assessment of the MRP. The detailed discussion is set out in the MRP section. In short, the AER considers that the empirical evidence in support of this relationship is not strong. This conclusion is supported by advice from McKenzie and Partington in their February 2012 MRP report, commissioned in response to Aurora's revised proposal.[503]

Addressing interdependencies between parameters

While maintaining integrity in the estimation of each parameter is important, so is recognising the economic interdependencies between parameters where they exist.

Consistency in the term of the risk free rate and the MRP is one such interdependency. For example, in *Application by GasNet [2003] ACompT 6*, the Tribunal stated that:

> While it is no doubt true that the CAPM permits some flexibility in the choice on the inputs required by the model, it nevertheless requires that one remain true to the mathematical logic underlying the CAPM. In the present case, that requires a consistent use of the r_f in both parts of the CAPM equation where it occurs so that the choice was either a five year bond rate or a ten year bond rate in both situations.[504]

For both the risk free rate and MRP, the AER has estimated a 10 year forward looking rate that is commensurate with prevailing conditions in the market for funds. In this context, prevailing conditions can be considered ‘prevailing expectations’ over the relevant forward looking timeframe which is 10 years.[505] Accordingly, both the risk free rate and MRP are forward looking estimates, though are estimated using different types of data due to the differing nature of these parameters:

- A 10 year forward looking risk free rate is more directly observable as it can be estimated based on current market data (using 10 year CGS yields as the proxy). 10 year CGS yields can be expected to have priced into them the market’s expectations of movements in the yields of short term CGS bonds over the next 10 years.

- A 10 year forward looking MRP is more challenging to estimate as current market data will not necessary reflect forward looking expectations. Accordingly, consideration of a broader set of evidence is needed to form a judgement on the MRP. Long term historical average excess returns are one such source of evidence and are used on the basis that investors’ forward looking expectations are likely to be influenced by their historical realised returns. The AER has also

502 Federal Court of Australia, ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639, 8 June 2011, paragraph 148.

503 McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012, pp. 9-12.

504 Australian Competition Tribunal, Application by GasNet Australia (Operations) Pty Ltd [2003] ACompT 6, paragraph 46.

505 AER, Final decision—WACC review, pp.72-77.

considered forward looking evidence, such as survey evidence, in determining the appropriate estimate for the MRP.

CGS market is liquid

The evidence suggests that the market for CGS bonds is liquid and efficiently priced. The Australian Office of Financial Management (AOFM) stated that the CGS market represents the most liquid single debt market in Australia.[506]

In mid 2007, the ACCC asked the RBA and the Treasury to comment on whether there were significant distortions in the nominal and indexed CGS markets at the time. Both RBA and the Treasury concluded in their responses that there were no distortions in the nominal CGS market and the nominal CGS bond yield was a good proxy for the risk free rate.[507]

The Treasury stated in its 2007 response that:

> The outcome of the Government's review of the CGS market in 2003 was the decision to continue issuance of sufficient nominal bonds to support a well functioning market. This is achieved by the regular issuance of new bonds as existing lines mature with the aim of supporting the Treasury bond futures market. In contrast to the index bond market, the nominal CGS market continues to display the attributes of a well functioning market.[508]

It is apparent that moderating supply, where necessary, to ensure a well functioning CGS market remains government policy and this policy is being actively implemented. In a recent Economic Round-up, the Treasury noted that:

> The Government announced in the 2011-12 Budget that it will continue to monitor the liquidity of the CGS market as the budget returns to surplus to ensure that it continues to support the bond futures market. This will mean at some stage the issuance of CGS to acquire financial assets alone rather than to finance the budget (Budget Paper No. 1).[509]

These statements from the RBA and Treasury provide the AER with a level of confidence that the CGS market, both now and at other points in time, is efficiently priced and liquid.

CGS is low risk

CGS are low risk securities issued by the Australian Government which are AAA rated.[510] In appendix A, the AER compares the yields on CGS against that of state government debt, which is another form of low risk debt.

The low risk nature of the CGS is a desirable characteristic for the risk free rate proxy. No new information has come to light since the time of the WACC review that causes the AER to depart from using the CGS yield. To the contrary, new evidence further supports the adoption of CGS yields as an appropriate proxy for the risk free rate. In November 2011, Fitch Ratings upgraded Australian Government debt (issued in foreign currencies) rating to AAA from AA+ for the first time in its history,

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506 AOFM, Commonwealth Government Securities, <http://www.aofm.gov.au/content/investors/CGS.asp?NavID=203>.

507 Debelle, G (RBA) to J Dimasi (ACCC), Letter, 9 August 2007; Murphy, J (Australian Treasury) to J Dimasi (ACCC), Treasury bond yield as a proxy for the CAPM risk free rate, 7 August 2007.

508 Murphy, J (Australian Treasury) to J Dimasi (ACCC), Treasury bond yield as a proxy for the CAPM risk free rate, 7 August 2007, p. 3.

509 Australian Treasury, Economic Round-up Issue 4 2011 – Debt, the Budget and the Balance Sheet, p.8.

510 AOFM, Commonwealth Government Securities, < http://www.aofm.gov.au/content/investors/CGS.asp?NavID=203>.

joining Standard & Poor's (S&P) and Moody's in giving Australia the highest possible rating.[511] This rating upgrade reflects the view of major rating agencies that Australia is one of the safest countries to lend to and CGS bonds face minimal default risk.

The high credit rating of CGS is not surprising considering:

- The four major Australian banks are among only 20 banks in the world rated within the AA band or higher.[512] The likelihood that the Australian Government may need to 'bail out' the banking sector in the foreseeable future therefore remains low relative to other developed countries.
- Australia's level of net government debt to GDP remains low by international standards. In 2011-12, Australian Government net debt is expected to peak at 7.2 per cent of GDP, which is less than one tenth of the average net debt position of other developed economies in 2011.[513]

This appears to indicate that the prevailing CGS yield is responsive to market conditions as the low risk of CGS are desired by both domestic and foreign investors. In turn, this would appear to provide further justification for its use, rather than call its use into question.

CGS yields are market determined

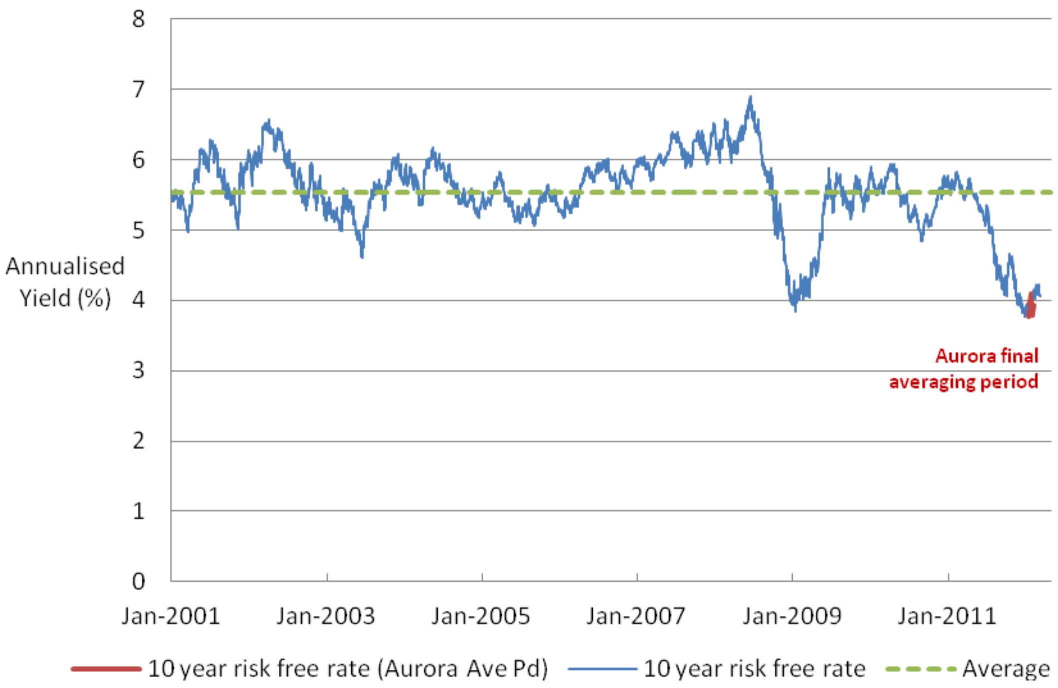
The AER recognises that the yield on 10 year CGS is currently lower than the historical average over the past 10 years. This is reflected in Figure 10.2

511 ABC News, Australia now fully AAA, surplus or not, 29 November 2011, < http://www.abc.net.au/pm/content/2011/s3379347.htm>.

512 Notwithstanding S&P and Fitch recently downgraded the credit rating of the four Australian major banks by one notch to AA-. RBA, Statement on monetary policy, February 2012, p. 52.

513 Australian Treasury, Budget Paper No. 1 2011-12 Statement 7: Asset and Liability Management, 10 May 2011, S7-6.

Figure 10.2 Yield on 10 year CGS over time



Source: RBA, AER analysis.

A prevailing 10 year CGS yield which is 'low', in of itself, does not imply either that the 10 year CGS is a poor proxy for the risk free rate or that it is inappropriate to measure the risk free using the most up to date data.

In times of uncertainty, investors are prepared to accept a lower yield on relatively safe assets. The AER agrees with Aurora that the current low CGS yields are likely to be driven by the strong demand caused by a "flight to quality" from offshore investors. This is an expected outcome in a well functioning efficiently priced market to an increase in demand. An increase in demand drives up the price of the CGS and the yields for the CGS are reduced as a result.

An alternative explanation might be that CGS are currently 'over priced', in the sense that the price of CGS exceeds its fair value, and therefore the yield is 'artificially low'. For the AER to make such a conclusion, the AER would, effectively, be saying that it has better information than the market or that it 'knows better' than the many traders in the market whose interactions set the price of CGS. The AER considers there is not a reasonable basis to draw such a conclusion on the evidence before it.

SRI methodology is objective and unbiased

Determining the averaging period in advance promotes the achievement of an unbiased estimate for the risk free rate. When an averaging period is agreed or specified in advance, it minimises opportunities for regulatory gaming as at that time there is a degree of uncertainty over what the risk free rate will be in that future period. However, once the averaging period has commenced, the service provider will be aware of the relevant CGS yields. The AER considers that allowing the service provider to re-open the issue once the averaging period commences opens the process to gaming. If the CGS yields are 'low' the regulated business would have an incentive to argue for a different averaging period or method of setting the risk free rate. However, if the CGS yields are 'high' the service provider would not have such an incentive. As a result, it seems likely that a service provider would only seek a different averaging period where the CGS yields are 'low', promoting an upward bias in regulatory outcomes over time if these amendments to the averaging period were accepted.

An alternative approach to achieving an unbiased rate would be to commit in advance to use a long term average risk free rate for all service providers. The AER makes the following comments on this approach:

- No service provider proposed this approach in the WACC review.
- This approach would not lead to the best forward looking 10 year risk free rate at any particular point in time. The best forward looking 10 year risk free rate is the prevailing 10 year rate.
- On the need for consultation before making a significant change in a WACC methodology, Aurora's proposal contains mixed and seemingly inconsistent positions. On the one hand, Aurora submitted that the AER should not change its position on the use of geometric and arithmetic averages of historical excess returns in the context of an individual DNSP's determination. Aurora stated:

  > The periodic, industry-wide review is the appropriate forum for such innovation to be raised and properly tested by all stakeholders.[514]

  On the other hand, Aurora proposed that a long run average risk free rate be used in the calculation of the cost of equity. The change in the risk free rate is a more substantive methodological shift than the change in the emphasis placed on different averages of historical excess returns.

A number of approaches to setting the risk free rate may have some merit. However, whichever approach is chosen, it should be applied consistently so as to retain its 'unbiased' characteristic and avoid incentives for 'gaming' the outcome.

The AER notes that Aurora first raised its proposal to change how the risk free rate is set in its revised proposal on 16 January 2012. By that time, Aurora's averaging period had commenced.[515] The AER considers such change, if permitted to occur, will likely result in an upward bias over time.[516]

Addressing Aurora's submission

The AER has considered arguments put forward by Aurora in its revised proposal and submission. The precise nature of Aurora's contentions is not clear. It seems to the AER that Aurora argued that the outcome is unfavourable rather than presenting evidence justifying a departure from the SRI methodology. The AER notes Aurora's main arguments supporting a long term historical average risk free rate appear to be based on:

- The CGS yields are currently 'plummeting' due to the 'flight to quality' from overseas investors.

[514] Aurora, Revised proposal—Supporting information: Return on capital, January 2012, pp.21-22.
[516] The unbiased nature of the SRI methodology and the biased nature of Aurora's revised proposal is considered further in section A.1.5.
[516] The unbiased nature of the SRI methodology and the biased nature of Aurora's revised proposal is considered further in section A.1.5.

- The AER uses a 'short term' risk free rate with a 'long term' MRP
- The AER's approach is different to IPART's approach.

Other matters raised by Aurora and others are addressed in appendix A.

Current level of the CGS yield

In the revised proposal, Aurora raised the concern that the strong demand for Australian CGS has been manifested in a 'plummeting CGS yield.'[517] It is unclear to the AER as to what Aurora was intending to argue.

The AER considers Aurora might be arguing that the market for CGS is currently 'distorted' creating yields that are 'artificially low'. However, Aurora did not submit any evidence for this case. Nor did Aurora state in its revised proposal that it considered the market is 'distorted'. Instead Aurora stated that the market was 'plummeting'. As discussed above, the AER considers the recent evidence suggests that the CGS market remains liquid and efficiently priced.

The AER considers Aurora might simply be arguing that the yields are lower than the past as a result of the strong demand. The AER agrees with Aurora's statement in this case and the AER recognises the CGS yields are currently lower than the historical average. However, as discussed above, this represents the outcome of a well functioning efficiently priced market.

The fact that the CGS yield is at or close to historical lows is not very informative. It does not necessarily result in an unreliable estimate of the risk free rate such that it no longer reflects a reasonable forward looking estimate. Interest rates fluctuate from time to time and reflect the investors' expectation on the return of the risk free asset. McKenzie and Partington further suggested in their February 2012 supplementary MRP report that the prevailing government bond yield represents the opportunity cost that a risky investment must beat:

> At the time of writing investors can invest in a 10 year government bond at yield of 3.84%. So a ten year project that offers say 4.5% is worth considering if the risk is low enough. The question is how risky is the investment and what is the required risk premium? The fact that bond yields were higher in the past does not make 4.5% a bad deal, or 3.84% too low a benchmark. We see no reason to switch from using the current 10 year government bond yield as the proxy for the risk free rate.[518]

For the AER to intervene, it is insufficient that the outcome appears unfavourable to Aurora. Something more must be present. As mentioned above, that could be some failure in the methodology itself or a distortion in the market. However, as the reasoning above indicates, there is

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517 Aurora, Revised proposal—Supporting information: Return on capital, January 2012, p. 11 Aurora also noted this position is supported by ENA's submission on the AER's rule change proposal. CEG, TransGrid, and Transend raised similar arguments. CEG submitted that the AER determined 9.08 per cent nominal return on equity in Aurora's draft determination is "by far the lowest cost of equity allowance allowed by the AER, or the ACCC before it, for an energy transport business." CEG suggested that this is a result of the AER methodology which sets the risk free rate equal to the prevailing risk free rate and sets the MRP primarily based on the AER's estimate of the historical average. CEG, A report on the cost of equity in Aurora's revised regulatory proposal, February 2012, pp.1-2, TransGrid, Submission on the AER's draft decision on Powerlink, February 2012, p.2, and
Balchin, J., Dermondy, C. and G. Houston, Joint expert report on WACC issues—Report for the ENA, pp.18-19. Transend stated that the standard estimation approach using the CAPM would result in an "artificially depressed" estimate of the cost of equity. Transend, Submission to AER's draft determination on Aurora Energy, 20 February 2012, p.1.

518 McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012, p. 11.

not persuasive evidence of any such failure or distortion, nor did Aurora make this case in its revised proposal.

That said, in one section of Aurora's submission on its revised proposal it describes the risk free rate as "downwardly biased due to current financial conditions".[519] This appears to be the only place Aurora makes this contention. However, even if this understood to be Aurora's contention, for the reasons set out in this attachment and appendix A the AER is not persuaded by the evidence before it that the CGS yields are a biased proxy for the risk free rate.

Short term risk free rate and long term MRP

In the revised proposal, Aurora suggested the WACC determined by the AER is biased as the AER adopts an MRP that reflects the long term average and uses a risk free rate that reflects the current market environment.[520]

As discussed above, the AER considers it is incorrect to characterise the method for calculating these WACC parameters as a long term historical MRP coupled with a short term risk free rate. The risk free rate is not 'short term'. The risk free rate and MRP are both reflective of a forward looking return over the next 10 years. However, there are different considerations and evidence available for each parameter. The approach adopted by the AER is therefore internally consistent.

Comparison with IPART's approach

Aurora submitted in its revised proposal that IPART had made an upward adjustment to the risk free rate in recognition of the low CGS yield in its Sydney Desalination Plant (SDP) decision.[521] In that decision IPART estimated the risk free rate at 3.9 per cent using a 20 day averaging period ending on 28 October 2011.[522] However, IPART chose an overall rate of return that was 80 basis points higher than the midpoint of the estimated WACC range. IPART stated that this 80 basis point adjustment was informed by the WACC derived using the long term historical average estimate for all parameters, rather than short term prevailing rates.[523]

The AER acknowledges that IPART made such an upward adjustment to the overall rate of return in the SDP decision. Aurora's representation of IPART's approach to the risk free rate may, at face value, appear to have some merit. However, closer analysis suggests otherwise.

The AER considers IPART decisions are not completely comparable to those of AER. IPART's approach involves adopting a range for some WACC parameters.[524] This approach results in a range

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519 Aurora, AER's draft distribution determination—Return on capital, Submission, 20 February 2012, p.10.

520 Aurora, Revised proposal—Supporting information: Return on capital, January 2012, p. 15.

521 Aurora, Revised proposal 2012-2017, February 2012, p. 94. This is also noted by CEG and TransGrid, see: CEG, A report on the cost of equity in Aurora's revised regulatory proposal, February 2012, p.9 and TransGrid, Submission on the AER's draft decision on Powerlink, February 2012, p.3.

522 This risk free rate is based on the 5 year CGS, not the 10 year CGS (as per the AER approach). IPART, Review of water prices for Sydney Desalination Plant Pty Limited, From 1 July 2012, Water - Final report, December 2011, p. 85.

523 IPART, Review of water prices for Sydney Desalination Plant Pty Limited, From 1 July 2012, Water - Final report, December 2011, pp. 93–95.

524 Further, the IPART uses a different approach to estimating other WACC parameters compared to the Aurora proposal. Adopting the IPART DRP approach, for example, would give Aurora a DRP of 3.3 per cent, which is 81 basis points lower than the DRP determined by the AER. Further, IPART set the equity beta for SDP using a midpoint of 0.7, rather than the 0.8 determined for Aurora by the AER. [The AER discusses the comparability of equity betas across water and energy sectors in AER, *Draft decision, Roma to Brisbane Pipeline*, April 2012, Appendix C.]

for the overall rate of return, IPART then exercises its judgement in choosing an appropriate overall WACC from within this range. The AER notes that IPART often chooses a point estimate which differs from the midpoint of the derived WACC range.[525]

The AER's approach arises from the NER and SRI requirements, which are different to the requirements IPART faces. They set separate requirements for determining the appropriate point estimate for each WACC parameter. While the approaches of the AER and IPART differ, they are both internally consistent over time. Consistency is important to achieve unbiased outcomes. The AER considers that it is inappropriate for it to make an upward adjustment in the current framework. To do so on an ad hoc basis creates the potential for arbitrariness and introduces subjectivity, which results in the potential for biased regulatory outcomes.[526]

10.3.2 Market risk premium

The AER considers there is persuasive evidence justifying a departure from the 6.5 per cent MRP set out in the SRI. In the AER's opinion, a value of 6.5 per cent is now inappropriate as:

- The AER's reasons for moving from the long term value of 6 to 6.5 per cent at the time of the WACC review appear less relevant now. Specifically, the AER is less convinced on the likelihood that the GFC led to a structural break in the market, and it appears that the heightening of market risk at the time has since eased.

- McKenzie and Partington advised that the AER's reasons for moving to 6.5 per cent were not well justified in the WACC review.[527] McKenzie and Partington advised the AER to adopt an MRP of 6 per cent

- Historical excess returns and survey evidence support 6 per cent as a forward looking 10 year MRP estimate

- In the recent Envestra matter, the Tribunal held that it was open for the AER to adopt 6 per cent for the MRP.

For these reasons, the AER does not approve Aurora's revised proposal MRP value of 6.5 per cent. For these same reasons, the AER has substituted Aurora's proposal with a value of 6 per cent which is amended from Aurora's proposal only to the extent necessary to enable it to be approved in accordance with the NER.

The AER considers that an MRP of 6 per cent satisfies the requirements of the NER.[528] It will result in a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing standard control services. It will also:

525 For example, the IPART chose a WACC 60 basis points above the midpoint in its 2009 Rail Access undertaking (the risk free rate was 5.4 per cent). IPART, New South Wales Rail Access Undertaking—Review of the rate of return and remaining mine life from 1 July 2009, Rail access - Final report and decision, August 2009, p. 6.

526 IPART's approach is considered further in section A.1.8.

527 McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012, December 2011, pp.28-30; this was also noted by SFG, Market risk premium, 11 October 2011, pp.6-8; SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, 20 February 2012, pp.4-6.

528 NER, clause 6.5.4(h).

- achieve an outcome that is consistent with the NEO, in promoting efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity

- provide Aurora with a reasonable opportunity to recover at least efficient costs, and effective incentives to promote economic efficiency with respect to the provision of network services.

In the following sections the AER examines:

- the practice among Australian regulators over the MRP before the GFC and the AER's WACC review

- the reasons for the AER's adoption of 6.5 per cent in the WACC review—both whether those reasons remain relevant now and whether the adjustment was appropriate at the time

- the practice among Australian regulators over the MRP since the height of the GFC and the AER's WACC review

- the strengths and weaknesses of each piece of evidence on the MRP—historical excess returns, survey evidence, DGM estimates, implied volatility, other financial market indicators, market commentary and the economic outlook

- the relationship between the risk free rate and the MRP.

Six per cent consensus prior to the GFC

Prior to the 2009 WACC review, Australian regulators consistently applied an MRP of 6 per cent in regulatory decisions.[529] The regulators determined the MRP under a specific CAPM framework:

- The MRP is forward looking (not an historical measure), and cannot be directly observed

- The MRP is for a 10 year term, which means that short-term market fluctuations are of little relevance

- The MRP is for a domestic CAPM, which means overseas evidence is of little relevance.

Since the forward looking MRP cannot be observed, the value of the MRP is contentious amongst academics and market practitioners. There is conflicting expert opinion and no definitive answer.[530] For this reason, Australian regulators were informed by a variety of evidence. This included historical estimates, survey based estimates, estimates derived from various dividend discount models and qualitative data on market conditions.

However, given the nature of the task, the determination of an MRP has always involved the exercise of regulatory judgement in the context of conflicting evidence. Regulators considered the various arguments and limitations surrounding the forms of evidence presented to them.

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529 AER, Final decision—WACC review, May 2009, p. 176.

530 See for example Mehra R. and Prescott E.C., *The equity premium, A puzzle, Journal of Monetary Economics*, 15, 1985, pp. 145–161; Damodoran A., *Equity Risk Premiums (ERP), Determinants, Estimation and Implications*, September 2008, p. 1; Doran J.S., Ronn E.I. and Goldberg R.S., *A simple model for time-varying expected returns on the S&P 500 Index*, August 2005, pp. 2–3.

The MRP is estimated using a 10 year term. In this context, Australian regulators gave appropriately limited weight to transient market sentiment or short-term fluctuations. That is, evidence on short-term market expectations was only relevant to the extent that it influenced long-term (10 year) market expectations. Further, the regulators did not simply adopt the 'latest' estimates presented at any one regulatory reset, noting that year by year updates of a highly volatile series could be unstable.[531]

The use of a domestic CAPM reflects the conditions observed in Australian capital markets, recognising international investors only to the extent that they invest in the domestic capital market.[532] The 6 per cent consensus is illustrated in Table 10.3, which shows decisions from Australian state and territory regulators dealing with electricity and gas. It also includes decisions by the ACCC concerning various regulated sectors.

Table 10.3 The 6 per cent consensus prior to the GFC

Regulator	Year	Sector	MRP (per cent)
ACCC	2000	Telecommunications	6.0
ACCC	2001	Airports	6.0
ACCC	2002	Rail	6.0
ICRC	2004	Gas	6.0
ACCC	2005	Electricity	6.0
IPART	2005	Gas	6.0
ESCOSA	2006	Electricity	6.0
QCA	2006	Gas	6.0
OTTER	2007	Electricity	6.0
ESC	2008	Gas	6.0
ACCC	2008	Postal services	6.0
ERA	2008	Rail	6.0

Source: ACCC,[533] ICRC,[534] IPART,[535] ESCOSA,[536] QCA,[537] OTTER,[538] ESC[539], ERA[540]
Notes: This list is not exhaustive. Reported decisions were selected to give a spread of years and industry sectors.

531 AER, Final decision—WACC review, May 2009, p. 236.

532 AER, Final decision—WACC review, May 2009, pp.100–101.

533 ACCC, *A Report on the Assessment of Telstra's Undertaking for the Domestic PSTN Originating and Terminating Access Services*, July 2000, pp. 74–77; ACCC, *Sydney Airports Corporation Limited, Aeronautical Pricing Proposal, Decision*, May 2001, p. 194; ACCC, *Decision Australian Rail Track Corporation Access Undertaking*, May 2002, p. 158; ACCC*, Final decision, NSW and ACT transmission network revenue cap, TransGrid 2004–05 to 2008–09,* April 2005, pp. 147–151;.ACCC*, Australian Postal Corporation, Price Notification, Decision*, July 2008, p. 173.

534 ICRC, *Final decision, Investigation into prices for electricity distribution services in the ACT*, March 2004, p. 70.

535 IPART, *Revised access arrangement for Country Energy gas network, Final decision*, November 2005, p. 69.

536 ESCOSA, *Proposed revisions to the access arrangement for the South Australian as distribution system, Final decision*, June 2006, p. 80.

537 QCA, *Final decision, Revised access arrangement for gas distribution networks: Allgas Energy*, May 2006, p. 62.

538 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania, Final report and proposed maximum prices*, September 2007, p. 152.

539 ESC, *Gas access arrangement review 2008–2012, Final decision, Public version*, March 2008, p. 489.

Adoption of 6.5 per cent in the WACC review

As presented in the draft determination, the SRI applicable to the Aurora distribution determination was released by the AER in May 2009 at a time where there was significant uncertainty about the effects of the GFC on future market conditions. That is, there was a particularly heightened level of uncertainty over whether the future was going to reflect the past. The AER considered that market risk was elevated at the time and acknowledged two possible scenarios that could explain that—a temporary elevation or a structural break—and considered that either option supported an increase in the MRP (though not a significant increase). These reasons led to the AER's departure from the previously adopted value of 6 per cent and adoption of a 6.5 per cent MRP. The AER has assessed these reasons to determine whether there has been a material change in circumstances or any other factor that would now make the 6.5 per cent MRP inappropriate, having regard to the underlying criteria.

Likelihood of a structural break

Consistent with the draft decision, the AER considers that the likelihood of the GFC generating a structural break in the MRP has reduced, even though this might have been a plausible interpretation of the available evidence in May 2009. The AER reaches this conclusion based on the following evidence:

- Survey measures since the height of the GFC accord with those from before the GFC[541]
- Implied volatility since the height of the GFC has returned to its long run average.[542]

These matters are discussed in detail below in the remainder of this section 10.3.2 and in appendix A. The GFC was a significant event and its magnitude should not be understated. However, the AER notes that the impact of the GFC for Australian capital markets was moderate relative to international experience.

Cyclical trends are observed in financial markets over time and typically involve shifts between periods of strong economic growth (boom) and periods of relative stagnation or sharp decline (recession). The fluctuations in financial markets are unpredictable and the duration of cycles varies from more than a year to twelve years.[543] When an investor considers the likely return across a 10 year horizon, these cyclical fluctuations are a normal experience. The long-term expected return takes account of the expected future investment growth and decline. That is, the long-term MRP has always been determined in the inevitable presence of these business cycles.

Temporary elevation subsides

The alternative scenario contemplated by the AER in the WACC review—that there was a temporary elevation above the long-term MRP—does not provide grounds for keeping the MRP above the long run average in perpetuity. Information and data available since the release of the SRI suggests that

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540 ERA, *Final Determination, 2008 Weighted Average Cost of Capital for the Freight (WestNet Rail) and Urban (Public Transport Authority) Railway Networks*, June 2008, p. 22

541 See Fernandez (2009), Fernandez and Del Campo (2010), Fernandez et al (2011), Asher (2011).

542 For clarity, the AER notes the differing opinions on the implications of implied volatility measurements for the long run MRP. This statement does not depend on such an assessment. Rather, the return of the implied volatility index to the pre–GFC average indicates that this indicator of financial markets conditions did not undergo a structural break.

543 Burns and Mitchell, *Measuring business cycles*, National Bureau of Economic Research, 1946.

the prevailing medium-term MRP has not been above the long-term MRP. This includes the following evidence that supports an MRP of 6 per cent:

- Survey measures since the height of the GFC accord with those from before the GFC[544]
- Implied volatility since the height of the GFC has returned to its long run average[545]
- Market commentary from the RBA and other economic commentators does not indicate that the GFC resulted in a structural break in market risk.[546]

The return to the 6 per cent MRP as used in the pre-GFC period should not be misconstrued. In part this is because the definition of ‘pre-GFC’ is rather vague when considering the cyclical nature of financial markets. The AER does not consider that the prevailing (short-term) market conditions now are identical to the, (short-term) market conditions just before GFC began (that is, the 2006–07 financial year). However, evidence seems to suggest that the present market conditions are comparable to the market conditions that generally existed across the fluctuating business cycles through the last fifteen years

Appropriateness of 50 basis point uplift in the WACC review

McKenzie and Partington called into question the AER's decision in the WACC review to increase the MRP to 6.5 per cent in the first place, stating that the AER's reasons for increasing the MRP were not well justified. McKenzie and Partington concluded in their February 2012 MRP report:

> We further consider that the decision to increase the MRP by 0.5% for a ten year regulatory period was not well justified as we would not expect the crisis conditions and extreme volatility to extend over such a long period. With the benefit of observing what has happened post-GFC it is appropriate for the AER to move back to the relatively safe ground of the unconditional MRP of 6% rather than persist with the conditional MRP of 6.5%. To put it another way the conditions justifying the shift to a conditional MRP have substantially abated so there is good reason to move back to the unconditional MRP.[547]

Regulatory practice since the height of the GFC

The return to the 6 per cent MRP also accords with the practice of other Australian regulators, and for sectors other than electricity, as is shown in Table 10.4.

544 See Fernandez (2009), Fernandez and Del Campo (2010), Fernandez et al (2011), Asher (2011).

545 For clarity, the AER notes the differing opinions on the implications of implied volatility measurements for the long run MRP. This statement does not depend on such an assessment. Rather, the return of the implied volatility index to the pre–GFC average indicates that this indicator of financial markets conditions did not undergo a structural break.

546 IMF, *World Economic Outlook (WEO)*, pp. 86–87 and Table A.2, September 2011; RBA, *Statement on monetary policy*, August 2011, p. 72; OECD, *Australia economic outlook 89—country summary*, May 2011.

547 McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012, pp.28-30.

Table 10.4 Regulatory decisions from 2010 onwards

Regulator	Decision date	Sector	MRP
ACCC	May 2010	Postal services	6.0
QCA	June 2010	Water	6.0
QCA	September 2010	Rail	6.0
ACCC	December 2010	Rail	6.0
ERA	February 2011	Gas	6.0
AER	June 2011	Gas	6.0
ACCC	July 2011	Telecommunications	6.0
ACCC	July 2011	Water	6.0
ESCV	August 2011	Rail	6.0
ACCC	September 2011	Airports	6.0
ERA	October 2011	Gas	6.0
QCA	November 2011	Water	6.0
IPART	December 2011	Water	5.5 - 6.5
ESCOSA	February 2012	Water	6.0
IPART	March 2012 (draft decision)	Water	5.5 - 6.5
IPART	March 2012 (draft decision)	Water	5.5 - 6.5
ERA	March 2012 (draft decision)	Electricity	6.0
IPART	April 2012 (draft decision)	Electricity	5.5 - 6.5

Source: ACCC,[548] AER,[549] ERA,[550] ESC,[551] QCA.[552] IPART[553], ESCOSA[554]

548 ACCC, *Australian Postal Corporation, 2010 Price Notification*, May 2010 p. 80–81; ACCC, *Position Paper in relation to the Australian Rail Track Corporation's proposed Hunter Valley Rail network Access Undertaking*, 21 December 2010, p. 104; ACCC, *Inquiry to make final access determinations for the declared fixed line services, Final Report*, July 2011, p. 63; ACCC, *Pricing principles for price approvals and determinations under the Water Charge (Infrastructure) Rules 2010*, July 2011, pp. 32–33; and ACCC, *Airservices Australia price notification, Final decision*, September 2011, p. 26, 29.

549 AER, *Final Decision, APT Allgas Access arrangement proposal for the Qld gas network, 1 July 2011–30 June 2016*, 17 June 2011, p. 41.

550 ERA, *Final decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid–West and South–West Gas Distribution systems*, 28 February 2011, p. 103; ERAWA, *Final Decision,* Access Arrangement Information for the Dampier to Bunbury Natural Gas Pipeline, December 2011, p.159; ERAWA, *Draft Decision,* Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, March 2012, p 206.

551 ESCV, *Metro proposed access arrangement, Final decision, August 2011*, p. 85.

552 QCA, *Final Report, Gladstone Area Water Board: Investigation of Pricing Practices*, June 2010, p. 124; QCA, Final decision, Dalrymple Bay Coal Terminal 2010 Draft Access Undertaking, September 2010, p. 8; QCA, *Draft Report -,* SunWater Irrigation Price Review: 2012-17 - Volume 1, November 2011, p. 392.

553 IPART, Final report, *Review of water prices for Sydney Desalination Plant Pty Limited*, December 2011, p. 80; IPART, Draft report, *Review of prices for Sydney Water Corporation's water, sewerage, drainage and other services*, March 2012, p. 79; IPART, *Review of prices for the Sydney Catchment Authority*, March 2012, p. 85; IPART, Draft report - *Changes in regulated electricity retail prices from 1 July 2012*, April 2012, p. 96.

Notes: Only final decisions are listed, omitting draft or interim reports where a later document includes consideration of the MRP. Where multiple decisions since 2010 have used an MRP of 6 per cent, only the first decision by that regulator/for that sector is listed.

The AER conducted the WACC review during 2008 and published its SRI in May 2009. This review increased the MRP for electricity distribution and transmission service providers to 6.5 per cent. Across the next year or so, several regulatory decisions applied this elevated MRP,[555] including in the AER's gas network decisions in March and June 2010.[556] However, table 9.5 shows that from the second half of 2010 and throughout 2011, there has been a return to the 6 per cent consensus.[557] This includes determinations by different Australian regulators and for various regulated sectors. Importantly, those that had increased their MRP have subsequently had published decisions returning to the 6 per cent MRP.[558]

Australian regulators increased the MRP during the height of the GFC to take account of the uncertainty prevailing at that time. However, the key message from table 9.5 is that in accordance with the easing of concerns arising from the GFC, there is now a generally consistent return across all regulated sectors to the 6 per cent MRP.

It should also be noted that the period immediately before the GFC was one of strong market outlook (for example, due to the commodity boom) when compared to a longer term average. However, rather than reducing the MRP due to any short-term effects, the AER maintained setting the MRP at its long-term estimate of 6 per cent.

Historical excess returns

Historical excess returns, though strictly not forward looking, have predominantly been used to estimate the MRP on the assumption that investors base their forward looking expectations on past experience. In a regulatory context, the use of historical excess returns has a number of advantages as supported by McKenzie and Partington in their December 2011 MRP report:

- the estimation methods and the results are transparent
- the estimation methods have been extensively studied and the results are well understood, and
- historical estimates are widely used and have support as the benchmark method for estimating the MRP in Australia.[559]

The long-term averages of historical excess returns, adjusted to incorporate a value for the imputation credit utilisation rate (theta) of 0.35, produce a range of 5.7 to 6.1 per cent (based on arithmetic

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554 ESCOSA, *Final Advice, Advice on a Regulatory Rate of Return for SA Water – Final Advice*, February 2012, p. 50

555 For example, in ACCC decisions for Telecommunications and Postal services. See ACCC, *Draft pricing principles and indicative prices for LCS, WLR, PSTN OTA, ULLS, LSS*, August 2009, p. 72; and ACCC, *Australia Post's Draft 2009 Price Notification, ACCC View*, December 2009, p. 137.

556 AER, *Final decision, Access arrangement proposal, ACT, Queanbeyan and Palerang gas distribution network, 1 July 2010–30 June 2015*, March 2010, p. 63; AER, *Final decision, Access arrangement proposal, Wagga Wagga natural gas distribution network, 1 July 2010–30 June 2015*, March 2010, p. 44; AER, *Final Decision, Jemena Gas Networks, Access arrangement proposal for the NSW gas networks, 1 July 2010 – 30 June 2015*, June 2010, p. 201; AER, *Final decision, Envestra Ltd, Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016*, June 2011, p. 59.

557 Specifically, the three sectors were an MRP of 6.5 per cent was used—Telecommunications, Postal Services and Gas—have all had subsequent decisions applying an MRP of 6 per cent.

558 Several regulators for different sectors did not apply the elevated MRP in the first place—though this may be because there were no decisions made in the relevant period.

559 McKenzie, M. and G. Partington, Equity market risk premium, 21 December 2011, pp. 5–6.

averages) and 3.5 to 4.7 per cent (based on geometric averages) over the periods 1883-2011, 1937-2011 and 1958-2011.[560] These results are set out in Table 10.5. The starting point for each of the five estimation periods in Table 10.5 were chosen because of changes in the quality of the underlying data sources (1883, 1937, 1958 and 1980) and the introduction of the imputation tax system (1988).[561] Consistent with the AER's position in the WACC review, the AER places greater emphasis on the three longest estimation periods.

Table 10.5 Historical excess return estimates—assuming a utilisation rate of distributed imputation credits 0.35 (per cent)

Sampling period	Arithmetic mean	Geometric mean
1883–2011	6.1[a]	4.7
1937–2011	5.7[a]	3.7
1958–2011	6.1[a]	3.5
1980–2011	5.7	3.1
1988–2011	4.9	3.0

Source: Handley.[562]
Notes: (a) Indicates estimates are statistically significant at the 5 per cent level using a 2 tailed test.

In the WACC review, the AER considered it was appropriate to consider a range of estimation periods, having regard to the strengths and weaknesses of each period:

- Longer time series contain a greater number of observations and therefore produce a more statistically precise estimate.
- The quality of the underlying data source, with significant increases in the quality of the data becoming available in 1937, 1958 and 1980.
- More recent sampling periods closely accord with the current financial environment, particularly since financial deregulation (1980) and the introduction of the imputation credit taxation system (1988).
- Shorter time series are more vulnerable to influence by the current stage of the business cycle or other (one off) events.[563]

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560 The 0.35 value for theta is consistent with the Tribunal's position in Application by Energex Limited (Gamma) (No 5) [2011] ACompT9.

561 Brailsford, Handley and Maheswaran, *Re-examination of the historical equity risk premium in Australia, Accounting and Finance*, vol. 48, 2008, pp. 85–86.

562 Handley, An estimate of the historical equity risk premium for the period 1883 to 2011, April 2012, p.6.. Handley's estimate of the arithmetic averages starting in 1883 and 1958, updated to 2011, are also found in and confirmed by the report by NERA submitted by the Victorian DNSPs. Handley's and NERA's update of the geometric average over the periods 1883-2011 and 1958-2011 differ by one basis point. The reason for this difference is unclear to the AER but the difference appears immaterial. NERA, The market risk premium, 20 February 2012, pp.8-9. In the draft decision the AER had regard to historical excess returns ending in 2010 which were the latest estimates available at that time. Now that estimates ending in 2011 are available the AER has also had regard to those estimates. However the AER's conclusions on historical excess returns are the same whether having regard to estimates ending in 2010 or in 2011.

563 AER, Final decision—WACC review, May 2009, pp. 200, 204; Brailsford, Handley and Maheswaran, *Re-examination of the historical equity risk premium in Australia, Accounting and Finance*, vol. 48, 2008, pp. 78–82.

On balance, the AER considers that the three longest estimation periods (from 1883, 1937 and 1958) should all be given primary consideration, but the shorter estimation periods (from 1980 and 1988) are also relevant.[564]

In arriving at an estimate of a 10 year forward looking MRP using historical annual excess returns, the AER considers it is important to consider both the arithmetic and geometric averages. Arithmetic averages of annual returns result in an overestimate of a 10 year forward looking rate whereas geometric averages of annual returns result in an underestimate. The best estimate of historical excess returns over a 10 year period is therefore likely to be somewhere between the geometric average and the arithmetic average of annual excess returns. Further details of the AER's analysis and reasons for its decision on this issue are set out in section A.2.1.

Based on the estimates reported in Table 10.5, the AER considers that the latest historical excess return estimates support a forward looking long term MRP of 6 per cent. Given that this estimate is towards the top of the quoted range, the AER considers that, if anything, it is more likely to overstate the MRP based on historical excess returns.

Aurora, in its revised proposal, stated:

> By its nature, the long term average historical excess return to equity cannot change materially over the space of two or three years, and hence it is implausible for this source of evidence to provide persuasive evidence for change.[565]

Aurora is partially correct in that the long term average of historical excess returns does not change materially as each new year of data is added (though it does change to some degree). However, what Aurora's statement does not appreciate is that the latest historical excess return estimates, in combination with factors leading to a change in the emphasis placed on historical excess returns, can result in persuasive evidence justifying a change.

At both the time of the WACC review and now, the arithmetic averages of historical excess returns across the long term historical periods the AER considers most relevant were and are below 6.5 per cent. It was not through placing substantial weight on historical excess returns that led to the AER's departure from 6 per cent and adoption of 6.5 per cent.

The AER departed from 6 per cent because of its concerns over a possible structural break or prolonged period of heightened market risk that the GFC might have caused. There was greater uncertainty than usual at the time of the WACC review over whether the future was going to resemble the past. The AER said in the WACC review that had "relatively stable market conditions" existed the AER would have considered 6 per cent to the best estimate of a forward looking long term MRP.[566] The AER's concerns over these two potential factors have now lessened. Accordingly, the AER now places greater emphasis on historical excess returns than at the time of the WACC review.

Further, as explained in section A.2.1, the AER's view on the upwards biased nature of using the arithmetic average of historical annual excess returns to estimate a forward looking multi-period (10 year) has strengthened. The AER now looks closely at both arithmetic and geometric averages.

564 In forming this view, the AER has had regard to NERA's view on the volatility of historical excess returns in the first half of the previous century. The AER's considerations on this issue are set out in section A.2.2.

