Draft Distribution Determination

Aurora Energy Pty Ltd

2012–13 to 2016–17

November 2011

Submissions

This document sets out the Australian Energy Regulator's (AER) draft distribution determination for Aurora Energy Pty Ltd (Aurora) for the regulatory control period 1 July 2012 to 30 June 2017.

The AER will hold a pre-determination conference on its draft distribution determination on Tuesday, 13 December 2011 at the Grand Chancellor Hotel in Hobart to explain its reasons and receive oral submissions from interested parties. Interested parties can register to attend the pre-determination conference by calling the AER's Network Regulation branch on (02) 6243 1233, or by emailing AERInquiry@aer.gov.au by 5 December 2011.

The AER invites interested parties to make a written submission on this draft determination and the consultants' reports to the AER by the closing date 20 February 2012. The AER will deal with all information it receives in the distribution determination process, including submissions on the draft determination, in accordance with the Australian Competition and Consumer Commission (ACCC) / AER information policy (available at www.aer.gov.au).

Submissions can be sent electronically to AERInquiry@aer.gov.au, or mailed to:

Mr Warwick Anderson
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GPO Box 3131
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The AER prefers all submissions to be publicly available to facilitate an informed and transparent consultative process. The AER will treat submissions as public documents unless otherwise requested. Parties wishing to submit confidential information must:

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

The AER will publish all non-confidential submissions on its website (www.aer.gov.au). Also available on the AER's website are a copy of Aurora's regulatory proposal and supporting information, consultancy reports and submissions from interested parties.

Please direct enquiries about the AER's draft distribution determination, or about lodging submissions, to the Network Regulation branch on (02) 6243 1233, or by email to AERInquiry@aer.gov.au.

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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
SORI	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 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 draft distribution determination for Aurora, which is predicated on several constituent decisions. [3] The AER must also provide reasons for its draft determination, including the basis and rationale of the determination.[4] The AER has changed the format in which it presents its draft determination, so that it is more concise. The AER's draft 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 appendixes, collectively called 'Draft Distribution Determination') sets out the reasons for the draft 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.

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

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 6.10.1 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 draft determination and reasons for the determination under clauses 6.10.1 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.

applied for the period 1 July 2008 to 30 June. The AER's determination will take effect from 1 July 2012.

In making this draft distribution determination, the AER has reviewed Aurora's 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-determination 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 proposal—Aurora submitted its regulatory proposal and proposed negotiating framework to the AER on 31 May 2011.

- 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 three submissions on Aurora's regulatory proposal, which it has considered as part of this draft decision.

- 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 its submission on Aurora's regulatory proposal, one stakeholder requested that the AER investigate how the AER's current review of the Chapter 6 and Chapter 6A regulatory framework would impact its draft distribution determination for Aurora.[11] The AER has not undertaken this task because the AER is required to administer the NER as it currently stands.

Another stakeholder 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 considers that Tasmanian electricity customers are burdened both in a financial sense and in poor service delivery relative to elsewhere in Australia.[12] Although the AER acknowledges this concern, the business boundary between Transend and Aurora is beyond the scope of the AER's review of Aurora's regulatory proposal.[13]

11 Energy Users Association of Australia, *Submission to the Australian Energy Regulator on Aurora Energy's Regulatory Proposal on Distribution Prices for 2012–2017*, August 2011, pp. 4–6.

12 Mr David Asten, *Submission to the Australian Energy Regulator*, 12 August 2011.

13 This point is acknowledged by Mr Asten.

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.[14]

The AER's draft determination and indicative price impacts

Aurora proposed total revenue for the regulatory control period 1 July 2012 to 30 June 2017 of $1,571.6 million ($nominal). Aurora's proposal is for a real increase in revenue (from its current allowance) of 13.37 per cent in 2012–13, and real decreases of 0.13 per cent for each subsequent year.

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 regulatory proposal as being consistent with the requirements of the NER. However, the AER does not accept all elements of Aurora's regulatory proposal. The AER's draft determination is for total (smoothed) expected revenues of $1,305.4 million ($nominal) for the forthcoming regulatory control period. The AER's allowance is 17 per cent below Aurora's proposal.

The AER estimates its draft determination will result in distribution prices falling by 0.2 per cent per annum (on average) over the forthcoming regulatory control period. The AER's draft determination should, on average, result in no increase in typical residential bills.

Drivers of the difference between Aurora's proposal and the AER's view

The main drivers of the difference between the AER's draft determination and Aurora's regulatory proposal are the weighted average cost of capital (WACC), capital expenditure (capex) and operating expenditure (opex).

WACC

The WACC is the most significant driver of the AER's lower revenue allowance. In particular, a change in market conditions since Aurora submitted its regulatory proposal means the AER's nominal risk free rate is lower than Aurora's. The AER also considers Aurora's proposed market risk premium and debt risk premium values are too high. If the AER was to accept Aurora's values for these three

[14] NEL, section 7.

WACC parameters the draft determination would have resulted in total revenue increasing by a further $191.6 million ($nominal) over the forthcoming regulatory control period.[15]

Operating expenditure

The AER considers Aurora's proposed total forecast opex is more than Aurora requires to achieve the opex objectives. The AER has substituted Aurora's total forecast opex with its own forecast. The AER considers Aurora's proposed opex forecast exceeds its requirements for recurrent opex adjusted for network growth, real cost escalation and step changes. If the AER was to accept Aurora's opex forecast the draft determination would have resulted in total revenue increasing by a further $36.5 million ($nominal) over the forthcoming regulatory control period.

Capital expenditure

The AER considers Aurora's proposed total forecast capex is more than Aurora requires to achieve the capex objectives. The AER has substituted Aurora's total forecast 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 seem to be primarily driven by opex savings and/or reliability improvements. On the evidence presented to the AER, this capex is not otherwise required to achieve the capex objectives. If the AER was to accept Aurora's capex forecast the draft determination would have resulted in total revenue increasing by a further $30.1 million ($nominal) over the forthcoming regulatory control period.

Alternative control services

Some of the services that Aurora provides are not currently regulated. These include public lighting services and some services that Aurora provides on a fixed fee or quoted basis. The AER decided to regulate these services as alternative control services in its framework and approach paper.[16] The AER has not accepted Aurora's proposed prices for alternative control services.

The AER's review of the proposed prices for alternative control services has resulted in price caps for metering services that are on average 29 per cent below, and public lighting price caps that are on average 19 per cent below those proposed by Aurora.

Outputs

Aurora is currently regulated by the Office of the Tasmanian Economic Regulator (OTTER). The AER's determination is therefore the first electricity distribution determination to apply to Aurora under the NER.

Under the NER framework, 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.

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15 The AER conducted sensitivity analysis using its draft determination inputs, but adopting Aurora's WACC parameters to demonstrate the impact of Aurora's proposed WACC parameters on the AER's revenue allowance. The AER conducted similar analysis using Aurora's capex and opex forecasts.

16 AER, *Framework and approach paper, Aurora Energy Pty Ltd, Regulatory control period commencing 1 July 2012*, 29 November 2010, pp. 84–85.

Overview

1 Revenue

Aurora lodged its revenue proposal for the regulatory control period 2012–13 to 2016–17 with the AER on 31 May 2011. Aurora proposed total (smoothed) expected revenues of $1,571.6 million ($nominal), which Table 1.1 displays.

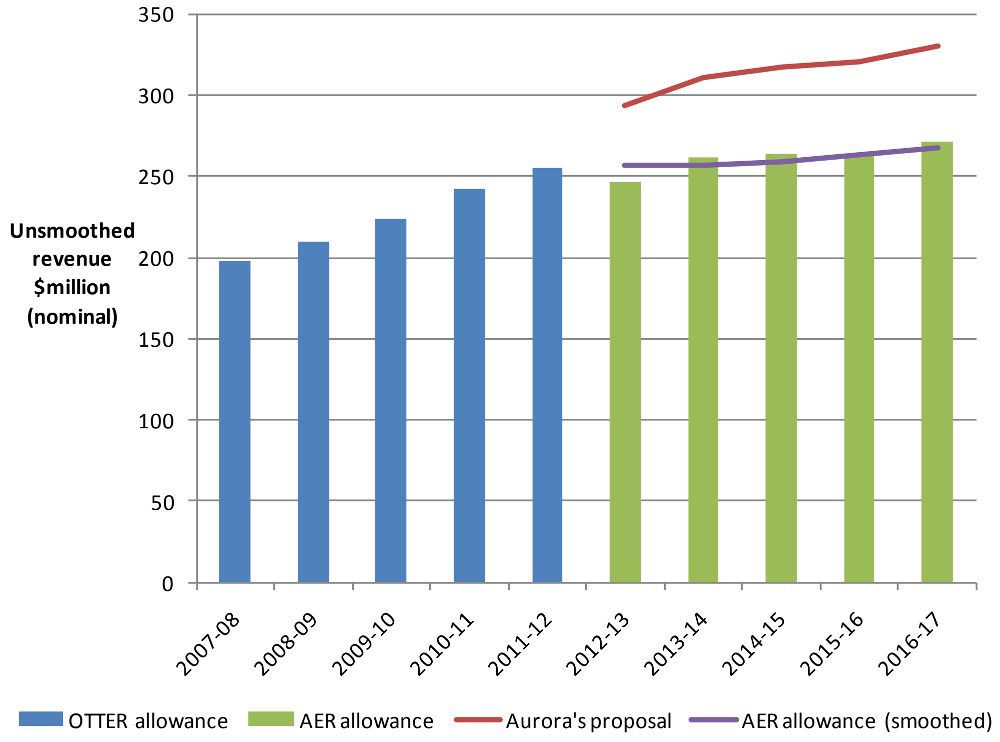
Table 1.1 Aurora's proposed revenue allowance ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Aurora's proposal	299.4	306.7	314.1	321.8	329.6	1,571.6

Source: Aurora, Regulatory proposal, Addendum, June 2011, p. 37.

The AER has accepted much of Aurora's regulatory proposal as being consistent with the requirements of the NER. However, the AER does not accept all elements of Aurora's regulatory proposal. The AER's draft determination is for total (smoothed) expected revenues of $1,305.4 million ($nominal) over the forthcoming regulatory control period. The AER's adjustment of $266.2 million ($nominal) is 17 per cent below Aurora's proposal. Figure 1.1 demonstrates the difference between Aurora's proposal and the AER's draft determination.

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



Source: AER analysis, OTTER[17], Aurora's PTRM.

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

Table 1.2 The AER's draft 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	116.3	121.0	125.6	130.5	135.5	628.9
Regulatory depreciation	46.6	52.9	49.1	42.2	42.1	232.9
Operating expenditure	66.6	68.8	71.4	74.0	76.3	357.1
Corporate income tax	16.9	18.7	17.8	17.6	17.5	88.6
Annual revenue requirement (unsmoothed)	246.4	261.5	263.9	264.2	271.4	1,307.5

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's draft determination WACC value results from a lower nominal risk free rate, a lower market risk premium (MRP), and a lower debt risk premium (DRP).

The nominal risk free rate is determined by observing market determined Commonwealth Government bond rates over an averaging period.[18] For this draft determination, the AER has used an indicative averaging period. Since Aurora proposed its indicative WACC, a change in market conditions has been reflected in the observed market data. Hence, the nominal risk free rate the AER has applied in this draft determination is lower than that set out in Aurora's proposal. The AER will update the risk free rate, based on the agreed averaging period, at the time of its final determination.

The AER considers that Aurora's proposed MRP and DRP are too high. There is persuasive evidence that the AER's statement of regulatory intent (SRI) value for MRP is inappropriate, and the AER has justified a departure from this value.[19] The AER also considers its method to calculate the DRP, based on the average of observed bond yields, appropriately incorporates relevant information from the market. This will contribute to a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and with the risk involved in providing standard control services.

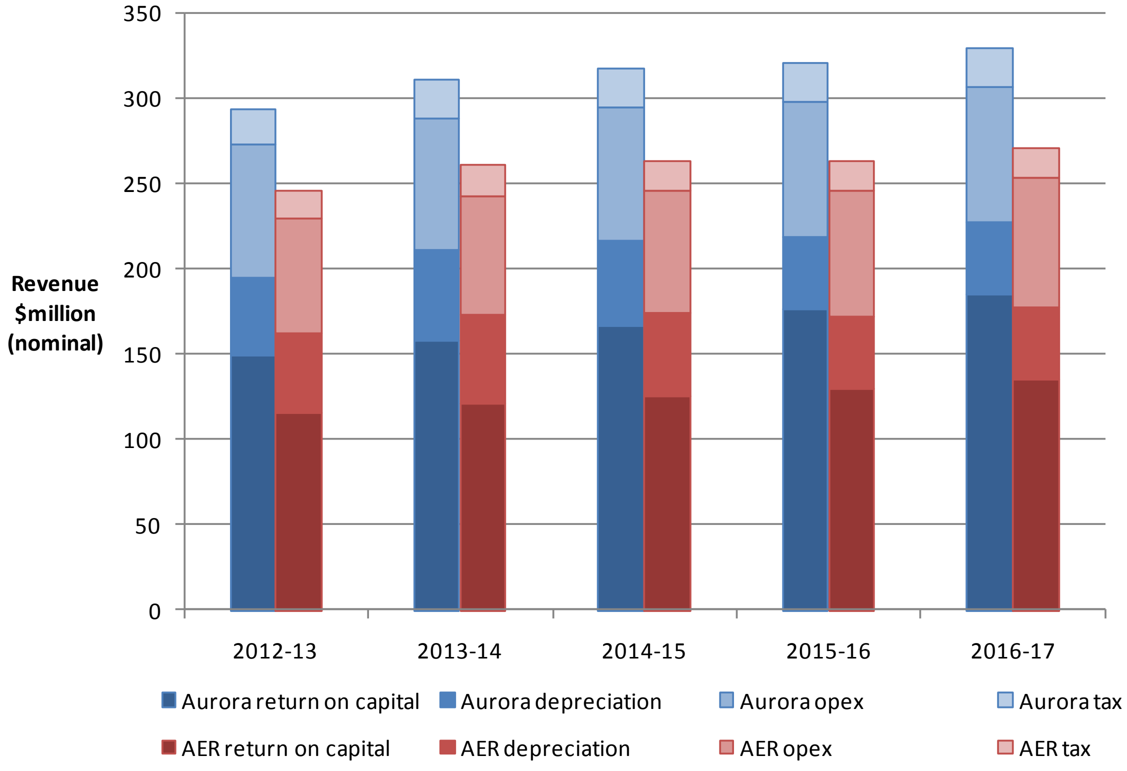
Other key adjustments the AER has made to Aurora's proposed revenue allowance include:

- reducing Aurora's total forecast capex—Aurora's capex proposal is too high given forecast demand for electricity. Aurora's capex proposal also includes projects and programs that seem to be primarily driven by opex savings and/or reliability improvements. On the evidence presented to the AER this capex is not otherwise required to achieve the capex objectives. Aurora has also proposed to replace more assets than is necessary to maintain its network.
- substituting Aurora's total forecast opex with the AER's forecast—Aurora's opex proposal is more than Aurora requires to achieve the opex objectives. The AER considers Aurora's opex forecast exceeds its requirements for recurrent opex adjusted for network growth, real cost escalation and step changes.

18 NER, clause 6.5.2(c).
19 NER, clause 6.5.4(g).

The AER also did not accept some elements of Aurora's proposed revenue cap control mechanism. 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.

Figure 1.2 The AER's draft determination adjustments to Aurora's proposed revenue allowance ($million, nominal)



Source: Aurora's PTRM, AER analysis.

The AER has conducted sensitivity analysis of these adjustments on the draft 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 draft 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)	109.4	8.4
Debt risk premium (DRP)	66.0	5.1
Market risk premium (MRP)	16.2	1.2
Rf + DRP + MRP	191.6	14.7

Source: AER analysis.

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

	Increased revenues ($million, nominal)	Increased revenues (per cent)
Opex	36.5	2.8
Capex + capital contributions	30.1	2.3

Source: AER analysis.

Table 1.5 displays the AER's total adjustments 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 revenues over the regulatory control period.

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

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Aurora's proposal (X factors)	–13.37	0.13	0.13	0.13	0.13	n/a
AER draft determination (X factors)	2.62	2.62	1.77	1.00	1.00	n/a
Aurora's proposal ($million, nominal)	299.4	306.7	314.1	321.8	329.6	1,571.6
Expected revenue (smoothed) ($million, nominal)	257.5	257.3	259.4	263.5	267.7	1,305.4

Source: Aurora's PRTM, AER analysis.

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.[20] Stakeholders raised this issue in submissions on Aurora's regulatory proposal.[21] 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.[22] 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.[23]

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 1.4 per cent.

20 See NER, clause 6.5.9(b)(2). NEL, clause 7.
21 Tasmanian Council of Social Service, *TasCOSS submission to the AER re Aurora Energy's Regulatory Proposal 2012-2017*, August 2011; EUAA, *Submission on Aurora's regulatory proposal*, August 2011, p. 22.
22 NER, clause 6.5.9 (b)(3).
23 NER, clause 6.5.9 (b)(2)

With expected demand growth of about 1 per cent per annum and a forecast inflation rate of 2.62 per cent per annum, the AER's draft determination X factors suggest that in nominal terms, distribution prices will fall by 0.2 per cent per annum (on average) over the forthcoming regulatory control period.

With distribution charges representing about 48 per cent of the retail tariffs, residential bills will fall by 0.1 per cent per annum (on average) over the forthcoming regulatory control period. 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. The impact of the AER's determination on consumers will therefore be less than proposed by Aurora.[24] Section 10 discusses price impacts in further detail.

[24] The impact of Aurora's proposal on consumers is a concern raised by stakeholders. See TASCOSS, *TasCOSS submission to the AER re Aurora Energy's Regulatory Proposal 2012-2017*, August 2011; EUAA, *Submission on Aurora's regulatory proposal*, August 2011, p. ii.

2 Aurora's outputs

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

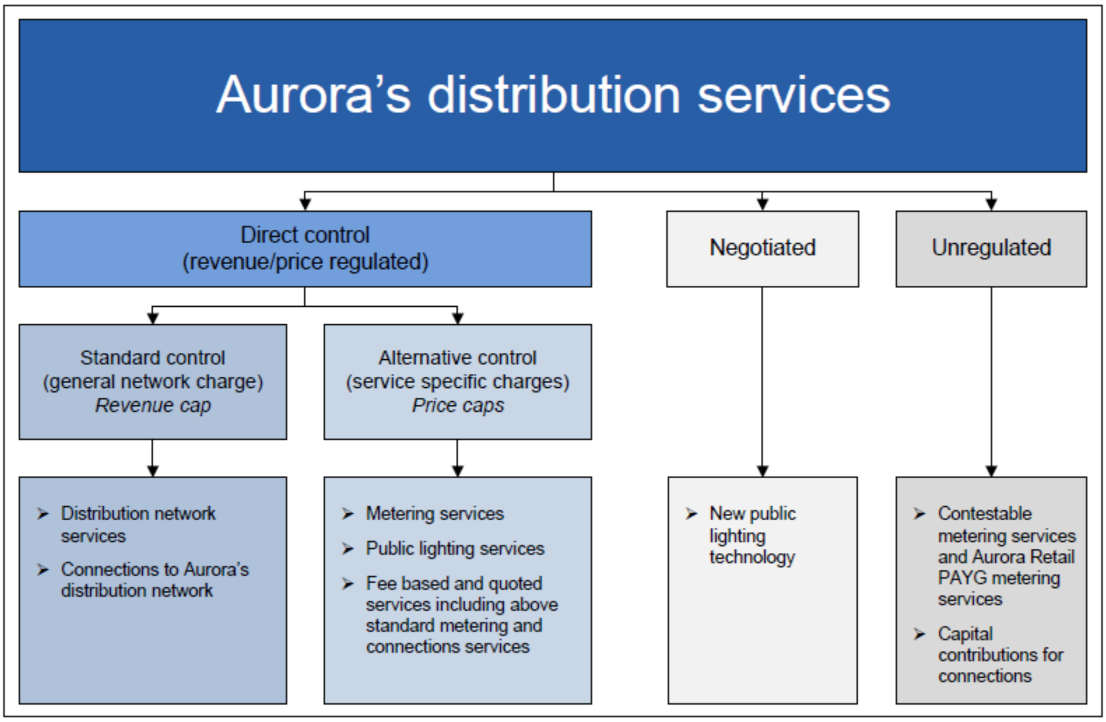
2.1 Aurora's distribution services

The AER decided the appropriate forms of regulation for the distribution services Aurora provides in its framework and approach paper.[25] 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 has set out its reasoning for service classification in more detail in Attachment 1.

Figure 2.1 Aurora's distribution services



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

The majority of the AER's draft 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

25 AER, *Framework and approach paper, Aurora Energy Pty Ltd, Regulatory control period commencing 1 July 2012*, 29 November 2010, Chapter 2 (AER, *Framework and approach paper*, November 2010).

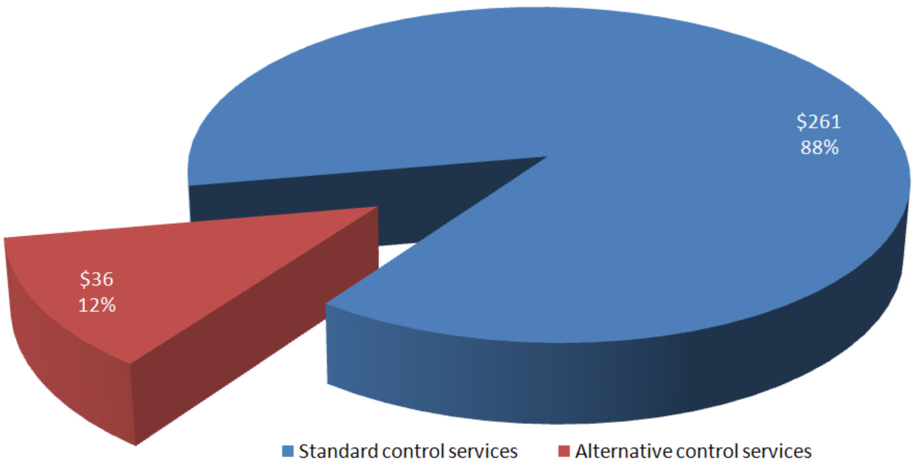
control period is limited to the amount the AER determines. The AER has not accepted Aurora's proposed revenue allowance for standard control services.

The AER has also not accepted Aurora's proposed prices for alternative control services. However, the AER considers these prices will comply with the NER with the following adjustments:

- changing the basis of the control mechanism for metering services from Aurora's proposed annuity approach to a building block approach because it better satisfies the NER. Using this approach, the AER has also made the following adjustments to Aurora's methodology and model inputs:
  - removed fully depreciated meters from the initial asset base
  - reduced the costs of meters
  - increased the regulatory life of mechanical meters from 20 to 30 years
  - reduced the proposed rate of installation of new meters
  - applied a post-tax weighted average cost of capital with Aurora's accelerated tax depreciation rate
- substituting the AER's forecast opex into Aurora's public lighting model
- making several minor adjustments to inputs to Aurora's fee based services model.

In its framework and approach paper, the AER decided to regulate alternative control services by determining caps on the prices that Aurora can charge for them.[26] The AER has set out an overview of its reasoning for alternative control services in section 11, and in more detail in Attachment 15 (and related appendixes). Figure 2.2 compares the five year average of the AER's draft determination revenue allowance for Aurora for 2012–17 for standard control services and 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.

[26] AER, *Framework and approach paper*, November 2010, pp. 84–85.

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:[27]

- 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 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.[28]

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
- new customers connect to the network
- the overall consumption of electricity increases.

Peak demand

Peak demand is a snapshot of the highest level of demand on Aurora's distribution system at a point in time. The AER considers that Aurora’s total system maximum demand forecast is too high, and has developed a substitute forecast as shown in Figure 2.3. The AER’s substitute forecast provides an annual average growth rate of 1.11 per cent from 2010 to 2017, while Aurora’s forecast provides an annual average growth rate of 1.54 per cent over the same period. The AER also considers that Aurora's proposed initial increase in maximum demand from 2010 to 2011 is too high, but that the subsequent growth rate is reasonable given historical trends and forecasts of demand drivers such as gross state product and population growth.