565 Aurora, Revised proposal—Supporting information: Return on capital, January 2012, p.21.

566 AER, Final decision—WACC review, May 2009, pp.235-238.

The AER's reasons for placing greater emphasis on historical excess returns, more generally, in addition to the AER's reasons for also placing greater emphasis on geometric averages of historical excess returns, more specifically, both support a conclusion that 6.5 per cent is now inappropriate and that there is persuasive evidence justifying a departure from 6.5 per cent. These same reasons also support a conclusion that 6 per cent is an appropriate forward looking 10 year MRP.

Survey based estimates

Survey based estimates of the MRP are relevant for consideration as they are forward looking and reflect actual market practice. However, the Tribunal and others have noted that the relevance of some survey results depend on how clearly the survey sets out the framework for MRP estimation. This includes the term over which the MRP is estimated and the treatment of imputation credits. Survey based estimates may also be subjective, though this concern may be mitigated as the sample size increases. The AER recognises that survey based evidence, like other types of evidence, should be carefully reviewed before it is relied upon.

In the WACC review, the AER focused on the following survey evidence on the MRP:

- KPMG (2005) surveyed 33 independent expert reports on takeover valuations from January 2000 to June 2005. It found that the MRP adopted in valuation reports ranged from 6–8 per cent. KPMG reported that 76 per cent of survey respondents adopted an MRP of 6 per cent.[567]
- Capital Research (2006) found that the average MRP adopted across a number of brokers was 5.09 per cent.[568]
- Truong, Partington and Peat (2008) in the last quarter of 2004 surveyed chief financial officers, directors of finance, corporate finance managers, or similar finance positions of 365 companies included in the All Ordinaries Index as of August 2004. From the 87 responses received, 38 were relevant to MRP. They found the MRP adopted by Australian firms in capital budgeting ranged from 3–8 per cent, with an average of 5.94 per cent. The most commonly adopted MRP was 6 per cent.[569]

The AER concluded that survey measures of the MRP across different years, different survey respondents or sources, and different authors results in similar outcomes. The AER noted that the above survey measures indicated that an MRP of 6 per cent was by far the most commonly adopted value by market practitioners (noting that these surveys were conducted prior to the onset of the GFC). The AER did not know whether surveys of market participants in the then current financial conditions would have led to the same results.

Following from the SRI final decision, new survey evidence has become available. The AER considered these in recent regulatory reviews. The latest surveys conducted after the onset of the GFC indicate that the forward looking MRP expected to prevail in the future did not change as a result of the GFC and that 6 per cent remains a reasonable estimate of the long term MRP. In chronological order, these surveys include the following:

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567 KPMG, *Cost of capital – market practice in relation to imputation credits*, August 2005, p. 15.

568 Capital Research, *Telstra's WACC for network ULLS and the ULLS and SSS businesses – Review of reports by Prof. Bowman*, March 2006, p. 17.

569 G. Truong, G. Partington and M. Peat, *'Cost of capital estimation and capital budgeting practices in Australia', Australian Journal of Management,* Vol. 33, No. 1, June 2008, p. 155.

- Bishop (2009) reviewed valuation reports prepared by 24 professional valuers from January 2003 to June 2008. It found that the average MRP adopted is 6.3 per cent and 75 per cent of these experts adopted an MRP of 6 per cent.[570]

- Fernandez (2009) surveyed university finance and economic professors around the world in the first quarter of 2009. The survey received 23 responses from Australia and found that the required MRP used by Australian academics in 2008 ranged from 2–7.5 per cent with an average of 5.9 per cent.[571]

- Fernandez and Del Campo (2010) surveyed analysts around the world in April 2010. The survey received 7 responses from Australian analysts and found that the MRP used by them in 2010 ranged from 4.1–6 per cent with an average of 5.4 per cent.[572]

- A further survey by Fernandez et al (2011) in April 2011 reported that average MRP used by 40 Australian respondents ranged from 5–14 per cent, with an average of 5.8 per cent.[573]

- Asher (2011) surveyed 2,000 members of the Institute of Actuaries of Australia. Asher reported that 33 out of a total of 58 Australian analysts who responded to the survey expect the 10 year MRP to be between 3 to 6 per cent. The most commonly adopted MRP value is 5 per cent. The report also illustrated that expectations of an MRP much in excess of 5 per cent were extreme.[574]

The key findings of the surveys are summarised below.

Table 10.6 Key findings of MRP surveys

	Numbers of responses	Mean	Median	Mode
KPMG (2005)	33	7.5%	6.0%	6.0%
Truong, Partington and Peat (2008)	38	5.9%	6.0%	6.0%
Bishop (2009)	27	NA	6.0%	6.0%
Fernandez (2009)	23	5.9%	6.0%	NA
Fernandez and Del Campo (2010)	7	5.4%	5.5%	NA
Fernandez et al (2011)	40	5.8%	5.2%	NA
Asher (2011)	49	4.7%	5.0%	5.0%

For the surveys under consideration, the most commonly used MRP is 6 per cent.

570 Bishop, S. (2009), IERs—Aconservative and consistent approach to WACC estimation by valuers, Value Advisor Associates.

571 Fernandez and Del Campo, *Market Risk Premium used by Professors in 2008: A Survey with 1400 Answers, IESE Business School Working Paper*, WP-796, May 2009, p. 7.

572 Fernandez and Del Campo, *Market Risk Premium Used in 2010 by Analysts and Companies: A Survey with 2400 Answers, IESE Business School*, May 21 2010, p. 4.

573 Fernandez, Arguirreamalloa and Corres, *Market Risk Premium used in 56 Countries in 2011: A Survey with 6,014 Answers,* IESE Business School Working Paper, WP-920, May 2011, p. 3.

574 Actuary Australia 2011 Issue 161, Asher, *Equity Risk Premium Survey—results and comments*, July 2011, pp. 13–14.

The AER acknowledges that survey evidence must be treated with caution as the results may be subject to limitations. This is noted by the Tribunal and the following comments were made in its decision on the Envestra matter:

> Surveys must be treated with great caution when being used in this context. Consideration must be given at least to the types of questions asked, the wording of those questions, the sample of respondents, the number of respondents, the number of non-respondents and the timing of the survey. Problems in any of these can lead to the survey results being largely valueless or potentially inaccurate.
>
> When presented with survey evidence that contains a high number of non-respondents as well as a small number of respondents in the desired categories of expertise, it is dangerous for the AER to place any determinative weight on the results.[575]

The AER engaged McKenzie and Partington to review the survey evidence used in its draft decision in light of the Tribunal's comments. McKenzie and Partington have considered the following criteria in the review of survey evidence:

- the timing of the survey
- the type of survey questions asked and the wording of the questions
- sample of respondents
- numbers of responses and response rate.

The AER has taken the McKenzie and Partington report into account when considering the reliability of survey evidence. McKenzie and Partington's assessment of the available survey evidence against these criteria is set out in Appendix A.

Based on its own review and the advice from McKenzie and Partington, the AER considers that survey based estimates of the MRP are relevant for consideration to inform the forward looking MRP. Survey estimates provide some indication that expectations of the forward looking long-term MRP have not been affected by the GFC. They also suggest a reduced likelihood that there was a structural break of the type considered at the time of the WACC review. Moreover, this evidence supports the view that a forward looking MRP of 6 per cent is commensurate with prevailing conditions in the market for funds.

Dividend growth model estimates

DGM based estimates of the return on equity and inferred estimates of the MRP are highly sensitive to the assumptions made. It is necessary that all assumptions have a sound basis, otherwise estimated results from DGM analysis may be inaccurate and lead analysts into error. [576] The AER considers that DGM based analysis of the MRP can provide some information on the expected MRP. However, due to the sensitivity of results to input assumptions in the model, the DGM analysis should be limited to providing a general point of reference for assessing the reasonableness of MRP. For

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[575] Australian Competition Tribunal, Application by Envestra Limited (No 2) [2012] ACompT 3, 11 January 2012, paragraphs 150–154.

[576] For example corporate finance texts have noted “The simple constant-growth DCF [discounted cash flows] formula is an extremely useful rule of thumb” but “Naive trust in the formula has led many financial analysts to silly conclusions.” Brealey, Myers and Allen, *Principles of Corporate Finance: International Edition,* 9th Edition, Boston: McGraw-Hill, 2008, p. 95.

this reason, the AER has not used the DGM based analysis for estimating the return on equity, and therefore the MRP.

At the time of the WACC review, the AER noted or considered:

- The implied MRP produced by DGM estimates are very sensitive to both the exact specification of the model used and the exact point in time in which they are estimated
- Generally the expected market growth rate in dividends per share (a key input) is proxied with analysts' short term forecasts of market wide earnings per share growth, or long term expectations of GDP growth (or both). The AER referenced advice from Associate Professor Lally that explained how:
    - DGM estimates based on analysts' short term forecasts of earnings extrapolated into perpetuity will likely produce an upwards bias in the resultant MRP estimates, and
    - DGM estimates based on long run expected GDP growth will produce an "upper bound on the true value" of the MRP.
- That regulators had previously been wary to lower the MRP when DGM estimates had been below 6 per cent and that the AER was similarly wary to increase the MRP (based on DGM estimates) even though those estimates at the time of the WACC review produced estimates above 6 per cent
- Academics (Officer and Bishop, CEG) and industry representatives (ENA (which represents Aurora), APIA, GridAustralia) considered DGM estimates should be used as a "cross check" on the reasonableness of other methods to estimate the MRP rather than used as the primary method.

No new information has come to light since the WACC review that causes the AER to place any greater reliance on DGM estimates. To the contrary, McKenzie and Partington's advice supports the AER's position of placing little weight on this measure of the MRP.

In their December 2011 MRP report, McKenzie and Partington’s main criticism of DGM estimates was that the MRP estimates derived from valuation models (such as the DGM) are sensitive to the assumed growth rate of dividend used in the models. Their review found that there was no consensus on how the either short term or long term expected growth rates should be estimated.[577] McKenzie and Partington recommended that little weight should be attached to the use of implied cost of capital estimates such as those derived from the DGM in determining the MRP for the purpose of regulation.[578]

Other financial market indicators

Other financial market indicators (implied volatility, dividend yields and relative debt spreads) have been proposed as relevant factors in the estimation of the MRP. The AER considers that each has limitations:

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577 McKenzie, M. and G. Partington, Equity market risk premium, 21 December 2011, pp. 25–27.

578 McKenzie, M. and G. Partington, Equity market risk premium, 21 December 2011, pp. 25–27.

- Implied volatility relies on certain assumptions to derive an MRP estimate.[579] Some of these are contentious. In particular, the assumption that the price of risk per unit of implied volatility is constant is disputed on theoretical and empirical grounds.[580] The method only provides a short-term estimate of the MRP (usually 3 months, matching the term of the implied volatility measure) and the AER is unaware of any settled method to extrapolate to a longer term. Given that the relevant MRP is the 10 year forward looking rate, the AER places limited weight on the MRP estimate derived on this basis.

- Dividend yield in this context is calculated for the entire market, using forecast distributions (dividends) for all firms in a broad share market index divided by the total value of those shares. As a practical matter, the dividend yield estimate will differ based on the choice of index, the method of obtaining and aggregating dividend forecasts and the horizon of those dividend forecasts. The key limitation is the lack of clarity around the relationship (if any) between dividend yield and the 10 year forward looking MRP.

- Relative debt spread refers to the difference in yields between bonds with high (AAA-rated) and low (BBB-rated) credit ratings. Relative debt spreads will differ based upon the method chosen to measure the bond yields. The key limitation is that it is not clear to the AER how a change in relative debt spreads relates to a change in the 10 year forward looking MRP.

The conditional MRP approach put forward by SFG uses these three financial market indicators as 'conditioning variables' to adjust the MRP estimate around its long run average (here called the unconditional MRP).[581] The AER does not consider that the SFG conditional MRP approach is a relevant basis to estimate the 10 year forward looking MRP. This is because there is insufficient evidence to establish a quantifiable relationship between the three conditioning variables and the MRP. This point is discussed in detail in appendix A. The most prominent of the three is implied volatility, which has also been proposed as a separate indicator of the MRP. The AER considered the use of implied volatility to inform the forward looking MRP in the SRI and in the draft determination. The underlying principle is that higher implied volatility is indicative of higher risk and consequently a higher MRP. Implied volatilities are typically calculated based on short term (3 month or less) option prices.

Recent data for one common measure of implied volatility, based on three month options over the S&P/ASX 200, is shown in Figure 10.3.

579 Further, there are problems determining the appropriate measure of implied volatility, with different measures (based on different underlying options) producing conflicting figures.

580 AER, *Draft decision, Envestra Ltd, Access arrangement proposal for the Qld gas network*, February 2011, pp. 282–283.

581 SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, pp. 8–13, 26–30

Figure 10.3 Implied volatility (VIX) over time

Source: Citibank VIX implied volatility index (3 month put/call options on S&P/ASX 200), sourced via Bloomberg code CITJAVIX.

It is evident that implied volatility is quite variable and that the level can change substantially in a matter of months. Further, although implied volatility was high during the worst of the GFC, the current level is below the long run average. Using data updated to the end of March 2012, this measure of implied volatility is at 15.2 per cent, 3.6 per cent below the long run average of 18.8 per cent (measure from the commencement of this series in 1997).

If this latest point estimate is to be used to inform the forward looking 10 year MRP, as proposed by SFG,[582] it appears to support a value at or slightly below the long term average MRP (that is, 6 per cent).[583]

The AER considers this result should be treated with caution, and does not propose to use it to set the forward looking 10 year MRP. The AER considers that implied volatility is not able to be directly related to the MRP, because of:

- Term mismatch—The implied volatility measures are short term (usually less than 3 months), in accordance with the term of the underlying financial derivatives (options). There is no reasonable method to extrapolate to a longer term, and the relevant MRP is over 10 years.[584] Even if (for

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582 To clarify, SFG proposed to use implied volatility to inform the estimate of the MRP. SFG did not propose to use the latest point estimate of implied volatility (but rather an older point estimate), SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, p. 9.

583 Briefly, the proposed relationship is that the current value of implied volatility relative to its long term average is indicative of the current value of the market risk premium relative to its long term average.

584 AER, Aurora *2012–17 draft distribution determination*, November 2011, pp. 215–216.

example) implied volatility indicated that the three month MRP was double its long run average, this still would not indicate that the 10 year MRP had departed from the average.

- Measurement problems—Different implied volatility measures produce different (and sometimes conflicting) results. Further, there is evidence that these measures are systematically biased (upwards).
- Contentious assumptions—Observing the amount of risk (via implied volatility) does not equate to the price of that risk (which is what is relevant to the MRP). This gap is most commonly breached by assuming a constant ratio, for instance that if the current implied volatility is double the long run average, the MRP will also be double its long run average. This assumption is disputed on theoretical and empirical grounds.

The AER's view is shared by McKenzie and Partington who concluded in their February 2012 supplementary MRP report that:[585]

> Further work on this technique (implied volatility) might be warranted, but given the current state of play it could hardly be regarded as a validated method, let alone an accurate and reliable adjustment to the MRP.

The AER maintains its view that option implied volatility is not a reliable basis for estimating the forward looking 10 year MRP. For this reason, the AER places little weight on the implied volatility analysis to inform the appropriate MRP for this draft decision.

A detailed discussion of the AER's assessment of the conditional MRP approach, and the three financial indicators can be found in section A.2 of appendix A.

Market commentary and economic outlook

General market commentary and economic outlook provided by eminent bodies gives some useful insights to their thoughts about the current and future state of the financial market. However, the AER accepts that since most commentaries do not make specific reference to returns in equity markets, the link between the commentary and the MRP is difficult to quantify. Consistent with comments made by the Tribunal in a recent decision,[586] the AER placed limited weight on this evidence.

The AER noted Aurora and other interested parties made reference to market commentaries discussing the GFC and the European Sovereign debt crisis, including reference to the joint expert report provided with the ENA's submission on WACC matters in response to the AER's rule change proposal.[587] Specifically, this report noted that the RBA stated in its March 2009 Financial Stability Review:

> The global financial system has continued to experience significant stress. ... A notable feature of the current crisis has been a marked increase in the price of risk, after risk had been underpriced in many markets for a number of years. This repricing of risk has resulted in large falls in the price of

585 McKenzie, M. and G. Partington, Supplementary report on the Equity market risk premium, 22 February 2012, pp. 26–27

586 McKenzie, M. and G. Partington, Supplementary report on the Equity market risk premium, 22 February 2012, p. 19.

587 NERA discussed the views of AMP Chief Economist Shane Oliver. NERA, The market risk premium, 20 February 2012, p. 39. ENA submission was referred to by both Aurora and TransGrid. See: Aurora, Revised regulatory proposal—Supporting information: Return on capital, January 2012, p.13 and TransGrid, Submission on Powerlink's Revenue Proposal for the 2012-2017 regulatory control period, February 2012, p.2.

> many financial assets, often by considerably more than can be explained by changes in the expected underlying cash flows.[588]

Consistent with the Tribunal decision, the AER does not consider such commentaries make specific reference to returns in equity markets. Therefore the AER does not consider these commentaries can be used to inform the appropriate estimate for the MRP.

The relationship between the risk free rate and MRP

Aurora suggested in its revised proposal that 6 per cent for the market risk premium is too low and the AER should address this problem through a higher risk free rate. The AER continues to recognise the importance of integrity in the individual parameters. The AER remains of the view that it is not appropriate to address an MRP issue via an adjustment in the risk free rate. This is because the NER prescribes the CAPM formula for calculating the nominal post-tax WACC and sets out separate requirements for calculating each of its inputs such as the risk free rate and MRP. The AER considers that this indicates an intention that the AER seek to ensure the integrity of each parameter and not alter an otherwise appropriate parameter to resolve an issue elsewhere.

As discussed in the risk free rate section, the AER considers Justice Katzmann’s conclusion provides strong support of the AER’s view that it is inappropriate to address an MRP issue via an adjustment to the risk free rate. In essence, Aurora's revised proposal suggests that as a consequence of lower CGS yields, there should be a compensating increase in the MRP. Such an argument relies on the assumption that there is an inverse relationship between the long term CGS yield and the long term MRP. However, the AER is not aware of any persuasive evidence to support this assumption.[589]

McKenzie and Partington supported this view in their February 2012 supplementary report. They noted that there is some empirical evidence supporting a negative correlation between the short term nominal government bill yield and future nominal excess returns on the market. However this negative correlation gets weaker as the time horizon gets longer[590]. The AER acknowledges that there is evidence suggesting an inverse relationship between the short term government bill rate and the short term nominal excess returns on the market. However, the AER considers the concern raised by McKenzie and Partington is relevant, as the AER estimates a forward looking 10 year MRP.

McKenzie and Partington further advised in their February 2012 supplementary MRP report that there is some empirical evidence supporting an inverse relationship between the nominal government bond yield and future nominal excess returns. However, the explanatory power of these regressions is low. The consequence is that these regressions are unlikely to provide a reliable forecast of excess returns. McKenzie and Partington stated:

> Low explanatory power is usual for equations that predict returns, but in the current case it does mean that the effect of the yield is readily offset by random variation in other factors. In other words, random variation represents most of the excess returns. It also seems that the relation is not particularly stable. A consequence of low explanatory power and instability is that the regression between yields and excess returns is unlikely to provide a reliable forecast of excess returns.[591]

[588] Balchin, J.,Dermody, C. Houston G and B. Quach, Assessment of the AER's proposed WACC framework: a joint report for the Energy Networks Association, 8 December 2011, p. 18.

[589] McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012, pp. 9-12.

[590] McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012, p. 10.

[591] McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012,, p.10

10.3.3 Debt risk premium

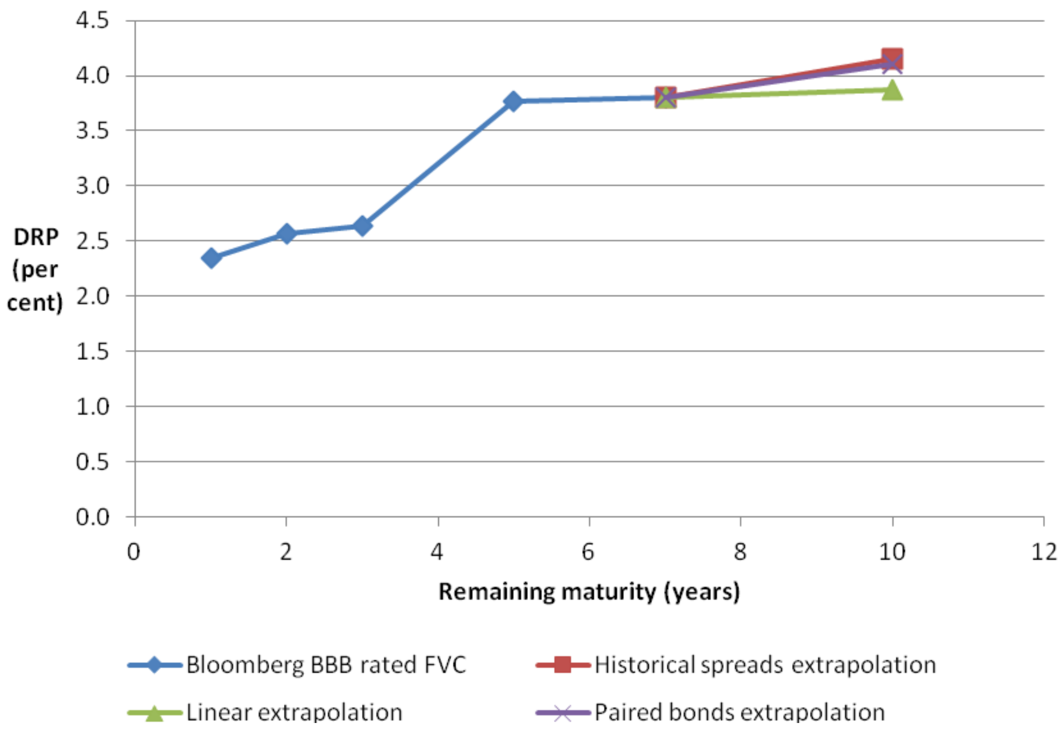
The AER accepts Aurora's revised proposal to estimate the DRP using the extrapolated Bloomberg BBB rated FVC. Based on Aurora's revised proposal, the AER has determined a benchmark DRP of 4.11 per cent (effective annual compounding rate) for this final determination.[592]

The AER has assessed Aurora's revised proposed method to extrapolate the Bloomberg 7 year BBB rated FVC against two alternative approaches.[593] These include:

- Historical spreads analysis—This approach uses the last historical spread[594] between the Bloomberg 7 and 10 year AAA rated FVCs to extrapolate the 7 year DRP estimate to 10 years.
- Linear extrapolation—This approach takes the difference between the 5 and 7 year DRPs published by the Bloomberg BBB rated FVC. The 7 year DRP is then extrapolated in a straight line to a 10 year term by adding that difference.

The three extrapolation approaches are set out in Figure 10.4.

Figure 10.4 Extrapolation approaches for the Bloomberg 7 year BBB rated FVC



Source: Bloomberg, RBA, AER analysis.

The historical spreads approach results in a 10 year DRP estimate of 4.15 per cent. The linear extrapolation approach results in a 10 year DRP estimate of 3.87 per cent. The AER considers that all three of the extrapolation approaches have shortcomings, and all three rely on contentious

592 This is based on the same averaging period used to estimate the risk free rate.

593 Aurora's revised proposed method extrapolates the Bloomberg 7 year BBB rated FVC using the 'paired bonds' analysis. This approach uses the change in observed spreads for a pair of bonds with different terms issued by the same corporation.

594 Specifically, it is based on the last published 20 days prior to 22 June 2010.

assumptions.[595] In the absence of a more robust alternative approach to extrapolate the Bloomberg 7 year BBB rated FVC, the AER accepts Aurora's revised proposed approach.

The Energy Users Association of Australia (EUAA),[596] Energy Users Group[597] and the Powerlines Action Group Eumundi[598] submitted that the extrapolated Bloomberg BBB rated FVC results in an excessively high DRP estimate.[599] In contrast, ElectraNet, TransGrid and Transend submitted that the AER should apply the Bloomberg BBB rated FVC to estimate the DRP.[600] Specifically:

- ElectraNet submitted the AER should consider the Bloomberg BBB rated FVC in combination with direct market analysis.
- Transend submitted the continued use of the Bloomberg BBB rated FVC to estimate the DRP would promote regulatory stability and confidence, and that the AER should consult widely on any change in approach before applying a new methodology.

The AER notes the submissions, and considers that its previous analysis has shown that the extrapolated Bloomberg 7 year BBB rated FVC results in a DRP higher than that indicated from market evidence, such as observed bond data and independent market commentary.[601] However, in light of the recent Tribunal decisions, the AER accepts Aurora's revised proposal to apply the extrapolated Bloomberg BBB rated FVC for estimating the DRP, until it has undertaken a public consultation process to determine alternative methodologies.

10.3.4 Reasonableness checks on overall rate of return

In previous sections the AER evaluates the evidence on each WACC parameter individually, while also taking into account the interdependencies between WACC parameters where relevant. In this section the AER evaluates the overall rate of return that results from the individual WACC parameter values being combined in accordance with the WACC and CAPM formulae. The AER considers that the overall rate of return is commensurate with the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by Aurora.[602] In turn,

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595 The AER set out its detailed analysis of the use of historical AAA curve spreads in its recent electricity draft decisions. For example, see: AER, *Draft distribution determination, Aurora Energy Pty Ltd 2012–13 to 2016–17*, November 2011, pp. 246–249; AER, *Draft decision, Powerlink transmission determination 2012–13 to 2016–17*, November 2011, pp. 229–232. The AER has also set out its analysis of the use of paired bonds in its recent electricity draft decision for Powerlink, in the context of reasonableness checks proposed by PricewaterhouseCoopers on behalf of Powerlink: AER, Draft decision, Powerlink transmission determination 2012–13 to 2016–17, November 2011, pp. 229–232. Similarly, the AER set out its detailed analysis of the use of historical linear extrapolation in: AER, *Final decision, Jemena Gas Networks 2010–2015*, June 2010, p. 189.

596 EUAA, *Submission to the Australian Energy Regulator (AER) on its Draft Decision on Aurora Energy's Regulatory Proposal 2012-2017 and Aurora Energy's Revised Proposal*, February 2012, p. 22.

597 Energy Users Group, *AER 2011 review of Queensland electricity transmission—Response to Draft Decision, February* 2012, pp. 14–15.

598 Powerlines Action Group Eumundi, *Submission to the AER draft determination & Powerlink revised revenue reset application for 2012 to 2017*, February 2012, p. 6.

599 These submissions were made on the AER's draft decision for Powerlink.

600 These submissions were made on the AER's draft decision for Powerlink. ElectraNet, *re: Powerlink draft transmission determination 2012–13 to 2016–17*, February 2012, p. 4; TransGrid, *Submission on the Powerlink draft decision,* February 2012, p. 4; Transend, *Submission to AER's draft decision for Powerlink*, February 2012, p. 10.

601 See market evidence at: AER, *Draft distribution determination, Aurora Energy Pty Ltd 2012–13 to 2016–17*, November 2011, pp. 241–246; AER, *Draft decision, Powerlink transmission determination 2012–13 to 2016–17*, November 2011, pp. 223–229.

602 NER, clause 6.5.2(b).

the AER considers that the overall rate of return provides a reasonable opportunity for Aurora to recover at least its efficient costs.[603]

The overall rate of return is determined using market data and finance theory. There are techniques available to assess the overall rate of return, which can produce a range of plausible results. Nevertheless, these techniques provide a useful reasonableness check for the AER's primary approach of using a detailed bottom-up analysis of the WACC input parameters.

The AER examines asset sales, trading multiples and broker WACCs for listed regulated business in Australia; as well as recent decisions by other Australian regulators and the historical range of WACC values provided by the AER for other electricity and gas service providers. These cross checks suggest that the regulated rate of return is reasonable.

For this final determination, the AER determines an indicative overall rate of return using a nominal vanilla WACC of 8.28 per cent. This is based on a cost of equity of 8.69 per cent, a cost of debt of 8.00 per cent and a gearing level of 60 per cent.

Trading multiples analysis suggests the overall rate of return is reasonable given market and sales valuations. The overall rate of return also falls within the range of estimates found in broker reports. Also, while the overall rate of return is at the lower end of recent AER decisions, it is in line with recent decisions made by other Australian regulators.

Recent regulated asset sales

For recent transactions of regulated assets, for which relevant data is available, the AER compares the market value (i.e. the sale price) with the book value (i.e. the regulatory asset base).

Over the past few years, regulated assets have generally been sold at a premium to the RAB. If the market value is above the book value, this may imply that the regulatory rate of return is above that required by investors. Conversely, when the market value is below the book value, this may imply that the regulatory rate of return is below that required by investors.

Caution must be exercised before inferring that the difference indicates a disparity in WACCs, particularly where the difference is small. A range of factors may contribute to a difference between market and book values. A RAB multiple greater than one might be the result of the buyer:

- expecting to achieve greater efficiency gains that result in actual operational and capital expenditure below the amount allowed by the regulator
- increasing the service provider's revenues by encouraging demand for regulated services
- benefiting from a more efficient tax structure or higher gearing levels than the benchmark assumptions adopted by the regulator, and growth options
- expecting to achieve higher returns if regulation is relaxed.[604,605]

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603 NEL, section 7A 2

604 Grant Samuel & Associates Pty Limited, *Financial Services Guide and Independent Expert Report in relation to the Recapitalisation and Restructure of Babcock and Brown Infrastructure*, 9 October 2009, p.77.

605 Each of these reasons assume the purchasing firm is making a rational purchasing decision. Another reason for a RAB multiple greater than one might be that the purchasing firm misjudged the value of the target assets and paid too much

Regulated asset sales in the market are also infrequent allowing limited opportunity to conduct this analysis.

Regulated asset sales do, however, provide a useful real-world indication of whether market participants consider the AER's benchmark WACC is within a reasonable range. The consistent positive trend as discussed below provides evidence that the AER's WACC approach is not unreasonable.

In October 2010, Envestra purchased Country Energy's NSW gas network at a multiple of 1.25 times the 2010 RAB.[606] Further details on this transaction can be found in the AER's draft decision for the QLD/SA gas distribution networks.[607]

In July 2011, DUET sold its 25.9 per cent stake in West Australian Gas Network (WAGN) to ATCO Ltd in return for a 20 per cent interest in the Dampier to Bunbury pipeline (DBP) and a 20.1 per cent interest in Multinet.[608]

In December 2011, APA Group divested 80 per cent of its holding of APT Allgas (a gas distributor in South East Queensland) to Marubeni Corporation and RREEF; each acquiring 40 per cent equity stakes.[609]

APA Group stated that net funds released from the sale were $477 million after transaction costs and the net enterprise value was $526 million.[610] Applying a RAB value, estimated at the sale date, to this enterprise value produces a multiple of 1.20.

This transaction involved the sale of both regulated and unregulated assets. Accordingly the RAB multiple may overstate the premium on the regulated assets as unregulated assets generally require a higher cost of capital.[611]

APA Group also stated that the sale price was in line with the book value of the assets. The gross sale price was $500.9 million, with the book value of assets sold at $488.8 million.[612] This equates to a multiple of 1.02. These multiples can be considered the upper and lower bound estimates of the RAB multiple for this transaction.

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for those assets. Each transaction considered by the AER involved sophisticated investors with significant knowledge of the industry. Accordingly, the AER does not consider it likely that the RAB multiples greater than one result from poor valuations of the target assets.

606 AER, Final decision, *Wagga Wagga natural gas distribution network, 1 July 2010-30 June 2015*, March 2010 and ASX, *Envestra company announcement*, 26 October 2010, viewed 10 January 2012, <http//www.asx.net.au/asxpdf/20101026/pdf/31tcvlnblp4xqc.pdf>.

607 AER, *Draft decision, Envestra draft decision, 1 July 2011-30 June 2015*, 17 February 2011, p. 63.

608 ASX, DUET company announcement, 29 July 2011, viewed 9 February 2012, <http://asx.com.au/asx/statistics/announcements.do?by=asxCode&asxCode=due&timeframe=Y&year=2011>

609 APA Group, *Completion of the sale of 80% of Allgas*, 16 December 2011, viewed 10 January 2012, <http://apa.com.au/investor-centre/news/asxmedia-releases/2011/completion-of-the-sale-of-80-per-cent-of-allgas.aspx>.

610 APA Group, *Completion of the sale of 80% of Allgas*, 16 December 2011, viewed 10 January 2012, <http://apa.com.au/investor-centre/news/asxmedia-releases/2011/completion-of-the-sale-of-80-per-cent-of-allgas.aspx>.

611 Allgas is a holding company that also owns the unregulated Moura pipeline and the Gatton-Gympie easement.

612 Net proceeds after transaction costs was $478.4 million, with transaction costs of $22.5 million and a gain on sale of $12.1 million. The APA Group, Interim Financial Report for the half year ended 31 December 2011, 22 February 2012, p. 3.

Other historical sales have been at premiums of between 20 and 119 per cent to the regulated asset base.[613] The RAB multiples from each of these transactions, together with the transactions discussed above, are summarised in 0 from most recent to least recent.

Table 10.7 Selected acquisitions – RAB multiples

Date	Acquirer	Entity/Asset acquired	RAB multiple (times)
July 2011	ATCO	25.9% of West Australian Gas Networks	1.20
July 2011	DUET	20% of Multinet Gas	1.13
July 2011	DUET	20% of Dampier to Bunburry Natural Gas Pipeline	0.95[614]
Dec 2011	Marubeni Corp/RREEF[615]	Allgas	1.20
Dec 2011	Marubeni Corp/RREEF[616]	Allgas	1.02
Dec-06	APA	Directlink	1.45
Oct-06	APA	Allgas	1.64
Aug-06	APA	GasNet	2.19
Apr-06	Alinta	AGL Infrastructure assets	1.41-1.52
Mar-06	APA	Murraylink	1.47

Source: DUET[617], APA Group[618], Grant Samuel, AER calculations.

As Grant Samuel has previously explained, listed infrastructure entities should theoretically trade at, and be acquired at, 1.0 times the RAB.[619] However, nearly all recent asset sales have been transacted at RAB multiples of greater than one.

Acquisition premiums have been substantial and are, as a result, unlikely to be explained away by the factors noted above alone. This suggests that the regulated rate of return has been at least as high as the actual cost of capital faced by regulated businesses. Moreover, the consistency of the numbers across many transactions lends support to the conclusion that the regulated rate of return is at least consistent with the efficient rate of return.

613 Grant Samuel & Associates Pty Limited, *Financial Services Guide and Independent Expert Report in relation to the Recapitalisation and Restructure of Babcock and Brown Infrastructure*, 9 October 2009, p. 78.

614 Dampier to Bunbury Natural Gas Pipeline presents an unusual case because it is 96% contracted until 2016 under shipper contracts. As the Economic Regulation Authority of Western Australia (ERAWA) states, these contracts 'are substantially independent of the access terms and reference tariffs established under the access arrangement for the DBNGP.' ERAWA, Final Decision, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline—Submitted by DBNGP (WA) Transmission Pty Ltd, 31 October 2011, p. 14. For this reason the DBNGP RAB multiple appears to be not driven by regulatory rates of return and does not provide a useful comparison for RAB multiples analysis.

615 Quoted net enterprise value/calculated RAB.

616 Gross sale price/book value of assets.

617 DUET, *Presentation to Macquarie Retail Adviser Network*, 12 January 2012, viewed 9 February 2012.

618 APA Group, *Completion of the sale of 80% of Allgas*, 16 December 2011, viewed 10 January 2012, <http://apa.com.au/investor-centre/news/asxmedia-releases/2011/completion-of-the-sale-of-80-per-cent-of-allgas.aspx>.

619 Grant Samuel & Associates Pty Limited, *Financial Services Guide and Independent Expert Report in relation to the Recapitalisation and Restructure of Babcock and Brown Infrastructure*, 9 October 2009, p.77.

The AER therefore considers that market transactions suggest that regulated rates of return network service providers the opportunity to recover at least efficient costs.

Trading multiples

A comparison of the asset value implied by share prices against the regulatory asset base—often expressed as a 'trading multiple'—also provides insight into the required rate of return.[620]

As with regulated asset sales, a trading multiple above one may imply that the market discount rate is below the regulated WACC. The same caution with interpreting the results of regulated asset sales approach apply to trading multiples. In addition, this assessment relies on the assumption that share prices reflect the fundamental valuation of the company.

First, Grant Samuel showed in 2009 that trading multiples for listed businesses operating regulated networks have ranged from 1.15 to 1.81 times the RAB as outlined in Table 10.8.[621]

Table 10.8 RAB trading multiples of regulated assets

Entity	Average RAB as at June 2009	Average RAB as at June 2010
SP AusNet	1.50	1.40
Spark	1.81	1.73
DUET	1.21	1.15
Envestra	1.28	1.21

Source: Grant Samuel[622]

Second, recent broker reports have also identified RAB trading multiples. These multiples are consistently greater than one, as shown in Table 10.9 to Table 10.12. None of these multiples are less than or equal to one.

Table 10.9 JP Morgan—Various report dates in February 2012

Date of report	Company	FY10A	FY11A	FY12E
22 Feb 2012	ENV	1.11	1.20	1.23
17 Feb 2012	DUET	1.33	1.26	1.12
13 Feb 2012	SKI	1.07	1.12	1.05

Source: JP Morgan[623]

620 The AER has not made any calculations of its own in this section. Trading multiples have only been stated where they could be identified in an external report.

621 Grant Samuel & Associates Pty Limited, *Financial Services Guide and Independent Expert Report in relation to the Recapitalisation and Restructure of Babcock and Brown Infrastructure*, 9 October 2009, p. 77.

622 Grant Samuel & Associates Pty Limited, *Financial Services Guide and Independent Expert Report in relation to the Recapitalisation and Restructure of Babcock and Brown Infrastructure*, 9 October 2009, p. 77.

623 JP Morgan, *Envestra Limited—1H12 Result Preview*, 22 February 2012, pg. 4; JP Morgan, *DUET Group—Transition costs exert downward pressure*, 17 February 2012, pg. 8; JP Morgan, Australian Regulated Utilities 2012 Outlook—*Regulatory Clouds Gathering*, p. 19.

Table 10.10 Macquarie—8 November 2011

Company	2011	2012	2013
ENV	1.18	1.16	1.14
DUET	1.07	1.10	1.10
SKI	1.23	1.17	1.13
SPN	1.08	1.15	1.10

Source: Macquarie Group[624]

Table 10.11 Credit Suisse—22 February 2012

Company	Date unspecified
ENV	1.29
DUET	1.09
SKI	1.32
SPN	1.13

Source: Credit Suisse[625]

Table 10.12 Goldman Sachs—6 December 2011

Company	Various dates
SKI	1.15
ENV	1.25
SPN	1.14

Source: Goldman Sachs[626]

Finally, Spark Infrastructure recently released a *Fact Book* showing an unadjusted trading multiple of 1.34 as at 24 February 2012. The *Fact Book* reports that this decreases to 1.10 when adjusted for total revenue excluding customer contributions.[627]

There are also other listed entities that hold regulated assets, such as APA Group and Hastings Diversified Utilities Fund. These companies are not conducive to RAB multiples analysis because they have a diverse portfolio of assets, sometimes unregulated, which makes it difficult to isolate the RAB.

Each of these figures cannot be considered definitive without careful consideration of the assumptions and methodologies used. They do, however, provide a useful insight into whether market analysts, and indeed industry analysts, consider the AER's benchmark WACC is appropriate. Importantly, each multiple is calculated after the GFC and also after the AER's WACC review.

624 Macquarie, *DUET Group— Limited RAB growth—At fair value*, 8 November 2011, p. 4.
625 Credit Suisse, *APA Group—Forget 1H12 result; all eyes on HDF refinance*, 22 February 2012, p. 8.
626 Goldman Sachs, *Reinstating coverage: Prefer SKI, Ahead of APA, ENV & SPN*, 6 December 2011, p. 2.
627 Spark Infrastructure, *2012 Fact Book*, 27 February 2012, p. 9.

Recent comments by Macquarie in a broker report also suggest the AER's WACC approach does not under-compensate service providers:

> The importance of the RAB growth reflects our belief there is a sustainable arbitrage beyond the current regulatory period, that justifies paying a premium above RAB for these assets…This arbitrage reflects WACC calculations in the regulatory setting have a degree of conservatism.[628]

Comments made by the AEMC in its recent Directions Paper also lend support to the AER's interpretation of broker reports and suggest the cost of debt may be a driver of the RAB multiple premiums:

> A number of these [broker] reports indicate that the recommended valuations placed on these businesses by the equity analysts assume an ability for the NSPs to raise debt at a rate lower than the cost of debt allowed by the regulator. A number of the reports have indicated that a major reason why they value the NSPs at above their RAB is due to their ability to out-perform their cost of debt allowance. [629]

When coupled with the consistently high multiples shown above, these comments suggest the regulatory rate of return has been at least as high as the actual cost of capital, and most likely has been in excess of it. The conclusion then is that the AER's approach to setting WACC parameters is reasonable and allows a reasonable opportunity to recover at least efficient costs.

Broker reports

Equity analysts publish broker reports on listed companies operating regulated energy networks in Australia. These reports generally include WACC estimates along with a range of information, including analysis of current financial positions and forecasts of future performance.

The AER uses broker WACC estimates as a reasonableness check for the overall rate of return. The Tribunal noted in the recent APT Allgas and Envestra decisions that it was acceptable for the AER to use broker reports in this manner.[630]

The broker reports generally do not state the full assumptions underlying their analysis, or provide thorough explanations of how they arrive at their forecasts and predictions. As such, caution should be exercised in the interpretation of these broker reports. In particular, the AER considers that the price and dividend forecasts from these reports do not constitute a sufficiently reliable basis for calculation of an overall rate of return. However, the broker reports do reliably report discount rates, which are equivalent to the broker's estimate of the WACC for the company.

It is important to note that the five listed companies undertake both regulated and unregulated activities, which are assessed by the brokers in aggregate. However, only the regulated activities are directly relevant to the benchmark firm.

It is generally considered that the regulated activities of the firms—operation of monopoly energy transmission and distribution networks—are less risky than the unregulated activities they undertake in competitive markets. As they are less risky, the return required on regulated activities is less than the return required by the firm as a whole. This means that the overall rate of return implied by broker reports will likely overstate the rate of return for the benchmark firm. Therefore the WACC for a

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628 Macquarie, *DUET Group—Limited RAB growth—At fair value*, 8 November 2011, p. 2.

629 Australian Energy Market Commission, *Directions Paper*, 2 March 2012, p. 108.

630 Australian Competition Tribunal, *Application by Envestra Ltd (No 2)[2012] ACompT 3*, 11 January 2012, paragraph 167.

regulated benchmark firm should be in the lower half of the observed range, noting the large range of broker WACCs.

The AER analyses recent equity broker reports, coinciding with the most recent round of earnings announcements for these companies. Only those brokers who report the WACC in nominal vanilla form or provide sufficient detail to enable conversion to this form were considered. The reports considered were from:

- Credit Suisse
- Goldman Sachs
- JP Morgan
- Deutsche Bank
- Macquarie Equities Research
- Bank of America Merrill Lynch.

The companies evaluated by the broker reports are:

- APA Group
- DUET Group
- Envestra Limited
- Spark Infrastructure Group
- SP AusNet.

The output from this analysis is shown in Table 10.13. The nominal vanilla WACC of 8.28 per cent for Aurora falls within the lower half of that range.