The AER considers that the general basis of Aurora's method of forecasting maximum demand is appropriate and consistent with current industry standard practices.[29] However, the AER disagrees with Aurora's application of this method in a number of areas:

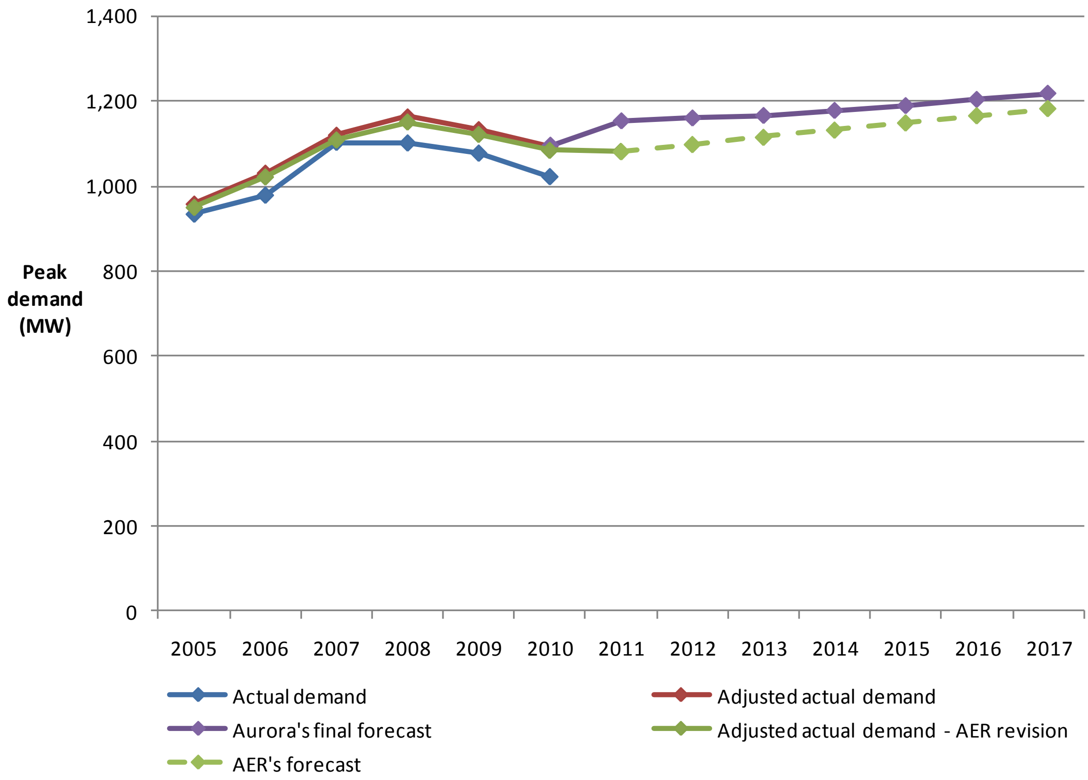
- reconciling to Transend’s state maximum demand forecast developed in early 2010. The AER considers this forecast is obsolete given recent movements in demand since it was developed

27 NER, clauses 6.5.6(a) and 6.5.7(a).
28 NER, clauses 6.5.6(c) and 6.5.7(c).
29 SKM-MMA, *Review of Aurora Energy’s maximum demand forecasting methodologies in its 2012–2017 regulatory proposal, Final report to the Australian Energy Regulator*, 26 September 2011, pp. 31-32.

- measuring the impact of temperature on maximum demand. Aurora did not account for recent trends of warmer temperatures. Aurora also used data from non-business days, which the AER considers are not relevant to measuring the impact of temperature on demand

- adjusting historical demand data (used for forecasting) to an amount inconsistent with Aurora's chosen level of risk. Aurora plans for its assets to have sufficient capacity to meet a forecast level of demand that would be exceeded one in every two years. To derive its forecasts, Aurora used historical demand data that was not adjusted to correctly reflect this level of risk

Figure 2.3 Historical and AER forecast peak demand (system level) (megawatt)



Note: Adjustments to actual demand are for weather and transient loads.
Source: AER analysis, Attachments to Aurora's regulatory proposal,[30] information provided by Aurora in response to AER request.[31]

The consequence of the AER's lower peak demand forecast is a lower capex allowance for Aurora because some of Aurora's capex requirements are driven by peak demand. However, the effect of the AER's adjustment is relatively minor, so the resultant capex reduction is modest. The AER has set out its reasoning for peak demand in more detail in Attachment 3.

New customer connections

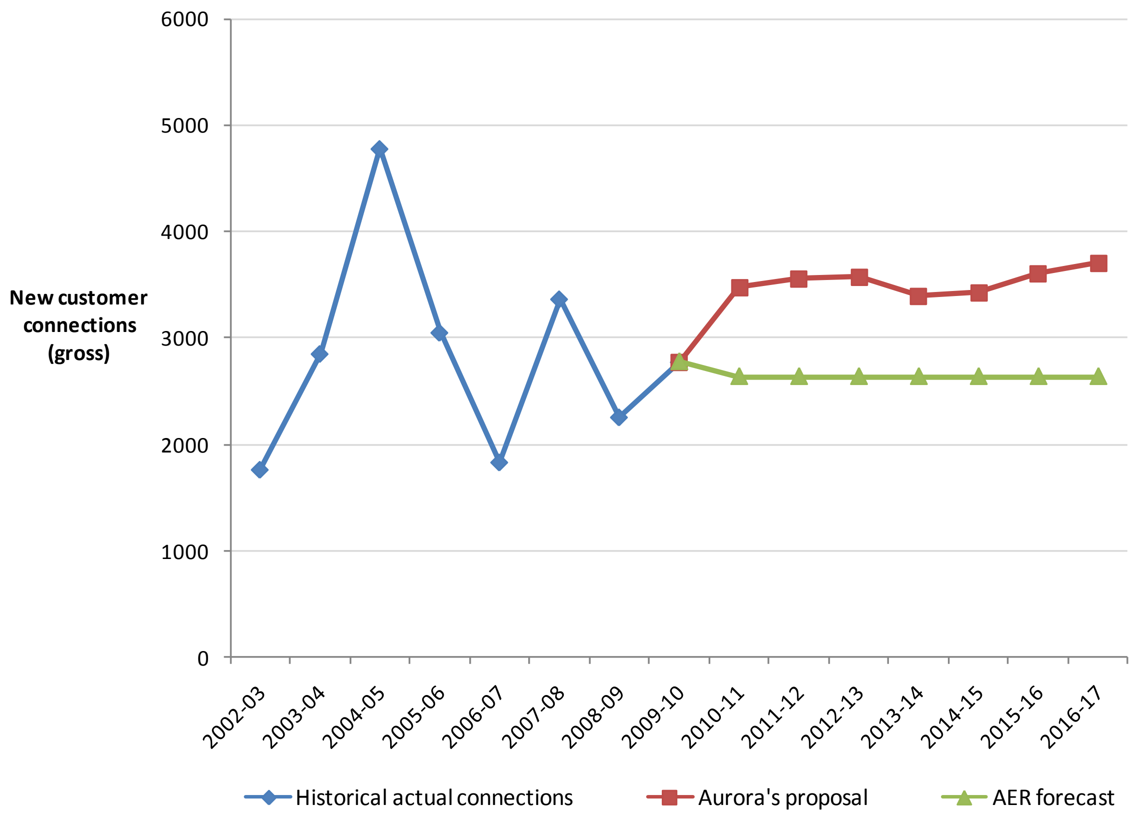
The AER considers the volume of new customers connecting to Aurora's network per annum will be lower than Aurora's forecast. The AER accepts Aurora's forecasts of net new customer connections but does not consider Aurora's forecasts of maximum demand and gross new customer connections

30 Aurora, *Regulatory Information Notice*, template 6.7.
31 Aurora, *Response to AER information request sent on the 23 June 2011: NW-#30195655-v1-Transend_NIEIR_System_forecast_2009*, sheet 2 template.

to be realistic.[32] The AER considers Aurora's forecasts for residential connections are too high when grossed up to reflect demolitions.

The AER considers new connections will increase at a moderate rate over the forthcoming regulatory control period, consistent with the subdued forecast macroeconomic environment expected to prevail in Tasmania.[33] Figure 2.4 compares the AER's forecast with Aurora's proposal. The AER has set out its reasoning for new customer connections in more detail in Attachment 3.

Figure 2.4 Historical and AER forecast gross new customer connections



Source: ACIL Tasman, *Aurora new customer connections forecasts*, *Prepared for Aurora Energy*, February 2011; AER analysis.

Electricity consumption

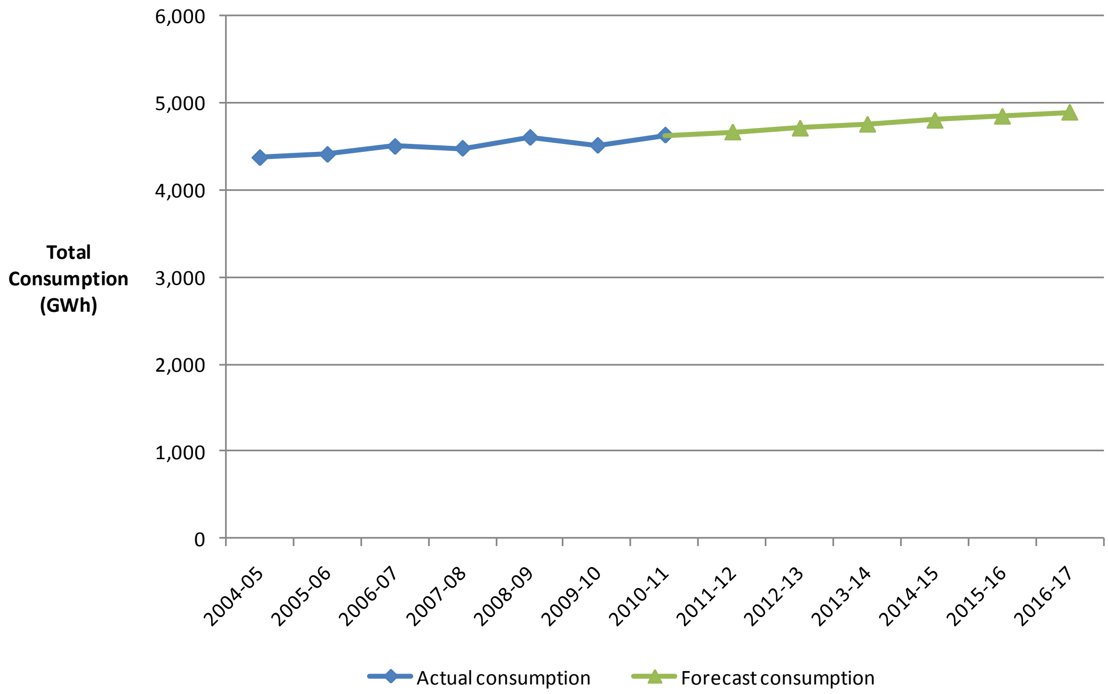
Aurora provided consumption forecasts for the forthcoming regulatory control period as part of its regulatory proposal.[34] The AER has accepted Aurora's forecast for total electricity consumption for the forthcoming period. Aurora has forecast consumption to increase moderately over the 2012–17 period, as Figure 2.5 shows. The AER has replicated Aurora's regression methodology for forecasting consumption and considers it to be robust. However, the AER does not require electricity

32 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.
33 ACIL Tasman, *Energy consumption forecasts 2010-11 to 2016-17: Energy consumption forecasts for Aurora Energy covering six customer classes*, June 2011, pp. 18-19.
34 Aurora, *Regulatory proposal,* May 2011, pp. 93–95.

consumption forecasts to determine Aurora's revenue allowance because the AER is regulating Aurora's standard control services under a revenue cap.[35]

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.[36] The AER considers Aurora's forecasts are appropriate for the purposes of illustrating indicative tariffs and pricing impacts of the AER's draft and final determinations.

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



Source: ACIL Tasman, *Energy consumption forecasts 2010-11 to 2016-17: Energy consumption forecasts for Aurora Energy covering six customer classes*, June 2011, p. 6.

Demand management incentive scheme

To assist Aurora with meeting and managing expected demand, the AER has implemented a demand management incentive scheme for the forthcoming regulatory control period.[37] 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.[38] This equates to $1.9 million over the forthcoming regulatory control period. The AER has set out its detailed reasoning for the DMIS in Attachment 13.

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 5 and 6.

[35] Revenue cap regulation means that Aurora's revenue is fixed regardless of electricity consumption levels.
[36] NER, clause 6.18.2(a).
[37] This is a constituent decision of a distribution determination under clause 6.12.1(9) of the NER.
[38] AER, *Framework and approach paper*, November 2010, p. 136.

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.[39] These include:

- 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*)*.

Aurora does not anticipate any expenditure arising from new regulatory obligations for 2012–17.[40] However, during the forthcoming regulatory control period, Aurora will be subject to new requirements arising from the *National Energy Customer Framework*[41] and may be affected by outcomes arising from the review of the Tasmanian electricity supply industry.[42] 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) will apply to Aurora in the forthcoming regulatory control period.[43] 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. The AER has applied an s-factor (STPIS) adjustment of ±5 per cent of Aurora's total revenue cap.[44] Aurora will continue to be subject OTTER's jurisdictional guaranteed service level scheme in the forthcoming regulatory control period.

[39] Aurora, *Regulatory proposal,* May 2011, Attachment AE064.
[40] Aurora has assumed its compliance obligations will remain unchanged for the forthcoming regulatory control period. Aurora, *Regulatory proposal,* May 2011, p. 120.
[41] Aurora, *Regulatory proposal,* May 2011, p. 61.
[42] The Electricity Supply Industry Expert Panel has been established to conduct a review into the Tasmanian electricity supply industry. Aurora, *Regulatory proposal,* May 2011, p. 61.
[43] This is a constituent decision of a distribution determination under clause 6.12.1(9) of the NER.
[44] NER, clauses 6.4.3(a)(5) and 6.4.3(b)(5).

The average number of interruptions per customer and average duration of interruptions per customer in different parts of Aurora's network are presented below. These measures reflect the reliability of supply experienced by Aurora's customers. These measures are separated by network area to reflect the performance experienced by customers in those areas of the network. The data shows that the number and duration of interruptions has been decreasing in recent years. In part, this has been due to targeted reliability improvement programs undertaken by Aurora to adhere to TEC reliability standards introduced in 2008.[45]

The AER's STPIS sets performance targets based on the average of the previous five years.[46] This is because annual STPIS performance can vary due to extraneous factors such as the weather. An average of the previous five years mitigates any once off effects caused by these extraneous factors. The AER has adjusted these targets to account for the expected improvement in reliability that has come about due to the targeted reliability improvement programs.

Table 2.1 Average number of interruptions per customer (SAIFI)

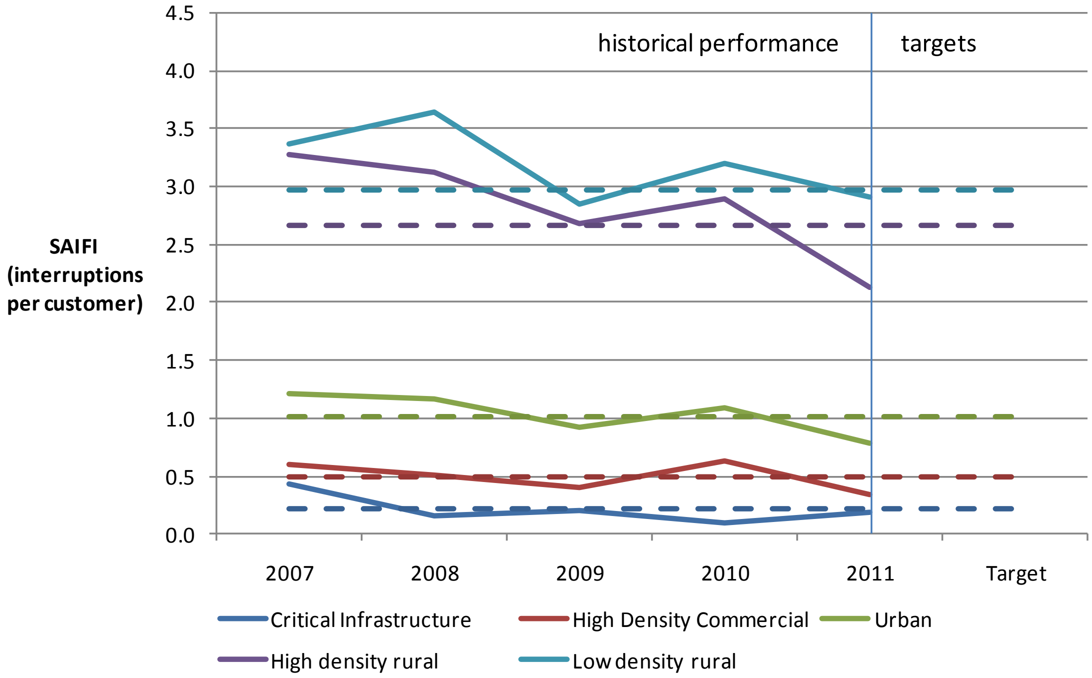
	2006-07	2007-08	2008-09	2009-10	2010-11	Target
Critical infrastructure	0.44	0.16	0.20	0.09	0.16	0.22
High density commercial	0.60	0.53	0.40	0.56	0.32	0.49
Urban	1.27	1.19	0.92	1.04	0.71	1.01
High density rural	3.41	3.14	2.68	2.69	2.06	2.66
Low density rural	3.62	3.79	2.84	3.05	2.87	2.97

Source: AER analysis.

45 TEC, clause 8.6.11.

46 AER, *Electricity distribution network service providers—service target performance incentive scheme*, November 2009, p. 15.

Figure 2.6 Aurora's historical SAIFI performance and its proposed targets



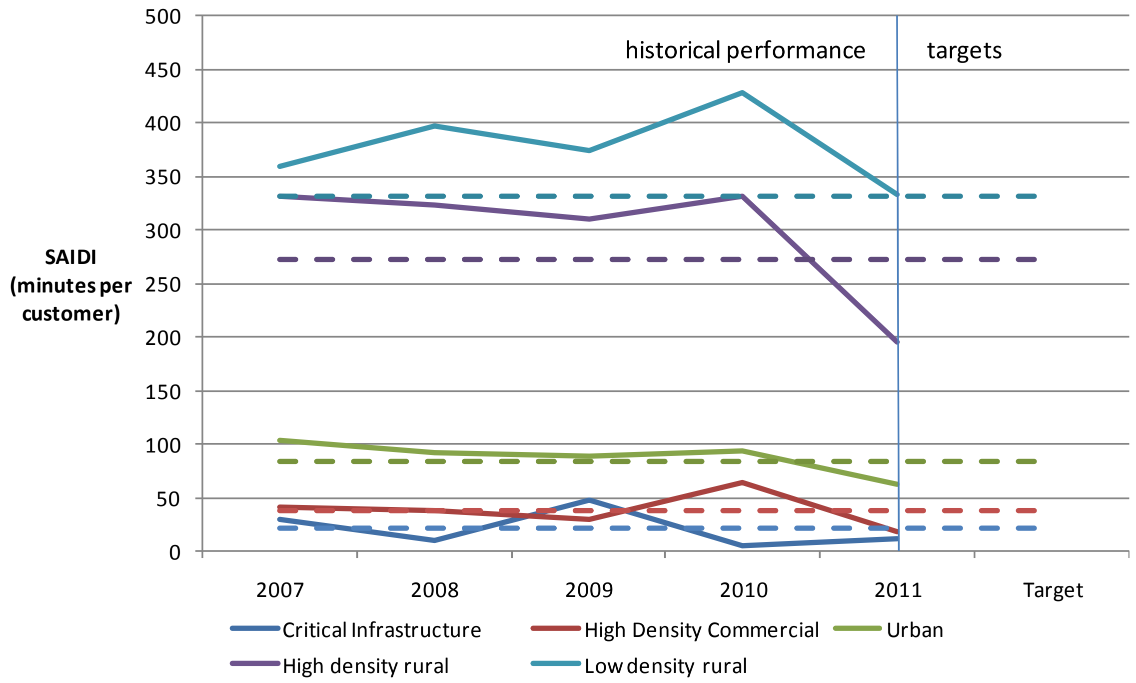
Source: AER analysis.

Table 2.2 Average duration of interruptions (minutes) per customer (SAIDI)

	2006-07	2007-08	2008-09	2009-10	2010-11	Target
Critical infrastructure	29.77	9.59	47.86	5.01	7.07	20.79
High density commercial	41.50	39.06	30.19	62.82	17.89	38.34
Urban	111.86	92.85	87.69	89.16	55.20	84.04
High density rural	346.99	330.41	310.77	295.31	189.29	272.74
Low density rural	411.74	430.83	373.39	395.56	326.75	331.34

Source: AER analysis.

Figure 2.7 Aurora's historical SAIDI performance and its proposed targets



Source: AER analysis.

The AER has also set 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 also gathers network performance information through its call centre. The AER has set a target for Aurora to answer 73.5 per cent of calls to its call centre within 30 seconds of receiving the call. 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 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.

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

- older or poorer condition assets
- unsafe assets
- environmental factors.

Aurora's proposal identifies many reliability, safety and security issues with its network, and Aurora has forecast capex and opex to address them. The AER considers Aurora's distribution network faces a number of safety and security issues and has accounted for this in developing substitute total capex and opex forecasts. The AER has set out its reasoning for the forecast capex and opex it considers

Aurora requires to maintain the reliability, safety and security of the distribution system in more detail in Attachments 5 and 6.

3 Regulatory asset base

Aurora's past investment in assets forms its regulatory asset base (RAB) which is used to calculate the return on, and return of, capital. [47] Aurora recovers the cost of this capital over the expected lives of the assets. The AER must therefore make a determination on Aurora's proposed opening RAB.[48] This is the starting point for the AER's distribution determination.

The AER determines an appropriate value for Aurora's opening RAB by assessing Aurora's RAB at the start of the previous regulatory period, and rolling it forward. The AER adds forecast capital expenditure to, and subtracts depreciation from, this RAB to complete the roll forward.

3.1 Draft determination

The AER accepts Aurora's proposed RAB as at 1 July 2006 of $908.2 million. Aurora derived this RAB from the value of its RAB as at 1 January 2008 as set out in the NER,[49] with some adjustments.

However, the AER does not accept Aurora's proposed opening RAB as at 1 July 2012. The AER has determined Aurora’s opening RAB as at 1 July 2012 to be $1,439.0 million ($nominal), a 0.6 per cent reduction on that proposed by Aurora. The difference reflects changes the AER has made to indexation and the treatment of capitalised provisions.

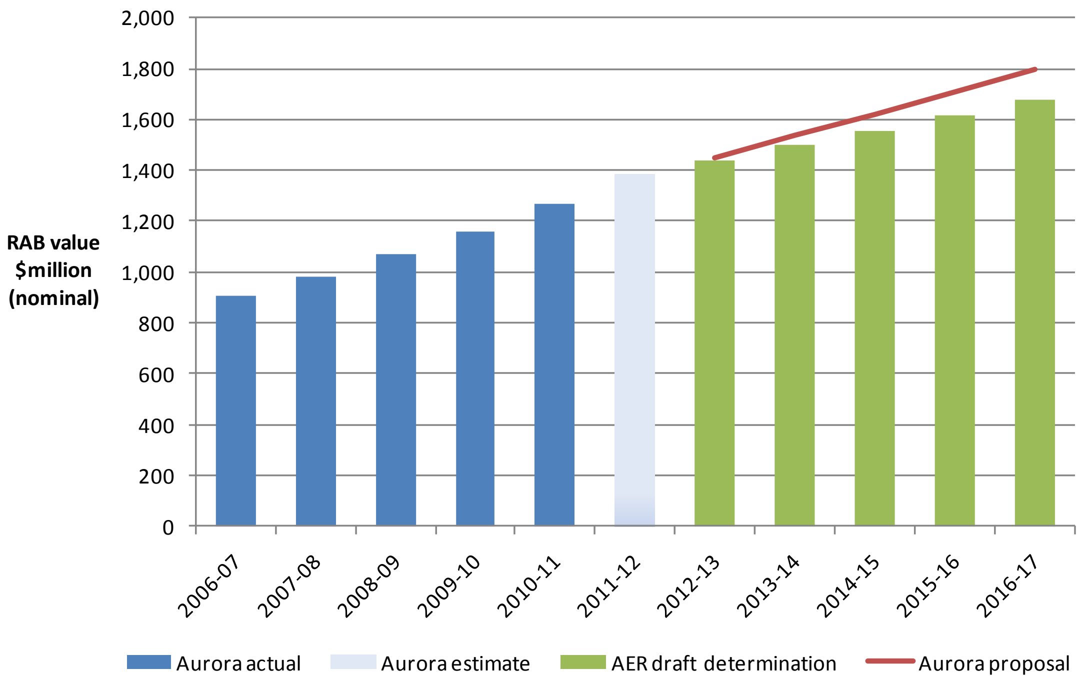
The AER has forecast Aurora’s closing RAB as at 30 June 2017 to be $1,740.7 million ($nominal), an 8.1 per cent reduction on Aurora’s proposed value of $1,894.6 million ($nominal). The difference reflects the AER’s changes to the opening RAB as at 1 July 2012, the inflation forecast for the forthcoming regulatory control period, forecast capital expenditure, and forecast depreciation. Figure 3.1 displays Aurora's past actual opening RAB values compared to the AER's forecast values.