Table 10.13 Broker WACC estimates (per cent)

Measure	Minimum	Maximum
Broker headline post-tax WACC	6.30	8.60
Calculated vanilla WACC	7.52	10.02

Source: AER calculations.

Recent decisions by other regulators and AER historical rates of return

The AER reviews a range of returns it approved for other gas and electricity service providers and also the rates of return in recent decisions by other Australian regulators. This provides a test of the reasonableness of the rate of return in this determination. Recent rate of return values set by the AER since the WACC review are lower than those previously provided. However, recent decisions by other regulators suggest that these values—and 8.28 per cent in this case—are reasonable.

The rate of return range applied by the AER in recent decisions for other gas and electricity service providers is 8.28 to 10.43 per cent.[631] This range covers gas and electricity decisions made by the AER since the WACC review was completed in 2009 and includes the Aurora and Powerlink final decisions.

The AER has also considered recent decisions by other regulators giving a rate of return range from 6.45 to 9.08 per cent.[632] The decisions reviewed are shown in Table 10.14 and have been taken from those made in the last 12 months. The WACC of 8.28 per cent applied for Aurora falls within this range. This suggests that the rate of return for this determination is reasonable and in line with regulatory decisions that have been made in the past year.

Table 10.14 Recent decisions by Australian regulators (per cent)

Regulator	Decision	Date	Nominal vanilla WACC
ACCC	FAD Fixed line services – Final decision	Jul 2011	8.54
ESCV	Metro Access arrangement – Final decision	Aug 2011	9.08
ACCC	Airservices Australia – Final decision	Sep 2011	8.60
ERAWA	Dampier to Bunbury Pipeline – Final decision	Oct 2011	7.57
QCA	SunWater – Final decision	Nov 2011	7.55
IPART	Sydney Desalination Plant – Final decision	Dec 2011	8.16–8.59[a]
ESCOSA	Advice on a regulatory rate of return for SA Water – Final decision	Feb 2012	8.07
IPART	Sydney Catchment Authority – Draft decision	Mar 2012	8.14–8.25[a]
IPART	Sydney Water Corporation – Draft decision	Mar 2012	8.14–8.25[a]
ERAWA	Western Power – Draft decision	Mar 2012	6.45

Notes: For comparative purposes, all WACCs have been converted to the nominal vanilla WACC formulation consistent with the AER's reported figure for Aurora (which excludes debt raising costs).

(a) Ranges are presented for recent decisions by the IPART where the point estimate (real post-tax or real pre-tax) was not sufficiently disaggregated so as to allow precise conversion to the correct formulation (nominal vanilla WACC).

631 AER, *Final Decision—Distribution determination—Aurora Energy Pty Ltd 2012-13 to 2016-17*, April 2012; AER, *Final Decision—Powerlink Transmission determination 2012-13 to 2016-17*, April 2012; AER *Final Decision—Victorian electricity distribution service providers, Distribution determination 2011-15*, October 2010, p. 519; AER, *Final Decision—Queensland distribution determination 2010-11 to 2014-15*, May 2010, p. 267; AER, *Final decision—Access arrangement proposal for the Amadeus Gas Pipeline, 1 August 2011-30 June 2016*, July 2011, p. 80; Australian Competition Tribunal, *Envestra—Annexure A (Part 2)—Amended Access Arrangement*, February 2012, p. 13; Australian Competition Tribunal, *APT Allgas—Annexure A—Amended Access Arrangement*, February 2012, p. 17; Australian Competition Tribunal, *NSW Gas Networks—Annexure A—Amended Access Arrangemen*t, June 2011, p. 18; Australian Competition Tribunal, *ActewAGL Gas Distribution Network—Order,* September 2010, p. 2.

632 ACCC, *Final Report—Inquiry to make final access determinations for the declared fixed line services*, July 2011, p. 59; ESCV, *Final Decision—Metro Proposed Access Arrangement*, August 2011, p.87; ACCC, *Final Decision—Airservices Australia price notification*, September 2011, p.7; ERAWA, *Final Decision—Access Arrangement Information for the Dampier to Bunbury Natural Gas Pipeline*, December 2011, p.159; QCA, *Draft Report—SunWater Irrigation Price Review: 2012-17*, Volume 1, November 2011, p. 392; IPART, *Final Report—Review of water prices for Sydney Desalination Plant Pty Limited*, December 2011, p. 80; ESCOSA, *Final Advice—Advice on a Regulatory Rate of Return for SA Water*, February 2012, p. 50; IPART, *Draft Report—Review of prices for Sydney Water Corporation's water, sewerage, drainage and other services*, March 2012, p. 79; IPART, *Draft Report—Review of prices for Sydney Catchment Authority,* March 2012, p. 85; ERAWA, *Draft Decision—Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, March 2012, p 207.

10.3.5 Expected inflation rate

For this final determination, the AER adopts an inflation forecast of 2.60 per cent per annum because it represents the best estimate for a 10 year period.

In the draft determination, the AER forecast an inflation rate of 2.62 per cent per annum based on its approach for estimating forecast inflation.[633] The AER stated it would update its inflation forecast based on the latest RBA forecasts for 2012–13 and 2013–14 for the final determination.

Aurora's revised proposal accepted the AER's approach to estimating the expected inflation rate.[634] It provided an updated inflation forecast of 2.63 per cent per annum based on its understanding of the AER's approach for estimation forecast inflation. Since the AER's draft determination, the RBA has released its February 2012 *Statement on Monetary Policy* which includes updated inflation forecasts for 2012–13 and 2013–14. The AER has therefore used this latest RBA statement to update its inflation forecasts as shown in Table 10.15.

Table 10.15 AER inflation forecast (per cent)

	2012–2013	2013–2014	2014–15 to 2021–2022	Geometric average
Forecast inflation	3.25	2.75[a]	2.50	2.60

Source: RBA, Statement on Monetary Policy, February 2012, p. 67.
Notes: (a) The RBA published a range of 2.5–3.0 per cent for its 2013–2014 forecast of inflation. The AER has selected the mid-point of 2.75 per cent for the purposes of this final determination.

10.4 Revisions

The AER determines the following revision to Aurora's revised proposal in relation to its WACC:

Revision 10.1: The AER has determined a WACC of 8.28 per cent for Aurora as set out in table 10.1.

[633] AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 257-258.
[634] Aurora, *Revised proposal 2012–17*, January 2012, p. 98.

11 Corporate income tax

The AER is required to make a decision in relation to the estimated cost of corporate income tax applicable to Aurora.[635] This attachment sets out the AER's assessment of Aurora's proposed corporate income tax liabilities for the forthcoming regulatory control period. Aurora is currently regulated under a pre-tax framework and will be regulated in the forthcoming regulatory control period under a post-tax framework, in accordance with the requirement of clause 6.4.3(a)(4) of the NER.

Under a post-tax framework, a separate corporate income tax allowance is calculated as part of the building blocks assessment. The post-tax revenue model (PTRM) is used to calculate this allowance. As part of the transition from a pre-tax to post-tax approach, Aurora must establish an opening tax asset base which the AER must then assess in order to estimate Aurora's corporate income tax allowance.[636] The AER is also required to determine the value of assumed use of tax imputation credits (gamma).[637]

11.1 Determination

The AER confirms its draft decision to accept Aurora's proposed methodology used to establish the opening tax asset base (TAB) as at 1 July 2012 for the transition from pre-tax to post-tax framework. The AER also accepts the standard tax asset lives as being consistent with the requirements of the tax provisions in the NER and has updated the remaining tax asset lives used for tax depreciation purposes. These are as shown in table 11.1.

Table 11.1 AER's final decision on standard and remaining tax asset lives (year)

Asset class	AER's determination on opening tax asset values ($million, 1 July 2012)	AER's approved standard tax asset life	AER's approved remaining tax asset lives
Overhead subtransmission lines (urban)	4.3	44.5	38.7
Underground subtransmission lines (urban)	2.3	50.0	48.2
Urban zone substations	31.7	32.8	28.6
Rural zone substations	1.7	32.8	30.7
SCADA	4.5	32.8	29.2
Distribution switching stations (ground)	25.5	36.3	28.7
Overhead high voltage lines urban	89.3	34.9	29.1
Overhead high voltage lines rural	247.2	33.4	24.7
Voltage regulators on distribution feeders	2.3	45.5	43.6
Underground high voltage lines	128.9	31.4	18.9

635 NER, clause 6.12.1(7).
636 NER, clause 6.5.3(b).
637 NER, clause 6.5.3.

Underground high voltage lines SWER	0.0	31.4	0.00
Distribution substations HV (pole)	1.2	37.6	33.1
Distribution substations HV (ground)	6.9	33.2	25.3
Distribution substations LV (pole)	75.0	36.6	31.8
Distribution substations LV (ground)	36.8	34.1	28.7
Overhead low voltage lines underbuilt urban	41.1	37.4	31.3
Overhead low voltage lines underbuilt rural	18.3	38.7	34.4
Overhead low voltage lines urban	45.5	35.3	28.6
Overhead low voltage lines rural	44.0	36.7	30.8
Underground low voltage lines	31.1	42.5	39.5
Underground low voltage common trench	19.9	43.1	40.9
HVST service connections	0.0	36.4	0.00
HV service connections	0.9	36.4	31.4
HV metering CA service connections	0.1	36.4	35.0
HV/LV service connections	1.5	36.4	31.5
Business LV service connections	4.5	36.3	31.1
Business LV metering CA service connections	3.3	36.4	34.9
Domestic LV service connections	40.8	36.4	31.9
Domestic LV metering CA service connections	3.0	36.4	34.6
Emergency network spares	0.0	n/a	0.00
Motor vehicles	24.4	9.2	4.4
Minor assets	28.3	5.2	2.9
Non-system property	25.0	34.5	21.2
Spare parts	0.0	n/a	0.00
NEM assets	6.4	3.0	1.5
Equity raising costs	0.0	5.0	n/a
Land	0.0	n/a	n/a
Easements	0.0	n/a	n/a

Source: Aurora PTRM, AER analysis.

However, as discussed in the draft determination, the AER does not accept Aurora's revised proposed cost of corporate income tax allowance of $103.6 million ($nominal) for the forthcoming regulatory control period. This is because the AER's adjustments to the opening tax asset base as at 1 July 2012, and other building blocks including the proposed return on capital and forecast opex, impact the estimated corporate income tax allowance under clause 6.5.3 of the NER. The AER’s adjustments result in an estimated cost of corporate income tax allowance of $85.6 million ($nominal), as shown in table 11.2.

Table 11.2 AER's final decision on corporate income tax allowance for Aurora ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Tax payable	22.0	23.9	23.0	22.7	22.5	114.2
Less value of imputation credits	5.5	6.0	5.8	5.7	5.6	28.5
Net corporate income tax allowance	16.5	17.9	17.3	17.0	16.9	85.6

Source: AER analysis

11.2 Assessment approach

The AER has not changed its assessment approach to corporate income tax since its draft determination, so it is not repeated here. See the draft determination at section 10.3 of attachment 1 on corporate income tax for this detail.

11.3 Reasons

The AER has calculated the corporate income tax allowance for its final determination using the same method outlined in its draft determination. In its revised proposal, Aurora did not contest the AER's method to calculate its corporate income tax allowance. The AER has updated its estimate of Aurora's allowance for corporate income tax using the forecast building block components, including capital and operating expenditures determined in this final determination.

11.3.1 Uncontested Issues

Standard tax life for equity raising costs

In its draft determination, the AER rejected Aurora's proposed tax standard life of 33.2 years for equity raising costs in the PTRM. The AER instead applied a tax standard life of 5 years, consistent with a relevant ATO determination on tax rates.[638]

Aurora has accepted the AER's draft decision in respect of the tax standard life for equity raising costs.[639]

Utilisation of imputation credits (gamma)

In its draft determination, the AER accepted Aurora's proposal to adopt the value of 0.25 for gamma. As part of the post tax framework and in accordance with clause 6.5.3 of the NER, the value of gamma must be applied to calculate the net tax allowance.

638 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 165–166.
639 Aurora, *Response to questions raised by the AER: Debt and equity raising costs*, 31 January 2012, p. 3.

11.3.2 Establishing Aurora’s opening tax asset base

In its draft determination, the AER accepted Aurora's methodology to establish a TAB as at 1 July 2012. Aurora's proposed methodology employed appropriate standard and remaining tax asset lives for each asset class, as well as policies governing additions and disposals related to the tax asset base.[640]

The AER accepts Aurora’s revised proposal, as it outlined a methodology to establish a TAB that is identical to that in its initial proposal, consistent with clause 6.5.3(2).[641] However, The AER has determined an opening tax asset base of $995.9 million as at 1 July 2012. The represents an increase of $2.14 million compared to Aurora’s TAB of $993.74 million as outlined in Aurora’s revised proposal. The AER’s final determination of Aurora’s TAB reflects the AER’s changes made to Aurora’s treatment of provisions, and shared assets over the previous regulatory control period.[642]

11.3.3 Corporate income tax allowance

The AER’s final determination on Aurora’s forecast corporate income tax allowance is $85.6 million (nominal) over the forthcoming regulatory control period. This represents a reduction of $18 million (nominal) or 17.4 per cent of Aurora’s revised proposal.

The AER does not accept Aurora’s corporate income tax allowance of $103.6 million (nominal) for the forthcoming regulatory control period. The AER’s final determination on corporate income tax is calculated from the revised estimates of the building block components, including:

- Aurora’s opening RAB (outlined in attachment 8)
- Aurora’s forecast opex (outlined in attachment 7)
- Aurora’s cost of capital (outlined in attachment 10).

The AER’s final determination of corporate income tax is also affected by the amount of depreciation calculated for tax purposes. Aurora proposed a forecast of tax depreciation based upon an estimate for remaining tax asset lives. In its final determination, the AER has updated the remaining tax asset lives to reflect its adjustments, including for the opening TAB, CPI indexation, the movement of provisions and allocation of shared assets.

The AER has recalculated the remaining tax asset lives to account for these changes, but otherwise employs the same method Aurora used to calculate its proposed remaining asset lives. The AER's determination on Aurora's remaining asset lives by asset class is shown in table 11.1.

11.4 Revisions

Revision 11.1: The AER has determined Aurora’s estimated cost of corporate income tax to be $85.6 million ($nominal) over the forthcoming regulatory control period as set out in table 11.2.

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640 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 286–287.

641 Aurora, *Revised regulatory proposal 2012–17*, January 2012,, p. 106.

642 See attachment 8 on the regulatory asset base for further detail.

12 Service target performance incentive scheme

The AER's Service Target Performance Incentive Scheme (STPIS) provides a financial incentive for Distribution Network Service Providers (DNSPs) to maintain and improve their performance. Service performance is predominately measured in terms of the reliability of DNSP's networks, but also customer service. The STPIS is designed to counter the financial incentive under revenue regulation to pursue cost reductions at the expense of service performance. In making its distribution determination, the AER must specify how the STPIS is to apply to Aurora.

12.1 Determination

The STPIS lists all the matters on which the AER will decide in its distribution determination when applying the scheme.[643] The AER has made the following decisions on how the STPIS will apply to Aurora.

12.1.1 Parameters and components[644]

The AER will apply the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability of supply parameters. These indexes will be calculated based on the effect of outages on embedded transformer capacity (or kVA capacity) in the relevant areas of Aurora's network. Individual SAIDI and SAIFI targets have been set for segments of Aurora's network in accordance with the *Tasmanian Electricity Code's* (TEC's) supply reliability categories.[645]

The AER will also apply the telephone answering parameter, but not the STPIS Guaranteed Service Level (GSL) scheme. This is because Aurora must comply with the existing TEC GSL scheme. Aurora's forecast of operating expenditure includes a revenue allowance to cover Aurora's forecast payments under the GSL scheme.

The AER's final determination is to apply the exclusions specified in the framework and approach paper.[646] The definition of total fire ban days is to be as set out in the draft determination. A total fire ban day is "a day of total fire ban as advised by the Tasmanian Fire Service in accordance with section 70 of the Fire Service Act 1979". [647]

12.1.2 Revenue at risk[648]

The revenue at risk caps the risk of the STPIS to Aurora. The penalty or reward to Aurora of the STPIS is calculated as a percentage adjustment to Aurora's total revenue (the S-factor adjustment). This revenue adjustment will be capped at ±5 per cent. Within this there will be a cap of ±0.25 per cent on the telephone answering parameter for performance in the first three years of the next

643 AER, *Electricity distribution network service providers, service target performance incentive scheme*, November 2009, clause 2.1(d) (AER, *STPIS*, November 2009)

644 AER, *STPIS*, November 2009, clause 2.1(d)(1).

645 The calculation of SAIDI and SAIFI performance for the supply reliability categories is to be undertaken in accordance with schedule 8.1 of the Tasmanian Electricity Code. However the outages excluded from this calculation should be the STPIS excluded outages, and not the exclusions specified on page 2 of schedule 8.1.

646 AER, *Framework and approach, Aurora 2012–17*, November 2010, pp.99-120.

647 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p.278.

648 AER, *STPIS*, November 2009, clause 2.1(d)(2).

regulatory period (2012-13, 2013-14 and 2014-15), and then a cap of ±0.5 per cent for the last two years (2015-16 and 2016-17).

12.1.3 Incentive rates[649]

Incentive rates are the penalty or reward that Aurora receives for a single unit variation in performance. Table 12.1 presents the AER's incentive rates to apply to Aurora's SAIDI and SAIFI targets. The incentive rate for the telephone answering parameter will be – 0.040 per cent per unit of the telephone answering parameter.

Table 12.1 Incentive rates to apply to Aurora's STPIS targets

TEC reliability category	Critical infrastructure	High density commercial	Urban	High density rural	Low density rural
SAIFI	0.5351	0.6147	4.4911	1.3871	1.1289
SAIDI	0.0063	0.0089	0.0547	0.0137	0.0100

Source: AER analysis.

12.1.4 Performance targets[650]

Table 12.2 presents the AER's final determination on the performance targets for Aurora's STPIS parameters.

Table 12.2 AER's final determination of Aurora's SAIDI and SAIFI targets

TEC reliability category	Critical infrastructure	High density commercial	Urban	High density rural	Low density rural
SAIFI	0.22	0.49	1.04	2.79	3.20
SAIDI	20.79	38.34	82.75	259.48	333.16

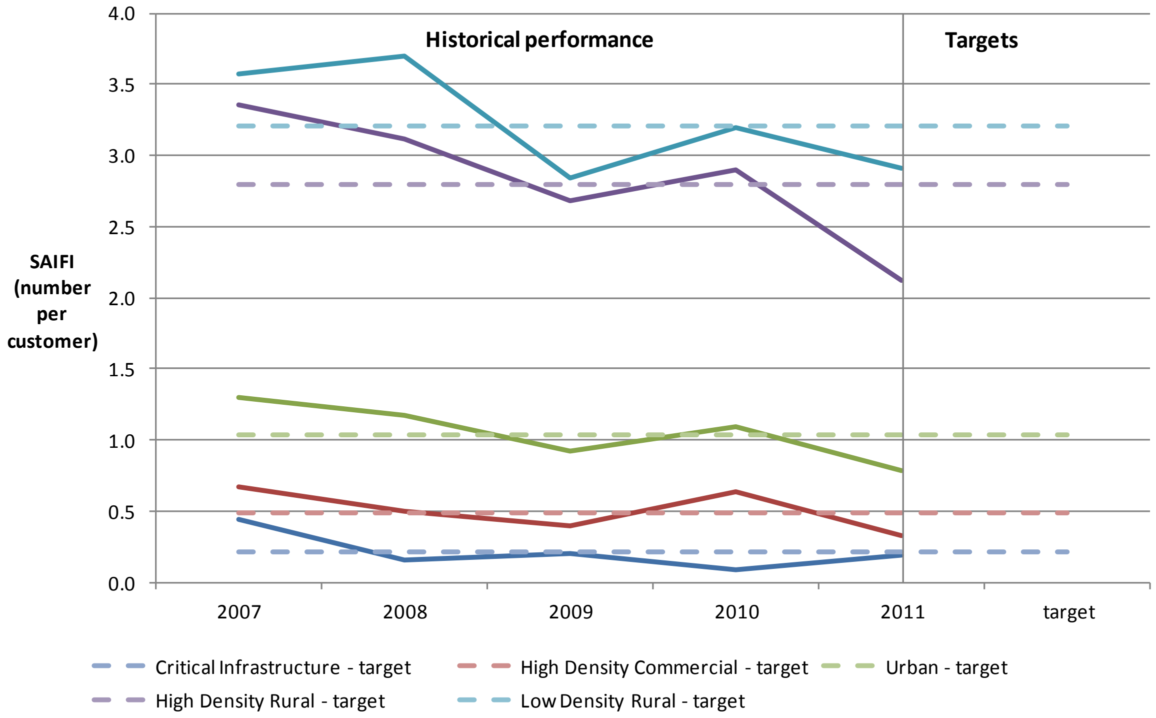
Source: AER analysis.

Telephone answering

For the first three years of the next regulatory period, Aurora's telephone answering performance target will be 73.6 per cent. For the final two years, the target will be reset at the level of Aurora's average call centre performance for the preceding three, years calculated in accordance with the STPIS.[651]

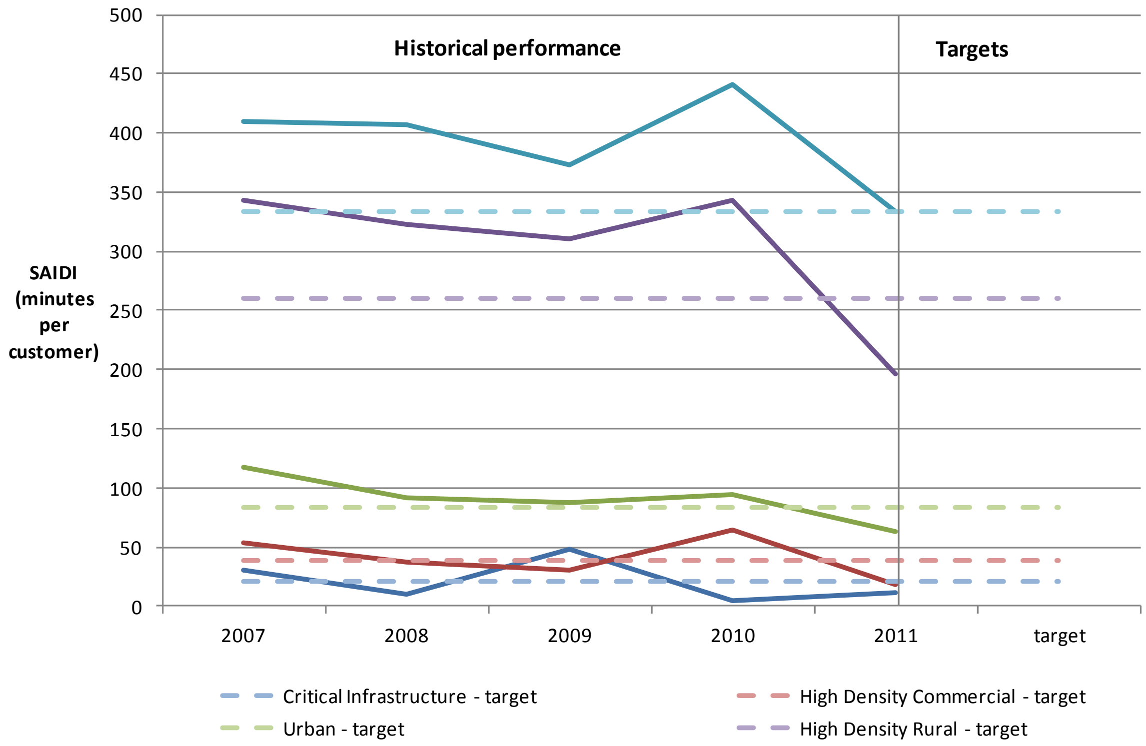
649 AER, *STPIS*, November 2009, clause 2.1(d)(3).
650 AER, *STPIS*, November 2009, clause 2.1(d)(4).
651 AER, *STPIS*, November 2009, clause 5.3.1 - performance targets.

Figure 12.5 Aurora's historical SAIFI performance and AER targets



Source: AER analysis.

Figure 12.6 Aurora's historical SAIDI performance and AER targets



Source: AER analysis.

12.1.5 Transitional arrangements – MAIFI

The AER will collect and publically report available data on Aurora's Momentary Interruption Frequency Index (MAIFI) performance. The AER will not apply a financial incentive to MAIFI.

12.1.6 Major event day boundary

The major event day threshold is set to exclude days on which SAIDI is more than 2.5 standard deviations greater than the mean of the log normal distribution of five regulatory years of SAIDI data. The major event day threshold is to be calculated annually in accordance with section 3.3 of the STPIS. For the first year of the next regulatory period, the MED threshold for Aurora will be a SAIDI of 8.06.

12.2 Assessment approach

In its distribution determination the AER must:

1. determine all performance targets, incentive rates, revenue at risk and other parameters required to apply the STPIS[652]
2. consider any proposals to vary the STPIS made by the distribution network service provider (DNSP) to which the scheme is to apply. [653].

The AER in assessing a DNSPs proposal to vary the STPIS will consider the AERs objectives under section 1.5 of the STPIS.

The AER has decided to adopt its draft determination of the STPIS, unless elements of it were contested by Aurora or other stakeholders. When contested, the AER considered the merits of the application against the objectives of the STPIS.[654] Section 12.3 outlines this reasoning.

12.3 Reasons

This section presents the AER's reasoning for its final determination on the STPIS. Aurora commented on the AER's draft determination on the application of the STPIS. No other submissions received from stakeholders commented on the STPIS.

12.3.1 Uncontested issues

Aurora did not contest the following matters, and as a result the AER has upheld these aspects of the draft determination.

- Aurora accepted the application of the SAIDI and SAIFI STPIS parameters calculated using kVA capacity as per the AER's draft determination.[655] Aurora also accepted the segmentation and

[652] AER, *STPIS*, November 2009, clause 2.1(d).
[653] AER, STPIS, November 2009, clause 2.2(a)-(c)
[654] The objectives of the STPIS are set out in clause 1.5 of the STPIS [AER, *STPIS*, November 2009]
[655] Aurora, *Revised regulatory proposal 2012–17,* January 2012, p.116.

calculation of separate SAIDI and SAIFI targets for different reliability areas in its network in accordance with the Tasmanian Electricity Code (TEC) supply reliability categories.[656]

- Aurora accepted the proposed application of the telephone answering parameter.[657]
- Aurora also accepted the targets for the telephone answering parameter.[658]
- Aurora accepted the AER's draft determination on events to be excluded from the calculation of performance.[659]

Matters contested by Aurora and other stakeholders are considered individually below.

12.3.2 Cap on revenue at risk

The cap on revenue at risk limit's the penalties or rewards of the STPIS. The AER's final determination is to cap the revenue at risk at ± 5 per cent of total revenue.[660]

The AER considers a cap on revenue at risk of ± 5 per cent provides Aurora with the appropriate level of incentive to maintain and improve its reliability performance. The AER does not consider that Aurora has demonstrated that a cap on revenue at risk of ± 2.5 per cent is consistent with the objectives of the scheme, for the following reasons:

- Aurora's reasons are not linked to the objectives of the scheme
- A higher revenue at risk provides a larger incentive to maintain and improve performance which is consistent with the objectives of the scheme

Clause 6.6.2(b)(3) of the NER requires that in developing and implementing the STPIS the AER must take into account a number of factors. The AER considers that Aurora's proposal to alter the cap on revenue at risk to account for the Tasmanian GSL scheme is not consistent with clause 6.6.2(b)(3) for the reasons presented in Table 12.3.

656 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p.115.
657 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p.115.
658 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p.115.
659 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p.117.
660 AER, *STPIS*, November 2009, clause 2.5(a).

Table 12.3 Rule requirements and the cap on revenue at risk.

Rule requirements under 6.6.2(b)(3)	Reasoning
(i) the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for Distribution Network Service Providers	The penalties or rewards under the STPIS are calculated based on the value of customer reliability (VCR). This ensures that the benefits to consumers are sufficient to warrant any penalty or reward to Aurora. Thus the AER considers that this factor is not relevant when determining the cap on revenue at risk.
(ii) any regulatory obligation or requirement to which the Distribution Network Service Provider is subject;	Aurora is also subject to the TEC GSL scheme. The STPIS is designed to run concurrently with jurisdictional GSL schemes. Further, the STPIS incentives run in parallel with the incentives of the GSL scheme. A higher revenue at risk under the STPIS is preferred because it does not unduly cap the combined incentives to deliver improved performance under the STPIS and GSL scheme.
(iii) the past performance of the distribution network	The AER considers this factor is not relevant to the determination of the revenue at risk for Aurora.
(iv) any other incentives available to the Distribution Network Service Provider under the Rules or a relevant distribution determination;	As per the AER's considerations against (ii), the AER has accounted for the Tasmanian GSL scheme when applying the STPIS.
(v) the need to ensure that the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels	A lower revenue at risk does not give effect to this NER requirement because the cap on revenue at risk limits the incentives of the STPIS relative to the incentive to reduce costs at the expense of service levels.
(vi) the willingness of the customer or end user to pay for improved performance in the delivery of services	The penalties or rewards under the STPIS are calculated based on the value of customer reliability (VCR). This approach ensures that Aurora only has an incentive to improve performance where customers are willing to pay for it. With a higher cap on revenue at risk, Aurora will have a broader incentive to deliver reliability improvements desired by customers.
(vii) the possible effects of the scheme on incentives for the implementation of non-network alternatives.	The AER considers the STPIS does not necessarily counteract the incentives to pursue non-network alternatives. Aurora and other stakeholders did not comment on the potential impact of the revenue at risk on incentives to implement non network alternatives.

Further, a higher cap on revenue at risk is consistent with the National Electricity Objective.[661] It provides a greater incentive for Aurora operate and investment in its distribution network efficiently with respect to reliability.

Aurora proposed a cap on revenue at risk of ± 2.5 per cent in its revised proposal. Clause 2.5(b) of the STPIS allows Aurora to propose an alternative cap on revenue at risk. Clause 2.2 and clause 2.5(b) of the STPIS both specify that Aurora must demonstrate why any proposed alternative application of the STPIS is consistent with the objectives of the STPIS. Aurora did not directly link its

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661 The National Electricity Objective is as follows:
The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-
(a) price, quality, safety, reliability and security of supply of electricity; and
(b) the reliability, safety and security of the national electricity system.

reasoning to the objectives of the STPIS. It specified that revenue at risk of 2.5 per cent should be adopted because:

- the existing Tasmanian GSL scheme[662] provides an incentive for Aurora to meet minimum reliability standards, and should be considered when determining the cap on revenue at risk. The GSL scheme was designed as a standalone service incentive scheme with an appropriate revenue at risk component.[663]

- The AER will not retain the two GSL 'safety nets', the revenue at risk associated with the GSL scheme is much greater than that intended by the Office of the Tasmanian Energy Regulator (OTTER). It is also potentially in excess of the revenue at risk under the impost of the AER's STPIS and the jurisdictional GSL scheme.[664]

- the proposed annual revenue at risk is much greater than the previous incentive scheme applied by OTTER which had a cap of 1.25 per cent on revenue at risk.[665]

The AER does not accept the above reasoning because:

- Even though the Tasmanian GSL scheme was designed to be a standalone scheme, the STPIS was designed to run concurrently with jurisdictional GSL schemes.[666] The STPIS incentives run in parallel with the incentives for Aurora to meet the minimum reliability standards in the GSL scheme. If not unduly capped, these incentives together will deliver better outcomes for Aurora's customers.

- The risk of the GSL scheme in the next regulatory period is lessened because Aurora was granted expenditure in the current period to deliver reliability improvement programs. [667] Consequently, Aurora will have less difficulty in meeting its GSL targets in the next period.

- OTTER elected not to extend the scheme's "safety nets" by amending the scheme to include them.[668]

- Under OTTER's GSL scheme, Aurora can apply to have rare events excluded.[669] Thus the financial consequences to Aurora of individual outage events are capped. This cap limits the financial risk of the scheme.

- For the next regulatory period, the AER has granted Aurora an allowance to cover its expected GSL payments. This forecast is based on Aurora's historical payments and includes that amount that Aurora would have recovered though the risk mitigation mechanism in the current period. Aurora will only incur a GSL penalty if its GSL payments are greater than the AER's forecast allowance. Aurora will still have to make GSL payments. However, Aurora will profit if its total GSL payments are less than the AER’s forecast allowance for those payments.

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662 Office of the Tasmanian Energy Regulator, *Guideline, Guaranteed Service Level (GSL) Scheme*, December 2007, version 2. (OTTER, *GSL scheme*, 2007)

663 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p.114.

664 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p.114.

665 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p.114.

666 AER, *Explanatory statement and discussion paper, proposed electricity distribution network service providers service target performance incentive scheme,* April 2008, p.28.

667 OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices,* September 2007, p.105.

668 Aurora, *Regulatory Proposal*, May 2012, p.198.

669 OTTER, *GSL scheme*, 2007.

- The observed financial implications of the current GSL scheme have not been significant. Aurora's GSL payments have been only moderately more than OTTER's forecast allowance for those payments (by about 7 per cent in real terms). In present value terms, the total penalty under Aurora's GSL scheme for the current period been about $0.53 million ($2010-11).
- The financial effects of the 'safety net' mechanisms have also not been significant. Aurora has not reached the cumulative cap on GSL payments, and it has recovered only $575,000 ($2010–11) through the single outage duration GSL payments cap.
- The revenue at risk is much greater than that under the previous scheme. However, the revenue at risk is consistent with the AER's most recent determinations for the Victorian DNSPs. These were ±5 per cent for all the DNSPs apart from SP AusNet. SP AusNet had a ±7 per cent cap on revenue at risk.[670]

12.3.3 Adjustment to SAIDI and SAIFI targets for reliability improvement expenditure

The AER has determined final STPIS targets that differ from Aurora's revised proposal targets, because Aurora inaccurately factored targeted reliability improvement programs (TRIPs) into its performance targets. Table 12.4 presents the AER's adjusted STPIS targets.

Table 12.4 AER's final determination of Aurora's STIPS targets

	AER – final	Aurora – revised	AER – draft
SAIDI			
Critical infrastructure	20.79	20.79	20.79
High density commercial	38.34	38.34	38.34
Urban	82.75	84.04	84.04
High density rural	259.48	272.74	272.74
Low density rural	333.16	363.94	331.34
SAIFI			
Critical infrastructure	0.22	0.22	0.22
High density commercial	0.49	0.49	0.49
Urban	1.04	1.01	1.01
High density rural	2.79	2.66	2.66
Low density rural	3.20	3.11	2.97

Source: AER analysis, Aurora's revised proposal[671], AER draft determination[672]

Aurora accepted the AER's draft determination approach on its reliability targets to account for jurisdictional reliability targets.[673] But it noted 'the AER appears to have made a coding error in its

670 AER, *Victorian electricity distribution network service providers, Distribution determination 2011–2015*, October 2010, p. 741.
671 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p. 117.
672 AER, *Constituent decisions, Aurora 2012–17*, November 2011, p.6.
673 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p. 115.

spreadsheet, and has used data from two different sources with differing exclusions'.[674] Aurora provided an amended spreadsheet as an attachment to its revised proposal.

Aurora and the AER both consider clause 3.2.1 of the STPIS requires Aurora's STPIS targets to account for the TRIPs.[675] Aurora's TRIPs were proposed to meet the supply reliability standards in the TEC (the TEC standards).[676] Thus, to account for the TRIPs, Aurora's STPIS targets should reflect Aurora's performance had it met the TEC standards.

In its draft determination, the AER calculated the STPIS targets using data different from that which it used to calculate Aurora's performance against TEC standards.[677] The Calculation of Aurora's performance against the TEC standards should exclude only TEC excluded events. It would be inappropriate to calculate Aurora's performance against the TEC standards excluding STPIS exclusions. The STPIS exclusions are quite different from the TEC exclusions.

Aurora's revised proposed STPIS targets apply the AER's STIPS exclusions in calculating performance against the TEC standards. Consequently, these targets do not reflect Aurora's performance against the TEC standards.

However, in the AER's draft determination the exclusions applied in the AER's calculation of Aurora's performance targets might have been incorrect. Specifically, the AER used Aurora's data to derive Aurora's performance against the TEC minimum reliability targets. Events excluded from this data were not clear.

The AER has revised its calculation of Aurora's reliability performance against the TEC standards. The calculation now excludes only TEC excluded events. This approach accurately reflects Aurora's performance against the TEC standards.

The AER had Nuttall Consulting review its updated STPIS calculations. Nuttall Consulting concluded that the AER's approach of adjusted actual outage data in order to infer the ongoing impact of the TRIPs to the end of the current period is a reasonable approach.[678] Nuttall consulting also concluded that the AER's approach seems to transparently and objectively allow the requirement to comply with the TEC standards by the end of this period, to be incorporated into the calculations of the STPIS targets.[679]

12.3.4 Incentive rates

Aurora provided updated incentive rates, using total revenue as proposed in its revised regulatory proposal.[680]

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674 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p. 115.

675 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p. 115.

676 Aurora, *Aurora submission to the Investigation of prices for electricity distribution services on mainland Tasmania*, 2007, p. 84.

677 AER, *Aurora STPIS targets*, Nov 2011

678 Nuttall Consulting, *Aurora electricity distribution revenue review – revised proposal: A report to the AER*, April, 2012, p.74.

679 Nuttall consulting, *Aurora electricity distribution revenue review – revised proposal: A report to the AER*, April, 2012, p. 74.

680 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p. 116.

Aurora noted the AER draft determination of the incentive rate for telephone answering differed from the incentive rate in the STPIS. The incentive rate in the AER's draft determination was 0.040 per cent, whereas the STPIS incentive rate is –0.040 per cent.[681] Aurora proposed an incentive rate for the telephone answering parameter be –0.040 per cent in accordance with the STPIS. [682] The AER accepts Aurora's position and will apply an incentive rate of –0.040 per cent for the telephone answering parameter. The AER has updated the incentive rates for the other STPIS parameters to reflect its final determination.

12.4 Revisions

Revision 12.1: The AER has adjusted the STPIS targets to appropriately account for Aurora's TRIPs.

Revision 12.2: The AER has updated the incentive rates to be used in the s-factor calculations

Revision 12.3: The AER will apply a ± 5 per cent cap on revenue at risk.

681 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p. 115.
682 Aurora, *Revised regulatory proposal 2012–17,* January 2012, p. 115.

13 Efficiency benefit sharing scheme

The NER requires the AER to specify in this final determination how it will apply the efficiency benefit sharing scheme (EBSS) to Aurora.[683] The EBSS operates in conjunction with the ex ante incentive framework, to provide DNSPs with a continuous incentive to reduce operating expenditure (opex). It provides this continuous incentive by ensuring a DNSP retains efficiency gains for five years before passing them on to consumers. It also removes the incentive to overspend in the opex base year to receive a higher opex allowance in the following regulatory control period.

Aurora does not currently operate under an EBSS, or similar jurisdictional scheme. For the reasons discussed in the AER's framework and approach paper published on 29 November 2010,[684] the AER considers that the electricity distribution EBSS should apply to Aurora in the forthcoming regulatory control period.

13.1 Determination

The AER's position on the application of an EBSS to Aurora remains unchanged from its draft determination. Aurora has contested the AER's decision not to exclude trunk mobile radio costs from the EBSS.[685] However, Aurora's further submissions have not convinced the AER that it should depart from the position reached in its draft determination.

Therefore, the AER will apply the electricity distribution EBSS to Aurora in accordance with the AER's framework and approach paper.[686] The AER will adjust the forecast opex amounts used to calculate carryovers if Aurora changes its capitalisation policies during the forthcoming regulatory control period to ensure consistency with the actual opex amounts.[687]

The AER will not adjust the forecast opex amounts used to calculate EBSS carryover amounts for the cost consequences of any differences between forecast and actual network growth over the forthcoming regulatory control period. There is no explicit relationship between growth and expenditure in the method used to establish forecast total opex.[688]

Consistent with its draft determination, and Aurora's revised regulatory proposal, the AER will exclude the following cost categories from forecast and actual opex for the calculation of EBSS carryover amounts in accordance with section 2.3.2 of the EBSS and this final determination:

- superannuation costs for defined benefits schemes
- Demand Management Incentive Allowance (DMIA) expenditure
- expenditure for non-network alternatives

683 NER, clauses 6.3.2(a)(3) and 6.12.1(9).

684 AER, *Framework and approach paper*, November 2010.

685 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 111–112.

686 AER, *Framework and approach paper*, November 2010.

687 AER, *Electricity distribution network service providers: Efficiency Benefit Sharing Scheme*, 26 June 2008, p. 6 (AER, *Electricity DNSPs: EBSS*, 26 June 2008).

688 AER, *Electricity DNSPs: EBSS*, 26 June 2008, p. 6.

- recognised pass through events and recognised regulatory change events or service standard events
- Electrical Safety Inspection Levy payments
- National Energy Market (NEM) Levy payments
- NEM and retail contestability operating costs
- movements in provisions.

In addition, the AER will exclude the following cost categories from the EBSS in the forthcoming regulatory control period. The exclusion of the following cost categories will provide Aurora with a continuous incentive, so far as is consistent with economic efficiency, to reduce opex:[689]

- debt raising costs
- Guaranteed Service Level (GSL) payments.

The calculation of carryover amounts under the EBSS will include all other opex costs relating to standard control services in accordance with section 2.3.2 of the EBSS. It will also include events that qualify as pass through events but do not satisfy the materiality threshold.[690]

Table 13.1 shows the total controllable opex forecasts that the AER will use to calculate efficiency gains and losses for the forthcoming regulatory control period, subject to adjustments required by the EBSS. Attachment 7 further discusses the determination of Aurora's total forecast opex for the forthcoming regulatory control period.

Table 13.1 AER determination on Aurora's forecast controllable opex for EBSS purposes ($million, 2009–10)

	2012–13	2013–14	2014–15	2015–16	2016–17
Total forecast opex	68.9	67.9	68.7	68.5	68.0
Adjustment for excluded cost categories	–6.9	–7.0	–7.1	–7.2	–7.3
Forecast opex for EBSS purposes	61.9	60.9	61.6	61.3	60.6

Source: AER analysis.

13.2 Assessment approach

The AER has not changed its assessment approach for the EBSS since its draft distribution determination, so it is not repeated here. See section 11.3 of attachment 11 of the AER's draft determination for this detail.[691]

689 NER, clause 6.5.8(c)(2).
690 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 265.
691 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 266.

13.3 Reasons for determination

The AER maintains its position from the draft determination that most of the cost categories proposed by Aurora for exclusion from the EBSS are reasonable. In its revised regulatory proposal, Aurora accepted the majority of the AER's draft determination on the EBSS.[692]

13.3.1 Uncontested issues

Aurora accepted the AER's draft determination on the cost categories to be excluded from the EBSS, except for trunk mobile radio (TMR).[693] Aurora also accepted the AER's draft determination that self insurance costs should not be excluded from the EBSS on the basis that Aurora did not propose any self insurance costs.[694] These uncontested issues are not discussed further.

13.3.2 Trunk mobile radio

In its draft determination, the AER considered Aurora should not be allowed to exclude TMR from the EBSS because absent a legal obligation on Aurora to participate in the TMR, the decision to continue to participate and incur costs rests with Aurora.[695] To clarify what was meant by 'legal obligation' in the draft determination, the AER was referring to a legislative requirement or government direction, rather than a contractual obligation.