47 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.

48 NER, clause 6.12.1(6) .

49 NER, clause S6.2.1.

Figure 3.1 Aurora's past RAB and AER forecast 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 draft determination on Aurora's RAB for the current regulatory control period ($million, nominal)

	2006–07	2007–08	2008–09	2009–10	2010–11[a]	2011–12[b]
Opening RAB	908.2	984.1	1,056.7	1,163.4	1,257.9	1,378.7
Capital expenditure[c]	111.7	104.7	127.5	140.3	158.5	141.2
CPI indexation on opening RAB	18.8	29.1	39.0	24.5	33.3	37.9
Straight-line depreciation[d]	–51.3	–61.3	–59.8	–70.3	–71.1	–73.1
Closing RAB	984.1	1,056.7	1,163.4	1,257.9	1,378.7	1,484.7
Difference between forecast and actual capex (1 July 2006 to 30 June 2007)						–21.8
Return on difference for 2006–07 capex						–11.4
Adjustment for shared assets						–12.5
Opening RAB as at 1 July 2012						1,439.0

Source: AER analysis.

Notes:

(a) Based on estimated capex. The asset base roll forward will be updated for actual capex at the time of the AER final determination.

(b) Based on estimated capex and forecast inflation. The asset base roll forward will be updated for actual CPI at the time of the AER final determination. However, the update for actual capex will be made at the next reset.

(c) Net of disposals and capital contributions, and adjusted for actual CPI and WACC.

(d) Adjusted for actual CPI.

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

Table 3.2 AER draft 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	1,439.0	1,497.1	1,554.2	1,613.8	1,675.6
Capital expenditure[a]	104.8	110.1	108.6	104.0	107.2
Inflation indexation on opening RAB	37.7	39.2	40.7	42.3	43.9
Straight line depreciation	–84.3	–92.2	–89.8	–84.5	–86.0
Closing RAB	1,497.1	1,554.2	1,613.8	1,675.6	1,740.7

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 draft determination opening RAB for Aurora for 1 July 2012 is lower than Aurora's forecast due to changes the AER has made to indexation and the treatment of capitalised provisions.

3.2.1 Indexation approach

The AER considers that Aurora has not indexed its RAB appropriately as part of the roll forward during the current regulatory period. Accordingly, the AER has made two changes to the way Aurora has applied actual inflation adjustments in its roll forward model (RFM). The AER has:

1. applied actual inflation over the current regulatory control period based on the change in December to December CPI, consistent with Aurora's current control mechanism.[50] Aurora's proposal applies June to June CPI.

2. changed the forecast inflation rate input in Aurora's RFM to 3 per cent for the current regulatory period, consistent with the forecast used by OTTER in its final determination. Aurora proposed a figure of 4.5 per cent. To maintain net present value neutrality, the AER considers that the forecast inflation rate used in the RFM must equal the forecast inflation rate approved by OTTER.[51]

50 This is required under NER, clause 6.5.1(e)(3).

51 NER, clause 6.5.5(b)(2).

3. The inflation rate for 2011–12 is a forecast. The AER will update this figure in the final determination when the December 2011 actual CPI is published.

3.2.2 Treatment of provisions

The AER has reduced the capex inputs to Aurora's proposed RFM by $8.7 million ($nominal) for movement in capitalised expense provisions. Aurora included provisions for labour expenses such as superannuation and long service leave obligations in the accounts it prepared for OTTER. These expenses have not been paid but are likely to be incurred at some time in the future. Aurora has capitalised a proportion of these expenses and included this proportion as capex in its RAB.

The AER considers Aurora's capitalised provisions are not consistent with good regulatory practice, the NEL or NER. Allowing a DNSP to earn a return on, and of, capital for payments not yet made is not efficient or consistent with the long term interests of consumers.[52] Further, provisions for costs to be incurred in the future are inconsistent with the requirement that Aurora's RAB be adjusted only for actual or estimated capital expenditure incurred during the previous control period.[53]

3.2.3 Forecast closing RAB as at 30 June 2017

The AER has determined Aurora's RAB to be $1,740.7 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 7
- the inflation forecast for the forthcoming regulatory control period, as discussed in attachment 9
- forecast capital expenditure, as discussed in attachment 5, and
- forecast depreciation, as discussed in attachment 8.

The AER has set out its detailed reasoning for Aurora's RAB in Attachment 7.

[52] NEL, section 7.
[53] NER, clauses S6.2.1(e)(1) to (4).

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.[54]

4.1 Draft determination

The AER accepts Aurora's proposed asset classes, standard asset lives and straight-line method of depreciation to calculate the depreciation allowance. However, the AER does not accept Aurora's proposed forecast depreciation allowance of $231.9 million ($nominal) for the forthcoming regulatory control period. The AER's draft determination on Aurora's regulatory depreciation is $232.9 million ($nominal), as Table 4.1 shows.

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

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Straight-line depreciation	84.3	92.2	89.8	84.5	86.0	436.7
Less: indexation on opening RAB	37.7	39.2	40.7	42.3	43.9	203.8
Regulatory depreciation	46.6	52.9	49.1	42.2	42.1	232.9

Source: AER analysis.

4.2 Summary of analysis and reasons

The AER does not accept Aurora's forecast depreciation allowance. It does not accept Aurora's remaining asset lives, RAB indexation approach or Aurora's total forecast capex. The AER has also created two additional asset classes for land and easements.

The AER considers that Aurora's asset classes and standard asset lives are consistent with those approved by OTTER. Aurora's standard asset lives are comparable to previous regulatory decisions the AER has made for electricity DNSPs. The AER has revised Aurora's proposed remaining asset lives to reflect the changes the AER has made to Aurora's opening RAB as at 1 July 2012. The AER has, however, adopted Aurora's proposed approach to determining these lives.

Aurora did not separately identify asset classes for land and easement expenditures, which are non-depreciating assets. The AER considers expenditures for these assets should be allocated to separate asset classes in the PTRM from assets subject to depreciation. For this draft determination, using information provided by Aurora, the AER has created new asset classes for land and easements, and allocated the approved capex for land and easements over the forthcoming regulatory control period into these classes.[55] The AER has set out its detailed reasoning for Aurora's depreciation in Attachment 8.

[54] NER, clause 6.12.1(8).
[55] Aurora, *Response to information request AER/047 of 6 October 2011*, received 11 October 2011, pp. 3–4.

5 Capital expenditure

Aurora proposed total forecast capex of $675.3 million ($2009–10) for 2012–13 to 2016–17. The AER must accept Aurora's proposed total forecast capex if satisfied it reasonably reflects the capex criteria.[56] 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.[57] In doing so, the AER must have regard to the capex factors.[58]

5.1 Draft 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.

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 proposal of total forecast capex only to the extent necessary to comply with the NER.[59] Overall, the AER estimates a total forecast capex of $535.8 million ($2009–10) over the forthcoming regulatory control period. This equates to a reduction of approximately $139.5 million ($2009–10), or 21 per cent of Aurora's proposed 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.[60]

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

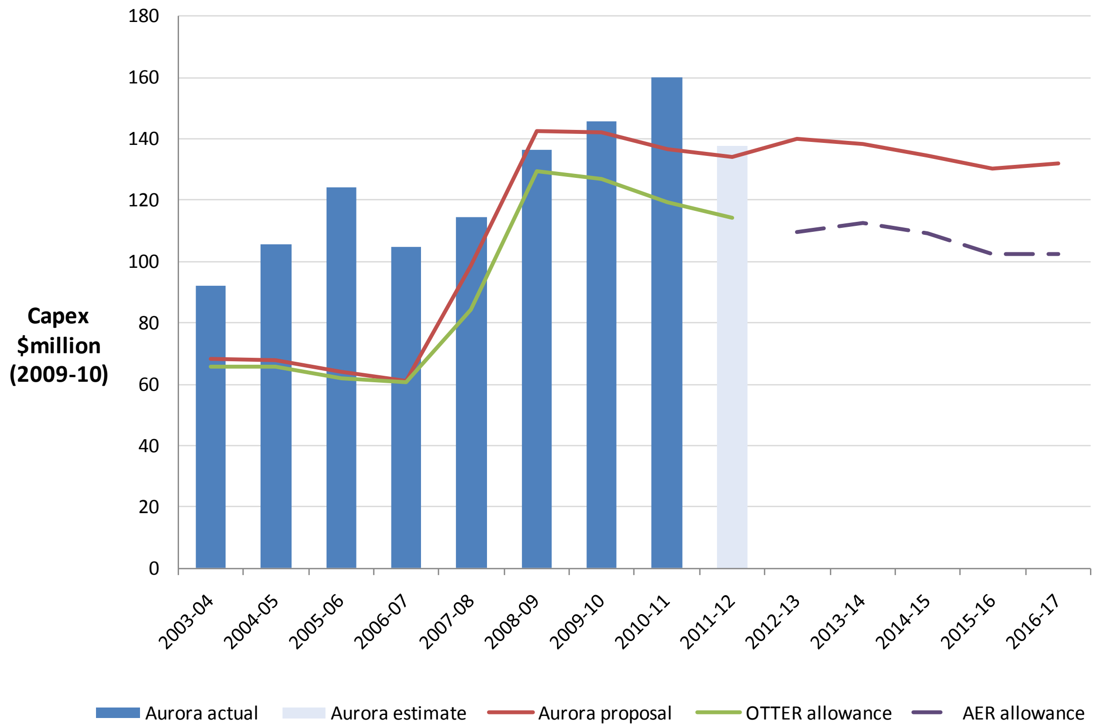
	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Aurora's proposal	139.9	138.5	134.7	130.3	131.9	675.3
Adjustment	-30.5	-25.9	-25.4	-28.0	-29.6	-139.5
AER draft determination	109.4	112.6	109.3	102.2	102.3	535.8

Source: AER analysis.

Figure 5.1 compares Aurora's past and forecast total capex with proposed and approved capex.

56 NER, clauses 6.5.7(c) and 6.12.1(3)(i).
57 NER, clauses 6.5.7(d) and 6.12.1(3)(ii).
58 NER, clause 6.5.7(e).
59 NER, clause 6.12.3(f).
60 NER, clause 6.12.1(3)(ii).

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



Source: AER analysis, Aurora's RIN template.[61]

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,[62] and has considered the impact of its substitute 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:[63]

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

[61] Aurora has claimed confidentiality over some parts of its RIN template.
[62] NER, clause 6.5.7(c)(1) and (2).
[63] NER, clause 6.5.7(c)(3).

The AER considers that much of the capex proposed by Aurora is consistent with the requirements of the NER. However, the AER considers that several elements of Aurora's total forecast capex proposal are overstated. The AER's main concerns[64] with Aurora's 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 $32.7 million ($2009–10) (4.8 per cent of Aurora's total forecast capex proposal) is required to address this concern.
- Aurora's forecast for new residential connections are too high. The AER has developed a substitute forecast of new residential connections. The AER estimates the impact of this substitute forecast, using unit costs as proposed by Aurora, should reduce Aurora's forecast capex by $30.1 million ($2009–10) (4.5 per cent of Aurora's total forecast capex proposal).
- Aurora's forecast unit costs for new connections are also too high. The AER considers more realistic unit costs, derived from historical trends, should reduce Aurora's forecast capex by an additional $5.1 million ($2009–10) (0.8 per cent of Aurora's total forecast capex proposal).
- $24.6 million ($2009–10) (3.6 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. 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 should be 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 $12.0 million ($2009–10) (1.8 per cent of Aurora's total forecast capex proposal) is required to address these concerns.
- Approximately $30.8 million ($2009–10) (4.7 per cent of Aurora's total forecast capex proposal) appears to be primarily directed at achieving operational efficiencies or reliability improvements. The AER considers this expenditure is not required to achieve the capex objectives in a manner that reasonably reflects the capex criteria.

Attachment 5 contains the AER's detailed reasons for Aurora's total forecast capex.

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

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).[65] 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.[66] Under the NER, the rate of return the AER must apply is based on the nominal vanilla WACC formulation.[67] 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 Draft determination

The AER has not accepted Aurora's proposed WACC of 10.33 per cent. The AER considers it does not reflect the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by Aurora.[68]

For this draft determination, the AER has determined an indicative WACC of 8.08 per cent for Aurora as set out in Table 6.1. This WACC reflects market based parameters—nominal risk free rate and debt risk premium (DRP)—estimated over an indicative averaging period. The AER will update the WACC for its final determination.

In establishing the WACC, the AER has accepted Aurora's proposed averaging period to calculate the nominal risk free rate. The AER has also accepted the proposed values for the equity beta and gearing. This is because for these parameters, the AER considers there is no persuasive evidence justifying a departure from the SRI. The AER has not accepted Aurora's proposed values for the market risk premium (MRP) and DRP. The AER has accepted Aurora's proposed value of assumed utilisation of imputation credits (gamma), which affects the tax building block allowance.

65 NER, clause 6.12.1(5).
66 NER, clause 6.5.4(c).
67 NER, clause 6.5.2(b).
68 NER, clause 6.5.2(b).

Table 6.1 AER draft determination on Aurora's rate of return (WACC)

Parameter	Aurora's proposal	AER draft determination
Nominal risk free rate	5.53%	4.28%
Equity beta	0.8	0.8
Market risk premium	6.50%	6.00%
Gearing level (debt/debt plus equity)	60%	60%
Debt risk premium	4.54%	3.14%
Assumed utilisation of imputation credits (gamma) a	0.25	0.25
Inflation forecast	2.58%	2.62%
Cost of equity	10.73%	9.08%
Cost of debt	10.07%	7.42%
Nominal vanilla WACC	10.33%	8.08%

Notes: (a) The gamma parameter affects the corporate income tax allowance, which Attachment 10 discusses.
Source: AER analysis, Aurora's PTRM.

6.2 Summary of analysis and reasons

The AER's draft determination WACC differs from Aurora's proposal primarily due to lower values for the nominal risk free rate, MRP and DRP. The AER has applied the persuasive evidence test in the NER in making its draft distribution determination on SRI values, methods or credit rating level.[69] As a result, the AER considers there is persuasive evidence justifying a departure from the SRI value for the MRP.

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.[70] For this draft determination, the AER has used an indicative averaging period. Since Aurora proposed its indicative WACC, a change in market conditions has been reflected in the observed nominal risk free rate. Consequently, the nominal risk free rate the AER has applied in this draft determination is lower than that set out in Aurora's proposal. The AER will update the risk free rate, based on the agreed averaging period, at the time of its final determination.

6.2.2 Market risk premium

Aurora proposed to adopt a value of 6.5 per cent for the MRP value (the value specified in the SRI).[71] Aurora did not provide any particular assessment or reasoning on this issue. The AER has rejected Aurora's proposed MRP value because there is persuasive evidence justifying a departure from this value. The AER has adopted an MRP value of 6 per cent for the purposes of calculating Aurora's WACC.

[69] NER, clause 6.5.4(g).
[70] NER, clause 6.5.2(c).
[71] Aurora, *Regulatory Proposal 2012–2017 addendum*, p. 13.

The AER considers that the value of the MRP in the SRI is no longer appropriate. There has been a material change in circumstances since the SRI was published. The AER considers an MRP of 6.5 per cent is no longer appropriate because:

- prior to the May 2009 WACC review, Australian regulators consistently applied an MRP of 6 per cent in regulatory decisions
- the AER's decision to depart from the consensus value of 6 per cent at the time of the WACC review was influenced by uncertainty about the effects of the global financial crisis (GFC) on future market conditions[72]
- the GFC did not generate a structural break in the MRP, even though this might have been a plausible interpretation of the available evidence during the WACC review
- information and data available since the release of the SRI suggests that the prevailing medium-term MRP has not been above the long-term MRP
- the latest historical excess return estimates, derived from more up to date data since the SRI, supports a forward looking long-term MRP of 6 per cent
- the long-term outlook for Australian economic and financial market conditions is more robust than it was at the height of the GFC
- the latest survey based estimates of the MRP indicate that the forward looking MRP expected to prevail in the future has not changed as a result of the GFC
- dividend growth model analysis suggests that a forward looking 10 year MRP of 6 per cent is not unreasonable.

6.2.3 Debt risk premium

Aurora proposed a DRP using the Bloomberg BBB rated 7 year fair value curve (FVC) extrapolated to a 10 year term to maturity. [73] The AER does not accept Aurora's proposed approach because of a sustained divergence between the FVC and market evidence. Relevant market data and expert commentary suggests that debt market conditions have improved since the GFC, but this has not been reflected in the long dated (5+ year) Bloomberg BBB rated FVC. As such, the AER considers it is appropriate to update its previous approach to incorporate observed market bond yields for the purposes of estimating the DRP.

The AER considers its updated methodology to estimate the DRP based on observed market data uses the best available source of information on prevailing Australian bond market conditions. The AER has previously relied largely on extrapolated fair value curves to set the DRP, due to limited data availability. The AER's updated approach is based on a larger sample of data, which on average is representative of the benchmark Australian corporate bond with a 10 year term to maturity and BBB+ credit rating.

The AER considers that its method to calculate the DRP based on the average of observed bond yields appropriately incorporates relevant information from the market. This will contribute to a forward

[72] AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, p. 228.
[73] Based on the indicative averaging period of 20 business days ending on 25 March 2011. Aurora, *Regulatory proposal addendum*, June 2011, p. 14.

looking rate of return that is commensurate with prevailing conditions in the market for funds and with the risk involved in providing standard control services.

The AER's draft 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 9.

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

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Aurora’s proposal	149.6	158.4	167.2	176.0	185.4	836.6
Adjustment	33.3	37.4	41.5	45.6	50.0	207.7
AER draft determination	116.3	121.0	125.6	130.5	135.5	628.9

Source: Aurora, Regulatory proposal, Addendum, June 2011, p. 33, AER analysis.

7 Operating expenditure

Aurora proposed total forecast opex of $340.1 million ($2009–10) over the forthcoming regulatory control period. Aurora developed its opex forecasts from a detailed work program that included each of the operating and maintenance projects it considered would be required during the forthcoming regulatory control period. Aurora used management plans as the basis for each proposed project and estimated volumes and rates for each project. Aurora's engineers and management derived forecasts in accordance with Aurora policies and procedures.[74]

Aurora also applied an annual three per cent efficiency factor to its labour rates forecast to deliver operational efficiencies.[75] As Aurora applies its labour rates to both capex and opex, Aurora applied the efficiency factor across its forecast capex and opex proposals as a means of reducing total expenditure.[76]

Aurora's total forecast opex also includes shared costs. Aurora used its indirect cost allocation model (ICAM) to allocate corporate and shared services costs between Aurora’s divisions and subsidiaries. Aurora then used its cost allocation method (CAM), as approved by the AER, to allocate costs between various classifications within the distribution business.[77]

The AER must accept Aurora's proposed total forecast opex if satisfied it reasonably reflects the opex criteria.[78] 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.[79] In doing so, the AER must have regard to the opex factors.[80]

7.1 Draft 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.[81]

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.[82] Overall, the AER estimates a total forecast opex of $311.0 million ($2009–10) over the forthcoming regulatory control period. This equates to a reduction of approximately $29.1 million ($2009–10), or 8.6 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.[83]

[74] Aurora, *Regulatory proposal*, May 2011, p. 133.
[75] Aurora, *Regulatory proposal*, May 2011, p. 165.
[76] Aurora, *Response to information request AER/046 of 5 October 2011*, received 11 October 2011, p. 3.
[77] Aurora, *Regulatory proposal*, May 2011, p. 134.
[78] NER, clauses 6.5.6(c) and 6.12.1(4)(i).
[79] NER, clauses 6.5.6(d) and 6.12.1(4)(ii).
[80] NER, clause 6.5.6(e).
[81] NER, clause 6.5.6(c). Clause 6.5.6(a) specifies the opex objectives.
[82] NER, clause 6.12.3(f).
[83] NER, clause 6.12.1(4)(ii).

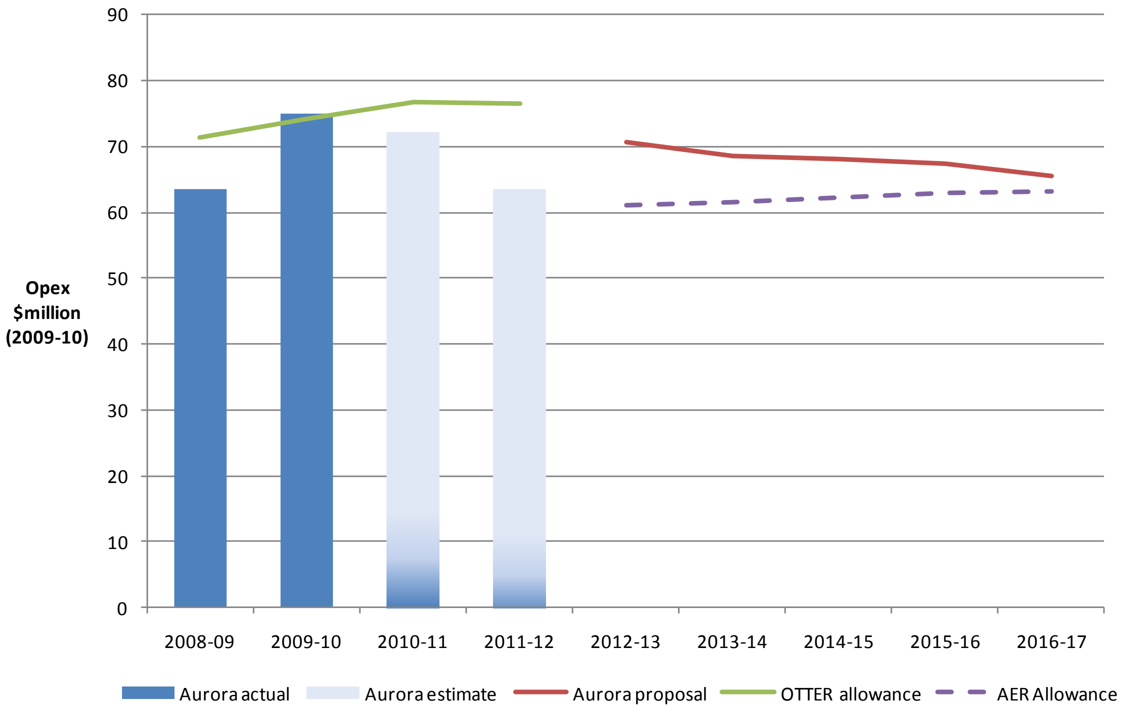
Table 7.1 AER draft determination on Aurora's total forecast opex ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Aurora's proposal	70.6	68.6	68.1	67.3	65.4	340.1
Adjustment	9.5	7.1	5.8	4.4	2.2	29.1
AER draft determination	61.1	61.6	62.2	62.9	63.2	311.0

Source: AER analysis.

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

Figure 7.1 Comparison of Aurora's past and forecast total opex and AER draft determination ($million, 2009–10)[84]



Source: AER analysis, Aurora's RIN template.

7.2 Summary of analysis and reasons

The AER is not satisfied that Aurora's total forecast opex reasonably reflects the opex criteria. The AER has formed this view by comparing Aurora's proposed forecast opex with an alternative forecast of opex using a base year forecasting methodology.

- The AER has reached this view after testing Aurora's forecast using two main approaches. First, the AER has reviewed Aurora's recent opex and its circumstances. Taken together, this review

84 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.

suggests that the AER could not rely on Aurora's actual costs alone to calculate a total forecast opex for Aurora. Through further analysis, the AER has found that:

- Aurora has not been subject to an EBSS and therefore has not faced a continuous incentive to reduce opex in the current regulatory period
- Aurora has spent close to its OTTER allowance, suggesting that it may not have strongly responded to incentives to reduce costs
- benchmarking suggests that Aurora's opex is slightly higher than its peers.

Second, the AER has developed an alternative forecast which places some reliance on Aurora's recurrent expenditure as a base, but accounts for other factors that the AER expects would affect Aurora's costs over the forecast period. In producing its alternative forecast, the AER has:

- used 2009–10 as the preferred base year
- removed non-recurrent expenditure and movements in provisions
- reviewed and adjusted some categories of the base year expenditure that deviate from past expenditure.
- projected the base year forward by adjusting for step changes, network growth and real cost escalation.