Aurora has re-submitted the same arguments from its regulatory proposal.[696] These are:[697]

- the arrangements surrounding the provision for this service to all Tasmanian Government agencies have yet to be finalised and the costs for the provision of this service still remain uncertain
- the charge is calculated by the Police and Emergency Management Department each financial year and is beyond Aurora's control.

Aurora also attached the (confidential) TMR contract to its revised proposal in support of its position (AE103).

For the reasons discussed in attachment 2, the AER maintains the position expressed in its draft determination that these costs are controllable.[698] The AER acknowledges that some of the TMR costs may be uncertain. However, it is important to distinguish between uncertainty and controllability. If particular costs are uncertain, it does not necessitate that those costs are uncontrollable. If only costs that were known with certainty were included in the EBSS the scheme would provide few rewards or penalties and would be effectively redundant. The AER maintains that Aurora has some control over TMR costs because it can choose whether or not to use the service. As such those costs should be included in the EBSS.

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692 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 111–112.
693 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 111–112.
694 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 111.
695 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 268.
696 Aurora, *Regulatory proposal 2012–17*, May 2011, p. 194.
697 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 112.
698 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 268.

13.3.3 Demand growth adjustment

Section 2.3.2 of the EBSS requires the AER to adjust Aurora's forecast opex for the cost consequences of any differences between forecast and actual demand growth over the regulatory control period to calculate carryover amounts. The AER must make these adjustments using the same relationship between growth and expenditure it uses in establishing the forecast opex.[699] This approach reduces the possibility that Aurora will be rewarded (or penalised) for cost decreases (increases) due to network growth factors beyond its control. Aurora did not propose a method for performing this adjustment in either its initial or revised regulatory proposals.

For the draft determination the AER included a scale escalation allowance for network growth in its substitute total forecast opex allowance for Aurora.[700] However, for this final determination the AER has determined an opex allowance using the program of works provided by Aurora. This program of works does not include an explicit relationship between growth and expenditure. Aurora advised the AER that, given there is no explicit relationship between growth and expenditure, it did not consider the opex forecasts used to determine EBSS carryover amounts should be adjusted for any cost consequences of any differences between forecast and actual demand growth.[701] The AER is satisfied that this is consistent with the requirements of the EBSS.

13.4 Revisions

Revision 13.1: The AER does not accept Aurora's revised proposal to exclude TMR from EBSS.

699 AER, *Electricity DNSPs: EBSS*, 26 June 2008, p. 6.

700 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 173–177.

701 Aurora, *Response to information request AER/080 of 5 April 2012*, received 12 April 2012, p. 3.

14 Pass through events

A pass through is a cost that a DNSP incurs, which is added to its allowable revenue during a regulatory period rather than included in the allowance at the time of the AER's determination. The NER provides pass throughs to allow DNSPs to recover legitimate costs of supply which otherwise would be too uncertain and potentially large to allow for in advance. When a pass through event occurs, a DNSP may submit to the AER for a determination on how much of the cost may be added to user charges.[702]

The NER allow pass throughs only if they result from a defined pass through event.[703] It prescribes the following five events:

(a) a regulatory change event

(b) a service standard event

(c) a tax change event

(d) a terrorism event

(e) and an event nominated in a distribution determination as a pass through event.[704]

The AER must make a constituent decision on the additional pass through events (nominated events) to apply in the forthcoming regulatory control period.[705]

14.1 Determination

No material issues were raised by Aurora or stakeholders on pass through events, so the AER’s position on pass through events has not changed from the draft determination. That is, the AER nominates three events proposed by Aurora as additional pass through events. These events are:

- Natural disaster event
- Insurer credit risk event
- Liability above insurance cap event.

The AER considers that the other six events proposed by Aurora are more appropriately covered under other pass through events or cost recovery arrangements.[706]

702 NER, clause 6.6.1. The amount approved for cost pass through is added to the building block allowable revenue in the relevant years. In the case of a negative pass through (cost decrease), the DNSP *must* inform the AER.

703 NER, clause 6.6.1.

704 NER, chapter 10 (glossary) – definition of 'pass through event'. Each of the four events is defined in the glossary.

705 NER, clause 6.12.1(14).

706 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 283–284.

However, in its revised regulatory proposal, Aurora sought some clarification from the AER that certain proposed pass through events are indeed covered by other recognised events.[707] The AER has provided additional information in section 14.3. Aurora accepted the AER's materiality threshold in its revised regulatory proposal.[708]

14.2 Assessment approach

The AER has not changed its assessment approach to pass throughs since its draft distribution determination, so it is not repeated here. See section 14.3 of attachment 14 of the AER's draft determination for this detail.[709]

14.3 Reasons for determination

In its draft determination, the AER accepted three of Aurora’s proposed nine nominated pass through events. The AER considered these events complied with the pass through requirements and were also allowed in the distribution determinations for the Victorian DNSPs.[710]

Attachment 14 of the AER’s draft distribution determination sets out the AER’s consideration of additional pass through events proposed by Aurora for the forthcoming regulatory control period.[711] In its revised regulatory proposal, Aurora did not dispute the AER's draft determination. However, Aurora requested clarification from the AER that the following events are indeed covered by other recognised events:[712]

- Bushfires event
- Storms event
- Industry restructure event
- Retailer of last resort (RoLR) event
- Carbon price event.

The AER's draft determination set out the reasons why the AER considered that the above five events proposed by Aurora were all likely to be covered by at least one other pass through event.[713] The AER continues to hold those views and confirms that, in its view, the existing types of pass through event incorporate those events (subject to materiality and other legal requirements).

The AER received a submission from the Energy Users Association of Australia (EUAA) on pass through events. The EUAA stated that notwithstanding its misgivings about pass through events in

707 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 120–121.
708 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 20.
709 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 284–286.
710 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 287.
711 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 283–292.
712 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 120–121.
713 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 287–290.

general, it supports the AER's decision on Aurora's nominated pass through events.[714] The AER appreciates the EUAA's support on this matter. However, the EUAA also stated that it disagrees with the AER's draft determination allowance of a carbon tax event for Aurora.[715] Since the AER did not allow a carbon tax event for Aurora in its draft determination, the AER has not further addressed this statement.

14.4 Revisions

The AER's position on pass through events has not changed since the draft determination. The AER has made no revisions.

[714] EUAA, *Submission to the AER on its draft distribution for Aurora Energy, and Aurora's Energy's revised proposal*, February 2012, pp. 23-24.

[715] EUAA, *Submission to the AER on its draft distribution for Aurora Energy, and Aurora's Energy's revised proposal,* February 2012, pp. 23-24.

15 Control mechanism for alternative control services

In making its distribution determination for Aurora the AER must determine the control mechanism to apply to alternative control services.[716] The AER must also determine how compliance with that control mechanism is to be demonstrated.[717] The control mechanism is the means by which the AER imposes controls over the prices of alternative control services. This attachment sets out the AER's reasons for these determinations.

15.1 Determination

The AER has determined that price caps will apply to all alternative control services. The AER's reasons are set out below at paragraph 1.3. The specifics of these price caps are provided below.

15.1.1 Metering, public lighting and fee based services

For 2012-13, actual price caps for individual alternative control services have been developed. The prices determined for alternative control services are exclusive of GST. Price caps for the following years will be calculated using the following price control formula:

Alternative control services price control formula for 2013–14 to 2016–17

$$P_t = P_{t-1} \times (1 + \Delta CPI_t) \times (1 - X)$$

Where:

- P_t is the price for regulatory year t
- P_{t-1} is the price in regulatory year t-1
- X is the X–factor for the alternative control service
- ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics Consumer Price Index (CPI) for All Groups, Weighted Average of Eight Capital Cities for the most recent prior year ending in March.

Compliance with control mechanism

The AER must make a decision on how compliance with a relevant control mechanism is to be demonstrated.[718] Prices for the first year (2012–13) must be as determined by the AER escalated for the change in CPI for the most recent prior year ending in March (March 2011 – March 2012). Prices for each subsequent year of the forthcoming regulatory control period must be determined in accordance with the price control formula above. The annual pricing proposal must be submitted to the AER in accordance with clause 6.18.2 of the NER.

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716 NER clauses 6.2.4(a) and 6.2.5(a), having regard to the criteria in clause 6.2.5(d)

717 NER clause 6.12.1(13)

718 NER clause 6.12.1(13)

15.1.2 Quoted services

The following price control formula will apply to quoted services. The prices determined for alternative control services are exclusive of GST.

Quoted services price cap formula

$$P = \sum_{i} \left(Units_i \times LR_i \right) + Materials + Contractors + OtherCosts + Overheads$$

Where:

- *P* is the price cap
- *Units*$_i$ is the number of units of labour type "i" required for the provision of the service
- *LR*$_i$ is the labour rate for labour type "i" in the year the service is provided. The labour rates for 2012-13 have been determined by the AER and are available in attachment 19. These labour rates are to be escalated for the change in Consumer Price Index (CPI) for the most recent prior year ending in March (March 2011 – March 2012). In subsequent years the AER has set real labour rates in $2011-12. To calculate labour rates for individual regulatory years after 2012-13 these will be adjusted for CPI inflation. The CPI inflation to be used is the annual percentage change in the Australian Bureau of Statistics CPI All Groups, Weighted Average of Eight Capital Cities. The CPI adjustment will be the change in CPI from March 2011 to March in the preceding regulatory year.
- *Materials* are the materials costs incurred in the provision of the service
- *Contractors* are the contractor costs incurrent in the provision of the service
- *Other Costs* are any other costs incurred in the provision of the service
- *Overheads* are the overheads costs incurred in the provision of the service

Compliance with control mechanism

Aurora is to comply with the price cap control mechanism by providing its annual calculation of labour rates to the AER in its pricing proposal.[719]

15.2 Assessment approach

The AER has not changed its assessment approach for alternative control services since its draft distribution determination, so it is not repeated here. See section 15.3 of attachment 15 of the AER's draft determination for this detail.[720]

[719] NER clause 6.12.1(13)

[720] AER, *Aurora 2012–17 draft distribution determination,* November 2011, pp. 300-302.

15.3 Reasons

This section presents the AER's reasoning for its final determination.

15.3.1 Uncontested issues

In its submissions on the draft determination, Aurora did not oppose the AER's approach to forecast costs for alternative control services. Consequently the AER has maintained these aspects of the draft determination. The draft determination approach to forecast costs for alternative control services was:

- Metering services – a limited building block approach based on the regulated asset base roll forward approach[721]
- Public lighting services – an annuity approach[722]
- Fee based and quoted services – Aurora's proposed cost build up method[723]

15.3.2 Control mechanism

The AER's final determination revises the method by which price caps are calculated for alternative control services. Instead of setting a schedule of real prices, the AER will set prices for the first year of the next period. Those prices will then be adjusted annually using the formula in section 15.1.

The AER has accepted Aurora's proposed approach to set initial prices and then adjust these prices using an appropriate control mechanism in its revised proposal. However, the AER does not accept the addition of a real labour escalation factor to the control formula to adjust prices for real labour price outcomes. This is because real labour escalations have already been factored into cost forecasts for alternative control services. If included again, they would be double counted.

In the AER's draft determination, the AER set price caps for individual alternative control services for each year of the forthcoming regulatory control period. These prices were calculated based upon the AER's forecast of inflation. These prices were to be adjusted annually to account for the difference between forecast and actual inflation.[724]

For alternative control metering, public lighting, and fee based services, Aurora contested the AER's draft determination approach to setting price caps. Aurora submitted that the AER's proposed control mechanism could result in uncertainty about pricing because of the year by year approach to price setting for these services. To address these concerns Aurora proposed a "base-year" approach to be used to set prices for the first year of the forthcoming regulatory control period, with the base year to be escalated by a similar methodology to that used to escalate the annual revenue for standard control services. Aurora submitted that this approach would simplify the annual price setting for these services and provide a degree of certainty about the future movements of prices.[725]

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721 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 331.
722 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 345.
723 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p. 357.
724 AER, *Constituent decisions, Draft distribution determination, Aurora 2012–17*, November 2011, p 10.
725 Aurora, *Revised regulatory proposal 2012–17*, January 2012, Attachment AE138, p.3.

To set prices, Aurora proposed that the AER develop an initial starting price and then calculate prices for subsequent years by escalating the base prices by CPI, the real labour escalators and an appropriate X–factor determined in the initial smoothing process.[726] Aurora specified its preference for the following formula to be used to calculate price caps:[727]

$$P_i = P_{i-1} \times (1 + CPI) \times (1 + real\_labour\_escalator_i) \times (1 - X_i)$$

In deciding on a control mechanism for alternative control services, the AER must have regard to the potential for development of competition in the relevant market and how the control mechanism might influence that potential.[728] The AER considers that the best way to facilitate competition would be through setting prices at the level of efficient costs.[729]

In terms of efficiency the AER's draft determination approach and Aurora's proposed approach are equivalent. This is because the prices developed under both approaches are net present value neutral and do not differ materially. [730]

The inclusion of a real labour escalation factor in the price control formula would not lead to efficient prices. The AER has already factored real labour escalation into its cost forecasts for alternative control services. Also, Aurora's revised proposal incorporates movements in real labour rates. Labour escalations would be double counted if a factor that adjusts prices for real labour escalation was incorporated into the control formula.

In deciding on a control mechanism for alternative control services, the AER must have regard to the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction).[731] Consistency is desirable. However, it is one consideration amongst several to which the AER must have regard in determining a control mechanism for Aurora's alternative control services.[732]

The AER notes that different forms of control are applied across the NEM jurisdictions to alternative control services. Further, the AER notes that in each jurisdiction these respective forms of control are applied consistently to similar services within the regulatory control period.[733]

The AER considers that Aurora's proposal to set price caps for individual alternative control services for 2012-13, and then escalate these prices using a consistent formula, provides consistency across alternative control services. The AER also notes that it is uncommon to escalate alternative control services annually by movements in real labour prices.

Consideration of the control mechanism for each group of alternative control services is considered in Table 15.1 to Table 15.3 below.

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726 Aurora, *Revised regulatory proposal 2012–17*, January 2012, Attachment AE138, p.3.

727 Aurora, *Information request response AER/071 of 1 March 2012*, recieved 3 March 2012, p3.

728 NER clause 6.2.5(d)(1)

729 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 301.

730 This will holds true if the real labour escalator is removed from the control formula.

731 NER clause 6.2.5(d)(4)

732 AER, *Framework and approach Aurora 2012–17*, November 2010, p. 76

733 AER, *Framework and approach Aurora 2012–17*, November 2010, p. 74

Table 15.1 NER factors and the metering control mechanism

NER Factor under 6.2.5(d)	AER consideration
Potential for development of competition	There is little if any potential for the development of competition in metering services.[734]
Administrative costs	The AER's control mechanism minimises administrative costs, both for Aurora and the AER. The control mechanism is simple and straight forward to apply.
Previous regulatory arrangements	The AER's control mechanism reflects arrangements applied in the current regulatory period. In the current regulatory control period Aurora has price caps for metering services. These are adjusted annually for movements in the CPI.[735]
Desirability for a consistent regulatory approach	The AER's control mechanism is consistent with the approach used for other DNSPs.
Any other relevant factor	The NEO and RPP are relevant to the AER's decision on the control mechanism. The AER's control mechanism will contribute to having efficient prices giving effect to the NEO and RPP.[736] The AER has assessed whether Aurora's forecast costs reflect efficient costs. The AER has not accepted the forecast costs were they do not reflect efficient costs. The inclusion of a real labour escalation factor in the form of control would not lead to efficient prices, as it would result in the double counting of real labour escalations.

Table 15.2 NER factors and the public lighting control mechanism

NER Factor under 6.2.5(d)	AER consideration
Potential for development of competition	For the public lighting assets owned by Aurora there is little if any potential for the development of competition. Public lighting services for assets not owned by Aurora in Tasmania are contestable.[737] The AER considers that the best manner in which to facilitate competition would be through cost reflective pricing. This is because cost reflective pricing provides accurate pricing signals for potential market entrants. Both control mechanisms are cost reflective as they are NPV neutral and appropriately allocate costs across years.
Administrative costs	The AER's control mechanism minimises administrative costs, both for Aurora and the AER. The control mechanism is simple and straight forward to apply.
Previous regulatory arrangements	In the current period public lighting services are not regulated. As such this is not a relevant consideration.
Desirability for a consistent regulatory approach	There is inconsistency in the control mechanisms for alternative control services across jurisdictions. However, the AER's control mechanism is consistent with the approach used for Aurora's other alternative control services.
Any other relevant factor	The NEO and RPP are relevant to AER's decision on the control mechanism. The AER's control mechanism will contribute to having efficient prices giving effect to the NEO and RPP.[738] The AER has assessed whether Aurora's forecast costs reflect efficient costs. The

[734] Aurora is the only party in Tasmania that can provide types 5–7 metering services in the areas prescribed by its licence. This is consistent with the AER's position on the Framework and Approach. [AER, *Framework and approach Aurora 2012–17*, November 2010, pp. 24–25]

[735] Aurora, *Network tariff strategy, periods 2 to 5 1 July 2008 – 30 June 2012, Version 1.1*, June 2008, pp. 16–17.

[736] AER, *Aurora 2012–17 draft distribution determination,* November 2011, pp. 300-302.

[737] AER, *Framework and approach Aurora 2012–17*, November 2010, p. 38.

[738] AER, *Aurora 2012–17 draft distribution determination,* November 2011, pp. 300-302.

	AER has not accepted the forecast costs were they do not reflect efficient costs. The inclusion of a real labour escalation factor in the form of control would not lead to efficient prices, as it would result in the double counting of real labour escalations.

Table 15.3 NER factors and fee based services control mechanism

NER Factor under 6.2.5(d)	AER consideration
Potential for development of competition	There is little if any potential for the development of competition for fee based services.[739] Therefore the choice of a cost build up approach will not have any material impact on the potential for competition.
Administrative costs	The AER's control mechanism minimises administrative costs, both for Aurora and the AER. The control mechanism is simple and straight forward to apply.
Previous regulatory arrangements	The AER control mechanism reflects arrangements applied in the current regulatory period. For fee based services OTTER determined prices for the first year of the regulatory control period. For subsequent years these prices were then escalated for movements in the weighted average wage index for the electricity and gas and water supply industry.[740] A real wage index price adjustment is not necessary as real changes in labour rates have already been incorporated in cost forecasts.
Desirability for a consistent regulatory approach	There is inconsistency in the control mechanisms for alternative control services across jurisdictions. However, the AER's control mechanism is consistent with the approach used for Aurora's other alternative control services.
Any other relevant factor	The NEO and RPP are relevant to the AER's decision on the control mechanism. The AER's control mechanism will contribute to having efficient prices giving effect to the NEO and RPP.[741] The AER has assessed whether Aurora's forecast costs reflect efficient costs. The AER has not accepted the forecast costs were they do not reflect efficient costs. The inclusion of a real labour escalation factor in the form of control would not lead to efficient prices, as it would result in the double counting of real labour escalations.

15.3.3 Quoted Services

The AER's final determination on the control mechanism for quoted services is to set price caps for the provision of these services based upon the formula in section 15.1.2.

Aurora accepted the AER’s decision on methodology for calculating quoted services, but proposed “that a formal control mechanism is included to establish the labour component prices that will apply.”[742] Aurora proposed a price cap control mechanism through formula based approach (ie non building block) with caps applied to the individual unit costs of inputs.

In the draft determination the AER set a cap on the charge out rates for labour. This incorporated real labour escalators. However the AER did not include a specific price control formula for quoted

739 In the framework and approach paper, the AER considered that there is a regulatory barrier to any party other than Aurora providing fee based services [AER, *Framework and approach Aurora 2012–17*, November 2010, pp. 41–44]

740 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania, supplementary final report and statement of reasons on maximum prices for special services provided by Aurora Energy*, June 2008, pVIII.

741 AER, *Aurora 2012–17 draft distribution determination,* November 2011, pp. 300-302.

742 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 157.

services. The price control formula for alternative control services above has been based upon Aurora's proposed formula. The AER does not accept that labour charge out rates should be adjusted for real labour escalations. This is because real labour escalations have already been factored into the real labour rates.

The AER considers that Aurora has proposed a control mechanism without a price cap incorporated within it. The AER therefore does not accept Aurora's proposed control mechanism. This is because the AER's draft determination on the form of control for quoted services was a price cap mechanism. In its submissions, Aurora did not oppose this determination.[743]

The AER has taken into account the factors under 6.2.5(d) of the NER in deciding on a control mechanism for alternative control services.[744]

Table 15.4 NER factors and quoted services control mechanism

NER Factor under 6.2.5(d)	AER consideration
Potential for development of competition	There is little if any potential for the development of competition for fee based services.[745] Therefore the choice of a cost build up approach will not have any material impact on the potential for competition.
Administrative costs	The AER's control mechanism minimises administrative costs, both for Aurora and the AER. The control mechanism is simple and straight forward to apply.
Previous regulatory arrangements	The AER control mechanism reflects arrangements applied in the current regulatory period.
Desirability for a consistent regulatory approach	The AER's control mechanism is consistent with the approach used for other DNSPs.
Any other relevant factor	The NEO and RPP are relevant to the AER's decision on the control mechanism. The AER's control mechanism will contribute to having efficient prices giving effect to the NEO and RPP. This is because the prices will equal the costs incurred in providing the service. The inclusion of a real labour escalation factor in the form of control would not lead to efficient prices, as it would result in the double counting of real labour escalations.

15.4 Revisions

Revision 15.1: The AER has adjusted the control mechanism for metering, public lighting and fee based services. For metering, public lighting and fee based services, price caps have been developed for individual services for 2012-13. The price control formula in section 15.1 will apply to these services in subsequent years.

Revision 15.2: The AER has adjusted the control mechanism for quoted services. The price control formula in section 15.1.2 will apply.

743 Aurora, R*egulatory proposal 2012–17*, May 2011, p.245.

744 NER clause 6.2.5(d)(2)

745 In the framework and approach paper, the AER considered that there is a regulatory barrier to any party other than Aurora providing quoted services. [AER, *Framework and approach, Aurora 2012*, November 2010, pp. 55,57–58]

16 Metering services

This chapter presents the AER's analysis and reasoning to supporting its decision on Aurora's metering services.

- The AER regulates Aurora's metering services which include the provision, installation and maintenance of standard meters (types 5, 6 and 7).

16.1 Determination

The AER's final determination on price caps for metering services in 2012–13 are presented in table 16.1. As per the AER's determination on the form of control for metering services[746] prices for years after 2012–13 will be escalated by an x-factor of 0 and CPI.

Table 16.1 Metering services prices ($cents per register per day, 2011–12)[747]

Year	2012–13
Business LV - Single Phase	7.088
Business LV - Multi Phase	14.179
Business LV - CT Meters	18.335
Domestic LV - Single Phase	6.853
Domestic LV - Multi Phase	14.220
Domestic LV - CT Meters	17.598
Other Meters (PAYG)	12.513
Business LV - Single Phase - Remote Read	5.890
Business LV - Multi Phase - Remote Read	13.321
Business LV - CT Meters - Remote Read	19.196
Domestic LV - Single Phase - Remote Read	5.890
Domestic LV - Multi Phase - Remote Read	13.321
Domestic LV - CT Meters - Remote Read	19.196

Source: AER analysis

The AER has calculated prices for metering services from the building block cost build up as set out in Table 16.2.

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[746] AER, *Aurora 2012–17 draft distribution determination*, November 2011, attachment 15.

[747] Note these prices are in $2011-12. As part of the annual tariff approval process Aurora will inflate these prices for movement in the all groups weighted average consumer price index (for March to March quarters).

Table 16.2 Metering services building block costs forecast ($million, nominal)

Year	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Building block components (nominal)							
Return on capital		3.45	3.65	3.77	3.88	4.06	18.81
Return of capital		2.75	3.29	3.57	3.51	3.82	16.94
O&M		6.65	6.56	6.78	7.06	7.20	34.25
Benchmark Tax liability		0.03	0.06	0.14	0.20	0.23	0.66
Total Revenue – AER[748]	15.28	12.89	13.57	14.25	14.64	15.31	70.65
Total Revenue - Aurora revised proposal[749]	15.36	13.77	14.88	16.12	16.88	17.79	79.45

Source: AER analysis.

16.2 Assessment approach

The AER has not changed its assessment approach for metering since its draft distribution determination, so it is not repeated here. See section 15 of attachment 15.3 of the AER's draft determination for this detail.[750]

16.3 Reasons

The AER has upheld the elements of its draft determination that have not been contested by stakeholders in submissions. Aurora’s revised regulatory proposal has raised a number of issues concerning the AER’s draft determination for metering services. No submissions were received from other stakeholders on the draft determination regarding metering services. The elements of the draft determination that have been contested by Aurora are considered individually below.

16.3.1 Uncontested issue - basis of control

In its draft decision, the AER proposed to apply a building block model and PTRM as the basis of control to apply to Aurora's metering services. Aurora did not contest the AER's proposed basis of control in its revised proposal. The AER has upheld this in the final determination.

16.3.2 Uncontested issue - replacement volume forecasts

In its draft determination, the AER did not accept Aurora's forecast of replacement volumes and developed an alternative forecast. In its revised proposal, Aurora accepted the AER's draft determination. The AER has upheld its position from the draft determination for the final determination.

748 AER, *Final metering model*, April 2012, Summary worksheet.

749 Aurora, *Metering model AE142, attachment to information request AER/066, of 15 March 2012*, received 15 March 2012, Summary worksheet.

750 AER, *Aurora 2012–17 draft distribution determination,* Nov 2011, pp. 300–302.

16.3.3 Control formula

In its revised proposal, Aurora contested the AER's proposed price path formula to calculate prices across alternative control services. The AER does not accept Aurora's proposed method to calculate a price path for alternative services and has developed an alternative method to calculate prices across alternative services. For a more detailed discussion of this matter, refer to attachment 15[751] of the AER's final determination.

16.3.4 Initial RAB valuation

The AER will apply a building block model and PTRM to Aurora's metering services for the first time, in the forthcoming regulatory control period. Accordingly, the AER must establish an initial RAB to calculate the revenue requirement under a building block model and PTRM. The AER calculated a written-down value of Aurora's asset base using the replacement cost of assets multiplied by the initial meter volumes, and adjusting the initial RAB for depreciation.

Aurora has contested the meter volumes, stating that timeclock assets should be included in the volumes of the initial RAB; and the depreciation of meter assets (derived from meter lives). Although Aurora did not contest the AER's replacement cost estimates (derived from purchase cost), it has misinterpreted the AER's draft determination. The effect of these items on the initial RAB valuation is considered below:

Timeclocks

The AER agrees with Aurora's revised proposal to include timeclocks in the initial metering RAB. The AER considers that timeclocks are a necessary and common item where time-of-use tariffs are used with existing mechanical meters.

In its revised proposal, Aurora submitted that the AER’s draft decision failed to take into account timeclock assets that are installed with off-peak mechanical meters. Aurora considers that timeclock assets should be included in the metering PTRM and added to the initial metering RAB. The inclusion of timeclocks into the asset base adds $1.03m to Aurora's initial metering RAB.[752]

The AER accepts that timeclocks should be rolled into the metering RAB but timeclock assets were not mentioned in Aurora’s initial proposal and the issue has first been raised by Aurora in its revised proposal. The AER notes that all new meter installations and replacements will use electronic meters, which include features provided by a standalone timeclock.[753] Therefore, standalone timeclock assets should not feature in forecasts of new meter installations and replacements and do not result in increased capex requirements.

Aurora proposed the cost of a timeclock as the average of mechanical meter installation and purchase costs. The AER is not aware of any publicly available information relating to the cost of timeclocks and in response to the AER’s request for contract details for bulk-order purchases of timeclocks, Aurora stated:

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751 AER, *Aurora final distribution determination*, alternative control services form of control attachment, April 2012.

752 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 140–141.

753 Aurora, *Response to information request AER/058 of* 6 February 2012, received 14 March 2012.

> "Aurora's most recent bulk purchase of new timeclocks occurred prior to 2007. Timeclocks currently used by Aurora are reconditioned assets that have been returned from the field."[754]

The AER has reviewed the cost of timeclocks against the benchmark meter asset base costs used in Victoria and performed a high-level assessment of the costs associated with timeclock installations.[755] The AER considers the value of timeclocks proposed by Aurora is reasonable and accepts that it should be rolled into Aurora's metering RAB at Aurora's proposed cost.[756] Further, the AER considers that refurbished timeclock assts would be considered to have a value similar to its original replacement value.[757]

The AER considers that the inclusion of timeclock assets into the initial metering RAB is necessary to generate an allowance for the efficient provision of metering services through mechanical meters. Accordingly, the AER considers that the inclusion of these assets in the RAB will allow Aurora to recover its efficient costs giving effect to the NER.[758]

Updated purchase cost of electronic meters

The AER has updated purchase cost estimates of electronic meters to reflect Aurora's most recent meter supply contract. Aurora did not contest the AER's draft decision of mechanical meter purchase costs.

For clarity, the AER's draft decision position proposed to use the most up-to-date meter purchase costs available at the time of writing the final determination.[759] In the draft decision the AER calculated electronic meter purchase costs from the most up-to-date forward-looking competitive quotes for electronic meters at the time.

In its revised proposal, Aurora accepted the meter costs provided in the AER's draft decision on electronic meter purchase costs but proposed that the AER's purchase cost estimates be updated to reflect the most recent CPI data.[760] Aurora proposed meter costs are provided in Table 16.3 of the confidential attachment of the AER's final determination.

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754 Aurora, *Response to information request AER/058 of* 6 February 2012, received 14 March 2012.

755 Nuttall Consulting, *Aurora electricity distribution revenue review – revised proposal: A report to the AER*, April 2012, pp. 79–80.

756 Nuttall Consulting, *Aurora electricity distribution revenue review – revised proposal: A report to the AER*, April 2012, pp. 79–80.

757 Nuttall Consulting, *Aurora electricity distribution revenue review – revised proposal: A report to the AER*, April 2012, pp. 79–80.

758 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 300–302.

759 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 336.

760 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 141.

Table 16.3 Aurora's proposed electronic meter purchase costs

Meter type	Purchase $ cost per meter
Single phase - Electronic	189
Multi phase - Electronic	246
CT meters - Electronic	384
Other meters - Electronic	200.27

Source: Aurora revised metering model[761]

The AER maintains its approach from the draft determination and has calculated purchase costs from the most recent meter supply contract, dated 11 September 2011. The contract was sourced from an open tender process, as evidenced from internal board papers provided by Aurora.[762]

Aurora was asked to provide the most recent supply contracts across all meter types but only provided an updated supply contract for single phase electronic meters. On that basis, the AER has maintained the decision to use the purchase costs for multi-phase and CT meters as outlined in its draft decision. The AER considers that electronic meter purchase costs sourced from supply contracts represent the most recent and efficient cost, supported by a competitive tendering process. The AER is therefore satisfied that its final determination satisfies the NER requirements in accordance with the AER's approach.[763] As per the AER's draft decision, the on-cost per meter will be calculated as 10 per cent of the meter purchase cost and added to the total meter cost.[764] The AER's final determination of purchase costs for meters are outlined in section D.2 of the confidential appendix of the AER's final determination.

Meter lives

The AER accepts Aurora's revised proposal to adjust the initial metering RAB to reflect the half-year change in the regulatory year that occurred during 2007–08.

In its draft decision, the AER did not accept Aurora's proposed meter lives and proposed an alternative set of standard asset lives for meter assets.[765]

In its revised proposal, Aurora accepted the AER's draft decision on meter lives but emphasised that the written-down value of the initial RAB subtracts depreciation expense which has been recovered in prices. Aurora submitted that this approach is inappropriate as it does not account for the change in Regulatory years that occurred during 2007–08. The models used by OTTER to calculate prices with a start date of 1 Jan 2008 and not 1 July 2007. Aurora considers that the depreciation charges should be adjusted to reflect this half-year change.[766]

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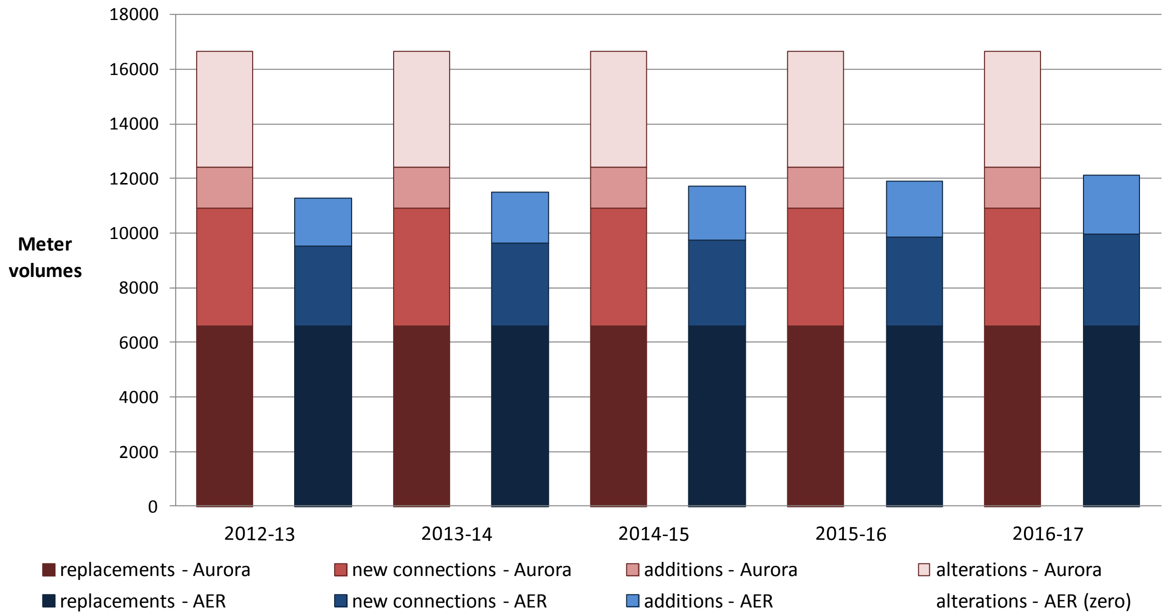
761 Aurora, *Metering revenue model AE142*, January 2012, unit costs worksheet.
762 Aurora, *Internal Board paper: Meter supply contracts*, April 2009, pp. 2–3.
763 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 300–302.
764 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 337.
765 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 336.
766 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 141.

The AER accepts Aurora's revised proposal to adjust the initial metering RAB to reflect the half-year change between 1 July 2007 and 1 January 2008. The AER's metering model has been updated to reflect this change.[767]

16.3.5 Capital expenditure

Capital expenditure is calculated as the product of forecast meter unit costs and forecast volumes of new meter installations and replacements. Meter installations are made up of new connections and customer initiated additions and alterations. Replacements concern the replacement of old faulty meters with new ones. The unit cost of meters is the costs associated with the purchase and installation of new meters. Figure 16.1 depicts the forecast volumes for new meter installations and replacements:

Figure 16.1 AER final determination of forecast meter volumes



Source: AER analysis.

New meter installation volumes

The AER does not accept Aurora's revised proposal in respect of forecast new meter installation volumes and has calculated an alternative new meter installation forecast as per Figure 16.1.

In its draft determination, the AER did not accept Aurora's forecast of new meter installations. The AER proposed an average forecast of 5788 register installations, in contrast to Aurora's 9986 average forecast register installation per annum.[768] The AER's forecast of new meter installations was derived from forecasts of new customer connections, as discussed in the AER's analysis of demand in the AER's draft determination.[769]

[767] AER, *Final metering model*, opening RAB WDV worksheet

[768] AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 338. Note these figures are the number of register installations and not meter installations. In Tasmania there are approximately two registers per meter.

[769] AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 88–94, 338–339.

In its revised proposal, Aurora disagreed with the AER's draft determination and proposed an updated forecast of 11320 meter installations per annum for the forthcoming regulatory control period. Aurora's revised meter installation forecasts are comprised of new meter connections and additions and alterations. Aurora submitted that the AER's draft determination only provided for meter installations related to new meter connections and did not account for new installations arising from customer initiated additions and alterations.[770]

Aurora also disagreed with the AER's draft determination forecast of new meter installations which related to new meter connections. Aurora provided the AER with an updated metering model which subtracted meter abolishments from forecast meter installations volumes.[771] The issue of abolishments was not raised by Aurora in its initial proposal and was first raised in Aurora's revised proposal. Aurora has provided updated forecasts of meter installations relating to new meter connections and the additions and alterations, as per table 16.4.

Table 16.4 Aurora's proposed meter installation volume forecasts per annum

	2012–13	2013–14	2014–15	2015–16	2016–17
New meter connections	4320	4320	4320	4320	4320
Additions	1500	1500	1500	1500	1500
Alterations	4250	4250	4250	4250	4250
Total meter installation	10070	10070	10070	10070	10070

Source: Aurora[772]

The AER has assessed Aurora's forecast metering installation volume forecasts and has determined final meter installation volume forecast estimates as per Table 16.5.

Table 16.5 AER final determination of meter installation volume forecasts per annum

	2012–13	2013–14	2014–15	2015–16	2016–17
New meter connections	2929	3045	3154	3260	3369
Additions[773]	1762	1861	1959	2057	2157
Alterations	0	0	0	0	0
Total meter installation	4,691	4,906	5,113	5,317	5,526

Source: AER analysis[774]

770 Aurora, *Revised regulatory proposal 2012–17*, January 2011, p. 141.

771 Aurora, *AE142 – Metering Revenue Model – attachment to information request AER/067*, Meter volumes data inputs(2) worksheet.

772 Aurora, *Revised regulatory proposal 2012–17*, January 2012, attachment AE113.
Additions were sourced from: Aurora, *Metering model AE142, attachment to information request AER/067, of 28 February 2012*, received 1 March 2012.

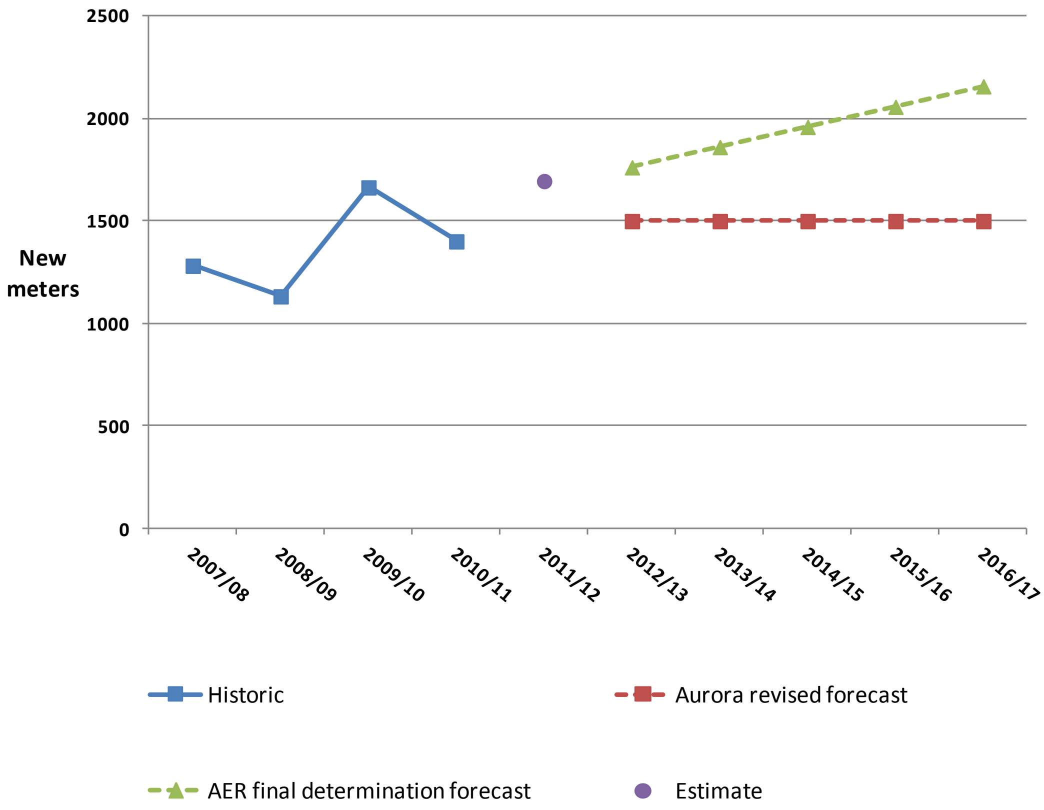
773 Nuttall Consulting, *Aurora electricity distribution revenue review – revised proposal: A report to the AER*, April 2012, p. 84.

774 AER, *Final metering model*, April 2012, Metering capex worksheet.

Meter installation volumes — additions

The AER considers that some provision should be made for meter installations associated with the additions category, as the cost of these installations are not currently covered under the new connections allowance provided in the AER's draft decision. Figure 16.2 depicts the difference in additions forecasts between Aurora's revised proposal and the AER's final determination.

Figure 16.2 Meter additions volume forecasts used to calculate capex requirements



Source: AER analysis, Aurora.[775]

Additions and alteration-related meter installations are new meters which are installed on request of the customer and are independent of the number of new connections that occur each year.[776] Aurora has described its additions and alterations categories:

> "Additions relate to additional meters installed as a result of customers adding additional tariffs to existing dwellings. Alterations relate to existing meters replaced when customers upgrade or modify existing dwellings such as upgrading consumer mains or relocating the meter box."[777]

The AER has estimated a forecast of additions which applies a linear trend from a historical data series of customer initiated additions works. The AER has determined that historical estimates of customer initiated additions serve as a reasonable basis for forecast additions, which are derived from customer requests to add tariffs to existing dwellings. This is consistent with Aurora's stated

[775] Aurora, *Response to information request AER/058 of* 6 February 2012, received 14 March 2012

[776] Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 141–142.

[777] Aurora, *Response to information request AER/067 of 28 February 2012*, received 1 March.

forecasting methodology which uses historical estimates of additions to forecast volumes.[778] The volumes of such customer initiated work is driven by external factors such as retailer activity in promoting off-peak products for various appliances.[779] The AER considers that its forecast of additions volumes are a reasonable input into calculating an allowance for the efficient provision of meter installation services. That is because these forecast volumes reflect the historical trend. The AER is therefore satisfied that its final determination satisfies the NER requirements in accordance with the AER's approach.[780] The AER has relied upon historical figures submitted by Aurora, as outlined in table 16.6. [781] The AER's final determination of forecast volumes for additions works are outlined in table 16.7.

Table 16.6 Aurora's historical estimates of additions works

	2007–08	2008–09	2009–10	2010–11	2011–12
Additions	1282	1133	1664	1401	1695

Source: Aurora revised revenue proposal[782]

Table 16.7 AER final determination of volume forecasts of additions works

	2012–13	2013–14	2014–15	2015–16	2016–17
Additions	1762	1861	1959	2057	2157

Source: AER analysis.

Meter installation volumes — alterations

The AER has reduced Aurora's forecast volumes to zero in each year of the forthcoming regulatory period.

The AER does not accept Aurora's proposed allowance for alterations, and considers that the material cost of performing an alteration should already be provided for in the AER's allowance for meter replacements.