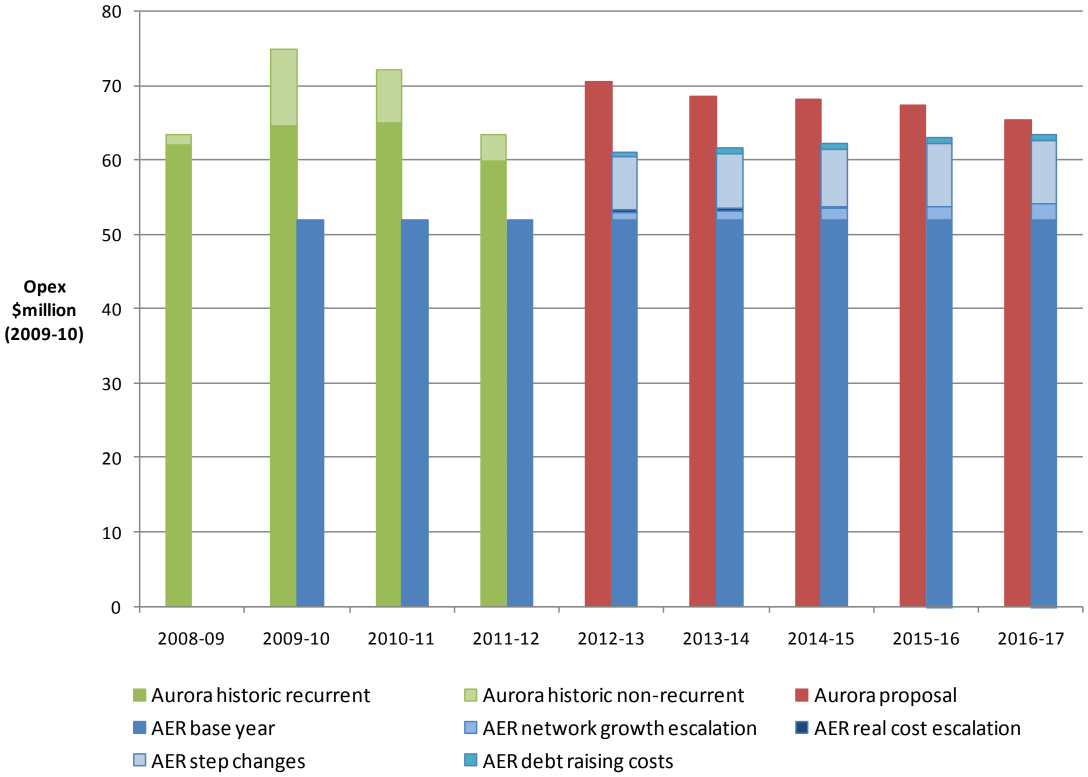
7.2.1 Base year forecast

Following its assessment of Aurora's historical costs, the AER has selected 2009–10 as the base year for its substitute opex forecast. Although the AER often uses the second last year of a regulatory period as the base year, at the time Aurora submitted its regulatory proposal, 2009–10 was the most recent year for which audited data was available. Based on a detailed review of categories of opex where material increases in expenditure occurred in 2009–10 compared to Aurora's historic average, the AER considers some adjustments are necessary to determine Aurora's recurrent costs. The AER's adjustments are primarily for expenditure that the AER considers is not reflective of the recurrent levels of opex.

The AER has also adjusted Aurora's base opex to exclude the movement in provisions to ensure Aurora's reported opex includes only expenditure actually incurred, thus representing Aurora's underlying economic circumstances. The AER's base opex amount of $51.9 million ($2009–10) is therefore lower than Aurora's actual expenditure for 2009–10.

The AER has adjusted Aurora's recurrent opex for network growth, real cost escalation and step changes. Following these adjustments, the AER has found that Aurora's proposed opex forecast is higher than the AER's forecast. Figure 7.2 compares Aurora's opex proposal with the AER's alternative forecast. Attachment 6 provides the AER's detailed reasoning for Aurora's proposed total opex forecast.

Figure 7.2 Comparison of Aurora's opex proposal with the AER's alternative forecast ($million, 2009–10)



Source: AER analysis.

7.2.2 Shared costs

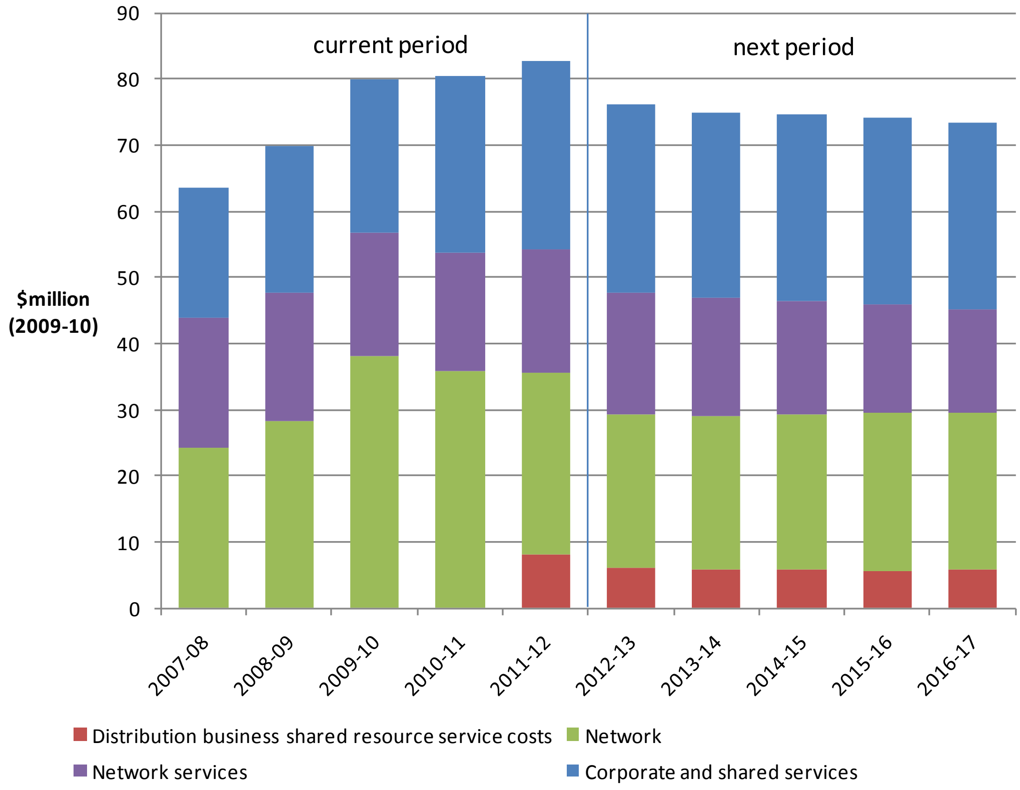
Shared costs are costs that cannot be directly attributed to a single service that Aurora provides.[85] Aurora has forecast its shared costs and allocated them to direct control services in accordance with its cost allocation method (CAM).[86]

Aurora's forecasts of shared costs allocated to distribution services is about $5 million lower in real terms than actual shared costs in the current regulatory period. The AER has applied a base year approach to assessing Aurora's forecast allowance of total shared costs attributable to alternative control services and capital expenditure. The AER has assessed Aurora's forecast shared costs for opex as part of its opex base year approach analysis. On the basis of this assessment the AER has accepted Aurora's forecast for these shared costs. Figure 7.3 shows the break down of Aurora's historical and forecast shared costs by business division. Attachment 6 contains the AER's detailed reasoning for shared costs.

85 Before Aurora submitted its regulatory proposal the AER approved Aurora's CAM. AER, *Final decision: Aurora Energy: Proposed Cost Allocation Method amendment*, May 2011. Aurora's CAM specifies Aurora's shared costs and how Aurora will allocate them to direct control services.

86 NER, clauses 6.5.6(b)(2) and 6.5.7(b)(2) require that capex and opex forecasts be for expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in the CAM for the DNSP.

Figure 7.3 Aurora's total historical and forecast shared costs ($million, 2009–10)



Source: Aurora.[87]

7.2.3 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.[88] 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 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.

The AER is satisfied that most of the cost categories proposed by Aurora for exclusion from the EBSS are reasonable. However the AER considers trunk mobile radio (TMR) costs should not be excluded. Aurora proposed to exclude TMR costs because arrangements for the provision of this service had

87 Aurora, *Response to information request AER/038 of 1 September 2011*, received 7 September 2011.

88 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.

yet to be finalised and the costs were uncertain and beyond the control of Aurora.[89] Absent a legal obligation on Aurora to participate in the TMR, the AER considers the decision to continue to participate and incur these costs rests with Aurora.[90] Attachment 11 provides the AER's detailed reasoning for the EBSS.

89 Aurora, *Regulatory Proposal*, May 2011, p. 194.
90 Aurora, *Response to information request AER/019 of 29 July 2011*, received 8 August 2011, p. 3.

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.[91] The NER requires the AER to publish a post-tax revenue model for Aurora for the forthcoming regulatory control period.[92] 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 Draft determination

The AER accepts Aurora's methodology for establishing its opening tax asset base and the proposed opening tax asset base of $1,015.3 million ($nominal) at 1 July 2012. The AER also accepts the tax asset lives used to calculate the opening tax asset base proposed by Aurora. Aurora's effective tax rate, as estimated in the PTRM, is approximately 30 per cent, which is similar to the statutory tax rate. This is due to the reasonably steady state of Aurora's ongoing capital expenditure. 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 draft determination on corporate income tax allowance for Aurora ($million, nominal)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Tax payable	22.6	24.9	23.8	23.4	23.4	118.1
Less: value of imputation credits	5.6	6.2	5.9	5.9	5.8	29.5
Net corporate income tax allowance	16.9	18.7	17.8	17.6	17.5	88.6

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.[93] 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).[94] 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 10 discusses the AER's detailed reasoning for Aurora's proposed tax.

[91] NER, clause 6.4.3.
[92] NER, clause 6.4.1(a).
[93] NER, clause 6.5.3. The AER engaged McGrathNichol to assist with this assessment.
[94] Australian Competition Tribunal, *Application by Energex Limited (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.[95] Aurora proposed a revenue cap inclusive of a several revenue adjustment mechanisms continuing from the current regulatory period.[96]

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.[97] 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 Draft determination

The AER accepts Aurora's proposal to apply a revenue cap control mechanism for standard control services.[98] Aurora must demonstrate compliance with the control mechanism through an annual pricing proposal.[99] 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.[100]

Aurora proposed nine pass through events[101], of which the AER nominates three as additional pass through events. The AER considers these three satisfy the AER's pass through criteria, which broadly require the events to have a high level of uncertainty and uncontrollability, and not be covered elsewhere.[102]

9.2 Summary of analysis and reasons

9.2.1 Control mechanism

The AER accepts the following elements of Aurora's proposed control mechanism:

- the distribution use of system (DUOS) under and over recovery mechanism because it minimises price shocks. Aurora proposed that the under or over recovery of revenues be recovered from consumers over two consecutive regulatory years (rather than a single year) per clause 6.18.6 of the NER.[103]
- the national electricity market charge (NEMC) because the *Electricity Supply Industry Act 1995* (Tas) requires Aurora to pay this charge. This is for Tasmania's costs of funding the Australian Energy Market Commission

95 AER, F*ramework and approach paper*, November 2010, pp. 62-85.
96 Aurora, *Regulatory proposal*, pp. 225-227.
97 NER, clause 6.6.1.
98 NER, clause 6.1.12(11).
99 NER, clause 6.12.1(13).
100 NER, clause 6.2.5(c).
101 Aurora, *Regulatory proposal*, p. 209.
102 The criteria are set out in AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015, November 2010,* Chapter 16.
103 Aurora, *Regulatory proposal*, p. 229.

- the electrical safety inspection service levy revenue adjustment mechanism, but only in the event Aurora is successful in its bid to provide these services. Aurora undertakes these services on behalf of Workplace Standards Tasmania (WST) in accordance with the *Electricity Industry Safety and Administration Act 1997*.[104] WST is responsible for providing these services, and tenders out for the contract to provide these services on behalf of WST. The contract for these services is set to expire on 30 June 2012 and the new tender process is yet to begin.

The AER does not accept the following elements of Aurora's proposed control mechanism because they insulate Aurora from risk and reduce the incentive properties of the building block model.