Aurora has explained its meter alterations service:

> "Aurora has a policy of replacing meters that have failed compliance testing or are very old and in poor condition. When Aurora crews attend a site to install an additional meter for a new tariff and a meter type that has been identified as requiring replacement is installed on the existing tariff, it is removed and replaced whilst the crew is on site. This removes the need for a second visit in the future to replace the existing meter."[783]

It is clear from Aurora's comments that meter alterations arise from either failed compliance testing, or meters that appear to be in poor condition. The AER considers that it is efficient for Aurora to replace meters that are identified as having failed meter compliance testing. However, the replacement cost

778 Aurora, *Response to information request AER/067 of 28 February 2012*, received 1 March.

779 Nuttall Consulting, *Aurora electricity distribution revenue review – revised proposal: A report to the AER*, April 2012, p. 82.

780 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 300–302.

781 Nuttall Consulting, *Aurora electricity distribution revenue review – revised proposal: A report to the AER*, April 2012, p. 83.

782 Aurora, *Response to information request AER/058 of* 6 February 2012, received 14 March 2012.

783 Aurora, *Response to information request AER/058 of* 6 February 2012, received 14 March 2012.

for meters that fail standard performance compliance tests are already separately accounted for under the allowance for meter replacements.[784] Additionally, Aurora has not demonstrated that the replacement of old meters in poor condition is any more or equally efficient than replacements driven by failed compliance testing. As such, Aurora has not provided any information which justifies meter replacements other than for failing compliance testing.

The AER requested Aurora to distinguish between replacement resulting from alterations works and replacements already funded by the AER's draft decision, and Aurora stated:

> "Costs for work associated with the replacement of older meters replaced in conjunction with alteration and addition works are not incorporated in charges for alterations and additions."[785]

Aurora did not provide further documentation to support its statement. Therefore, it did not demonstrate that replacement works under alterations are not already being recovered through the replacement allowance.

The AER considers that any allowance given for Aurora’s proposed meter alterations category would be double counting Aurora’s capital expenditure requirements for meter replacements. The AER determines that Aurora’s proposed forecasts of alterations should be removed from its forecasts of meter installations. The AER considers that its forecast of alterations volumes are a reasonable input into calculating an allowance to allow the efficient provision of meter installation services.

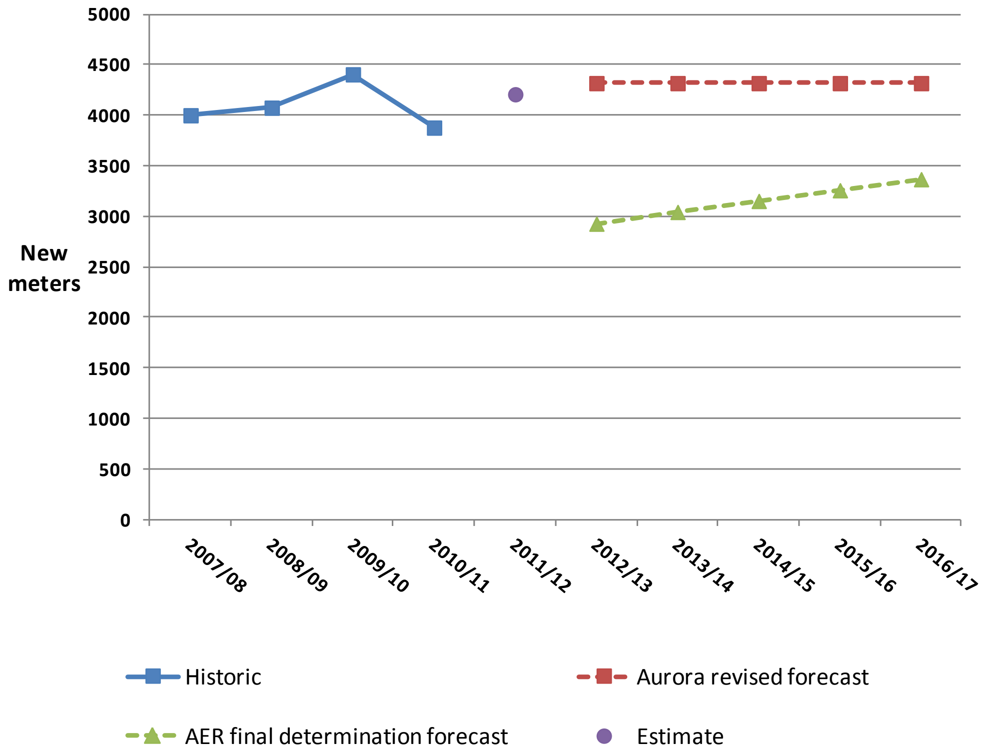
Hence, the AER has determined that Aurora should not be granted an allowance for meter alterations in accordance with its Assessment approach.[786]

Meter installation volumes — new connection forecasts

The AER maintains its forecast methodology of new meter connections from the draft determination, which were derived from forecasts of new customer connections. Figure 16.3 depicts the difference between Aurora revised proposal and the AER's final determination forecasts of new meter connections.

784 Aurora, *Management plan 2011: Metering assets*, May 2011, p. 11.
785 Aurora, *Response to information request AER/067 of 28 February 2012*, received 1 March.
786 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 300–302.

Figure 16.3 New meter connection forecasts



Source: AER analysis, Aurora.[787]

Aurora provided the AER with an explanation of the driver for new meter connections growth, stating "…new meters relate to additional meters installed as a result of the connection of new dwellings to the distribution network."[788] In the AER's draft determination, new customer connection forecasts were calculated from a gross estimate of new customer connections. Aurora has accepted the AER's forecast of new customer connections.[789]

In light of Aurora's definition of new meter connections and acceptance of the AER's new customer connections forecast, the AER maintains its forecasting method from the draft decision. The AER considers that its forecast of new meter connection volumes are a reasonable input into calculating an allowance to allow the efficient provision of meter installation services. The AER is therefore satisfied that its final determination satisfies the NER requirements in accordance with the AER's approach.[790] The AER forecasts new meter connections as per table 16.8.

Aurora's revised proposal meter connection forecasts have been based upon the historical data on new meter connections presented in Figure 16.3.[791] The AER considers that the use of historical new meter connections is not as robust a basis for forecasting new meter connections as using the AER's forecast of new customer connections. Aurora has previously stated that it does not collect information on whether a meter installation is an initial installation or a replacement, therefore it can only provide data on total number of installations, which includes replacements and new

787 Aurora, *Response to information request AER/058 of* 6 February 2012, received 14 March 2012.
788 Aurora, *Response to information request AER/067 of 28 February 2012*, received 1 March.
789 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 40.
790 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 300–302.
791 Aurora, *Revised regulatory proposal 2012–17*, January 2012, attachment AE113.

installations.[792] Further, the AER's forecast of new customer connections takes into account the economic drivers of customer growth.

Table 16.8 AER final deterination on forecast meter connections

	2012–13	2013–14	2014–15	2015–16	2016–17
New meter connections	2929	3045	3154	3260	3369

Source: AER analysis[793]

Meter installation volumes — abolishments

The AER accepts Aurora's revised proposal which contends that new meter installations should be adjusted by subtracting an amount of 710 meters per annum. Since the release of the draft decision, Aurora has provided an updated metering model that subtracts meter abolishments from meter installation forecast volumes. No additional information has been provided to explain Aurora's estimate of abolishments. However, the AER notes that meter abolishments are common where premises are disconnected to allow for renovations or rebuilding, or where premises are vacated for a long period of time.[794] The AER considers that Aurora's forecast of abolishments is within reasonable bounds and accepts Aurora's revised forecasts for abolishments.[795]

Unit costs

Unit costs are calculated as the sum of meter purchase and installation costs. Only meter purchase costs are a contested issue.

Meter purchase costs

The AER has revised meter purchase costs to reflect Aurora's most recent meter supply contract. See the discussion of meter purchase costs under the initial RAB section above – this applies equally to purchase costs as they relate to capex for meter installations.

Meter installation costs

The AER has maintained its position from the draft determination in respect of meter installation rates. More broadly, however, the AER has not accepted Aurora's revised unit rates across standard and alternative control services as it excludes the 3 per cent labour efficiency factor applied to unit rates. The AER will consider unit rates across alternative and standard control services with the labour efficiency factor included, as per Aurora's initial proposal – for further discussion of this matter, see attachment 3 of the AER's final determination.

792 Aurora, *RIN response attachment*, March 2011, p.7.

793 AER, *Final metering model*, Metering capex worksheet.

794 Nuttall Consulting, *Aurora electricity distribution revenue review – revised proposal: A report to the AER*, April 2012, pp. 84.

795 Nuttall Consulting, *Aurora electricity distribution revenue review – revised proposal: A report to the AER*, April 2012, pp. 84.

16.3.6 Building block approach

WACC

In its draft decision, the AER used a standard PTRM to calculate revenue allowances for Aurora's provision of metering services. The AER's metering PTRM calculates revenue using the same weighted average cost of capital (WACC) as applied in the Standard Control services PTRM.[796]

Aurora accepts the AER draft decision to apply the PTRM WACC but does not agree with the WACC figure used to calculate revenue for metering services.[797] The AER has applied its final determination PTRM WACC to calculate Aurora's metering tariffs. Attachment 10 contains the AER's reasons for its determination on the WACC.

Roll forward mechanism

The AER confirms that the administration of the roll-forward model for metering services will be consistent with the roll-forward model applied to standard control services.

The AER's draft decision proposed a limited building block approach to setting revenues which included a roll forward model, as per the AER's metering model.[798]

In its revised proposal, Aurora considered that the AER's draft decision did not detail how a roll-forward mechanism would be administered. Aurora proposed to adopt a roll-forward model as per clause 6.5.1 and schedule 6.2 of the NER. This is the same approach as for the PTRM which applies to standard control services.[799]

The AER agrees with Aurora's position and will administer the metering roll-forward model in the same way as for standard control services. The AER also emphasises that in making the draft decision, it had intended to administer the roll-forward model for metering services as per clause 6.5.2 and schedule 6.2 of the NER.[800]

16.3.7 Cost allocation for prices

The AER has adopted Aurora's proposed method of allocating revenue to each meter type, using a weighted average of meter costs.

In its draft decision, the AER did not accept Aurora's proposed annuity model approach to calculate revenue for metering services. Instead, the AER developed a building block approach to calculate revenue and scaled revenue figures into prices using an annuity calculation.[801]

In its revised proposal, Aurora disagreed with the AER's draft decision to use an annuity calculation to scale revenue into prices and has proposed an allocation model that allocates revenue to meter classes on the basis of weighted average of meter costs.[802]

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796 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 341.
797 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 142.
798 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 331.
799 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 140.
800 NER, clause 6.5.2 and schedule 6.2.
801 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 331.

16.3.8 Escalators

The AER has considered Aurora's proposed real cost escalation in attachment 4. Consistent with its draft determination, the AER has adopted this position for alternative control services.

16.3.9 Shared costs

The AER has reallocated shared costs so that they match the final allocation of direct costs. The AER's reasons for this are contained in attachment 7.

16.4 Revisions

Revision 16.1: The AER will use a price path calculating smoothed revenue from a single X–factor and adjusting revenue each year by CPI.

Revision 16.2: The AER will include timeclocks in the initial metering RAB.

Revision 16.3: The AER has revised the purchase costs of single phase meters. This will affect estimates of Aurora's initial RAB and forecast capex for new meter installations

Revision 16.4: The AER will adjust the initial written down metering RAB value to reflect the change in the length of the regulatory period during 2007/08.

Revision 16.5: The AER has adjusted new meter installation volume forecasts to reflect the categories of meter additions and abolishments.

Revision 16.6: The AER has updated the shared costs, units rates and escalators used for determining meter prices.

Revision 16.7: The AER's WACC has been used to calculate prices.

Revision 16.8: The AER's escalators and unit rates have been used to forecast costs.

802 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 142.

17 Public Lighting services

Aurora operates and maintains public lights throughout Tasmania on behalf of local councils and the Department of Industry, Energy and Resources (DIER). The AER draft determination classification of public lighting services as an alternative control services has not been contested by Aurora.[803] The AER will regulate Aurora's public lighting services by setting price caps for these services as outlined in attachment 15. Public lighting services consist of repair, replacement and maintenance of existing public lighting assets and the provision of new public lighting assets.

17.1 Determination

The AER has set daily price caps for the provision of Aurora's individual public lighting services for 2012–13. The AER will adjust Aurora's price caps for public lighting services in accordance with the price control formula in attachment 15 for each following year in the forthcoming regulatory control period. Attachment 15 contains the AER's reasons for this decision.[804] The X factor for the remainder of the regulatory period is 2.6.

The AER's final determination on price caps for 80W mercury vapour and 250W sodium vapour lights for 2012–13 is shown in Table 17.1. These two light types make up approximately 70 per cent of Aurora's public lighting services. Prices for all individual lighting types are set out in section 17.3.3 below.

Table 17.1 AER final determination for price caps for 80W mercury vapour and 250W sodium vapour lights for 2012–13 (cents per day, $2011-12)[a]

	Aurora proposed price cap for 2012–13	AER final determination price cap for 2012–13
80W mercury vapour (private contract)	22.074	22.225
80W mercury vapour (Aurora owned)	33.947	32.551
250W sodium vapour (private contract)	23.860	23.870
250W sodium vapour (Aurora owned)	41.032	38.722

Notes: (a) These prices exclude GST and will be adjusted for 2011-12 CPI escalation.
These light types represent 70 per cent of Aurora's public lighting population.
Source: AER analysis.

17.2 Assessment approach

The AER has not changed its assessment approach for public lighting since its draft distribution determination, so it is not repeated here. See section 15.3 of attachment 15 of the AER's draft determination for this detail.[805]

803 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 293.
804 Having regard to the five factors in NER Clause 6.2.5(d).
805 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 300-302.

17.3 Reasons

Aurora was the only stakeholder to comment on the AER's draft determination for public lighting services. The AER has upheld the parts of its draft determination that were not contested by Aurora. The elements of the draft determination that have been contested by Aurora are considered individually below.

17.3.1 Uncontested Issues

Aurora has accepted the AER's draft determination in relation to:[806]

- the use an annuity model to calculate price caps for public lighting services
- the AER's proposed capex for public lighting services.
- the unit costs for public lighting assets.

These parts of the draft determination have been upheld by the AER in its final determination.

17.3.2 Contested Issues

Operating expenditure

The AER's final determination for Aurora's public lighting operating expenditure is presented in Table 17.2. The AER concludes that the expenditure proposed in Aurora's revised proposal is efficient. This is because the AER considers that Aurora has demonstrated that the additional replacement program is efficient and consistent with other Australian DNSPs.

Table 17.2 AER final determination on public lighting opex for forthcoming regulatory control period ($million, 2009–10)

	2012–13	2013–14	2014–15	2015–16	2016–17
Aurora initial proposal	2.36	2.30	2.27	2.78	2.67
AER draft decision	1.59	1.56	1.53	1.42	1.38
Aurora revised proposal	2.21	2.12	2.06	1.93	1.85
AER final determination	2.27	2.13	2.09	1.97	1.92

Source: AER analysis

In the draft determination the AER substituted Aurora's proposed operating expenditure with expenditure that was consistent with historical trends. The AER did not accept Aurora's proposed public lighting opex for the following reasons: [807]

- Aurora did not provide sufficient evidence to support the large increase in total opex for the next regulatory period

806 Aurora, *Revised regulatory proposal 2012-17*, January 2012, p.146.
807 AER, *Aurora 2012–17 draft distribution determination*, November 2011, p. 347.

- Aurora did not provide sufficient evidence to support two proposed step change increases in 2012–13 and 2015–16
- Aurora's opex forecasts contain a number of errors
- Aurora's opex forecasts include costs for 'Trials/evaluation of new Road lighting technologies - Major and Minor'.

In its revised proposal Aurora accepted the AER’s findings of inconsistencies and has reviewed its Public Lighting Management plan and documentation. Aurora provided an amended Management Plan as an attachment to its revised proposal. Aurora also prepared revised forecasts for operating expenditure associated with the provision of public lighting services.[808] Aurora submitted that its increased opex forecasts are driven by increasing fault costs for public lighting.[809] Aurora also made an additional change to the opex forecast based on the volume of Sylvania B2224 luminaries to be replaced under the Bulk Lamp Replacement program.

The AER accepts that the additional expenditure associated with a return to a four year bulk lamp replacement cycle is reasonable and that the proposed staged replacement of the Sylvania B2224 luminaire is efficient. Aurora identified that it is currently lagging the current bulk replacement program by one year and that this backlog in lamp replacement has resulted in additional expenditures associated with lamp failures.[810] The AER has reviewed the lamp failure rates and confirms that a significant increase in lamp failures is evident from the information provided by Aurora.[811]

The AER has considered the information provided by Aurora and agrees that it appears that a backlog in bulk lamp replacements has built up in the last 1 to 2 years. This backlog is not considered consistent with good industry practice or with Aurora’s stated asset management plans. The AER notes that Aurora reduced the forecast expenditure associated with public lighting emergency repairs and maintenance consistent with the return to a 4 year bulk replacement cycle. Based on the additional information provided by Aurora, the AER considers that the additional replacement program is efficient and consistent with other Australian DNSPs.[812]

The AER reviewed the information provided by Aurora in relation to the volume of Sylvania B2224 luminaries to be replaced. The AER notes that concerns with failure rates, lumen depreciation and the availability of newer technologies mean that the replacement of this category of lamp type is efficient and consistent with other Australian DNSPs. [813]

Control mechanism

The AER does not accept Aurora's proposed form of control. Attachment 15 contains the AER's reasons for this decision.

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808 Aurora, *Revised regulatory proposal 2012-17*, January 2012, p.146.

809 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE112, Supporting Information – Public Lighting, January 2012, p.3.

810 Aurora, *Revised regulatory proposal 2012-17*, January 2012, Attachment AE112, Supporting Information – Public Lighting, January 2012, Section 2.3.

811 Nuttall Consulting, *Aurora electricity distribution revenue review - revised proposal: A report to the AER*, April 2012, p. 76.

812 Nuttall Consulting, *Aurora electricity distribution revenue review- revised proposal: A report to the AER,* April 2012, p. 79.

813 Nuttall Consulting, *Aurora electricity distribution revenue review- revised proposal: A report to the AER*, April 2012, p. 79.

WACC

The AER has considered Aurora's revised proposal WACC in attachment 10. For public lighting services the AER will apply a pre tax real WACC of 6.55 per cent. The calculation of the pre tax WACC is consistent with the calculation of the WACC for standard control services.

The draft determination for public lighting the AER utilised the standard control pre tax real WACC of 6.39.[814] Aurora did not contest the application of a WACC consistent with standard control services. However, Aurora did not agree with the value of the nominal vanilla WACC determined by the AER for standard control services. Aurora proposed a pre tax real WACC of 8.35 in its revised proposal for public lighting services.[815]

Escalators

In attachment 4 the AER considers real cost escalation. Consistent with its draft determination (see section 4.1) of attachment 4, the AER has adopted the approved escalators for alternative control services.

Unit rates

The AER has reincorporated Aurora's 3 per cent efficiency factor applied to unit rates as proposed in its initial proposal. Attachment 3 contains the reasons for this decision.

Shared costs

The AER has reallocated shared costs so that they match the final allocation of direct costs. The Operating expenditure Attachment (Attachment 7) contains the AER's reasons for this decision.

17.3.3 Prices

The AER's final decision on prices for Aurora owned lights are set out in Table 17.3.

Table 17.3 AER final determination on prices for Aurora owned public lights (cents per day, $2011-12)[a]

	2012–13
50W Mercury Vapour	32.551
80W Mercury Vapour (Aeroscreen)	32.551
80W Mercury Vapour (Art decorative)	51.565
125W Mercury Vapour	37.481
250W Mercury Vapour	37.915
400W Mercury Vapour	42.123
70W Sodium Vapour	34.667

814 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p.27.

815 Aurora, *Revised regulatory proposal 2012-17*, January 2012, p. 98.

100W Sodium Vapour	34.925
150W Sodium Vapour	38.604
250W Sodium Vapour	38.722
400W Sodium Vapour	38.915
150W Metal Halide	38.604
250W Metal Halide	38.722
2x20W Fluorescent	36.378
2x40W Fluorescent	36.130
42W Compact Fluorescent	34.612
60W Incandescent	31.949

Notes: (a) These prices exclude GST and will be adjusted for 2011-12 CPI escalation.
Source: AER analysis.

The AER's final determination on prices for contract lights is set out in Table 17.4.

Table 17.4 AER final determination on prices for private contract public lights (cents per day, $2011-12)[a]

	2012–13
50W Mercury Vapour	22.236
80W Mercury Vapour Aeroscreen	22.225
125W Mercury Vapour	23.225
250W Mercury Vapour	23.294
400W Mercury Vapour	23.346
70W Sodium Vapour	22.412
150W Sodium Vapour	23.902
250W Sodium Vapour	23.870
400W Sodium Vapour	23.940
150W Metal Halide	23.902
250W Metal Halide	23.870
400W Metal Halide	23.870
1x20W Fluorescent	22.287
2x20W Fluorescent	22.400
1x40W Fluorescent	22.295
2x40W Fluorescent	23.401
3x40W Fluorescent	23.521

4x40W Fluorescent	24.310
60W Incandescent	22.223
100W Incandescent	23.210
Pole Surcharge	20.393

Notes: (a) These prices exclude GST and will be adjusted for 2011-12 CPI escalation.
Source: AER analysis.

17.4 Revisions

Revision 17.1: The AER's form of control will be been used to calculate prices annually.

Revision 17.2: The AER's WACC has been used to calculate prices.

Revision 17.3: The AER's escalators and unit rates have been used to forecast costs.

Revision 17.4: The AER has reallocated the shared costs across distribution services to reflect the allocation of direct costs to those services.

Revision 17.5: The AER has accepted Aurora's forecast of operating expenditure for public lighting services.

18 Fee based services

The AER draft determination classification of fee based services as alternative control services has not been contested by Aurora.[816] Fee based services are services provided for the benefit of a single customer rather than uniformly supplied to all network customers, which are generally homogenous in nature and scope. These include energisation, de-energisation, meter testing and renewable energy connections

18.1 Determination

The AER has set price caps for the provision of Aurora's individual fee based services for 2012–13. For each following year in the forthcoming period Aurora's prices will be adjusted in accordance with the formula in attachment 15. Attachment 15 also contains the AER's reasons for this decision. The X factor for the remainder of the regulatory period is 1.7.[817]

The AER's final determination on price caps for the six most common fee based services for 2012–13 is shown in Table 18.11. The full list of fee based services prices is presented in section 18.3.3 below.

Table 18.1 AER final determination on price caps for the six most common fee based services for 2012–13 ($2011-12)[a]

	Aurora revised proposal price	AER final determination	% difference between Aurora revised proposal and AER final determination
Site visit – no appointment	53.19	51.92	-2.4
Site visit – credit action or site issue	80.84	76.10	-5.9
Tariff alteration – single phase	186.05	174.02	-6.5
Tariff alteration – three phase	253.83	237.30	-6.5
Renewable energy connection	186.05	174.02	-6.5
Truck tee-up (initial 30 mins)	188.28	126.29	-32.9
Truck tee-up (additional 15 mins)	94.51	51.90	-45.1

Notes: (a) These prices will be adjusted for 2011-12 CPI escalation and exclude GST.
Source: AER analysis.

816 AER, *Aurora 2012–17 draft distribution determination,* November 2011,p. 293.
817 Having regard to the five factors in NER Clause 6.2.5(d).

18.2 Assessment approach

The AER has not changed its assessment approach for fee based services since its draft distribution determination, so it is not repeated here. See section 15.3 of attachment 15 of the AER's draft determination for a description of the AER's assessment approach.[818]

18.3 Reasons

The AER has upheld the elements of its draft determination that have not been contested by stakeholders in submissions. Aurora's revised regulatory proposal has raised a number of issues concerning the AER's draft determination for fee based services. One submission from TasCOSS was received on the draft determination for fee based services. The elements of the draft determination that have been contested by Aurora are considered individually below.

18.3.1 Uncontested Issues

Aurora has accepted the AER's draft determination in relation to:

- the application of price caps for individual fee based services[819]
- the material input costs all fee based services[820]
- the removal of PAYG services from fee based services[821]
- not accepting of Aurora's proposed late cancellation fee[822]

The AER has upheld these aspects of its draft determination.

18.3.2 Contested Issues

Control mechanism

The AER does not accept Aurora's proposed control mechanism. Attachment 15 contains the AER's reasons for this decision.

Time for de-energisation

The AER does not accept Aurora's revised proposal that the time associated with undertaking de-energisation be 20 minutes.[823] The AER considers after taking into account the additional information provided by Aurora that 15 minutes is an efficient time for de-energisation.

Aurora accepted the bulk of the AER's determination of input times for services. Aurora only contested the input time for site visits for de-energisation purposes.[824] Aurora did not accept the

818 AER, *Aurora 2012–17 draft distribution determination,* November 2011, pp. 300-302.
819 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p.150.
820 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p.150.
821 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p.150.
822 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p.151.
823 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p.151.

AER's proposed alteration to the task time associated with the two services relating to site visits to de-energise for credit purposes or site issues. In the AER's draft determination the AER specified that the time associated with providing these services should be reduced from Aurora's proposal of 40 minutes to 8 minutes.[825]

Aurora's revised submission provided the following additional information:

- Rather than simply removing the fuses, as occurs for a normal de-energisation, these services require that Aurora must physically disconnect the customer premises from the distribution network.
- This may require opening a turret, in the case of an underground supply, or removing overhead infrastructure.
- Further, since these services may also be requested due to an "illegal connection", the actual physical disconnection may be at a non-standard location, and may involve the presence of police.

Aurora also provided the following additional information on de-energisation in the last 12 months in support of the revised proposal:[826]

- In approximately 60 per cent of cases only the fuse or link was removed.
- Approximately 5 per cent of cases resulted in the overhead service being removed or disconnected from the premises.
- Approximately 25 per cent of cases resulted in an underground turret being opened.
- Approximately 10 per cent of cases were due to "other" issues.
- There have been 6 instances (3 per cent of all credit disconnects) where police have been requested/required on site.

The AER accepts that activities to remove the overhead service and open a turret require additional time onsite. The involvement of police is a rare event, but also requires additional time onsite. The AER does not however agree with the Aurora's revised proposal of 20 minutes. This is based on the assessment of the times for each of the activities and weighting of them based on the respective volumes.[827] The AER considers an onsite weighted average time of 15 minutes is efficient based on the information provided by Aurora.[828]

De-energisation for credit action

The AER accepts Aurora's revised proposal for two crew members for the provision of a de-energisation for credit service.

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824 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p.151

825 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p.151

826 Aurora, *Response to information request AER/058 of 6 February 2012*, received 14 February 2012.

827 Nuttall Consulting, *Aurora electricity distribution revenue review-revised proposal: A report to the AER*, 10 April 2012, p. 87.

828 Nuttall Consulting, *Aurora electricity distribution revenue review-revised proposal: A report to the AER*, 10 April 2012, p. 87.

In its revised proposal, Aurora accepted the bulk of the AER’s draft determination on labour inputs. However, Aurora contested the labour input for de-energisation for credit service.[829] Aurora submitted that two crew members are required to alleviate safety concerns.[830]

Aurora advised that it has recently adopted a zero harm safety policy. In addition to the 6 instances involving police, there have been 81 instances where an illegal connection was de-energised and disconnected (approximately 35 per cent of all credit disconnects). Aurora consider that this justifies the 2 person crew due to the potential safety risks associated with credit disconnects. In support of the requirement for a 2 person crew, Aurora advised that it has seen a significant reduction in the number of instances (reportable events relating to safety) since the implementation of two person crews.[831]

TasCOSS applauded the AER for the downward adjustment to the fee for a ‘Site visit – credit action or site issue’ TasCOSS welcomed the adjustment since it is a fee generally imposed on households that are unable to meet the costs of their electricity consumption and will already be experiencing serious financial hardship.[832]

The AER however considers that two crew members are required for de-energisation based on the additional information provided by Aurora.[833] This is based on the potential for increased risk from interaction with the disconnected premises owners, and the need to have two crew to disconnect an overhead service. The AER considers two crew members is efficient for credit de-energisation.

Escalators

The AER has considered Aurora's proposed real cost escalation in attachment 4. The AER's final determination on real cost escalators in this attachment has been applied to fee based services.

Unit rates

The AER added back Aurora’s 3 per cent efficiency factor applied to unit rates as proposed in its initial proposal. The reasons for this are presented in attachment 3.

Shared costs

The AER has reallocated shared costs so that they match the final allocation of direct costs. Attachment 7 contains the AER's reasons for this reallocation.

WACC

The AER provides its reasons the final determination on the WACC in attachment 10. The AER will apply a pre tax real WACC of 6.55 per cent.

The Draft Determination for fee based services utilised the pre tax real WACC of 6.39.[834] Aurora did not contest the application of a WACC consistent with standard control services. However, Aurora did

829 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p.151.
830 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p.151.
831 Aurora, *Response to information request AER/058 of 6 February 2012*, received 14 February 2012.
832 TasCOSS, *Submission on the AER's draft distribution determination for Aurora Energy*, 17 February 2012, p.2.
833 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p.151.
834 AER, *Aurora 2012–17 draft distribution determination,* November 2011, p.27.

not agree with the value of the pre tax real WACC determined by the AER for standard control services. Aurora proposed a WACC of 8.35 in its revised proposal for all its distribution services.[835]

18.3.3 Prices

The AER's final decision on prices for Aurora's fee based services is set out in Table 18.2.

Table 18.2 AER final determination on fee based services prices for 2012-13[a]

	$2011–12
De-energisation, re-energisation and special reads	
Site visit – no appointment	51.92
Site visit – non scheduled visit	117.04
Site visit – same day premium service	302.35
Site visit – after hours	780.26
Site visit – credit action or site issues	76.10
Site visit - rectification of illegal connection	237.30
Site visit - interval metering	58.51
Site visit - late cancellation	-
Transfer of retailer	-
Tariff alteration – single phase	174.02
Tariff alteration – three phase	237.30
Adjust time clock	56.95
Install pulse outputs	158.20
Remove meter	263.03
Meter alteration – after hours visit	759.36
Meter alteration - late cancellation	-
Meter alteration Wasted visit	94.92
Meter test	
Meter test – single phase	284.76
Meter test – multi phase	569.52
Meter test – CT	632.80
Meter test – after hours	759.36
Meter test – late cancellation	-

835 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p. 98.

Meter test – wasted visit	94.92
Supply establishment	
New connection – after hours	759.36
Install additional service span - single phase	420.41
Install additional service span - single phase - additional spans	315.20
Install additional service span - multi phase	596.54
Install additional service span - multi phase - additional spans	491.32
New connection - late cancellation	-
New connection – wasted visit	94.92
Remove service & meters	263.03
Supply abolishment – after hours	759.36
Supply abolishment – late cancellation	-
Supply abolishment – wasted visit	157.82
Renewable energy connection	
Renewable energy connection	174.02
Renewable energy connection – after hours	1,367.79
Renewable energy connection – wasted visit	157.82
Renewable energy connection – late cancellation	-
Temporary builders connection	
Temporary supply underground – single phase - temporary position	189.84
Temporary supply underground – three phase - temporary position	284.03
Temporary supply underground – single phase - permanent position	284.03
Temporary supply underground – three phase - permanent position	284.03
Temporary supply overhead – single phase - temporary position	525.63
Temporary supply overhead – three phase - temporary position	701.75
Temporary supply overhead – single phase - permanent position	525.63
Temporary supply overhead – three phase - permanent position	701.75
Temporary supply – after hours	1,367.79
Temporary supply – Late cancellation	-
Temporary supply – wasted visit	157.82
Temporary show & carnival connection	
Temporary supply – underground	316.40
Temporary supply – overhead mains	396.44

Temporary supply – overhead service	816.54
Temporary supply – after hours	759.36
Temporary supply – late cancellation	-
Temporary supply – wasted visit	157.82
Truck tee-up	
Tee-up (initial 30 mins)	126.29
Tee-up (additional 15 min block)	51.90
Tee-up – after hours	1,419.08
Tee-up – no truck – after hours	1,262.58
Tee-up – late cancellation	-
Tee-up – wasted visit	157.82
Open turret	142.38
Addition/alteration to connection point	316.40
Connection of new mains to existing installation	221.48
Data download	316.40
Alteration to unmetered supply	237.30
Miscellaneous service	126.56
Miscellaneous service – after hours	759.36
Miscellaneous service – late cancellation	-
Miscellaneous service – wasted visit	157.82

Notes: (a) These prices will be adjusted for 2011-12 CPI escalation and exclude GST.
Source: AER analysis.

18.4 Revisions

Revision 18.1: The AER's control mechanism to be used to calculate prices.

Revision 18.2: A labour time of 15 minutes has been used to calculate the fee for de-energisation.

Revision 18.3: The AER's WACC has been used to calculate prices.

Revision 18.4: The AER's escalators have been used to calculate prices.

Revision 18.4: The AER's unit rates have been applied to calculate prices

Revision 18.5: The AER has reallocated shared costs for the final determination.

19 Quoted Services

The AER draft determination classification of fee based services as an alternative control service has not been contested by Aurora.[836] Quoted services are non-standard services where the nature and scope of the service are specific to individual customers' needs. These include the removal or relocation of Aurora's assets at a customer's request and above standard services.

19.1 Determination

The AER does not accept Aurora’s charge out rates for quoted services. The AER has determined that the charge out rates for quoted services in 2012-13 should be as in Table 19.1. The reason for the difference between the AER’s final determination and Aurora’s proposal is the application by the AER of escalators. Attachment 4 contains the AER's reasons for this decision.[837]

Table 19.1 AER final determination for price caps for labour charge-out rates for quoted services ($2011-12)[a]

	2012–13	2013–14	2014–15	2015–16	2016–17
Apprentice	77.35	72.35	68.08	64.37	64.92
Cable Joiner	59.49	57.81	56.48	54.86	53.30
CC Commercial Metering	66.71	64.82	63.02	61.32	59.71
CC Service Crew	60.07	58.37	56.76	55.24	53.80
Designer	74.73	72.70	70.79	68.98	67.28
Distribution Electrical Technician	59.85	58.15	56.52	54.96	53.49
Distribution Linesman	54.69	53.15	51.68	50.30	48.99
Distribution Linesman LL	59.65	57.96	56.36	54.84	53.40
Distribution Operator	64.58	62.47	60.96	59.84	57.98
Electrical Inspectors	63.69	61.96	60.48	58.64	57.34
Field Service Co-ordinator	83.44	81.00	79.03	76.33	74.16
Labourer OH	50.27	48.85	47.62	46.46	45.31
Meter Reader	45.80	44.59	43.42	42.33	41.31
Pole Tester	49.95	48.60	47.33	46.14	45.01
Project Manager	74.88	72.76	71.74	69.82	67.77

Notes: (a) As per attachment 15 these charge-out rates will be adjusted for CPI escalation.
Source: AER analysis.

836 AER, *Aurora 2012–17 draft distribution determination*, November 2011,p. 293.
837 Having regard to the five factors in NER Clause 6.2.5(d).

19.2 Assessment approach

The AER has maintained its assessment approach for quoted services set out at section 15.3 of attachment 15 of the AER's draft distribution determination.[838]

19.3 Reasons

Aurora was the only stakeholder to comment on the AER's draft determination for quoted services. The AER has upheld the parts of its draft determination that were not contested by stakeholders in submissions. Aurora's revised regulatory proposal has raised three issues concerning the AER's draft determination for quoted services. These are considered below.

19.3.1 Uncontested Issues

Aurora has accepted the AER's draft determination in relation to:

- methodology for calculating quoted services[839]
- Contested Issues - Control mechanism

Aurora stated that it accepts the AER's methodology for calculating quoted prices but proposed that a formal control mechanism be established.[840] The AER does not accept Aurora's proposed form of control. Attachment 15 contains The AER's reasons for this decision.

19.3.2 Contested Issues

Escalators

In attachment 4 the AER considers Aurora's proposed real cost escalation. Consistent with its draft determination (see section 4.1 of attachment 4), the AER has adopted the approved escalators for alternative control services.

Unit rates

The AER has added back Aurora's 3 per cent efficiency factor applied to unit rates as proposed in Aurora's initial proposal. Attachment 3 contains the reasons for this determination.

19.4 Revisions

Revision 19.1: The AER's form of control, as set out in attachment 15, will be used to calculate prices.

Revision 19.2: The escalators and unit rates used to calculate prices have been updated from those in Aurora's revised proposal.

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838 AER, *Aurora 2012–17 draft distribution determination*, November 2011, pp. 300-302.
839 Aurora, *Revised regulatory proposal 2012–17*, January 2012, p.157.
840 Aurora, *Revised regulatory proposal 2012–17*, January 2012, pp. 157-159.

Final Distribution Determination

Aurora Energy Pty Ltd

2012–13 to 2016–17

Appendixes

April 2012

AUSTRALIAN ENERGY REGULATOR

Contents

A Cost of capital

A.1 Risk free rate

In Aurora's revised proposal and submissions from other DNSPs, there were arguments for a departure from the *Statement of Regulatory Intent* (SRI) risk free rate methodology and support for using a higher long term historical value for the risk free rate. In attachment 10, the AER noted that some matters would be addressed, or addressed in more detail, in appendix A. In this appendix the AER considers:

- the risk free rate methodology from the AER's SRI
- the AER's ability to depart from the SRI's risk free rate methodology in a particular distribution determination
- the Australian Competition Tribunal's (Tribunal) decision on the risk free rate in the EnergyAustralia matter
- the Tribunal's decision on the risk free rate in the Telstra matter
- the approach to determine an unbiased estimate for the risk free rate
- the current level of the Commonwealth Government Securities (CGS) yield (including comparisons with State Government debt yields) and the appropriate proxy for the risk free rate
- consistency between the risk free rate used in the cost of equity and the cost of debt
- comparison with approaches taken by other regulators and in valuation reports.

A.1.1 Risk free rate methodology from the SRI

The nominal risk free rate methodology is specified in clauses 6.5.2(c) and (d) of the NER. However, it is specified with the stipulation that it applies 'unless some different provision is made by a relevant statement of regulatory intent'.[1] In the WACC review, the AER made one change to this methodology in the SRI as initially specified in the NER. That change was to insert that the averaging period was required to be 'one which is as close as practically possible to the commencement of the regulatory control period'.[2]

In full, the risk free rate methodology calculated in accordance with the SRI is therefore:

1. The nominal risk free rate for a regulatory control period is the rate determined for that regulatory control period by the AER on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years using:

    a. the indicative mid rates published by the Reserve Bank of Australia, and

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1 NER, clause 6.5.2(c)–(d).

2 AER, *Electricity transmission and distribution network service providers, Statement of the revised WACC parameters (transmission)—Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009, p. 7.

b. a period of time which is either:

i. a period ('the agreed period'), being one which is as close as practically possible to the commencement of the regulatory control period, proposed by the relevant DNSP, and agreed by the AER (such agreement is not to be unreasonably withheld), or

ii. a period specified by the AER, and notified to the provider within a reasonable time prior to the commencement of that period, if the period proposed by the provider is not agreed by the AER under subparagraph (i)

and, for the purposes of subparagraph (i):

iii. the start and end date of the agreed period may be kept confidential, but only until the expiration of the agreed period, and

iv. the AER must notify the DNSP whether or not it agrees with the proposed period within 30 business days of the date of submission of the building block proposal.

2. If there are no Commonwealth Government bonds with a maturity of 10 years on any day in the period referred to in paragraph (1)(b) the AER must determine the nominal risk free rate for the regulatory control period by interpolating on a straight line basis from the two Commonwealth Government bonds closest to the 10 year term and which also straddle the 10 year expiry date.

In the next section the AER considers whether this methodology itself can be departed from in a particular distribution determination.

A.1.2 AER's ability to depart from the risk free rate methodology set out in the SRI in a distribution determination

There has been some debate between the AER and Aurora over the AER's power to depart from elements of the risk free rate methodology resulting from the SRI.

In its initial proposal, Aurora proposed an averaging period of 20 business days commencing on 9 January 2012 and ending on 6 February 2012. However, Aurora proposed this period on a conditional basis requesting the opportunity to amend the period should a period of 'extreme volatility in the financial markets occur with significant changes to prices occurring across interest, currency and credit rates'.[3]

On 23 June 2011, the AER informed Aurora that it accepted the proposed averaging period. In respect of the condition Aurora had placed on its proposed period the AER stated:

> …at the time Aurora made its proposal, this issue was before the Federal Court. On 8 June 2011 the Federal Court handed down its judgement. In that judgement, the Court discussed this issue and clause 6.5.2(c)(2). Justice Katzmann held:
>
> > The rule does not contemplate a revision of the averaging period where agreement had earlier been reached or the AER had specified a period.
>
> Given this statement, and that the AER has agreed to the averaging period selected, Aurora is unable to amend the period.

3 Aurora, *Regulatory proposal addendum*, June 2011, p. 8.

On 5 January 2012, shortly before the agreed averaging period was to commence, Aurora wrote to the AER noting its disagreement with the AER's interpretation.[4] Aurora submitted that it and the AER should be able to agree to a revised averaging period at any time before the commencement of the regulatory control period. On 9 January 2012, the AER responded and reaffirmed its position from the previous correspondence.[5]

In its revised proposal, Aurora stated:

> Aurora notes that the AER's view of its power in this regard on the relevance of the Federal Court decision is contrary to Aurora's interpretation of the decision. Aurora notes that ActewAGL's building block proposal was submitted before the AER issued its SORI, which in effect entirely replaces clause 6.5.2(c) of the Rules in relation to the determination of the risk free rate (in accordance with clause 6.5.4 of the Rules). The Rules, in turn, provide the AER with the ability to depart from a method that is set out in the SORI if 'there is persuasive evidence justifying a departure'.[6]

Upon further consideration, the AER considers there is some limited merit to Aurora's interpretation. Specifically, the AER agrees that the SRI is applicable to Aurora's distribution determination. In turn, this means that clause 6.5.4(g) operates to allow the AER to depart from a method for calculating the risk free rate. However, that is a comment on the operation of clause 6.5.4(g). It is not a comment on the contents of the method for calculating the risk free rate. To determine the contents of that method, it remains necessary to correctly interpret the relevant drafting.

The SRI uses identical drafting to clause 6.5.2(c) except in two respects:

- it does not include a reference to an SRI
- it inserts an additional requirement that a DNSP must nominate an averaging period that 'is as close as practically possible to the commencement of the regulatory control period'.

Neither of these aspects touches on the ability to change an averaging period once it has been agreed or nominated. As a result, the SRI does not affect the correct interpretation of that ability. In other words, Justice Katzmann's findings still hold:

> The rule does not contemplate a revision of the averaging period where agreement had earlier been reached or the AER had specified a period.[7]

Therefore, the relevant aspect of the method for calculating the risk free rate is the same both before Justice Katzmann and here. Once the AER either agrees to the DNSP's proposed averaging period or notifies the DNSP of the AER's substitute period, that period cannot be amended.

This outcome means Aurora had only two options in relation to its initial proposal. First, it could propose an averaging period. Second, it could attempt to persuade the AER to exercise its discretion under clause 6.5.4(g) and depart from the SRI method for setting the risk free rate (so as to allow Aurora to amend its averaging period). However, it was not open to Aurora to act on the basis of a right to amend the averaging period, when such a right did not exist.

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4 Aurora, Return on assets (WACC)—Averaging period, 5 January 2012, p. 1.

5 AER, *Letter to Aurora: Return on assets (WACC)—Averaging period*, 9 January 2012, p. 1.

6 Aurora, *Revised proposal—Supporting information: Return on capital*, January 2012, p. 9.

7 Federal Court of Australia, *ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639*, 8 June 2011, paragraph 85.

In its initial proposal, Aurora proposed an averaging period. It did not request the AER change its method for calculating the risk free rate. The reference to amending the averaging period was invalid and should be disregarded.

In its letter dated 23 June 2011, the AER accepted Aurora's proposed averaging period. As a result, the AER did not raise any issues in respect of the risk free rate. Therefore, there were no changes required to address matters raised in the draft determination. In turn, this means that Aurora's revised proposal could not raise these matters.[8] Therefore, the AER considers that Aurora's revised proposal to use a long term estimate of the risk free rate is outside what clause 6.10.3(b) allows. Accordingly, the AER rejects that aspect of the proposal. However, the AER notes that Aurora's initial proposal may be viewed as an implicit request for the AER to depart from the SRI methodology. The AER does not agree with this characterisation. However, in case that is found to be the correct characterisation, the AER has assessed the merits of Aurora's revised proposal.

In undertaking this assessment, the AER has given consideration to what exactly must occur. For Aurora's proposed long term historical risk free rate averaging period to be acceptable, there would need to be persuasive evidence justifying:

- a departure from the SRI methodology's requirement that a DNSP's proposed averaging period be as close as is practically possible to the commencement of the regulatory control period
- a departure from the SRI methodology's requirement that the AER notify a DNSP of its averaging period prior to the commencement of the period if it does not agree with the proposed period, and
- a departure from the SRI methodology's requirement that after the period has been agreed or notified it cannot be amended.

A.1.3 The EnergyAustralia matter

Both Aurora's initial proposal and CEG's submission refer to the Tribunal's decision in *Application by EnergyAustralia and Others [2009] ACompT 8* (the EnergyAustralia matter) to support their position that the averaging period does not need to be as close as practically possible to the commencement of the regulatory control period.[9] The AER has considered carefully whether the Tribunal's decision in the EnergyAustralia matter is persuasive evidence justifying a departure from the SRI methodology for setting the risk free rate.

There is a history of the AER applying Tribunal decisions. There are two such examples in this determination. The AER considered that the Tribunal's decision on gamma was persuasive evidence justifying a departure from the SRI value for gamma.[10] Also, the AER has applied the Tribunal's decision on the use of the Bloomberg fair value curve to estimate the DRP.[11]

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8 NER, clause 6.10.2(c).

9 Aurora, Regulatory proposal attachment: Cost of capital, June 2010, pp. 7-8; CEG, *A report on the cost of equity in Aurora's revised regulatory proposal*, February 2012, pp. 9-11.

10 Australian Competition Tribunal, *Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9*, 12 May 2011.

11 Australian Competition Tribunal, *Application by Envestra Ltd (No 2) [2012] ACompT 3*, 11 January 2012. Also, in the Victorian electricity distribution determination, the AER accepted Jemena Electricity Network's proposed averaging period, despite it being inconsistent with the SRI methodology. This was on the basis of the Tribunal's decision in the EnergyAustralia matter. The AER stated at the time that it was still examining the full implications of the Tribunal's decision and its relationship to the requirements of the SRI as well as to the broader NER framework. AER, *Final*

In the time since the EnergyAustralia matter, the Federal Court has handed down its judgement in *ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639* (the ActewAGL matter). Also, the Tribunal handed down its decision in *Application by Telstra Corporation Limited ABN 33 051 775 556 [2010] ACompT 1* (the Telstra matter). Further, as the EnergyAustralia matter considered provisions in the transitional chapter 6 of the NER, there are differences in the legislation involved. Therefore, despite its history of applying the Tribunal's decisions, the circumstances surrounding the risk free rate for this determination and the EnergyAustralia matter are somewhat different. Specifically:

- The legislation in the EnergyAustralia matter included provisions deeming the MRP to be 6 per cent.[12] Aurora submitted that these provisions influenced the Tribunal's decision.[13] It is not clear to the AER the extent to which this is the case.[14] To the extent this occurred, the AER considers this interpretation was not appropriate. In the ActewAGL matter, the Federal Court upheld the AER's reasons for rejecting ActewAGL's submission that the risk free rate should be adjusted to take into account variations in the MRP. A key reason of the AER was that adjusting the risk free rate to make up for a higher MRP was an attempt by ActewAGL to circumvent the legislation and would undermine the intended certainty provided under the regulatory regime through the deeming provisions.[15]

- At any rate, the legislation here does not include deeming provisions and instead enables departures from SRI values, methods and credit rating (including the MRP) where there is persuasive evidence justifying a departure.[16] As explained in section 10.3.1, the AER has consistently held a position that each WACC parameter should be estimated based on considerations relevant to that parameter, rather than to deal with issues relating to another parameter. Arguably, considering the NER sets parameter-by-parameter requirements, the AER’s approach is also required by the NER. In the Telstra matter, the Tribunal made its position clear that CGS yields during the global financial crisis remained representative of the risk free rate, and the mere fact that the yields were 'low' did not change this conclusion.

- As Aurora mentioned in its proposal, in the EnergyAustralia matter, the Tribunal considered that the cost of capital needs to represent the return required by investors at the start of each regulatory year. The Federal Court recognised that the capital asset pricing model (CAPM), which is prescribed under the NER, requires the use of the most current information for deriving the cost of capital. According to the Federal Court, in theory, this involves the use of the risk free rate at the beginning of the regulatory control period. For the reasons set out in this section, the use of the risk free rate near the beginning of the regulatory control period is also consistent with the building block model required under the NER.

- In the EnergyAustralia matter, the Tribunal’s reasons for finding that the AER acted unreasonably in withholding consent to EnergyAustralia’s proposed averaging period included that the AER did not examine the evidence regarding forward interest rates.[17] However, the Federal Court noted

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decision, Victorian electricity distribution network service providers distribution determination 2011-15, October 2010, pp. 477-478.

12 NER, Transitional chapter 6 clause 6.5.2(b).

13 Aurora, *Regulatory proposal addendum—Cost of capital*, June 2011, p. 8.

14 Some support for Aurora's understanding of the Tribunal's decision can be found at paragraph 73(d)(1) where the Tribunal stated that a principle assisting it in the determination of the issue was '…whether the period proposed is likely to result in an unbiased risk free rate, given that the equity beta and market risk premium are deemed to be 1.0 [sic] and 6.0 per cent respectively'.

15 Federal Court of Australia, *ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639*, 8 June 2011, paragraph 148.

16 NER, clause 6.5.4(g).

17 Australian Competition Tribunal, *Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009) [2009] ACompT 8*, 12 November 2009, paragraph 94.

evidence that no Australian regulator has done so. It also very much doubted that the NER required the AER to deploy forward rates to make the averaging period decision.[18]

As the Federal Court noted, the Tribunal and the Federal Court apply different tests. However, given the differences noted above, the AER does not consider it appropriate to merely apply the Tribunal’s decision in the EnergyAustralia matter as if it were a precedent. Accordingly, in these circumstances, the AER does not consider that it should accept on face value that the Tribunal’s decision is persuasive evidence justifying a departure from the SRI methodology. Instead, throughout attachment 10 and this appendix the AER has assessed all of the evidence available on its merits.

For the reasons set out in this determination the AER does not consider the Tribunal's decision in the EnergyAustralia matter provides persuasive evidence justifying a departure from the SRI methodology.

In the remainder of this section the AER considers:

- The Tribunal's and the Federal Court's interpretations of the statutory scheme under clause 6.5.2 of the NER.
- The economic insights that can be gained from the 'present value principle' and how this principle is consistent with both the use of the building block model and the use of the CAPM (both requirements of the NER).
- The usefulness of forward interest rates in assessing a proposed risk free rate averaging period.

In section A.1.4 the AER considers the Tribunal's considerations in the Telstra matter.

The Tribunal's and the Federal Court's interpretation of the statutory scheme

In withholding its approval to EnergyAustralia's proposed averaging period, the AER stated that the AER's regulatory practice was supported by accepted expert views in the economic and finance literature.[19] In response to the reports referenced by the AER, the Tribunal set out its interpretation of the statutory scheme:

> The rate of return, or WACC, is applied to the value of the regulatory asset base of the NSP as at the beginning of a regulatory year to produce the return on capital (in dollar terms) for that regulatory year (cl 6.5.2(a)). (The regulatory asset base is updated each year (cl 6.5.1(e)(2).) Thus the WACC is applied in each of the five regulatory years within the regulatory control period. **It follows that the WACC to be applied each year should in principle be the rate of return required by investors at the beginning of that year.** This rate of return would naturally be expected to differ from year to year.
>
> That is not, however, the scheme set out in cl 6.5.2. Rather it provides for a single value of the WACC to be calculated and applied to each year's starting regulatory asset base.
>
> …

18 Federal Court of Australia, *ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639*, 8 June 2011, paragraph 145.

19 The AER referenced the following three reports in support of this statement: Lally, M, *Determining the risk free rate for regulated companies, August 2002*; Davis, K, *Report on the risk free interest rate and equity and debt beta determination in the WACC*, 28 August 2003; Lally, M, *The cost of capital for regulated entities—Report prepared for the QCA*, 26 February 2004.

> The risk free rate, whether agreed or specified, is, it seems to be agreed by all parties, that which prevails at some time (the averaging period) prior to the start of the regulatory control period; similarly with the benchmark corporate bond rate. Those inputs might generate a rate of return value reasonably close to that actually required by investors at the start of the regulatory control period, and applied to the first year's starting regulatory base. But with changes in market conditions over the regulatory control period, it is hard to see why the rate of return value would represent the return required by investors at, say, the start of the final year of the regulatory control period.
>
> In the meantime, the risk free rate and corporate bonds rates would almost certainly have varied from their initial values. Consequently, there appears to be no virtue in setting those rates at values that prevailed close to the start of the regulatory control period, or to the publication of a final determination.
>
> It may be accepted that, [the AER's practice] …and the practice of regulators more generally has been to apply a nominal risk free rate averaging period closer to the start of the regulatory period. This practice has been supported by economic experts. The Tribunal observes, however, that this is not a universal practice. In market conditions that are not wildly out of the norm, this may be expected to provide a figure that is fairly close to being an unbiased estimate of the risk free rate consistent with market conditions at the time of the final determination; and may consequently be expected to provide a reasonable estimate of the rate of return on capital that would be required by investors at the time of the final determination.
>
> But as explained above, there is no proper basis for seeking such an estimate. The views of economic experts appear to be based on a model where the regulatory control period is considered to be a single period (of five years), not five consecutive one-year periods. In the scheme set out in the Transitional Rules, the nexus is broken between the period to which the rate of return applies and the period for which that rate of return is estimated. Once that is realised, the basis for withholding agreement to an averaging period proposed by EA falls away.[20] [Emphasis added]

As is clear from this quote, the Tribunal considered that the statutory scheme rendered expert economic advice in support of the AER's position irrelevant. The Tribunal's view appears to be that the rate of return set under clause 6.5.2 of the NER needs to be representative of the (10 year) return required by investors at the start of each year of the regulatory control period.[21]

In the ActewAGL matter, the Federal Court was careful to point out that the tests it applied on judicial review are different from the tests applied in the Tribunal's merits review. The Federal Court expressly stated that the Tribunal's view on the merits of the AER's decision were irrelevant in the judicial review.[22] However, in commenting on the statutory scheme, the Federal Court also stated:

> The relevant equation is that which determines the return on equity (ke), which paragraph (b) provides must be determined using the Capital Asset Pricing Model ("CAPM") and certain defined parameters. …
>
> The Capital Asset Pricing Model requires the use of the most current information for deriving the rate of return. **This in theory involves the use of the risk-free rate on the day that required returns are to be estimated (in this case, the beginning of the regulatory period).** Nevertheless, there are recognised problems with the use of an on-the-day rate which an averaging period is intended to address. In particular, deploying an averaging period will minimise day-to-day volatility in the market.[23] [Emphasis added]

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20 Australian Competition Tribunal, *Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009) [2009] ACompT 8*, 12 November 2009, paragraphs 86–93.

21 The term of the risk free rate was deemed to be 10 years in the transitional chapter 6 clause 6.5.2 that applied in the EnergyAustralia matter.

22 Federal Court of Australia, *ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639*, 8 June 2011, paragraph 113.

23 Federal Court of Australia, *ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639*, 8 June 2011, paragraphs 22 and 28.

Clearly, this is not an express statement that the Tribunal's interpretation is incorrect. However, it appears that the Tribunal considered clause 6.5.2(a) to require the rate of return to be that required by investors at the beginning of each regulatory year. On the other hand, the Federal Court recognised that the CAPM—prescribed under clause 6.5.2(b)—requires the rate of return to be that required by investors at the beginning of the regulatory control period. It seems difficult to reconcile the two statements. Based on this reason and others,[24] the AER considers that the economic evidence it presented in the EnergyAustalia matter remains relevant. Further, the economic evidence presented in Associate Professor Lally's report to the Federal Court in the ActewAGL matter is also relevant. That report is considered in the next section.

On this basis, the AER considers that, conceptually, the rate of return set under clause 6.5.2 of the NER should represent the return required by investors at the beginning of the regulatory control period (over the relevant forward looking period). The AER does not consider that clause 6.5.2(a) requires a rate of return (over the specified term) representative of the return required by investors at the start of each year of the regulatory control period.

The present value principle and the building block model

The NER requires that the annual revenue requirement for a DNSP for each regulatory year of a regulatory control period must be determined using a building block approach.[25] The building block approach is otherwise known as the building block model. In a 2011 paper on public utility regulation in Australia, Dr Darryl Biggar explained the origins of the building block model and what it seeks to achieve. He stated:

> Starting in 1998 ... the regulators in Australia decided to adopt an approach to regulation which became known as the 'building block model'. This approach is not unique to Australia (very similar approaches are used in the UK and the US) but those jurisdictions apparently do not use this term. The building block model is a tool for ensuring that the present value of the revenue stream of the regulated firm matches, over time, the present value of its expenditure (plus or minus any incentive payments). The building block model is based around the use of a regulatory asset base, which is updated over time, and from which an annual revenue allowance is derived.[26]

Lally, in his report to the Federal Court in the ActewAGL matter, advised how this present value principle (that the building block model is designed to achieve) is met when the risk free rate is estimated at the beginning of the regulatory control period.[27] Lally advised:

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24 For example, if the Tribunal's interpretation is correct, it seems that the AER misinterpreted clause 6.5.2(a). If so, it seems likely that the Federal Court would have made a similar finding. However, it did not. The AER acknowledges that the Federal Court did not address this issue in detail.

25 NER, clause 6.4.3.

26 Biggar, D, *Public utility regulation in Australia: Where have we got to? Where should we be going, Working paper no. 4, ACCC / AER working paper series*, July 2011, p. 58. A similar description of the building block model supported by more detailed analysis can be found in Biggar, D, Incentive regulation and the building block model, 28 May 2004, pp.2-21, accessed on 19 April 2012, <http://editorialexpress.com/cgi-bin/conference/download.cgi?db_name=ACE2004&paper_id=133>.

27 In the WACC review, the AER also considered the present value principle to be a relevant and important consideration in determining the appropriate term of the risk free rate. The present value principle supports the risk free rate being estimated at the start of the regulatory control period and with a term that matches the length of the regulatory control period (in general, 5 years). This consideration largely contributed to the AER's decision to adopt a 5 year risk free rate term in the WACC review draft decision. However, along with considering the present value principle to be important the AER also considered providing appropriate compensation for refinancing risk to be a relevant consideration. In the WACC review final decision, the AER determined this would not be provided through adopting a 5 year term. This consideration largely contributed to the AER's decision to maintain a 10 year risk free rate term in the WACC review final

> I start with question (1), and initially with the question of whether the economic theory implies that the risk free rate averaging period should be as close as practicable to the commencement of the regulatory control period. It is a fundamental premise of price or revenue regulation that the regulator caps the output price or revenue so that the present value of the firm's future cash flows equals the initial investment; anything less will fail to entice producers to invest and anything more constitutes the very excess profit that regulation seeks to prevent. It then follows that the appropriate risk free rate for the regulator to use is that prevailing at the beginning of the regulatory control period.[28]

Lally illustrated this point through a worked example.[29] He also specifically considered the proposition of using a long term historical average risk free rate. On this approach he advised how this would not, in general, meet the present value principle:

> I now turn to the final question, which concerns the relevance of the long-run average risk free rate to the selection of the averaging period. In particular, this question is concerned with whether it is desirable for an averaging period to generate a risk free rate that approximates the long-run average rate, as argued by Mr Houston. The answer to this question follows from that to the first question. In particular, having argued in section 2 above that it is appropriate to average the risk free rate over a period that is as close as practicable to the commencement of the regulatory control period, it follows that it is not desirable to choose an averaging period in order to generate a risk free rate approximating the long-run average. As explained in section 2, using an averaging period that is as close as practicable to the commencement of the regulatory control period ensures that the present value of the future cash flows equals the initial investment. Any other period will in general not satisfy this requirement, even if that period involves a risk free rate that approximates the long-run average rate.[30]

The NEL revenue and pricing principles provide, among other principles, that an NSP should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control network services.[31] For the reasons explained by Lally, this principle is promoted by following the present value principle which requires the risk free rate to be estimated as close as practicably possible to the commencement of the regulatory control period. The SRI methodology is therefore consistent with the revenue and pricing principles, and consequently will or is likely to contribute to the achievement of the National Electricity Objective (NEO).[32]

Further, as recognised by the Federal Court, the CAPM requires the use of the most current information for deriving the rate of return. This in theory involves the use of the risk free rate on the day that required returns are to be estimated (in this case, the beginning of the regulatory control period).

The AER's position that the rate of return set under clause 6.5.2 of the NER should represent the return required by investors over the relevant forward looking period, as at the beginning of the

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decision. See AER, *Explanatory statement, Electricity transmission and distribution network service providers, Review of the WACC parameters*, December 2008, pp.109-128; AER, *Final decision, Electricity transmission and distribution network service providers, Review of the WACC parameters*, May 2009, pp.140-169.

28 Lally, M, *Expert report of Martin Thomas Lally*, 13 February 2011, pp. 4-5. Lally's understanding of the fundamental premise of price or revenue regulation is referenced to: Marshal, W, Yawitz, J, and Greenberg, E, *Optimal regulation under uncertainty, The Journal of Finance*, 1981, vol. 36, pp. 909-922; and Schamlensee, R, *An explanatory note on depreciation and profitability under rate-of-return regulation, Journal of Regulatory Economics*, 1989, vol. 1, pp. 293-298.

29 Lally, M, *Expert report of Martin Thomas Lally*, 13 February 2011, pp. 5-8.

30 Lally, M, *Expert report of Martin Thomas Lally*, 13 February 2011, p. 17.

31 NEL, section 7A(2)(a).

32 NEL, section 16.

regulatory control period, is therefore consistent with both the use of the CAPM and the present value principle.[33]

The use of forward interest rates

In the EnergyAustralia matter, the Tribunal said the AER should use forward interest rates to assess a service provider's proposed averaging period. The Tribunal stated:

> Rather than assume that the rate at a closer date would give a better estimate, the AER should have examined the evidence regarding expected future rates. Such evidence of forward interest rates, ie, rates that will apply at some future time for a prospective period, is available from market data. Comparisons could be made between the rates expected to prevail during the averaging period proposed by the NSP and rates expected at later periods. But it follows from the Tribunal's reasoning that it would be insufficient and inappropriate to only compare with rates expected to prevail close to the time of the final determination.[34]

The AER has considered the usefulness of forward interest rates to assess the averaging period's predictability of the risk free rate at a future point in time. In their reports to the Federal Court, Lally and Houston advised that they were not aware of any Australian regulatory decision in which forward rates had been used to guide the selection of an averaging period for the risk free rate.[35]

Lally further advised that there were 'two major difficulties' in using forward interest rates in this way. On the first major difficulty, he advised that the appropriate predictor of a future interest rate is not the forward rate but the forward rate less the term premium.[36] On estimating the term premium, Lally stated:

> However, the sizes of the term premiums vary over time and they are not precisely determinable. So, any attempt to estimate the extent to which an interest rate at a given point in time is a biased predictor of a subsequent rate would be fraught with difficulty.

Lally concluded:

> …in choosing an interest rate to serve as the best predictor of the rate prevailing at a particular future point in time, the best interest rate will be that which is closest in time to the predicted date.

As is clear from the Tribunal's decision, the Tribunal's view on the usefulness of forward interest rates was based on its view that the relevant rate of return is that required by investors at the start of each

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33 Similarly, in the WACC review the AER discussed that the requirement that the AER must have regard to the rate of return to be both forward looking and reflect prevailing conditions in the market for funds are not competing requirements. Rather, it is a requirement that the AER must have regard to the need for the rate of return to reflect forward looking expectations, as at the relevant point in time. That relevant point in time is at the time of the individual distribution determinations. Accordingly, the AER's task in the WACC review (which forms part of the WACC review underlying criteria) was to determine each parameter in such a way as it is relevant for a 10 year perspective (consistent with the AER's position on the term of the risk free rate) from the commencement of the next regulatory control period for each service provider effected by the WACC review. See AER, *Final decision, Electricity transmission and distribution network service providers, Review of the WACC parameters*, May 2009, pp. 72-77.

34 Australian Competition Tribunal, *Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009) [2009] ACompT 8,* 12 November 2009, paragraph 94.

35 Federal Court of Australia, *ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639*, 8 June 2011, paragraph 145.

36 Lally advised this is because the 'expectations hypothesis' is not a satisfactory characterisation of the term structure of interest rates. Lally went on to explain that even if the expectations hypothesis held, the use of forward interest rates to assess two different averaging periods is still a flawed approach. Lally, M, *Expert report of Martin Thomas Lally*, 13 February 2011, p. 15.

year of the regulatory control period rather than the rate required at the start of the regulatory control period. The AER does not agree with this position, as explained above.

The problems associated with using forward interest rates that Lally raised were in the context of predicting the 'spot' interest rate at the start of the regulatory control period—a period only two months after the publication of the AER's final determination. If forward interest rates are an unsuitable predictor of interest rates over such a short time horizon, they would appear to be at least an equally unsuitable predictor of the 'spot' interest rate at more distant points in the future (which is the context in which the Tribunal considered them).

Accordingly, there are both in principle and practical difficulties with using forward interest rates in determining the risk free rate.

In the ActewAGL matter there was some debate between the experts on the use of forward interest rates, in a context that involves a deemed MRP value. That aside, Justice Katzmann concluded:

> Whether or not the criticism of the AER's decision is valid, I very much doubt the AER is bound by the statutory scheme to deploy forward rates to make the averaging period decision.[37]

Based on the Federal Court's view, the AER concludes that the use of forward interest rates to assess averaging periods is not a requirement of the NER. Based on Lally's advice, the AER also concludes there are sound economic reasons for not using forward interest rates. The AER has not used forward interest rates to assess Aurora's proposed averaging period.

For the above reasons, the AER considers that the Tribunal's comments on forward interest rates in the EnergyAustralia matter do not constitute persuasive evidence to depart from the SRI methodology that the averaging period must be as close as practically possible to the commencement of the regulatory control period.

A.1.4 The Telstra matter

In its initial proposal, Aurora referred to the Tribunal's decision in the EnergyAustralia matter in relation to the risk free rate. In its revised proposal, Aurora referred to another Tribunal decision where the appropriate estimation of the risk free rate was contested. That decision was the Telstra matter. Specifically, Aurora submitted that:[38]

> …the potential for the use of a measure of the RFR drawn from an unrepresentative period to lead to an incorrect estimate of the cost of capital has been observed by the Australian Competition Tribunal.[39]

The AER has reviewed the relevant Tribunal decision. The AER sees nothing in the Tribunal's reasoning in the Telstra matter that supports Aurora's proposal to depart from the SRI methodology and to use a long term historical average risk free rate. Rather, the Tribunal's reasons appear to support the approach adopted in the SRI.

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37 Australian Competition Tribunal, *Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009) [2009] ACompT 8,* 12 November 2009, paragraph 145.

38 Aurora, *Revised regulatory proposal—Supporting information: Return on capital*, January 2012, pp. 13-14.

39 Australian Competition Tribunal, *Telstra Corporation Limited ABN 33 051 775 556 [2010] ACompT* 1, 10 May 2010, paragraph 422.

Like this determination, the Telstra matter also involved the appropriate estimation of the risk free rate at a time when CGS yields were 'low' compared to historically observed rates. The ACCC adopted a 4.51 per cent risk free rate. Telstra submitted the risk free rate was 6.33 per cent.[40]

Telstra submitted that the global financial crisis had significantly impacted on the yields of CGS resulting in an anomalous or unrepresentative risk free rate value during the relevant averaging period. The Tribunal disagreed. The Tribunal considered:

> The dispute turns on whether the data derived over the period chosen by the ACCC is anomalous or unrepresentative.
>
> The risk free rate refers to the return from an asset with no risk of default. There is every reason to assume (and little evidence to doubt) that the yields on commonwealth bonds over this period continued to provide an accurate proxy for a return on assets bearing no risk of default. To the extent that the yields factored the impacts of the global financial crisis, the bond rate continued to provide a representative indicator of the risk-free rate.
>
> It is also not unusual for yields to move from time to time in order to reflect prevailing market conditions and the expectations about the prospect for prices into the future. A downward movement in yields over this period is therefore hardly anomalous, given market conditions.[41]

The Tribunal also stated that Telstra's proposal introduced value judgements. This is similar to the AER's findings, in section 10.3.1, that Aurora's proposal creates the potential for arbitrariness and introduces subjectivity into the estimation of the risk free rate. The Tribunal considered:

> … that the approach advanced by Telstra would impose an obligation on the regulator (or the Tribunal) to make value judgments. Those value judgments include whether the period over which the data is taken is in some manner unusual, and whether the data derived is in some way anomalous or unrepresentative of the value that should apply to that parameter. This could involve predicting future rates, although means are available to do that.[42]

In support of its proposal, Aurora referred to one paragraph from the Tribunal's decision in the Telstra matter. Specifically, where the Tribunal stated:

> … that the use of the WACC formula is only a means to an end, which is to estimate the required rate of return for an investment with certain characteristics of riskiness and debt. That rate of return is unlikely to vary greatly over the short to medium term, and should not therefore be overly subject to the vagaries of short-term movements in parameters such as market interest rates. Moreover, the rate of return applies over the period of the undertaking. Both the access provider and the ACCC should keep these facts in mind to ensure that they do not, by lighting on parameter values that are unrepresentative, end up with a rate of return that is inappropriate to its purpose.[43]

It is unclear to the AER what it should take out of the above Tribunal's comment and apply in the current matter. Aurora's submission was not clear on this aspect. It is clear from other parts of the decision that the Tribunal did not consider that the decrease in CGS yields caused by the effects of the global financial crisis impinged upon CGS yields being an appropriate proxy for the risk free rate.

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40 Australian Competition Tribunal, *Telstra Corporation Limited ABN 33 051 775 556 [2010] ACompT 1*, 10 May 2010, paragraph 364.

41 Australian Competition Tribunal, *Telstra Corporation Limited ABN 33 051 775 556 [2010] ACompT 1*, 10 May 2010, paragraphs 415-417.

42 Australian Competition Tribunal, *Telstra Corporation Limited ABN 33 051 775 556 [2010] ACompT 1*, 10 May 2010, paragraph 418.

43 Australian Competition Tribunal, *Telstra Corporation Limited ABN 33 051 775 556 [2010] ACompT 1*, 10 May 2010, paragraph 422.

For the above reasons, the AER sees nothing in the Tribunal's reasoning in the Telstra matter that supports Aurora's proposal to use a long term historical average risk free rate. To the contrary, the Tribunal made its position clear that CGS yields during the global financial crisis remained representative of the risk free rate. The mere fact that the yields were 'low' did not change this conclusion.

The averaging period in the Telstra matter was in March to April 2009 and resulted in a risk free rate of 4.51 per cent. The averaging period adopted by the AER for Aurora is in January to February 2012 and results in a risk free rate of 3.89 per cent. The Tribunal's reasons why CGS yields remained an appropriate proxy for the risk free rate in March to April 2009 continue to apply in January to February 2012.

A.1.5 Approach to determine an unbiased estimate for the risk free rate

In considering the intent behind clause 6.5.2 (of the transitional chapter 6), the Federal Court considered the background paper to the ACCC's *Statement of principles for the regulation of electricity transmission revenues* (SRP). The Federal Court stated:

> The background paper to the SRP included the following statement (emphasis added):
>
>> In determining the risk free rate to apply to the WACC calculation it is theoretically correct to use the on-the-day rate as it fully reveals the latest information available. However, using the on-the-day rate exposes the TNSP [transmission network service provider] to day-to-day volatility. For this reason, an averaging period methodology is used to smooth out the volatility…
>>
>> [T]he ACCC considers that… the ability of TNSPs to game with the length of period used in calculating the moving average is minimal because **a TNSP has to specify the averaging period at the time of submitting its application for a revenue reset and can not [sic] change it afterwards.**
>>
>> Professor Davis has similarly stated on this issue:
>>
>>> Provided that the averaging period is it **well specified in advance**, there is little risk of 'gaming' behaviour…
>>
>> Therefore, the ACCC considers that the period (between 5 to 40 days) used to calculate the moving average of the bond rate should be left to the discretion of the TNSP when making its application. **However, the TNSP will not be allowed to change the averaging period after the application is lodged.**
>
> This makes it clear that the intention was that the averaging period would be fixed at an early stage and, once fixed, not altered.[44]

In the issues paper to the WACC review the AER explained its approach at that time to determining the averaging period:

> 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 corporate bond rate). To obtain an unbiased estimate, the averaging period should also be a future period (that is, the averaging period should be determined in advance).[45]

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44 Federal Court of Australia, *ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639*, 8 June 2011, paragraphs 80-81.

45 AER, *Issues paper, Review of the WACC parameters for electricity transmission and distribution*, August 2008, p. 36.

The AER formalised its then current approach into the SRI risk free rate methodology by amending the risk free rate methodology initially set out in chapters 6 and 6A.[46]

The AER appreciates that prior to the commencement of its initially proposed averaging period (5 January 2012) Aurora expressed its disagreement with the AER's position on amending the averaging period. However, Aurora did not propose a revision to the dates of its initially proposed averaging period until it submitted its revised regulatory proposal on 16 January 2012—by which stage its initially proposed averaging period had already commenced. Related to this is the fact that Aurora's revised proposal to use a long term historical average risk free rate (instead of a revised future period) adopted a period in which the outcome was already known.

Paradoxically, Aurora in its revised proposal appears to agree that the averaging period should be a future period, and yet, its revised proposal is inconsistent with this in proposing a historical period. Aurora stated:

> …that it is entirely consistent with clause 6.5.2 (c) (and the corresponding provisions in the SRI) that the distributor and the AER should be able to agree to a revised averaging period **at any time before its commencement** (Emphasis added).[47]

Determining an unbiased rate, free from regulatory 'gaming' is enhanced by adopting a future averaging period, and not altering that period once it is agreed or specified. These considerations weigh against there being persuasive evidence justifying a departure from the SRI risk free rate methodology.

A.1.6 Current level of the CGS yield (including comparison with State Government debt yields) and the appropriate proxy for the risk free rate

The fact that the prevailing 10 year risk free rate is 'low' is not a unique situation. The risk free rate was at a similar level at the time of the WACC review. At that time, CEG submitted that the fall in CGS yields in the latter half of 2008 coincided with a rise in the required cost of equity. CEG submitted this inverse relationship between CGS yields and the return on equity was well documented in the finance literature but not reflected in the Australian regulatory approach.

At the time of the WACC review, CEG submitted that this outcome was consistent with two possible explanations:

- the yield on CGS is a poor proxy for the risk free rate used to estimate the cost of equity in the CAPM, or
- the yield on CGS is a good proxy for the risk free rate used in the CAPM but the MRP had recently moved in the opposite direction to the yield on CGS.

In support of the first possible explanation, CEG's main contention was that the divergence between the yields on CGS and other (zero beta) risk free assets—State Government bonds and Commonwealth Government guaranteed bank debt—was evidence that CGS were no longer a true reflection of the risk free rate. CEG submitted that this divergence represented a 'convenience yield'

46 AER, *Final decision, Electricity transmission and distribution network service providers, Review of the WACC parameters*, 1 May 2009, pp. 170-171.

47 Aurora, *Revised regulatory proposal—Supporting information: Return on capital*, January 2012, p. 9.

that reflected investors willingness to pay a premium for the 'non-beta' attributes of CGS, which CEG contended included liquidity.[48]

In its current report, CEG again pointed to the widening of the spreads between State Government bond yields and CGS yields stating that the recent fall in CGS yields had not been associated with the same fall in the yields on other low risk assets.[49] It again appears that a major driver of this difference is liquidity. That is, the relative liquidity of CGS compared with the relative illiquidity of State Government bonds. This is confirmed by the RBA statement quoted by CEG that:

> The strong investor preference for CGS and a deterioration of liquidity in the state government securities market ... led to a widening of the spread between yields on these securities...[50]

In the WACC review, the AER was not persuaded that the liquidity of CGS made CGS an inappropriate proxy for the risk free rate.[51] The AER's conclusion was supported by advice from Associate Professor Handley.[52] CEG has not addressed the AER's previous response to CEG's previous comments on liquidity and the relevance of relatively illiquid State Government bond yields. For the same reasons as set out in the WACC review, the AER is not persuaded that the difference between CGS and State Government bond yields makes CGS an inappropriate proxy for the risk free rate.

In addition, the AER considers the higher yields on some State Government bonds may reflect the increased risk of those bonds. The AER notes that the Queensland government lost its AAA rating in February 2009.

On CEG's second possible explanation (at the time of the WACC review), the AER noted:

> …to the extent the second explanation is possible—that the risk free rate (proxy) and MRP move in opposite directions—CEG provides no solution to address this issue through the MRP. Rather CEG argue this is a reason why the AER should not lower the equity beta, at this time, from the previously adopted value.
>
> …the AER considers that the integrity in the estimation of each individual WACC parameter is important. This integrity includes that the MRP is a measure of market-wide systematic risk, whereas the equity beta is a measure of the benchmark efficient NSP's exposure to non-diversifiable risk relative to that of the market. To the extent that the prevailing MRP (and the MRP into the foreseeable future) is above the long term MRP, the AER does not agree that it is appropriate to address this issue via the equity beta.
>
> Accordingly, while theoretically the MRP could vary [sic] over time in line with different economic conditions, the view of the AER and the JIA's advisers (Professor Officer and Dr Bishop) is that, unlike for the nominal risk free rate, there is no adequate method to automatically update the MRP at the time of each reset determination.[53]

Neither Aurora nor CEG (in its current report) appear to have submitted that the yield on CGS is currently a poor proxy for the risk free rate.[54] Rather, it appears Aurora's revised proposal sought to

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48 AER, Final decision—WACC review, pp.134-136.

49 CEG, *A report on the cost of equity in Aurora's revised regulatory proposal*, February 2012, p. 3.

50 CEG, *A report on the cost of equity in Aurora's revised regulatory proposal*, February 2012, pp.3-4.

51 AER, Final decision—WACC review, pp.136-140.

52 Handley, Comments on the CEG report "Establishing a proxy for the risk free rate", November 2008.

53 AER, *Final decision, Electricity transmission and distribution network service providers, Review of the WACC parameters*, May 2009, p. 44.

54 That said, in one section of Aurora's submission on its revised proposal it describes the risk free rate as "downwardly biased due to current financial conditions". Aurora, AER's draft distribution determination—Return on capital, Submission, 20 February 2012. This appears to be the only place Aurora makes this contention. However, even if this

adopt a long run historical average risk free rate to address what are essentially Aurora's concerns with the MRP being too low.[55] CEG's comparisons of the CGS yields against State Government debt yields, implied stock market volatility, and debt spreads also each appear to be presented in support of CEG's contention that the MRP is heightened.

As discussed in sections 10.3.1 the AER continues to consider that integrity in the estimation of each WACC parameter is important. The AER does not consider it is appropriate to address an 'MRP issue' via an adjustment in the risk free rate.

Based on the reasons set in this appendix and attachment 10, the AER considers CGS yields remain an appropriate proxy for the risk free rate.

A.1.7 Consistency between risk free rates used in the cost of equity and the cost of debt

The AER considers that a departure from the SRI approach raises a consistency problem as the risk free rate applies to the cost of debt as well as the cost of equity. The same risk free rate for both the cost of equity and cost of debt is required by the NER.[56] If the debt risk premium (DRP) is added to the long term average risk free rate, consistent with Aurora's proposed risk free rate, the cost of debt will be subject to estimation error as explained by Lally.[57] On the other hand, if the cost of debt continues to be estimated using the prevailing yield, it results in inconsistency between the cost of equity and cost of debt. Lally illustrated this problem by the following example:

> ... suppose that the risk free rate and the debt risk premium resulting from use of the normal averaging period are 4% and 2% respectively, yielding a cost of debt of 6%. This is the correct value. Suppose also that an earlier averaging period is used for the risk free rate within the cost of equity and the resulting rate is 5%, which exceeds that arising from using the normal averaging period by 1%. It is very unlikely that the debt risk premium in this earlier averaging period will be less than that in the normal averaging period by exactly 1%. So, use of the earlier averaging period will probably generate a cost of debt differing from 6%. For example, suppose the debt risk premium in this earlier averaging period is 1.4%. The resulting estimate of the cost of debt using this earlier averaging period is then 6.4%, which exceeds the correct value of 6%.[58]

The SRI approach results in an internally consistent WACC that is free of all the problems discussed by Lally. Aurora attempts to achieve internal consistency by adding to its long term risk free rate what it describes as a "long term DRP". Aurora's submission states:

> Aurora's estimate of the cost of debt is 8 per cent, based on a spot risk free rate of 3.89 per cent and a DRP of 4.11 per cent. However, in its Revised Regulatory Proposal Aurora made a strong case for applying the long term risk free rate of 5.5 per cent rather than the spot rate. Aurora contends that it is not appropriate to pair the spot risk free rate (that is downwardly biased due current financial market instability) with a long term MRP. This means that the long term DRP implied by the 8 per cent cost of debt is 250 basis points.[59]

However, the internal consistency of Aurora's submission is more in appearance than in reality. As this quote shows, Aurora's "long term DRP" is derived from the prevailing cost of debt minus the long

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understood to be Aurora's contention, for the reasons set out in this appendix and attachment 10 the AER is not persuaded by the evidence before it that the CGS yields are a biased proxy for the risk free rate.

55 Aurora, Revised regulatory proposal supporting information: return on capital (WACC), January 2012, pp. 11-15.

56 NER, clause 6.5.2(b).

57 Lally, *Expert report of Martin Thomas Lally*, 13 February 2011, pp. 11-12.

58 Lally, *Expert report of Martin Thomas Lally*, 13 February 2011, p. 12

59 Aurora, AER's draft distribution determination—Return on capital, Submission, 20 February 2012, p.10.

run historical average risk free rate. It is not based on the long run historical average cost of debt. Accordingly, despite the label Aurora applied it is not a long term DRP. Aurora's submission results in an internal inconsistency between the cost of debt and cost of equity, and within the cost of debt.[60]

A.1.8 Comparison with approaches taken by other regulators and by market practitioners in valuation reports

IPART approach

Aurora submitted in its revised proposal that IPART had made an upward adjustment to the risk free rate in recognition of the low CGS yield in its recent Sydney Desalination Plant (SDP) decision.[61] The AER acknowledges that IPART made such an upward adjustment to the overall rate of return in the SDP decision. Aurora's representation of IPART's approach to the risk free rate may, at face value, appear to have some merit. However, a closer analysis suggests differently.

The AER considers that IPART's decisions are not completely comparable to those of the AER. IPART's approach involves adopting a point estimate for some WACC parameters and a range for other parameters.[62] This approach results in a range for the overall rate of return and IPART then exercises its judgement in choosing an appropriate overall WACC from within this range.

In the SDP decision, IPART estimated the 5 year nominal risk free rate at 3.9 per cent using a 20 day averaging period ending on 28 October 2011. IPART also adopted a range for several WACC parameters:

- a range between 5.5 per cent and 6.5 per cent for the MRP
- a range between 0.6 and 0.8 for the equity beta
- a range between 0 to 0.5 for the gamma.

These ranges led to an overall WACC (pre-tax real) range of 5.1 per cent to 6.9 per cent. IPART chose an overall rate of return that was 80 basis points higher than the midpoint of the estimated WACC range. IPART stated that this 80 basis point adjustment was informed by the WACC derived using the long term historical average estimate for all parameters, rather than short term prevailing rates.[63]

IPART's approach derives an overall WACC range in its regulatory decisions and excises its judgement in choosing the appropriate WACC point estimate within that range. The AER notes that IPART often chooses a point estimate which differs from the midpoint of the derived WACC range.[64]

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[60] The AER further notes that neither the 250 or 411 basis point DRPs in Aurora's submission match the 398 basis point DRP in Aurora's revised proposal.

[61] Aurora, *Revised proposal 2012-2017*, February 2012, p. 94.

[62] Further, IPART uses a different approach to estimating other WACC parameters compared to the Aurora proposal. Adopting the IPART DRP approach, for example, would give Aurora a debt margin of 3.5 per cent, which is 61 basis points lower than the debt risk premium determined by the AER.

[63] IPART, *Review of water prices for Sydney Desalination Plant Pty Limited, From 1 July 2012, Water—Final report*, December 2011, pp. 93–95.

[64] For example, IPART chose a WACC 30 basis points below the midpoint in its July 2009 Hunter Water price determination and it chose a WACC 60 basis points above the midpoint in its 2009 Rail Access undertaking (the risk free rate was 5.4 per cent).

For example, IPART made a 60 basis point uplift in its 2009 *New South Wales Rail Access Undertaking* final decision to take account of the underinvestment risk in the Hunter Valley coal network. Although Australian Rail Track Corporation argued for a 60 basis point increase to the risk free rate to reflect the impact of the global financial crisis, IPART considered that such a specific adjustment was not warranted.[65]

Further, a more recent decision by IPART on electricity prices shows that it does not consider this upward adjustment is always required.[66] In that decision, IPART estimated the risk free rate for electricity generators at 3.9 per cent using a 20 day averaging period ending on 3 February 2012.[67] IPART also estimated the risk free rate for electricity retailers at 4.1 per cent using a 20 day averaging period ending on 19 March 2012. IPART made no upward adjustment to the overall WACC in either case, but instead chose the midpoint of the resulting range.[68] This shows that IPART regularly but not always departs from the mid-point of its WACC parameter estimate in determining an overall WACC point estimate.

The AER's approach arises from the NER and SRI requirements, which are different to the legislation IPART operates under. The AER operates under a statutory scheme that sets requirements for determining the appropriate point estimate for each WACC parameter. The overall WACC is simply the output of combining each WACC parameter estimate. While the approaches of the AER and IPART differ, with these differences influenced by the differing legislation involved, both the AER and IPART consistently apply their own approaches over time. Consistency is important to achieve unbiased outcomes. The AER considers that it is inappropriate for it to make an upward adjustment following IPART. To do so creates the potential for arbitrariness and introduces subjectivity, which results in the potential for biased regulatory outcomes.

The AER also notes, despite the differences in the approaches, both approaches led to similar outcomes. In particular, IPART adopted a different approach to estimating the cost of debt that has not been put forward by Aurora. The AER notes that when IPART's WACC estimate for SDP is converted to allow comparison with the WACC determined by the AER in this decision, the two are similar. That is, IPART set a nominal vanilla WACC of between 8.16 and 8.59 per cent, compared to a nominal vanilla WACC of 8.28 per cent that the AER has determined for Aurora.[69]

IPART, *Review of prices for water, sewerage, stormwater and other services for Hunter Water Corporation*, July 2009, p. 203.

IPART, *New South Wales Rail Access Undertaking—Review of the rate of return and remaining mine life from 1 July 2009, Rail access—Final report and decision*, August 2009, p. 6.

65 IPART, *New South Wales Rail Access Undertaking—Review of the rate of return and remaining mine life from 1 July 2009, Rail access—Final report and decision*, August 2009, pp. 39-43.

66 IPART, *Changes in regulated electricity retail prices from 1 July 2012, Electricity—Draft report*, 12 April 2012, pp. 95–98.

67 These risk free rate figures are based on 10 year CGS, not 5 year CGS as in the IPART SDP decision, matching the AER benchmark term assumption.

68 For clarity, the MRP adopted by IPART was a range of 5.5 to 6.5 per cent, of which the midpoint (6.0 per cent) was used to derive the WACC estimate.

69 The IPART WACC is presented as a range because, starting at the IPART real pre-tax WACC point estimate, different assumptions lead to different nominal vanilla WACCs (and IPART did not provide sufficient details to allow a precise conversion). Adopting the IPART DRP approach, for example, would give Aurora a DRP of 3.3 per cent, which is 81 basis points lower than the DRP determined by the AER. Further, IPART set the equity beta for SDP at 0.7, rather than the 0.8 determined for Aurora by the AER. [The AER discusses the comparability of equity betas across water and energy sectors in AER, Draft decision, Roma to Brisbane Pipeline, April 2012, Appendix C.]

Approach of other regulators

Aurora also noted the advice to set a range for the MRP provided by Professors Franks and Myers to the New Zealand Commerce Commission (NZCC). Franks and Myers recommended the NZCC use the top of the range for the MRP until the world economy returns to normalcy and stable growth.[70] In addition, CEG submitted that Aurora's revised proposal is consistent with the approach adopted by UK and US regulators (and IPART). CEG argued that the AER approach wrongly estimates the cost of equity during periods of high risk aversion.[71]

The AER considers the recommendation received by the NZ regulator and decisions made by the UK and the US regulators are not comparable to those of the AER's as these decisions are made under a different legal framework. The AER considers it is inappropriate for it to adopt a range for the WACC parameters as the NER requires the AER to determine the point estimate for each parameter under the CAPM and WACC formulae. The AER notes the UK regulators adopt a fixed equity return strategy, while the US regulators tend to use the dividend growth model (DGM) to estimate the cost of equity.[72] Clause 6.5.2 of the NER prescribes the use of the CAPM for calculating the nominal post-tax return on equity and requires the AER to separately determine each input values such as the risk free rate and MRP. In addition, the AER places limited emphasis on DGM estimates to determine the MRP for reasons set out in sections 10.3.2 and section A.2.4.

Approach in valuation reports

Aurora referenced a valuation report from Lonergan Edward & Associates stating that independent experts are making an upward adjustment to the risk free rate to determine the cost of equity when applying the discounted cash flow (DCF) methodology.[73] Aurora submitted the Lonergan Edward & Associates report to the AER upon request. The AER has reviewed this report and is of the view that their decision to make an upward adjustment to the risk free rate was based solely on MRP related considerations. There is no evidence suggesting that Lonergan Edward & Associates considered that the prevailing CGS yield inappropriately reflects the prevailing risk free rate.[74] As discussed previously, the AER considers it is inappropriate to address an MRP issue via an adjustment to the risk free rate.

A.2 Market risk premium

In chapter 10, the AER presented its considerations on why there is persuasive evidence justifying a departure from the SRI value of a 6.5 per cent MRP and why adopting a MRP of 6 per cent is appropriate. The AER also noted that some matters would be addressed, or addressed in more detail, in appendix A. Those matters are addressed in this section, which are:

- the use of arithmetic and geometric averages of historical excess market returns
- the volatility of historical excess returns
- the assessment of survey evidence against the criteria suggested by the Tribunal

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70 Aurora, *Revised proposal—Supporting information: Return on capital*, January 2012, p.13.
71 CEG, *A report on the cost of equity in Aurora's revised regulatory proposal*, February 2012, p. 9.
72 CEG, *A report on the cost of equity in Aurora's revised regulatory proposal*, February 2012, p. 9.
73 Aurora, *AER's draft distribution determination—Return on capital*, Submission, 20 February 2012, pp.3-4.
74 Lonergan Edwards & Associates Limited, *Proposed acquisition by way of Scheme*, 21 October 2011, p. 98.

- the dividend growth model (DGM) estimates
- the adoption of a conditional MRP
- the financial market indicators of implied volatility, dividend yields and debt spreads.

A.2.1 Arithmetic and geometric averages of historical excess returns

Historical excess market returns are highly sensitive to the method of averaging returns over multiple periods. For example, Brailsford, Handley and Maheswaran found that, relative to bonds, the historical excess market return over 1958-2005 was 4.0 per cent using a geometric average or 6.3 per cent using an arithmetic average.[75]

If returns vary over time, a geometric average will always be less than an arithmetic average.[76] The greater the volatility in returns, the greater the difference between an arithmetic average and a geometric average. With the level of volatility present in historical stock market returns, a difference of around 200 basis points (2 per cent) is common.

WACC review

In the WACC review, the AER stated that in estimating a forward looking parameter from historical data some experts argue for an arithmetic average, some for a geometric average, and some for a weighted average of the two.[77]

The AER noted that in Australian regulatory practice, the use of an arithmetic average of historical excess market returns had been standard, and that this was based on two assumptions:

- that investors 'think' in terms of arithmetic, rather than geometric, averages and therefore investors' expectations will be influenced by arithmetic averages of historical returns, and
- that all returns are independent from each other, in a statistical sense. That is, the MRP in a given year is not influenced by the MRP in a prior year.[78]

Officer and Bishop noted that the arithmetic average is usually used and stated this is appropriate 'if' all historical observations are treated as independent draws from the same distribution.[79] The AER considered this second assumption may be questionable.

The AER noted that a geometric average is usually adopted when measuring historical performance, whereas an arithmetic average is commonly adopted when estimating a forward looking estimate from historical data. The AER further noted that some experts had argued that the use of an arithmetic average for estimating a forward looking parameter is biased up and a geometric average is biased down and had proposed various methods to average the two. Specifically, the AER noted that:

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75 T. Brailsford, J.C. Handley, and K. Maheswaran, 'Re-examination of the historical equity risk premium in Australia, Accounting and Finance, Vol.48, 2008, p.90.

76 For example, if an index starts at 100, falls to 80 and then increases again to 100, the arithmetic average return is 2.5 per cent (the average of the initial 20 per cent fall and subsequent 25 per cent rise) and the geometric average return is zero (because the value of the index at the end of the second period is the same as at the beginning of the first period).

77 AER, Final decision—WACC review, May 2009, p.198.

78 AER, Final decision—WACC review, May 2009, p.198.

79 B. Officer, and S. Bishop, Market risk premium, August 2008, p.6.

- Blume had developed an averaging technique where the arithmetic average is adjusted downwards where there are more return intervals in the estimation period than the forecast period, which Blume argued would otherwise lead to an arithmetic average being biased upwards as a measure of a forward looking estimate[80], and

- Dimson, Marsh and Staunton had developed an averaging technique where historical arithmetic averages are adjusted based on the relative historical volatility compared to expected future volatility.[81]

The AER considered there was some merit in the alternatives proposed by Blume, Dimson et al and other experts. However the AER acknowledged that there is no one alternative that is universally accepted and that each method involved a certain level of complexity. The AER concluded in the WACC review that:

> Therefore on balance, the AER maintains its position that the use of an arithmetic average is reasonable. However these estimates should be interpreted with the understanding that they may to some degree overestimate a forward looking MRP.[82]

Developments since the WACC review

Since the WACC review, the AER has developed a deeper understanding of the issue of averaging historical excess returns over multiple periods. This has led the AER to form a firmer position on the upward bias in the use of an arithmetic average of historical estimates as typically calculated. The AER held this position in its recent Envestra SA access arrangement decision, and consequently had regard to both arithmetic and geometric averages in considering the appropriate value for the MRP. Among other matters, Envestra sought review by the Tribunal of the AER's reliance on geometric averages in Application by Envestra Ltd [2012] ACompT3 (the 'Envestra matter'). In that matter, the AER considered:

- The arithmetic average of 10 year historical excess returns would likely be an unbiased estimator of a forward looking 10 year return (the appropriate benchmark).

- However, historical excess returns are conventionally estimated as the arithmetic or geometric average of one year returns. This convention was adopted in the historical excess return evidence available to the AER. Accordingly, the AER interpreted this (one year return) data based on the strengths and weaknesses of how closely this reflected the relevant benchmark (being a 10 year rate, expressed in annual terms).

- Mathematically, if there is variability in the one year historical excess returns, the arithmetic average of one year historical excess returns will overstate the arithmetic average of 10 year historical excess returns. This is because the process of averaging one year returns does not take into account the cumulative effect of returns over a 10 year time horizon.

- Also mathematically, if there is variability in the one year historical excess returns, the geometric average of one year historical excess returns will understate the arithmetic average of 10 year historical excess returns.

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80 Blume, Unbiased estimators of long run expected rates of return, Journal of the American Statistical Association, September 1974, Vol.69, No.347.

81 Dimson, Marsh and Staunton, Global evidence on the equity risk premium, The journal of applied corporate finance, Vol.15, No.4, Summer 2003.

82 AER, Final decision—WACC review, May 2009, p.198.

- The AER concluded that the arithmetic average of the data it considered was an overestimate of the relevant benchmark and the best estimate of historical excess returns over a 10 year period was likely to be somewhere between the geometric and arithmetic average of annual excess returns.[83]

The Tribunal stated that while it did not have to decide this matter, that some comments should be made. The Tribunal appeared to agree with the AER's view on both the upwards and downwards biases as it commented that:

> It may be accepted that an arithmetic mean of historical excess returns is an unbiased estimate of expected future one year returns. It is not, however, an unbiased estimate of expected future returns over longer time horizons. A geometric mean of historical annual returns does not provide an unbiased estimate of expected returns over longer time horizons, either.[84]

In the Aurora draft decision, the AER held the same position on this issue as that presented in the Envestra matter. Aurora, in its revised proposal, submitted that:

- The AER should wait until the next WACC review to revisit its position from the previous WACC review[85]—The AER does not agree with Aurora's reasoning on this issue which the AER addresses in section 10.2.1.

- The AER did not address one of the assumptions underpinning the use of an arithmetic average being that investors 'think' in terms of arithmetic averages[86]—The AER considers that this assumption (which may or may not be correct) is a factor that supports the use of arithmetic averages. However, as discussed in this section, there are other factors that indicate that the arithmetic average of annual returns produces upwardly biased estimates. Accordingly, in the AER's opinion, this factor is insufficient to conclude that sole reliance should be placed on arithmetic averages and no reliance should be placed on geometric means. The AER, recognising the strengths and weaknesses of each form of averaging, has had regard to both arithmetic and geometric averages.

SFG, in its October 2011 report, submitted that it is wrong to place any reliance on geometric averages, and that to the extent that reliance is (incorrectly) placed on geometric averages, the resulting estimate of the MRP will be downwards biased. In support of this position SFG presented a Harvard Business School case note.[87]

The AER sought McKenzie and Partington's review of the SFG report and Harvard Business School case note. In their February 2012 supplementary MRP report, McKenzie and Partington explained how the Harvard case study, by construction "assumes away the source of bias in arithmetic averages".[88] Accordingly, the AER does not find the evidence presented by SFG persuasive.

SFG also submitted that the MRP in the CAPM is an expected return and consequently the arithmetic average, not the geometric average, 'must' be used.[89] The Tribunal has previously dismissed this argument when it was presented by Envestra:

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83 Australian Competition Tribunal, Application by Envestra Ltd (No 2) [2012] ACompT3, 11 January 2012, paragraphs 150-153.

84 Australian Competition Tribunal, Application by Envestra Ltd (No 2) [2012] ACompT3, 11 January 2012, paragraph 154.

85 Aurora, Revised regulatory proposal—Supporting information: Return on capital, January 2012, pp.21-22.

86 Aurora, Revised regulatory proposal—Supporting information: Return on capital, January 2012, pp.21-22.

87 SFG, Market risk premium, 11 October 2011, p.16.

88 McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012, pp.5-6.

89 SFG, Market risk premium, 11 October 2011, p.18.

> Envestra's submission that, because the CAPM model uses expected returns, only the arithmetic mean may be used cannot be accepted once it is understood that the arithmetic mean of annual historic returns is not an unbiased estimate of expected ten-year returns.[90]

After a review of the academic literature on arithmetic and geometric averages, McKenzie and Partington concluded in their February 2012 MRP report:

> The evidence solidly supports the AER's position that over the ten year regulatory period the unbiased MRP lies somewhere between the arithmetic average and the geometric average of annual returns.[91]

NERA agrees with the AER that the arithmetic average of historical annual returns is a biased estimate of a forward looking 10 year MRP. It states:

> While the arithmetic mean of a sample of returns will always provide an unbiased estimate of the expected return to an asset over a single period, the use of arithmetic means and the use of geometric means can provide biased estimates of expected multi-period returns.[92]

However, NERA raises a new argument against using geometric averages which is based on the way in which the WACC is used to determine regulated revenues:

> While we agree that an estimate of the expected 10-year excess return that uses the arithmetic mean will be upwardly biased, at no stage in the regulatory process is the WACC compounded over 10 years—or indeed over more than one year. In other words, a regulated utility is not given the opportunity of reinvesting its earnings at the WACC. The utility can only earn the WACC on the regulated asset base and the evolution of the regulated asset base does not depend on the WACC.[93]

The AER understands NERA's contention as follows:

- Annual revenue requirements are determined using the building block equation (equation 3 in NERA's report)
- This equation deals with one year returns

The AER notes that, as discussed in section A.1.3, the building block model is a tool to achieve an outcome whereby the present value of expected revenue equals the present value of expected expenditure over the life of the regulated assets (the net present value (NPV)=0 condition or 'present value principle'). Accordingly, the AER considers that when there are questions about the operation of the building block model it is useful to address or consider these as questions over whether or not the NPV=0 condition still holds.

From this perspective, while the issues are technical and complex, the AER considers NERA's concerns are no longer valid. To determine a profile of revenues in which the NPV=0 outcome holds, an appropriate discount rate must be used, which requires the evaluation of an expected multi-period cost of equity. As NERA states it its report, there is a bias when the arithmetic average of annual returns is used to determine expected multi-period returns.

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90 Australian Competition Tribunal, Application by Envestra Ltd (No 2) [2012] ACompT3, 11 January 2012, paragraph 154.

91 McKenzie, M. and G. Partington, Supplementary report on the equity market risk premium, 22 February 2012, pp.5-7.

92 NERA, *The market risk premium*, 20 February 2012, p.12.

93 NERA, *The market risk premium*, 20 February 2012, p.12..

Further, the Tribunal in the Envestra matter also queried whether there was a method to produce an unbiased estimate. The Tribunal said it could not form a conclusion on that issue based on the material before it.

The AER sought McKenzie and Partington's advice on whether such a method was available. After examination of a number of alternative estimators proposed in the literature, McKenzie and Partington concluded in their February 2012 MRP report that there is no indisputable single best estimator for long run excess returns and the common practice is to use unadjusted geometric and arithmetic averages. Given the current state of knowledge, McKenzie and Partington found no strong case to depart from the common practice and recommended the use of both of these metrics, tempered by an understanding of their inherent biases.[94]

A.2.2 The volatility of historical excess returns

NERA observed that Australian excess market returns were less volatile prior to the 1950s than after this time. NERA suggested this lower historical volatility indicated that the MRP should have been lower before 1958 than after. NERA suggested that if the pre-1958 data were adjusted to reflect the volatility observed post-1958, then the historical estimates over the full period of over 100 years would support an MRP estimate above 6 per cent.[95]

In the WACC review, the AER considered arguments for adjusting the historical data for unexpected or one-off events that could make the historical data 'unrepresentative'.[96]

In considering whether or not to make those adjustments, the AER considered, among other evidence, advice from Officer and Bishop. Reflecting on that advice, the AER stated:

> ...comments in Officer and Bishop (in their current advice to the JIA) substantially reflected these earlier views. In both cases, the authors argued against the proposed adjustments, arguing they are ‘ad hoc’ and may themselves be a source of bias.
>
> ...
>
> Bishop argued that a lack of a well developed theory behind what drives the MRP makes events that might lead to bias in the historical data difficult to identify. Each set of authors also note that, except for Hathaway’s acknowledgement of the relationship between the MRP and imputation credits, only events that might bias the historical MRP upwards had been considered, and not events that might do the reverse.
>
> The JIA and Officer and Bishop stated that their general position on adjustments was that a longer estimation period that includes both positive and negative shocks should be used rather than making ‘ad hoc’ adjustments to historical estimates.[97]

Given the lack of a well developed guiding theory, and the potential for the introduction of bias, the AER concluded in the WACC review that explicit adjustments should not be made to the historical data. This was in the context of 'unrepresentative' events in one or a few years of historical data. In

94 McKenzie and Partington, Supplementary report on the equity risk premium, February 2012, pp. 7–9.
95 NERA, *The market risk premium*, 20 February 2012, pp.13-20.
96 The AER considered specific adjustments proposed by Hathaway, Hancock, and Officer and Bishop.
97 AER, *Statement of regulatory intent,* May 2009, pp.209-214.

contrast, NERA has, in effect, submitted that all of the data pre-1958 is 'unrepresentative'.[98] While not exactly the same circumstances, the AER considers that similar reasoning is applicable in this case.

It may be that NERA is right, and that the pre-1958 data is, in effect, 'too low'. On the other hand, the AER is aware of other arguments that would suggest that data in the first half of last century is, in effect, 'too high'. For example, some authors have stated that the transactions costs of trading shares has decreased over time. As a result the (pre-transaction cost) required return by investors has decreased.[99]

The lack of a well developed theory behind what drives the MRP makes the AER cautious of excluding large periods of data on the basis that it is unrepresentative of a forward looking MRP. For this and the other reasons set out in chapter 10, the AER considers it is reasonable to take into account historical excess returns from each of the periods beginning in 1883, 1937 and 1958.

Further, as shown in chapter 10, the arithmetic average of historical excess returns over 1883-2011 and 1958-2011 (grossed up for a 0.35 value of distributed imputation credits) both result in a historical MRP of 6.1 per cent. Accordingly, even if the AER were to only rely on the post-1958 data this would not change the AER's position on the appropriate value of the MRP.

A.2.3 Survey evidence

WACC review

At the time of the SRI, the AER considered the following survey evidence to inform the value of the forward looking MRP:

- KPMG (2005) surveyed 33 independent expert reports on take over valuations from January 2000 to June 2005. It found that the MRP adopted in valuation reports ranged from 6–8 per cent. KPMG reported that 76 per cent of survey respondents adopted an MRP of 6 per cent.[100]

- Capital Research (2006) found that the average MRP adopted across a number of brokers was 5.09 per cent.[101]

- Truong, Partington and Peat (2008) in the last quarter of 2004 surveyed chief financial officers, directors of finance, corporate finance managers, or similar finance positions of 365 companies included in the All Ordinaries Index as of August 2004. From the 87 responses received, 38 were relevant to MRP. They found the MRP adopted by Australian firms in capital budgeting ranged from 3–8 per cent, with an average of 5.94 per cent. The most commonly adopted MRP was 6 per cent.[102]

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98 NERA has also not explicitly adjusted the pre-1958 data, but rather made a conclusion on the basis of what that data would show if it were adjusted.

99 Siegel J., *The shrinking equity premium*, the journal of portfolio management fall 1999, p.13. For example, Siegel noted that lack of low cost index funds in the US prior to 1975 might overestimate the real returns. The AER understands the rising popularity of managed funds and the increasing use of online trading would have reduced the transaction costs in Australia. According to Siegel, if transaction costs are a factor which drives the MRP, then high transaction cost in the past indicates the long term historical MRP estimates that includes the data from early last century might be 'too high'.

100 KPMG, Cost of capital—Market practice in relation to imputation credits, August 2005, p. 15.

101 Capital Research, *Telstra's WACC for network ULLS and the ULLS and SSS businesses—Review of reports by Prof. Bowman*, March 2006, p. 17.

102 G. Truong, G. Partington and M. Peat, *'Cost of capital estimation and capital budgeting practices in Australia', Australian Journal of Management,* Vol. 33, No. 1, June 2008, p. 155.

The AER noted that the above survey measures strongly indicated that an MRP of 6 per cent is by far the most commonly adopted value by market practitioners. However, these surveys were conducted prior to the onset of the GFC. Given the uncertainty surrounding the on-going impact of the GFC, the AER considered that the following two scenarios could explain the market conditions at the time:

- The prevailing medium-term MRP was above the long-term MRP, but would return to the long-term MRP over time, or
- There had been a structural break in the MRP and the forward looking long-term MRP (and consequently also the prevailing) MRP was above the long-term MRP that previously prevailed.

Due to the uncertainty about the effects of the GFC on future market conditions, the AER exercised its judgment and departed from the previous consensus MRP estimate of 6 per cent and increased it to 6.5 per cent. This is despite other evidence such as survey measures which supported a forward looking estimate of 6 per cent.[103]

Developments since the WACC review

Following from the SRI final decision, new survey evidence has become available. The AER has considered this evidence in recent regulatory reviews. The latest surveys conducted after the on-set of the GFC indicate that the forward looking MRP expected to prevail has not changed. In chronological order, these surveys include the following:

- Bishop (2009) reviewed valuation reports prepared by 24 professional valuers from January 2003 to June 2008. It found that the average MRP adopted is 6.3 per cent and 75 per cent of these experts adopted an MRP of 6 per cent.[104]
- Fernandez (2009) surveyed university finance and economic professors around the world in the first quarter of 2009. The survey received 23 responses from Australia and found that the required MRP used by Australian academics in 2008 ranged from 2–7.5 per cent with an average of 5.9 per cent.[105]
- Fernandez and Del Campo (2010) surveyed analyst around the world and in April 2010. The survey received 7 responses from and found that the MRP used by Australian analysts in 2010 ranged from 4.1–6 per cent with an average of 5.4 per cent.[106]
- A further survey by Fernandez et al (2011) in April 2011 reported that average MRP used by 40 Australian respondents ranged from 5–14 per cent, with an average of 5.8 per cent.[107]
- Asher (2011) surveyed 2,000 members of the Institute of Actuaries of Australia. Asher reported that 33 out of a total of 58 Australian analysts responded to the survey expects the 10 year MRP

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103 AER, Final decision—WACC review, May 2009, pp. 221–225.

104 Bishop, S. (2009), IERs—A conservative and consistent approach to WACC estimation by valuers, Value Advisor Associates.

105 Fernandez and Del Campo, *Market Risk Premium used by Professors in 2008: A Survey with 1400 Answers, IESE Business School Working Paper*, WP-796, May 2009, p. 7.

106 Fernandez and Del Campo, *Market Risk Premium Used in 2010 by Analysts and Companies: A Survey with 2400 Answers, IESE Business School*, May 21 2010, p. 4.

107 Fernandez, Arguirreamalloa and Corres, *Market Risk Premium used in 56 Countries in 2011: A Survey with 6,014 Answers,* IESE Business School Working Paper, WP-920, May 2011, p. 3.

to be between 3 to 6 per cent. The most commonly adopted MRP value is 5 per cent. The report also illustrated that expectations of an MRP much in excess of 5 per cent were extreme.[108]

The key findings of the surveys are summarised below.

Table A.1 Key findings of survey responses

	Numbers of responses	Mean	Median	Mode
KPMG (2005)	33	7.5%	6.0%	6.0%
Captial Research (2006)	12	5.1%	5.0%	5.0%
Truong, Partington and Peat (2008)	38	5.9%	6.0%	6.0%
Bishop (2009)	27	NA	6.0%	6.0%
Fernandez (2009)	23	5.9%	6.0%	NA
Fernandez and Del Campo (2010)	7	5.4%	5.5%	NA
Fernandez et al (2011)	40	5.8%	5.2%	NA
Asher (2011)	49	4.7%	5.0%	5.0%

For the surveys under consideration, the most commonly used MRP was 6 per cent. The AER has placed some weight on this result to inform the forward looking MRP in recent regulatory reviews including, most recently, the final decision for 2011-15 Envestra gas distribution access arrangement review.

The final decision for Envestra was appealed and the issue regarding the use of survey evidence to inform the value of MRP was brought before the Tribunal.[109] Although the Tribunal did not made a ruling on this issue, it made the following comments:

> Surveys must be treated with great caution when being used in this context. Consideration must be given at least to the types of questions asked, the wording of those questions, the sample of respondents, the number of respondents, the number of non-respondents and the timing of the survey. Problems in any of these can lead to the survey results being largely valueless or potentially inaccurate.
>
> When presented with survey evidence that contains a high number of non-respondents as well as a small number of respondents in the desired categories of expertise, it is dangerous for the AER to place any determinative weight on the results.

NERA also raised questions over the use of survey evidence. Specifically, NERA stated that:

- the surveys that the AER cites typically do not explain how those surveyed were chosen
- a majority of those surveyed in the surveys the AER cites did not respond
- it is unclear what incentives were provided to individuals contacted by the surveys that the AER cites to ensure that respondents would provide accurate responses

108 Actuary Australia 2011 Issue 161, Asher, *Equity Risk Premium Survey—results and comments*, July 2011, pp. 13–14.

109 Australian Competition Tribunal, Application by Envestra Limited (No 2) [2012] ACompT 3, 11 January 2012, paragraph 150–154.

- it is unclear whether respondents are supplying estimates of the MRP that use continously compounded or not continuously compounded returns
- it is unclear what risk-free rate respondents use, and
- is it unclear how relevant some of the surveys that the AER cites are because of changes in market conditions since the time at which the surveys were conducted.[110]

In light of the Tribunal's comments, the AER engaged McKenzie and Partington to apply a set of criteria that are consistent with those highlighted by the Tribunal to the surveys considered in this final determination. The main findings of the McKenzie and Partington assessment and the AER's own review are set out below. These findings similarly apply to much of the comments from NERA.

Timing of the survey

The timing of the surveys is reasonably clear. They ranged from periods prior to the onset of the GFC (over 2000 to 2008), to the latest survey which was conducted in February 2011, around 2 to 3 years after the height of the GFC. Comparison of survey results over different time periods will provide some information on the likelihood of a structural break in the MRP following from the on-set of the GFC.

Sample of respondents

The target population for the surveys listed above are senior financial managers (CFOs), expert valuers, actuaries, and finance academics. For this reason, the AER considers that the target populations selected by the surveys are in a position to make informed judgements about the MRP.[111]

Wording of survey questionnaires

The quality of the wording of the questionnaires is essential to control bias and improve accuracy of survey results. The AER accepts McKenzie and Partington's view that there is a subjective element in judging whether the given wording in a survey is adequate and that it often relies on the quality of the authors. However, the AER agrees that it can be expected that confidence can be enhanced when the work is published in a refereed academic journal, or when the survey is repeated. In the former case, the work has been subject to peer review. In the latter case, a stable set of questions allows comparisons of response through time. With repeated surveys, the observed changes through time are less susceptible to issues in the wording of the questions. Furthermore, in the event of significant problems with wording and interpretation of questions by respondents this may be detected and corrected over time.[112] The AER notes that most of the surveys considered here are published in refereed journals and/or repeated through time. Therefore, on balance, the AER is reasonably confident about the wording in the survey questionnaires.

Adjustment for imputation credits

The AER acknowledges that apart from the Asher (2001) survey, in which 27 out of 49 respondents indicated that they have made adjustments to their MRP estimates for imputation credits, other survey evidence suggests that imputation credit are not typically allowed for. It is also unclear the extent of

110 NERA, The market risk premium, 20 February 2012, p.31.
111 McKenzie and Partington, Supplementary report on the MRP, February 2012, p. 17.
112 McKenzie and Partington, Supplementary report on the MRP, February 2012, pp. 17–18.

adjustments made to the MRP estimate in other surveys considered here. The AER acknowledge that this uncertainty around the extent survey respondents have included imputation credits is a limitation of surveys as a measure, and has taken this into account in the interpretation of the numeric results on MRP from survey evidence.

Survey response rate and representativeness, and non-response bias

A sufficient level of response rate is important for survey evidence, but it is a subjective judgement on what constitutes a sufficiently large sample. McKenzie and Partington suggests that a sample size of around 30 is statistically sufficiently large and therefore a representative sample of 30 respondents is expected to be adequate.[113] The AER notes that most of surveys considered here received responses of around 30.[114] However, the AER agrees with McKenzie and Partington's view that although the numbers of response in a survey is important, the main concern is the presence of representativeness and non-response bias. That is whether there might be a reason for non-respondents to systematically favour a higher or lower MRP than the respondents to the survey.

A direct assessment of response bias is difficult as by definition the responses of the non-respondents are unknown. One investigation technique McKenzie and Partington use to address this issue is the triangulation of survey evidence. The idea behind this is that suppose surveys under consideration systematically understate the market risk premium due to some form of bias. This may include non-response bias, or some other form of response bias, or due to the target population of the survey, or the way the survey was conducted. Downward bias might be the case for a specific survey, although there is no compelling demonstration of it. However, it is much less likely that this would be a consistent problem across surveys with diverse methods and different target populations.

Applying this technique to investigate the representativeness and non-response bias in the surveys, McKenzie and Partington found that the Australian surveys conducted using different methods and different target populations all support a MRP of about 6 per cent.[115] For example, for surveys prior to the high of the GFC, KPMG (2005) survey looks at the market risk premiums used in expert reports. The representativeness bias may arise under this survey method because the same expert might have produced many reports and thus that one expert's views are overweighted. Bishop (2009) addresses this problem by surveying experts' reports and collecting the MRP by expert, so each expert's opinion is equally weighted. Since both studies suggest the MRP used by most experts is 6 per cent, this triangulation leads to greater confidence in the results.[116]

The results from KPMG (2005) and Bishop (2009) surveys combined with survey results from Fernandez (2011) and Asher (2011), which both indicates that the MRP used by analysts and actuaries in Australia is around 6 per cent, also provides triangulation of the survey evidence that the MRP has not increased following the GFC.[117]

Conclusion on survey evidence

For the reasons set out above, McKenzie and Partington concluded that despite the potential problems, it is appropriate to place significant weight to the survey evidence.

113 McKenzie and Partington, Supplementary report on the MRP, February 2012, pp. 17–18.
114 McKenzie and Partington, Supplementary report on the MRP, February 2012, p. 18.
115 McKenzie and Partington, Supplementary report on the MRP, February 2012, p. 20.
116 McKenzie and Partington, Supplementary report on the MRP, February 2012, p. 19.
117 McKenzie and Partington, Supplementary report on the MRP, February 2012, p. 20.

After careful consideration of McKenzie and Partington's findings on the advantages and the potential problems of survey evidence against the criteria noted by the Tribunal. On balance, the AER accepts McKenzie and Partington conclusion and considers the survey evidence reasonably met the criteria.

Based on its own review and the advice from McKenzie and Partington, the AER considers that survey based estimates of the MRP are relevant for consideration to inform the forward looking MRP. Survey estimates provide some indication that expectations of the forward looking long-term MRP have not been affected by the GFC. They also show that the likelihood of a step change in MRP of the type considered at the time of the WACC review has reduced. Moreover, this evidence supports the view that a forward looking MRP of 6 per cent is the best estimate in the current circumstances.

A.2.4 DGM estimates

The AER has considered submissions advocating the use of DGM inferred estimates of the MRP. Both Aurora and NERA noted that applying a risk free rate of 4.28 to the assumptions used by the AER in the draft distribution determination would support a DGM based MRP estimate above 6 per cent.[118] NERA further submitted that the current Bloomberg and IBES forecasts support DGM based MRP estimates above 6 per cent and these estimates are conservative as they use a forecast of long-run DPS growth number.[119]

As discussed in section 10.3.2, the AER considers the DGM based estimates of the MRP are highly sensitive to the assumptions made. This view is support by McKenzie and Partington in their December 2011 MRP report:

> Clearly valuation model estimates are sensitive to the assumed growth rate and a major challenge with valuation models is determining the long run expected growth rate. There is no consensus on this rate and all sorts of assumptions are used: the growth rate in GDP; the inflation rate; the interest rate; and so on. A potential error in forming long run growth estimates is to forget that this growth in part comes about because of injections of new equity capital by shareholders. Without allowing for this injection of capital, growth rates will be overstated and in the Gordon model this leads to an overestimate of the MRP.[120]

The AER considers that DGM based analysis of the MRP can provide some information on the expected MRP. However, due to the sensitivity of results to input assumptions in the model, the DGM analysis should be limited to providing a general point of reference for assessing the reasonableness of MRP. This is consistent with McKenzie and Partington's recommendation that little weight should be attached to the use of implied MRP in regulatory determinations.[121]

The AER has also considered the DGM estimates proposed by Capital Research (CR). CR developed its own DGM analysis and estimated DGM implied MRP in the range of 6.6 to 7.5 per cent. In estimating this range, CR assumed a compound average growth rate of 7 per cent based on analysts' forecast, and a theta value of between 0 and 0.5.[122] As discussed above, the AER considers the DGM analysis is very sensitive to the assumptions made. This is supported by CR's own analysis - an increase of 0.5 in the theta assumption translates to a 0.8 to 1.2 per cent increase in the implied

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118 Aurora, Revised proposal—Supporting information: Return on capital, January 2012, p. 23. NERA, *The market risk premium*, 20 February 2012, p.29.

119 NERA, *The market risk premium*, 20 February 2012, pp.21-28.

120 McKenzie, M. and G. Partington, Equity market risk premium, 21 December 2011, p. 25.

121 McKenzie, M. and G. Partington, Equity market risk premium, 21 December 2011, p. 27.

122 CR, *Forward estimate of the mark risk premium: update*, February 2012, pp.19-23.

MRP.[123] The DGM assumes growth at a constant rate in perpetuity. The AER considers that analysts' forecast is often based on short to medium terms and therefore using analysts' forecast growth rate is likely to result in an upward bias in the DGM implied MRP estimate. Mckenzie and Partington further noted in their December 2011 MRP report:

> Since analysts only cover a subset of firms, whether we get a representative estimate for the market is an open question. Another problem is that analyst's forecasts are known to be biased (generally upwards) and subject to gaming (see Scherbina, 2004, and Easton and Sommers, 2006).[124]

A.2.5 Conditional estimates of the MRP

This section discusses the various proposals for estimating a 'conditional MRP', that is, an MRP estimate that is conditioned on (determined by) the value of particular financial market indicators, labelled conditioning variables. It focuses on the validity and relevance of this approach to the determination of the MRP. The individual merits of the three financial market indicators proposed as conditioning variables—implied volatility, dividend yields and relative debt spreads—are discussed after this section.

CEG suggested that the AER presumes the MRP is stable over time.[125] The AER considers such an assertion is inappropriate as the AER acknowledges that the MRP will vary and considers the prevailing market conditions that are relevant at each regulatory decision.[126] This overarching methodology has been called an 'implicit conditional CAPM', because the conditioning variables are not set out by the AER in the manner of an explicit formula.[127] Rather than mechanistically determine the MRP on the basis of three short term financial market indicators, the AER considers the full range of qualitative and quantitative evidence available across numerous different areas. In this broader context, the AER does give weight to the three variables put forward by SFG (implied volatility, dividend yields, relative debt spreads) in accordance with their relevance to the 10 year, forward looking MRP.

The AER does not consider that SFG's conditional MRP approach is a relevant basis to estimate a forward looking 10 year MRP. This is because there is insufficient evidence to establish a quantifiable relationship between the three conditioning variables and the MRP. Though SFG cites several academic papers as support for this general approach, broader consideration of the academic literature reveals that the merits of conditional MRP models are disputed. This point is echoed by McKenzie and Partington who state:[128]

> We do not claim this evidence is conclusive, but it does indicate the ongoing question mark over predictive regressions. Until this is resolved we consider it premature to adjust the MRP using conditioning variables.

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[123] CR, *Forward estimate of the mark risk premium: update*, February 2012, Table 2, p.21.

[124] McKenzie, M. and G. Partington, Equity market risk premium, 21 December 2011, p. 26.

[125] CEG, A report on the cost of equity in Aurora's revised regulatory proposal, February 2012, p.8.

[126] In this instance, the relevant market conditions are those expected to prevail across the 10 years commencing at the start of the access arrangement period.

[127] AER, *Final decision, Envestra Ltd, Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016*, June 2011, p. 171.

[128] McKenzie and Partington, Supplementary report on the MRP, February 2012, p. 25.

Further, even general results in favour of a conditional MRP would not necessarily apply to the particular implementation proposed by SFG. As detailed below, there are specific problems with the conditioning variables chosen, the selective application of data and the interpretation of those results.

In a report for the Victorian electricity businesses, SFG stated that using the longest data series of historical excess returns provided an unconditional MRP estimate.[129] Rather than adopt this unconditional MRP, SFG stated that current financial market indicators provided information which allowed the derivation of a conditional MRP estimate. This was a preferable estimate because the MRP estimate would then align with current market conditions.[130]

SFG suggested that the distribution of unconditional MRP estimates have a mean of 6 per cent with a standard deviation of 1.5 per cent.[131] The distribution of conditional MRP estimates is then derived by taking the expected value of the unconditional MRP conditioned on latest point estimate of conditioning variables. Citing several academic papers, SFG stated that conditioning variables explain about 50 per cent of variation in excess returns.[132] Based on this assumption, SFG derived the distribution for the conditional MRP as a mean of 6 per cent with a standard deviation of 1 per cent.

Three financial market indicators were used by SFG as conditioning variables: implied volatility, dividend yields, and relative debt spreads.[133] SFG estimated that on average, these conditioning variables were one standard deviation above their long run values. Hence, the conditional MRP proposed by SFG was one standard deviation (1 per cent) above the mean (6 per cent), for an MRP of 7 per cent.[134]

Though the MRP varies, the AER considers that there is no consensus on which factor or factors could be used to predict this variation, nor on the appropriate mathematical representation of such a relationship. SFG stated that the conditioning variables could explain 50 per cent of the variation in excess returns, and referenced studies by Fama and French (1988, 1989) and Kleim and Stambaugh (1986).[135] The AER considers that this interpretation does not accurately represent the academic literature on this subject. While it is true that some regressions studies have found conditioning relationships of this magnitude,[136] many find no statistically significant relationship at all. Further, even those results that seem (at face value) to present a strong relationship have been questioned by other academics, concerned that these might be spurious regressions with no underlying relationship at all.

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129 SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, p. 26.

130 SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, p. 2–3, 26–30.

131 SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, p. 26.

132 SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, pp. 27–28.

133 SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, pp. 7–13,

134 SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, pp. 28–30.

135 SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, p. 7, 27.

136 For clarity, none of the cited academic papers actually implement the three conditioning variables in the manner suggested by SFG.

This view is supported by the conclusion reached by McKenzie and Partington on this matter:[137]

> there are good reasons for regulators to use the unconditional market risk premium. Not least of which is the impossibility of knowing what that conditional market risk premium should be. In our opinion, therefore, there needs to be a very compelling case to switch to a conditional MRP. Also, as the required adjustment is uncertain, a switch to a conditional risk premium takes us onto dangerous ground. Consequently, while it takes a compelling case to switch to a conditional MRP, in our opinion much less evidence is required to justify a retreat to the safer ground of the unconditional MRP.

A secondary concern is the volatile nature of the conditional MRP generated in the manner suggested by SFG. The conditioning variables are short term financial market indicators and vary substantially over short periods. As a result, the conditional MRP will also substantially over a period of months. The AER considers that the underlying 10 year forward looking MRP is unlikely to move so dramatically in a short period of time. The core of this problem is that the term of the conditional MRP is intrinsically linked to the term of the conditioning variables. Such an approach does not aid regulatory consistency.

A final point concerns the choice of baseline averaging period. The conditional MRP assessment relies upon the comparison of the current values for each conditioning variable against their 'baseline' value—usually defined as the long run average. Hence, the selection of a particular long run averaging period can have a material impact on the outcome of the analysis. The clear theoretical preference is for an averaging period that matches the entire estimation period for the unconditional MRP underlying the approach. Unfortunately, data limitations mean it is often not possible to have such an extensive history for these conditioning variables, in which case the longest possible period should be selected.

Across recent reports, the conditioning variables presented by SFG have been relatively high. Table A.2 summarises the SFG results by presenting one key figure for each variable, the standardised difference between the current value and the long run average. 'Standardised' means that the difference is expressed in terms of the standard deviation for that data series. For example, a standardised value of +1.5 means that the current value is above the average value by 1.5 times the standard deviation for that series.

Table A.2 Conditioning variables presented by SFG in recent reports

SFG report date	Implied volatility	Dividend Yield	Relative debt spread
March 2011	+0.80	+0.44	+0.87
October 2011	+2.17	+1.59	+0.77
February 2012	+2.17	+1.02	+1.95

Source: SFG figures provided to the AER, AER analysis

In the latest SFG report, the three conditioning variables are all more than one standard deviation above their mean. On this basis, SFG proposed that the conditional MRP should be one standard deviation above its baseline value of 6 per cent.

As set out in the individual sections of the appendix, the AER considers that the implied volatility and dividend yield figures should use updated data and a baseline that encompasses the longest

137 McKenzie and Partington, Supplementary report on the MRP, February 2012, p. 25.

available data series. The AER considers that there is no reasonable data available for the relative debt spread; but presents the uncorrected SFG figures for comparative purposes. Table A.3 shows the standardised difference between the current value and long run average for the three financial market indicators.

Table A.3 Conditioning variables after correction

Data period	Corrected implied volatility	Corrected dividend yield	Uncorrected relative debt spread
To 15 March 2011	+0.10	+0.10	+0.87
To 23 September 2011	+2.25	+1.17	+0.77
To 31 January 2012	–0.12	+0.53	+1.95
To 31 March 2012	–0.48	+0.46	NA

Source: SFG figures provided to the AER, Bloomberg, AER analysis
Notes: The dates of the first three rows coincide with the data presented in the three SFG reports. The Datastream data on the relative debt spread (used by SFG) is not available to the AER and so cannot be updated. The Datastream data on dividend yields is not available to the AER, but an alternative series from Bloomberg has been used (correlation of 0.97).

As is evident in Table A.3, based on recent data, neither the implied volatility nor the dividend yield figures differ substantially from their long run average. The implied volatility series is below the long run mean. Even if the relative debt spread figure (1.95 standard deviations above the mean) were reliable,[138] there is no consistent pattern across the conditioning variables.

The AER considers that the conditional MRP approach is not reliable and does not apply weight to this approach. However, even if weight were to be given to this approach, it would support an MRP of 6 per cent as correct.

A.2.6 Implied volatility

Implied volatility is calculated from observing the price of put or call options over a broad share market index, such as the S&P/ASX 200. Applying a mathematical formula allows the calculation of the level of market volatility expected by market participants over the life of the underlying options.[139] Hence, the term of the implied volatility will accord with the option term—usually three months, but ranging between one year and one month.[140]

Both CEG and SFG stated that higher implied volatility indicates higher risk and consequently a higher market risk premium.[141] In the WACC attachment, the AER sets out the reasons why it is not reasonable to directly link these implied volatility measures to the 10 year forward looking MRP. In brief, the relationship between the two is tenuous and encompasses several contested assumptions that on current evidence cannot be resolved.

As further background on this point, McKenzie and Partington set out several key reasons why they consider that implied volatility is not a reliable technique for estimating the MRP:

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138 To prevent misinterpretation, the AER does not consider that this figure is reliable as discussed later in this appendix.

139 The Black-Scholes option pricing model is most often used, but other methods are possible.

140 To clarify, options are sold with different maturities beyond this range, but the implied volatility calculations are found only at these short term horizons.

141 CEG, A report on the cost of equity in Aurora's revised regulatory proposal, February 2012, pp.6-7.
SFG, Market risk premium—Report for APT Petroleum Pipelines Ltd, 11 October 2011, pp. 9-11.

- Merton (1980) used a volatility modelling approach to estimating the MRP. Merton pointed out that the implementation of this approach should be via a time series regression model of a return variable on volatility with non-negativity restrictions on the slope coefficient and corrections for heteroscedasticity. Merton tested three formulations of this model using U.S. data, and found that the approach added little to using a simple historical average MRP.[142]

- While implied volatility is a reasonable proxy for the short term expectations of the market, they may not provide any real forecast of future volatility. For example, Carr and Wu (2003) show that implied volatilities are very similar across different maturities. Moreover, they show that the shape of the implied volatility smirk does not flatten out for longer maturities but stays similar to that for short maturities. This does not accord with the expectations that the true volatilities are expected to change over time.[143]

- It is questionable that whether the implied volatility during financial crises is a good proxy for the rational market expectations of longer term returns. In another words, it is unclear that whether the marginal participants in the options market during a crisis are likely to be the marginal participants during more usual market conditions.[144]

- Certain options contracts are known to trade at a premium in the market, in which case the implied volatility estimates will be overstated.[145]

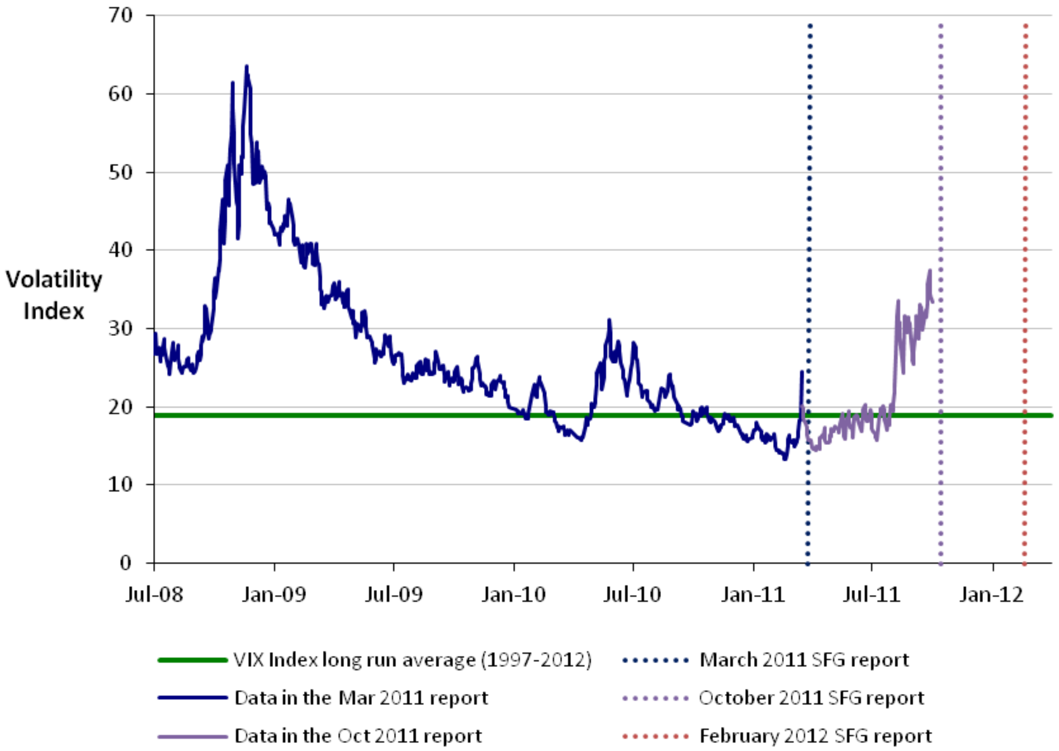
- The non-stationarity problem is often provided as an argument in favour of using a long time series for MRP estimation. Proponents of this view maintain that a shorter time series of more relevant data will have a standard deviation that is too high to provide useful estimates of the MRP. It seems somewhat inconsistent to argue in favour of the use of adjusted current market estimates of volatility when they exhibit the same high level of volatility.[146]

Attachment 10 also sets out that, even if implied volatility were directly related to the MRP, it would not support an estimate above the long run average (6 per cent). The current level of implied volatility is below the long run average.

In several recent regulatory processes, SFG has submitted arguments for an elevated MRP based on implied volatility analysis.[147] In general, SFG updates the data each time to show recent market developments. Figure A.1 shows the dates of three recent reports by SFG, together with the implied volatility data included by SFG in each report.

142 McKenzie and Partington, Equity market risk premiumDecember 2011, p. 32.
143 McKenzie and Partington, Equity market risk premium, December 2011, p. 32.
144 McKenzie and Partington, Equity market risk premium, December 2011, p. 32.
145 McKenzie and Partington, Equity market risk premium, December 2011, pp. 32–33.
146 McKenzie and Partington, Equity market risk premium, December 2011, p. 33.
147 SFG, Issues affecting the estimation of MRP, Report for Envestra, 21 March 2011, pp. 9–10; SFG, Market risk premium, Report for APT Petroleum Pipelines Ltd, 11 October 2011, pp. 9-11, 23–25; and SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, pp. 7–9, 28–29.

Figure A.1 Implied volatility data and SFG report dates



Source: SFG, Issues affecting the estimation of MRP, Report for Envestra, 21 March 2011, pp. 9–10; SFG, Market risk premium, Report for APT Petroleum Pipelines Ltd, 11 October 2011, pp. 9-11; SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, pp. 7–9; Underlying data file provided by SFG; AER analysis.

Notes: The March 2011 SFG report includes a sudden uptick ('spike') in implied volatility (to around 24.5) just before the reported data ends (15 March). This spike has been removed by SFG in its subsequent reports, and does not exist in current data downloaded from Bloomberg.

There is necessarily a short practical delay between the observation of data and the completion of a report. The first report, dated March 2011, included data up until 15 March 2011.[148] The second report, dated October 2011, included data up until 23 September 2011. The most recent report, dated 20 February 2012, does not update the implied volatility series, but only repeats the data from the preceding report (ending 23 September 2011).

Hence, the latest report by SFG breaks the pattern of updating the implied volatility analysis to include the latest available data. Given the evident variability in this measure, use of data that was five months old would appear to be a concern. SFG has previously stated that the latest available data should always be used to estimate parameters.[149]

The omission of updated data is even more puzzling in the context of the two other financial market indicators presented by SFG: dividend yields and relative debt spreads. In both cases, the March 2011 report included data up to February 2011, and the October 2011 report included data updated to

[148] This date was inferred from a graph and so may be out by one or two days.

[149] SFG, The required return on equity commensurate with prevailing conditions in the market for funds, Response to draft decision, Report prepared for Envestra, 23 March 2011, p. 3 (see also p. 12).

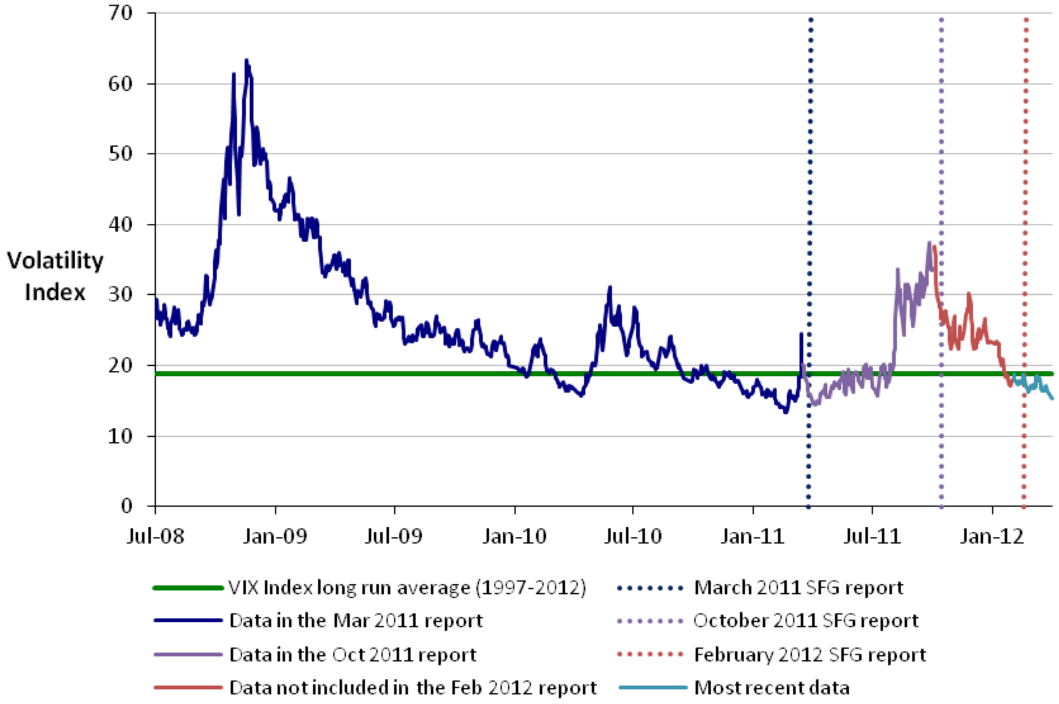
September 2011.[150] However, the February 2012 report updated both the dividend yield data and the relative debt spread data to 31 January 2012.[151] This updated data was presented alongside the out-of-date implied volatility data.[152]

All the SFG reports included a declaration that they adhered to the Federal Court Guidelines for Expert Witnesses:[153]

> In preparing this report, I have made all the enquiries that I believe are desirable and appropriate and no matters of significance that I regard as relevant have, to my knowledge, been withheld from the Court.

Figure A.2 highlights the implied volatility data series that was not submitted by SFG in its February 2012 report.

Figure A.2 Implied volatility series showing data omitted by SFG



Source: As per previous figure; Bloomberg; AER analysis.
Notes: As per previous figure, this graph shows an implied volatility spike in mid March 2011 that was later removed by SFG.

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[150] SFG, Issues affecting the estimation of MRP, Report for Envestra, 21 March 2011, pp. 11–12; and SFG, Market risk premium, Report for APT Petroleum Pipelines Ltd, 11 October 2011, pp. 11–14, 23–25.

[151] SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, pp. 10–13, 28–29.

[152] SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, pp. 28–29.

[153] SFG, Issues affecting the estimation of MRP, Report for Envestra, 21 March 2011, p. 19; SFG, Market risk premium, Report for APT Petroleum Pipelines Ltd, 11 October 2011, p. 3; SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, p. 2.

The AER considers that this was a significant omission from the February 2012 report. SFG's conditional MRP estimate relied upon three financial market indicators. One of those, implied volatility, was reported by SFG as being very high relative to its long run average (2.17 standard deviations above the mean).[154] In fact, this indicator was slightly below its long run average.

A final point concerns the choice of baseline averaging period. The conditional MRP assessment relies upon the comparison of the current values for each conditioning variable against their 'baseline' value—usually defined as the long run average. Hence, the selection of a particular long run averaging period can have a material impact on the outcome of the analysis. The clear theoretical preference is for an averaging period that matches the entire estimation period for the unconditional MRP underlying the approach. Unfortunately, data limitations mean it is often not possible to have such an extensive history for these conditioning variables, in which case the longest possible period should be selected.

In the February 2012 report, SFG selects the period post 2000 as its long run averaging period. No justification is provided for starting the average at this point. The available data goes back to 1997, and including the longer period would raise the baseline average. In turn, this would decrease the conditional MRP estimate in all scenarios.

A.2.7 Dividend yields

In the context of a conditional MRP estimate, dividend yield refers to the forecast dividends (or other distributions) for all shares in a broad based market index divided by the current price of all shares in that index. The dividend forecasts are generally aggregated by a data provider from reports by different equity analysts, with the forecast horizon generally one year. Hence, the dividend yield is a simple indicator of the expected return to equity holders through dividends (though with no allowance for capital gains/losses or imputation credits) over the next year. The consideration of dividend yields as a direct MRP indicator should be distinguished from the use of dividend growth models (though the two are closely related).[155]

SFG stated that higher dividend yields indicate a higher market risk premium.[156] This claim was based on several academic studies that found a statistically significant relationship when using dividend yields to predict equity market returns.[157] The intuitive explanation was that when dividend yields were high, a given set of cash flows was being discounted at a higher rate, indicating a higher MRP. SFG estimated that at 31 January 2012, the dividend yield for the Australian share market was 4.69 per cent, elevated above the normal level (1.02 standard deviations above the mean) supporting an MRP of 7 per cent.[158]

The primary reason why the AER does not use the dividend yield approach to inform its MRP estimate is that there is insufficient evidence of a relationship between the two. The AER

[154] SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, p. 29.

[155] More specifically, the DGM includes consideration of changes in dividends beyond the immediate dividend forecast horizon.

[156] SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, p. 12.

[157] SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, p. 7.

[158] SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, p. 29.

acknowledges the three reports cited by SFG which did report this finding.[159] However, a broader consideration of the academic literature, as undertaken by McKenzie and Partington, does not indicate that this is a statistically reliable relationship.[160] The AER agrees with the conclusion of McKenzie and Partington on this matter:[161]

> SFG presents the dividend yield as a conditioning variable as though it were established fact. In contrast, in our main report we begin by excluding consideration of predictive models based on dividend yield. This is because in our view, this is still a developing area of research, rather than a well developed practical tool. We are not alone in this view as it is shared by others such as Dimson, Marsh and Staunton (2011), who are leading scholars in the area of the MRP.

The AER considers that the underlying mechanism relating dividend yields and the MRP (as presented by SFG) is not persuasive. SFG appears to overlook a number of other factors that could result in a higher observed dividend yield even where the MRP was unchanged (or lower).[162] The forecast horizon for the dividends is short (generally one year); so a reduction in expected dividends beyond this point will result in a lower price and a higher dividend yield. That is, a change in expected cashflow (not the discount rate or MRP) explains the result. This point is explained by McKenzie and Partington.[163] The dividend yield calculation takes no account of expectations concerning capital gain or loss. Hence, a change to expect relatively more of the total return from dividends instead of capital appreciation would also result in a higher dividend yield. This would occur even if the MRP was unchanged.

Finally, as with the other conditioning variables, the assessment of a higher-than-average dividend yield is predicated on an accurate assessment of exactly what the baseline figure should be. SFG calculates their long run average using data from 2000 onwards, but provides no justification for the use of this time period.[164] In this instance, the relevant data series is available back to 1973.[165] Using the longer data series would result in a higher baseline dividend yield. In turn, this would reduce the extent to which the current dividend yield was above the average and so support a lower MRP (relative to that proposed by SFG).

A.2.8 Debt yield spread

The AER has review the use of debt yield spread to inform the forward looking MRP. The argument behind this is that the difference between an index of the yield to maturity on BBB-rated bonds and a corresponding index of AAA-rated bonds proxies for credit or default risk. During recessions, this debt

159 Fama and French (1988, 1989) and Keim and Stambaugh (1986); see also Cochrane (2011) cited by McKenzie and Partington.

160 For example, papers by Stambaugh (1999); Fisher and Statman (2000); Goyal and Welch (2003); Armitage (2011), Dimson, Marsh and Staunton (2011); Jun, Gallagher and Partington (2011); and Min (2011). Papers cited in McKenzie and Partington, Equity market risk premium, December 2011, p. 4; and McKenzie and Partington, Supplementary report on the MRP, February 2012, pp. 13–14, 23–25.

161 McKenzie and Partington, Supplementary report on the MRP, February 2012, p. 23.

162 Other techniques build on the dividend yield approach in an attempt to address these shortcomings. The DGM projects dividend movements beyond the immediate dividend forecast horizon. The SFG 'market based assessment' using dividend yields combines the dividend yield with a forecast for capital gain/loss.

163 McKenzie and Partington, Supplementary report on the MRP, February 2012, pp. 12–13.

164 SFG, Market risk premium: An updated assessment and the derivation of conditional and unconditional estimates, Report for the Victorian electricity distribution businesses, 20 February 2012, p. 12.

165 That is, the data series used by SFG and provided by them to the AER commences at this point.

yield spread widens, commensurate with an increase in risk premiums generally which implies a higher risk premium for equity.[166]

The AER considers that a direct comparison of yield on debt and the MRP is problematic. This is supported by M&P's review and the reasons are as follows[167]

- M&P expects that the widening credit spreads during the GFC were substantially driven by increasing concern about the risk of default and this concern dries up the liquidity in debt markets. Thus, it was a combination of default premiums and liquidity premiums that drove up returns in debt markets.

- As a consequence of the GFC it might reasonably be expected that the default risk component of the credit spread increased. Consequently, it is expected that much of the change in debt yields during and consequent to the GFC is due to a changed assessment of default risk.

- A key element of the GFC was increasing credit risk, with a widespread perception that default risk had increased sharply. Consequently, the expected cash flow on risky debt declined, which caused the price of the debt to fall. Since the yield is calculated on the promised cash flow relative to the price, the yield on risky debt went up and the credit spread widened. This would have happened even if there was no change in the MRP, or debt betas.

- Increase in credit spreads due to increased default risk does not automatically require a shift in the MRP. It is important point to note that the MRP is an expected return and the yields on debt are a promised return. The promised return is only the same as the expected return for debt where there is no default risk. For all other debt the promised return is higher than the expected return. Because the debt yield and the MRP measure different things, effectively they are measured in different dimensions, they are not constrained to move in a similar fashion and comparisons between them can be misleading.

Similarly the AER noted CEG's view that finance theory predicts a higher DRP will be associated with a higher MRP, therefore a more than 2 per cent increase in the MRP is required.[168] As noted above, the AER considers a direct comparison of debt risk premium and equity risk premium is problematic.

The AER further noted that it is not impossible that expected return on a stock could be less than the yield on its debt contrary the claim by APTPPL's consultant SFG.[169] This is because:[170]

- An increase in default risk will show up in higher promised yields on debt and will likely also show up as a reduction in share prices as expected cash flows to equity are likely to be revised downwards. However, there need not necessarily be any change in the MRP applied to those equity cash flows.

- To make the debt yield and the MRP comparable the promised return on debt must be converted to an expected return by adjusting the promised cash flows to debt holders for the probability of default. For highly rated firms in normal times the promised and expected returns are not much different, particularly at shorter maturities. However, for lower rated debt, in bad times and for longer maturities the difference between the expected and promised cash flows can be substantial. The more so during the GFC when confidence in credit ratings was likely to have

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166 SFG, Market risk premium—Report for APT Petroleum Pipelines Ltd, 11 October 2011, p. 11.
See also CEG, A report on the cost of equity in Aurora's revised regulatory proposal, February 2012, pp.5-6.

167 See McKenzie and Partington, Supplementary report on the MRP, February 2012, pp. 21–23.

168 CEG, A report on the cost of equity in Aurora's revised regulatory proposal, February 2012, p.6.

169 SFG, Market risk premium—Report for APT Petroleum Pipelines Ltd, 11 October 2011, p. 13.

170 McKenzie and Partington, Supplementary report on the MRP, February 2012, pp. 21–23.

been somewhat shaken. Indeed, consequent to the GFC it is possible that the expected return on a stock could be less than the yield on its debt. This would be an unusual situation, but it would not be unreasonable provided that after adjusting for default risk the expected return on the debt was less than the expected return on the stock.

- For these reasons, M&P recommend and the AER accepts that given there is no well developed and reliable way to isolate and quantify the exact relationship between changes in debt yield spread and the MRP, little weight should be placed on this evidence when determining the MRP.[171]

[171] McKenzie and Partington, Equity market risk premium, December 2011, pp. 30–31; and McKenzie and Partington, Supplementary report on the MRP, February 2012, pp. 21–23.

B Negotiating framework and negotiated distribution service criteria

This appendix sets out the negotiating framework proposed by Aurora and the negotiated distribution service criteria that is to apply to Aurora in the forthcoming regulatory period.

Aurora Energy Pty Ltd

Negotiating Framework

2012-17 Regulatory Control Period

Version	Remarks	Date	Approved by
1	Initial Version for Regulatory Proposal	29 May 2011	LM
2	Revision for submission to AER, Revised Regulatory Proposal	1 December 2011	JS
3	Revision for submission to AER, Revised Regulatory Proposal	28 December 2011	LM

1 National Electricity Rules

1.1 It is a requirement of the *National Electricity Rules (Rules)* that Aurora prepare this *Negotiating Framework* to govern the procedure for negotiations between Aurora and any person (the *Service Applicant*) who wishes to receive a *negotiated distribution service*, as to the *terms and conditions of access* for the provision of the service and its negotiations with *Service Applicants* for *negotiated distribution service*.

1.2 This *Negotiating Framework* must comply with, and be consistent with:

1.2.1 the applicable requirements of Aurora's distribution determination; and

1.2.2 the minimum requirements for a Negotiating Framework as prescribed by section 6.7.5(c) of the *Rules*.

2 Negotiated Distribution Services

2.1 During Aurora's 2012-17 *regulatory control period*, Aurora anticipates that it will provide a single *negotiated distribution service*, being the New Public Lighting Technology *distribution service*.

3 Application of this Negotiating Framework

3.1 This *Negotiating Framework* applies to Aurora and a *Service Applicant* that has made an application in writing to Aurora for the provision of a *Negotiated Distribution Service*, and sets out the procedure to be followed during negotiations as to the *terms and conditions of access* for the provision of that *distribution service*.

3.2 Aurora and any *Service Applicant* who wishes to receive a *negotiated distribution service* from Aurora must comply with the requirements of this *Negotiating Framework*.

3.3 The requirements set out in this *Negotiating Framework* are in addition to any requirements or obligations contained in the *Rules* or a relevant regulatory instrument of Tasmania.

3.4 In the case of inconsistency between the *Rules* or a relevant regulatory instrument of Tasmania, and this *Negotiating Framework*, the *Rules* or the relevant regulatory instrument will prevail.

3.5 Nothing in this *Negotiated Framework* or in the *Rules* will be taken to impose an obligation on Aurora to provide any *negotiated distribution services* to the *Service Applicant* and Aurora has the sole discretion to determine if it will provide the *negotiated distribution service* to the *Service Applicant* at the conclusion of the negotiation process.

3.6 The *Service Applicant* acknowledges that Aurora is not liable for any loss or costs incurred or suffered by the *Service Applicant* (if any) as a result of Aurora not providing the *negotiated distribution service* at the conclusion of the negotiation process for such service.

4 Request for Negotiated Distribution Service

4.1 A *Service Applicant* who wishes to receive a *negotiated distribution service* from Aurora must submit a written request to Aurora.

5 Obligation to negotiate in good faith

5.1 Aurora and the *Service Applicant* must negotiate in good faith the *terms and conditions of access* to a *negotiated distribution service* sought by the *Service Applicant*.

6 Provision of Commercial Information to Service Applicant

6.1 The *Service Applicant* may request certain Commercial Information from Aurora that the *Service Applicant* reasonably requires to engage in effective negotiation with Aurora for the provision of the *negotiated distribution service*.

6.2 Subject to clause 6.4, Aurora must provide all such Commercial Information a *Service Applicant* requests pursuant to clause 6.1.

6.3 Subject to clause 6.4, Aurora will use its reasonable endeavours to provide the *Service Applicant* with information requested under clause 6.1 within 10 Business Days of that request, or within such other time period as agreed by the parties.

6.4 Aurora reserves the right to withhold information requested by the *Service Applicant* pursuant to clause 6.1 if such information is legally privileged.

6.5 Aurora shall identify and provide to the *Service Applicant* the following information, regardless of whether it has been requested by the *Service Applicant* (the Requisite Information):

6.5.1 reasonable costs and/or increase or decrease in costs of providing the *negotiated distribution service*;

6.5.2 a demonstration of how the charges for providing the *negotiated distribution service* reflect those costs and/or the cost increment or decrement; and

6.5.3 an appropriate arrangement for assessment and review of the charges and the basis on which they are made.

6.6 Aurora agrees to provide the Requisite Information to the *Service Applicant* within a timeframe agreed by the parties, but in any case prior to or in conjunction with the provision of the *negotiated distribution service* offer.

7 Provision of Commercial Information to Aurora

7.1 Aurora may request the *Service Applicant* to provide Aurora with Commercial Information held by the *service applicant* that Aurora reasonably requires to enable it to engage in effective negotiation with that applicant for the provision of the *negotiated distribution service*.

7.2 The *Service Applicant* must provide to provide Aurora with the Commercial Information requested under clause 7.1 of this *Negotiating Framework* within 10 Business Days of that request, or within such other time period as agreed by the parties.

7.3 Aurora may request the *Service Applicant* to provide Aurora with any additional information, or to clarify any information, provided to Aurora pursuant to clauses 7.1 and 7.5, that it reasonably requires to enable it to engage in effective negotiation with that applicant for the provision of the *negotiated distribution service*.

7.4 The *Service Applicant* must use its reasonable endeavours to provide Aurora the information requested by Aurora under clause 7.3 within 10 Business Days of the date of the request, or within such other period as agreed by the parties.

7.5 The *Service Applicant* must use its reasonable endeavours to provide the following information to Aurora within 10 Business Days of the written request (Step 1 of Table 1 in clause 9) being submitted to Aurora, regardless of whether it is requested by Aurora under clause 7.1:

7.5.1 technical information such as life cycle analysis, maintenance requirements, performance criteria, electrical specifications, or any other information relevant to the application for a *negotiated distribution service*;

7.5.2 financial information such as technology costs, maintenance costs, or any other information relevant to the application for a *negotiated distribution service*;

7.5.3 details of the compliance of the *Service Applicant's* application with any law, the *Rules*, or applicable guidelines; and

7.5.4 details of the compliance of the *Service Applicant's* application with AS/NZ 3000:2007, or AS1158 or any other applicable standard.

8 Confidentiality

8.1 A party disclosing information pursuant to clause 6 or 7 may be required by the party receiving such information to enter into a confidentiality agreement on terms reasonably acceptable to both parties, before the disclosure of the Confidential Information to that person.

8.2 Notwithstanding clause 8.1, a party in receipt of Confidential Information under this *Negotiating Framework* (the Disclosing Party) shall:

(a) keep confidential the Confidential Information of the Disclosing Party;

(b) take all reasonable steps to protect the confidentiality and security of the Confidential Information of the Disclosing Party;

(c) without limiting the preceding paragraph, comply with the Disclosing Party's instructions regarding security of its Confidential Information;

(d) not, directly or indirectly, divulge, use, disclose or publish the Confidential Information of the Disclosing Party to any person;

(e) not make or allow to be made copies of, or extracts of, any part of the Confidential Information, except for the purpose of negotiating the *terms and conditions of access* to a *negotiated distribution service* sought by the *Service Applicant.*

8.3 Nothing in clause 8.2 restricts the disclosure of such information to the extent required by law.

8.4 Each party is liable for and indemnifies the other in respect of any claim, action, damage, loss, liability, cost, expenses or payment which the Disclosing Party suffers or incurs or is liable for as a result of a breach of this clause 8.

9 Process and timeframe for progressing negotiations

9.1 The target timeframe for commencing, progressing and finalising negotiations for the supply of a *negotiated distribution service* is set out in Table 1 (Target Timeframes) of this clause 9.

Table 1: Target Timeframes

	Event	Target Timeframe
1	*Service Applicant* makes written request to Aurora.	N/A
2	*Service Applicant* provides to Aurora the Commercial Information set out in clause 7.5.	No more than 10 Business Days after written request.
3	Aurora and the *Service Applicant* meet to discuss: • technical matters and the level of any technical evaluation required by Aurora; and • a preliminary project plan setting out a reasonable period of time for technical evaluation, including pilot studies, and the commencement, progression and finalisation of negotiations.	No more than 20 Business Days after written request.
4	Aurora and the *Service Applicant* finalise the preliminary project plan for commencing, progressing and finalising negotiations. The program may include, but is not limited to, milestones relating to: • the technical evaluation required by Aurora pursuant to step 3 of this Table 1; • the provision of information by Aurora pursuant to clause 6; • the provision of information by the *Service Applicant* pursuant to clause 7; • the notification and consultation with any affected *Distribution Network Users* in accordance with clause 13; and/or • the notification by Aurora of the reasonable direct expenses incurred in processing the application to provide the *negotiated distribution service* pursuant to clause 12.1.	No more than 30 Business Days after written request.
5	Aurora and the *Service Applicant* commence negotiations.	In accordance with negotiated timeframes.

6	Aurora provides to *Service Applicant* the Commercial Information set out in clause 6 of this *Negotiating Framework*.	In accordance with negotiated timeframes.
7	Aurora completes its assessment of the Commercial Information, technical evaluations, and/or other relevant information.	In accordance with negotiated timeframes.
8	Aurora provides to *Service Applicant* the information set out in clause 6.5 of this *Negotiating Framework* in accordance with clause 6.6 of this *Negotiating Framework*.	In accordance with negotiated timeframes, but not subsequent to step 9 of this Table 1.
9	Aurora provides the *Service Applicant* with an offer to provide the *negotiated distribution service*.	In accordance with negotiated timeframes.
10	Aurora and the *Service Applicant* finalise negotiations.	In accordance with negotiated timeframes.

9.2 Aurora and the *Service Applicant* must use reasonable endeavours to meet the timeframes set out in this clause 9, subject to the *Service Applicant* providing the required information to Aurora pursuant to clause 7.5.

9.3 The timeframe set out in Table 1 of this *Negotiating Framework* may be varied by agreement between Aurora and the *Service Applicant*, and any such agreement must not be unreasonably withheld or delayed.

9.4 Any project plan finalised in accordance with step 4 of Table 1 of this clause 9 may be modified from time to time by further agreement between Aurora and the *Service Applicant*, where such agreement must not be unreasonably withheld or delayed.

9.5 Aurora may request that the *Service Applicant* obtain technical and financial evaluation of any equipment associated with the *negotiated distribution service* that is proposed by the *Service Applicant*, and that the *Service Applicant* must provide this within the timeframes specified in Table 1.

9.6 Commencement of negotiations with a *Service Applicant* for the provision of the *negotiated distribution service* may be subject to the successful outcome of technical and financial evaluation pursuant to clause 9.5 of this *Negotiating Framework*.

10 Suspension timeframe for negotiation

10.1 The timeframes for negotiation of the provision of a *negotiated distribution service* set out in Table 1 of clause 9 are suspended if:

10.1.1 a dispute in relation to the *negotiated distribution service* is notified to the *AER* under Part 10 of the *National Electricity Law* (*NEL*), from the date of the notification of that dispute to the *AER* until:

(a) the withdrawal of the dispute under section 126 of the *NEL*;

(b) the termination of the dispute by the *AER* under section 131 or section 132 of the *NEL*; or

(c) a determination is made in respect of the dispute by the *AER* in accordance with section 128 of the *NEL*.

10.1.2 after 15 Business Days of Aurora requesting additional information under clause 7.3 of this *Negotiating Framework*, or, where an alternative timeframe for the provision of the Commercial Information has been agreed pursuant to clause 7.4 of this *Negotiating Framework*, after 5 Business Days after the date agreed for the provision of the requested information, the *Service Applicant* has not provided such information;

10.1.3 the *Service Applicant* fails to pay the reasonable direct expenses incurred in processing the application to provide the *Negotiated Distribution Service* in accordance with clause 12.3 of this *Negotiating Framework*, from the next business day after the amount is due until such time as the *Service Applicant* has paid the outstanding amount;

10.1.4 where Aurora has been required to notify and consult with any affected *Distribution Network Users* in accordance with clause 13.2 of this Negotiating Framework, from the date of the notification to the affected *Distribution Network User* until the end of the time limit specified by Aurora for any affected *Distribution Network Users* to provide to Aurora information regarding the impact of the provision of the *Negotiated Distribution Service*, or the date on which Aurora receives such information from the affected *Distribution Network Users*, whichever is the later; or

10.1.5 Where Aurora has been required to notify and consult with the Australian Energy Market Operator (AEMO), regarding the provision of the *negotiated distribution service*, from the date of the notification to AEMO until the date on which Aurora receives such information from the affected AEMO.

10.2 Each party will notify the other party if it considers that the timeframe has been suspended, within 5 Business Days of the date that the party considers the suspension took effect.

11 Dispute resolution

11.1 All disputes with respect to the *terms and conditions of access* for the provision of *negotiated distribution services* are to be dealt with in accordance with the relevant provisions of Part 10 of the *NEL* and Part L of Chapter 6 of the *Rules* for dispute resolution.

12 Payment arrangements

12.1 The *Service Applicant* may be required to pay Aurora's reasonable direct expenses which are incurred in processing the application to provide the *negotiated distribution service*.

12.2 From time to time, Aurora may give the *Service Applicant* a notice and tax invoice setting out the reasonable direct expenses incurred in processing the application to provide the *negotiated distribution service*.

12.3 The *Service Applicant* must, within 10 Business Days of the notice and tax invoice given pursuant to clause 12.2 of this *Negotiating Framework*, pay to Aurora the amount set out in the notice in the manner set out in the notice.

13 Impact on other Distribution Network Users

13.1 Aurora must determine the potential impact on other *Distribution Network Users* of the provision of the *negotiated distribution service*.

13.2 Aurora must notify and consult with any affected *Distribution Network Users* and ensure that the provision of *negotiated distribution service* does not result in non-compliance with obligations in relation to other *Distribution Network Users* under the *Rules* and the Tasmanian Electricity Code (TEC).

13.3 If Aurora is required to consult the affected *Distribution Network Users* pursuant to clause 13.2, the timeframes provided for in clause 9 shall be suspended until the information required to assess the impact is received from the affected *Distribution Network User*.

14 Results of negotiations

14.1 Aurora must publish the results of negotiations for access to a *negotiated distribution service* on its website.

15 Interpretation and Definitions

15.1 Words and expressions in *italics* have the same meaning as they do in the *NEL* and the *Rules*, unless context requires otherwise.

15.2 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.

15.3 The following definitions apply in this *Negotiating Framework*:

Aurora means Aurora Energy Pty Ltd.

AEMO means Australian Energy Market Operator

AER means the Australian Energy Regulator, as defined by the *Rules*.

Business Day means a day other than a Saturday or Sunday or a public holiday observed in the city of Hobart.

Commercial Information does not include Confidential Information provided to either party by another person, and will include at a minimum, the following classes of information in relation to a *Service Applicant*, where applicable:

(a) details of corporate structure, financial details relevant to creditworthiness and commercial risk and ownership of assets;

(b) technical information relevant to the application for a *negotiated distribution service*;

(c) financial information relevant to the application for a *negotiated distribution service*; and

(d) details of an application's compliance with any law, standard, *Rules* or guideline.

Confidential Information means information held by either party that is, by its nature confidential, is marked confidential or the receiving party knows or ought to know is confidential, and specifically includes:

(a) information relating to or about the business affairs and operations of Aurora;

(b) Commercial Information and Requisite Information provided by Aurora to *Service Applicant* pursuant to clauses 6.1 and 6.4 (respectively);

(c) information provided to Aurora by the *Service Applicant* pursuant to clause 7; and

(d) trade secrets, information, ideas, concepts, know-how, technology, processes and knowledge and the like provided, to or obtained by, a party by the other party (including but not limited to in relation to a party, all information reports, accounts or data in relation to that party's business affairs, finances, properties and methods of operations, regardless of the form in which it is recorded or communicated).

Disclosing Party has the meaning provided in clause 8.2.

Distribution Network User means a *Distribution Customer* or an *Embedded Generator* as defined by the *Rules*.

NEL means the National Electricity (Tasmania) Law pursuant to *Electricity – National Scheme (Tasmania) Act 1999*.

negotiated distribution service means a *distribution service* that is not a *standard control service* and that is specified as that service by the *Rules* or the *AER*.

New Public Lighting Technology means a *distribution service* relating to the provision of public lighting services by Aurora for the purpose of testing and piloting new public lighting technologies.

regulatory control period means a period of not less than 5 regulatory years for which the provider is subject to a control mechanism imposed by a distribution determination, as defined by the *Rules*.

Requisite Information has the meaning provided in clause 6.4.

Rules mean the National Electricity *Rules* made under Part 7 of the NEL as amended from time to time in accordance with that Part 7.

Service Applicant means a person who asks Aurora for access to a distribution service, as defined by the *Rules*.

***TEC** means the Tasmanian Electricity Code.*

terms and conditions of access means the terms and conditions described in clause 6.1.3 of the *Rules*, as defined by the *Rules*.

B.1 Negotiated Distribution Service Criteria

B.1.1 National Electricity Objective

1. The terms and conditions of access for a negotiated distribution service, including the price that is to be charged for the provision of that service and any access charges, should promote the achievement of the national electricity objective.

B.1.2 Criteria for terms and conditions of access

Terms and Conditions of Access

2. The terms and conditions of access for a negotiated distribution service 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 negotiated distribution service (including in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between a distribution network service provider (DNSP) and any other party, the price for the negotiated distribution service and the costs to a DNSP of providing the negotiated distribution service.

4. The terms and conditions of access for a negotiated distribution service must take into account the need for the 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 negotiated distribution service must reflect the costs that a DNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the relevant Cost Allocation Method.

6. Subject to criteria 7 & 8, the price for a negotiated distribution service must be at least equal to the cost that would be avoided by not providing that service but no more than the cost of providing it on a stand-alone basis.

7. If a negotiated distribution service is 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,

    iii. then the difference between the price for that service and the price for the shared distribution service which meets network performance requirements must reflect a DNSP's incremental cost of providing that service (as appropriate).

8. If a negotiated distribution service 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 a DNSP would avoid by not providing that service (as appropriate).

9. The price for a negotiated distribution service must be the same for all Distribution Network Users unless there is a material difference in the costs of providing the negotiated distribution service to different Distribution Network Users or classes of Distribution Network Users.

10. The price for a negotiated distribution service must be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person, in which case such adjustment must reflect the extent to which the costs of that asset are being recovered through charges to that other person.

11. The price for a negotiated distribution service must be such as to enable a DNSP to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiated service.

B.1.3 Criteria for access charges

Access Charges

12. Any charges must be based on costs reasonably incurred by a DNSP in providing distribution network user access, and, in the case of compensation referred to in clauses 5.5(f)(4)(ii) and (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).

13. Any charges must be based on costs reasonably incurred by a DNSP in providing transmission network user access to services deemed to be negotiated distribution services by clause 6.24.2(c) of the NER, and, in the case of compensation referred to in clauses 5.4A(h) to (j) 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).

C Assigning customers to tariff classes

The AER is required to decide on the principles governing assignment or reassignment of customers to tariff classes.[172] Aurora proposes to assign customers into one of four classes of network users, namely:

- individually calculated customers
- greater than 2MVA customers
- standard customers
- embedded generators.

Aurora proposed to assign customers into these classes in accordance with the requirements of the NER by:[173]

- taking account the nature of the customers connection, their forecast usage and size
- assigning customers with remote read interval meters to differing charges in accordance with Aurora's metering fees
- treating customers with the same connections and usage profiles on a consistent basis.

The AER sets out below the principles Aurora is to adhere to in assigning customers to tariff classes.

Procedures for assigning or reassigning customers to tariff classes

The procedures outlined in this appendix apply to all direct control services.

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

1. Aurora's customers will be taken to be “assigned” to the tariff class which Aurora was charging that customer immediately prior to 1 July 2012 if:

- they were an Aurora customer prior to 1 July 2012
- continue to be a customer of Aurora as at 1 July 2012.

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

2. If, after 1 July 2012, Aurora becomes aware that a person will become a customer of Aurora, then Aurora 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 paragraphs 2 or 5 of this appendix, Aurora must take into account one or more of the following factors:[174]

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172 NER, Clause 6.12.1(17).

173 Aurora, *Regulatory proposal,* May 2011, p. 230.

a. the nature and extent of the customer's usage

b. the nature of the customer's connection to the network[175]

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 of paragraph 3 above, Aurora, when assigning or reassigning a customer to a tariff class, must ensure:

   a. customers with similar connection and usage profiles are treated equally[176]

   b. customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.[177]

Reassignment of existing customers to another existing or a new tariff during the next regulatory control period

5. Aurora may reassign a customer to another tariff class if the existing customer's load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned or a customer no longer has the same or materially similar load or connection characteristics as other customers on the customer's existing tariff class, then it may reassign that customer to another tariff class. In determining the tariff class to which a customer will be reassigned, Aurora must take into account paragraphs 3 and 4 above.

Objections to proposed assignments and reassignments

6. Aurora must notify a customer in writing of the tariff class to which the customer has been assigned or reassigned, prior to the assignment or reassignment occurring.

7. A notice under paragraph 6 above must include advice informing the customer that they may request further information from Aurora and that the customer may object to the proposed reassignment. This notice must specifically include:

   a. either a copy of Aurora's internal procedures for reviewing objections or the link to where such information is available on the Aurora's website

   b. that if the objection is not resolved to the satisfaction of the customer under Aurora's internal review system, then to the extent resolution of such disputes are within the jurisdiction of the Energy Ombudsman Tasmania the customer is entitled to escalate the matter to such a body

   c. that if the objection is not resolved to the satisfaction of the customer under the Aurora's internal review system and the body noted in clause 7.b. above, then the customer is entitled to seek a decision of the AER via the dispute resolution process available under Part 10 of the NEL.

8. If, in response to a notice issued in accordance with paragraph 7 above, Aurora receives a request for further information from a customer, then it must provide such information. If any of the information requested by the customer is confidential then it is not required to provide that information to the customer.

9. If, in response to a notice issued in accordance with paragraph 7 above, a customer makes an objection to Aurora about the proposed assignment or reassignment, Aurora must reconsider the

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174 NER, Clause 6.18.4(a)(i).

175 The AER interprets 'nature' to include the installation of any technology capable of supporting time based tariffs.

176 NER, Clause 6.18.4(2).

177 NER, Clause 6.18.4(3).

proposed assignment or reassignment. In doing so Aurora must take into consideration the factors in paragraphs 3 and 4 above, and notify the customer in writing of its decision and the reasons for that decision.

10. If a customer's objection to a tariff class assignment or reassignment is upheld by the relevant body noted in paragraph 7 b and c above, then any adjustment which needs to be made to tariffs will be done by Aurora as part of the next annual review of prices.

11. If a customer objects to Aurora's tariff class assignment Aurora must provide the information set out in paragraph 7 above and adopt and comply with the arrangements set out in paragraphs 8, 9 and 10 above in respect of requests for further information by the customer and resolution of the objection.

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

12. Where the charging parameters for a particular tariff result in a basis of charge varies according to the customer's usage or load profile, Aurora must set out in its annual pricing proposal a method by which it will review and assess the basis on which a customer is charged.

13. If the AER considers the method provided under paragraph 12 above does not provide for an appropriate system of assessment and review by Aurora of the basis on which a customer is charged, the AER may, at any time, request additional information or request Aurora to submit a revised pricing method.

14. If the AER considers Aurora's method for reviewing and assessing the basis on which a customer is charged, provided in accordance with paragraph 12 and 13 above, is not reasonable it will advise Aurora in writing.