Excess GSL costs

Aurora proposed two adjustment mechanisms applied by OTTER in its 2007 determination. These mechanisms protect Aurora from the financial consequence of extreme weather events. [105] They are not part of the current jurisdictional GSL scheme, and will not continue to apply unless specified in the control mechanism for standard control services.

The AER considers the GSL cost revenue adjustment mechanisms should not form part of the control mechanism for standard control services in the forthcoming regulatory control period. The AER will account for the adjustment of GSL revenue costs occurring in the last year of the current regulatory period through the transitional parameter in the revenue cap formula. The AER also considers that:

- these mechanisms weaken the incentive for Aurora to undertake activity to reduce the likelihood and severity of events that are within its control as they limit Aurora's financial exposure to GSL payments more generally. This weakened incentive should not be part of Aurora's control mechanism as it results in a lower incentive to minimise outages than would occur in the absence of the adjustment mechanisms.
- Tasmania is the only jurisdiction in the NEM where these GSL revenue adjustment mechanisms in the control mechanism exist.
- Aurora is also seeking to limit its financial exposure by proposing separate pass through events for natural disasters, bushfires and storms.[106]
- Under the GSL scheme widespread interruptions related to rare events can be excluded if approved by the regulator.[107]

Trunk Mobile Radio

The AER considers TMR costs should be included as part of Aurora's total forecast opex. 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.[108]

[104] Aurora, *Regulatory proposal*, p. 226.
[105] OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: Final report and proposed maximum prices*, September 2007, pp. 182–183, 232.
[106] Aurora, *Regulatory proposal*, p. 209.
[107] OTTER, *Guideline - Guaranteed Service Level Scheme*, December 2007, pp. 2-6.
[108] Aurora, *Regulatory proposal*, p. 227.

Full retail contestability

The AER considers FRC should be treated as a pass through event. This adjustment is for the costs for Aurora to implement FRC.[109] Aurora has progressively undertaken first five tranches of retail contestability. The Tasmanian Government introduced a new tranche of contestability on 1 July 2011 for business customers that use between 50MWh and 150MWh of electricity per year.[110]

Unfunded shared network costs

The unfunded shared network events revenue adjustment is for unforeseen connection and network augmentation expenditure. This adjustment would allow Aurora to recover the costs for any significant new projects that take place during the forthcoming regulatory control period but were not known when Aurora prepared its regulatory proposal.[111] The AER considers this adjustment would eliminate Aurora's incentives to efficiently incur such costs. Aurora should incorporate its expectation of these costs into its total forecast capex.

Attachment 2 contains the AER's precise application of the revenue cap control mechanism and its detailed reasoning

9.2.2 Pass through events

The AER nominates three of Aurora's nine proposed pass through events because the AER considers they satisfy the AER's pass through criteria.[112] These are:

- natural disaster event. These events tend to be infrequent, but can be high cost. The AER recognises that is some potential overlap with other allowances or events such as liability above insurance cap. However, it will consider any specific cost claim under the most appropriate event and ensure it is not double-counted.
- insurer credit risk event. This event involves increases in Aurora's insurance costs as a result of its nominated insurer's insolvency.
- liability above insurance cap. The above-cap losses tend to be low probability, potentially high cost risks. Aurora can optimise its risk management by designing its network and externally insuring to a certain level of risk. Under this approach, it is more efficient to leave uninsured some losses which are below the deductible threshold or above the insurance cap.

The AER considers Aurora's six remaining proposed pass through events may be recovered under other pass through events (including the three nominated above) or other mechanisms. These are:

- bushfires event. Aurora proposed a bushfires event separately from the natural disaster event because it thought some fires, such as those caused by arson, may not be considered natural disasters.[113] The AER considers a specific new event for bushfires is not necessary. Small fires can be covered by opex or capex allowances including insurance and self insurance, or the costs absorbed within the materiality threshold. The AER considers that major bushfires could qualify under Aurora's definition of natural disaster event, regardless of whether they were initiated by

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109 Aurora, *Regulatory proposal*, p. 227.

110 See: http://www.power.tas.gov.au/domino/power.nsf/v-lu-pages/Contestability+Explained?OpenDocument.

111 Aurora, *Regulatory proposal*, p. 229.

112 See AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015, November 2010,* Chapter 16.

113 Aurora, *Response to information requested on 15 June 2011*, received 23 June 2011, p. 10.

humans. Very large fires could also involve costs above the insurance cap and thus qualify for the liability above insurance cap event.

- storms event. The AER considers a specific new event for storms is not necessary, for similar reasons as for bushfires. Smaller more frequent storms can be covered by components of opex or capex, or minor costs absorbed within the materiality threshold. The AER considers major storms could qualify under either the natural disaster event (as 'other natural disaster') or liability above insurance cap.

- industry restructure event. The Tasmanian Government is reviewing the electricity industry, which could result in separation of Aurora's businesses, with associated extra costs for Aurora. If such a restructure occurs, the AER considers that it could be covered by one of the prescribed pass through events—either a regulatory change event or service standard event.

- declared retailer of last resort (RoLR) event. When an electricity retailer fails, a DNSP could incur costs when customers of the failed retailer are transferred to the declared RoLR. Under the new National Energy Retail Law, the AER may determine payments that DNSPs are required to make to the RoLR to allow it to recover its RoLR scheme costs. The Law provides for the DNSP to recover such payments as pass through amounts. Further, the National Electricity (Retail Support) Amendment Rules 2010 introduce a new pass through event, a 'retailer insolvency event', through which a DNSP could recover the costs associated with unpaid distribution charges by an insolvent retailer.[114] The AER considers RoLR costs can be recovered through these mechanisms, and other related costs may be recoverable under existing mechanisms.

- carbon tax event. The Australian Government's Clean Energy Legislative Package was passed by Parliament on 8 November 2011. Under this legislation, a fixed carbon price will commence on 1 July 2012, and transition on 1 July 2015 to a flexible price set by the market under an emissions trading scheme (ETS). The AER considers this carbon pricing mechanism could be covered by one of the prescribed pass through events—regulatory change event, service standard event or tax change event.

- feed-in tariff event. Aurora offers, on a voluntary basis, a feed-in tariff through its net metering buyback scheme. The Tasmanian Government has a declared policy of mandating a feed-in tariff based on a net metering scheme, but has not legislated to implement this policy.[115] The NER now provides a mechanism for DNSPs to recover payments made under approved jurisdictional schemes. If a feed-in tariff is established under Tasmanian law and is determined to be a jurisdictional scheme, Aurora could recover payments under the tariff through the new NER mechanism.

Attachment 14 contains the AER's detailed reasoning for Aurora's proposed pass through events.

[114] *National Electricity (Retail Support) Amendment Rules 2010*, r. 3(2), r. 4.
[115] Hon David Llewellyn MP, Minister for Energy (Tasmania), *Statement On Energy*, 3 December 2009.

10 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 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 10.1 provides an indication of the price impacts of the AER's draft determination.

The AER expects a typical residential customer's bill to fall on average by about $2 per annum over the forthcoming regulatory control period. The AER has based this calculation on an estimated bill of $2,000 for 2010–11[116], an estimate that distribution costs make up 48 per cent[117] of the retail price (residential) of electricity, expected demand growth of 1.0 per cent per annum and expected inflation of 2.62 per cent over the regulatory control period.

Table 10.1 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	$2,000	$2,147	$2,164	$2,181	$2,199	$2,216	
Distribution charges	$968	$1,116	$1,132	$1,149	$1,167	$1,184	
Change in residential bill		$147	$17	$17	$17	$18	$43
Percentage change in residential bill		7.37%	0.78%	0.79%	0.79%	0.80%	2.1%
Percentage change in distribution prices		14.13%	0.53%	0.53%	0.53%	0.53%	3.3%
AER draft determination							
Residential bill	$2,000	$1,990	$1,980	$1,979	$1,985	$1,991	
Distribution charges	$968	$958	$948	$947	$953	$959	
Change in residential bill		-$10	-$10	-$2	$6	$6	-$2
Percentage change in residential bill		-0.50%	-0.49%	-0.08%	0.30%	0.30%	-0.1%
Percentage change in distribution prices		-1.02%	-1.02%	-0.16%	0.62%	0.62%	-0.2%

Note: Assumes a typical residential bill of $2,000, an inflation forecast of 2.62 per cent, demand growth of 1 per cent and distribution proportion of 48 per cent.
Source: AER analysis.

The AER estimates its draft determination will decrease a typical residential bill by approximately 0.1 per cent per annum (on average) over the forthcoming regulatory control period. This compares to the increase of approximately 2.1 per cent per annum (on average) from Aurora's regulatory proposal.

[116] 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.

[117] 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.

11 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 its framework and approach paper, the AER classified the following services as alternative control services:[118]

- 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.

11.1 Draft 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.[119] The AER considers that Aurora should demonstrate compliance with the control mechanism through an annual pricing proposal.[120]

The basis of the control mechanism for alternative control services must be determined in the distribution determination.[121] 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. This differs from Aurora's proposal to apply a replacement cost annuity approach for these services.[122]
- 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.
- 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.

118 AER, F*ramework and approach paper*, November 2010, pp. 84–85.
119 NER, clause 6.12.1(12).
120 NER, clause 6.12.1(13), clause 6.18.
121 NER, clause 6.2.6(b).
122 Aurora, *Regulatory proposal*, p. 234.

- 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.

11.2 Summary of analysis and reasons

The AER's decision to apply a limited building block based on the RAB roll forward approach as the basis of the control mechanism for metering services represents a significant departure from Aurora's regulatory proposal. Aurora proposed to apply a replacement cost annuity approach for these services.[123]

The AER considers that the RAB roll forward approach better satisfies the NER criteria.[124] The administrative costs are likely to be immaterial as Aurora currently collects the information required to establish a RAB. There is limited potential for the development of competition for metering services. The application of a RAB roll forward is supported by the desirability for a consistent regulatory approach in the NEM. The RAB approach better meets the requirements of the NEO and RRP by providing for recovery of efficient capital costs more accurately. It is not supported by the historical regulatory practice in Tasmania, but the AER considers the desire for NEM consistency and the NEO and RRP should be given more weight.

Using a RAB roll forward approach, the AER has also made the following adjustments to Aurora's methodology and model inputs:

- removal of fully depreciated meters from the initial asset base—The AER's estimate of the initial written-down RAB for meter stocks is $35 million ($2009-10). This RAB is based on depreciated replacement cost and includes about 62 per cent of the meters currently in service. The other 38 per cent of the meter population have been fully depreciated, based on their previous regulatory asset lives as applied by OTTER. Therefore these assets are not eligible to be included in the initial RAB to earn a further return.
- reduction in costs of meters—For the purpose of calculating the initial RAB, the AER has used:
    - for mechanical meters, the replacement costs as accepted by OTTER in 2007, escalated for inflation. Mechanical meters are no longer an industry standard for new meters and the AER found no evidence of current market prices to justify Aurora's proposed cost or set an alternative price.
    - for electronic meters, replacement costs based on a market quote obtained by Aurora in 2010. The AER accepts that current replacement costs may be an appropriate proxy for the reasonable and efficient costs for meters, in particular where these are based on competitive market prices. The AER found that Aurora's proposed cost for meter purchase is above recent costs for DNSPs in Victoria.[125]
- increase in the regulatory life of mechanical meters from 20 to 30 years—Based on analysis of data provided by Aurora, the AER considers a useful operating life for existing mechanical meters is between 30 and 40 years.[126] The AER considers a 30 year life for mechanical meters should be used in the building block model from 2012–13 since it is within this range, and matches Aurora's accounting life for this asset.

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[123] Aurora, *Regulatory proposal*, p. 234.
[124] NER, clause 6.2.5(d).
[125] Nuttall Consulting, *Aurora electricity distribution review: report to AER, Confidential final report—Appendix C: Alternative Control Services*, 5 October 2011, pp. 178–179.
[126] Ibid, pp. 187–188.

- reduction in proposed rate of installation of new meters—The AER considers reductions are required for new installations and Pay As You Go (PAYG) meters. The AER also made reductions in the proposed rate of replacement of mechanical meters by electronic meters.
- applying post-tax WACC with Aurora's accelerated tax depreciation rate.

Attachment 15 and Appendix C contain the AER's detailed reasoning for Aurora's metering services. Appendixes D and E contain the AER's detailed reasoning for Aurora's public lighting, fee based and quoted services.

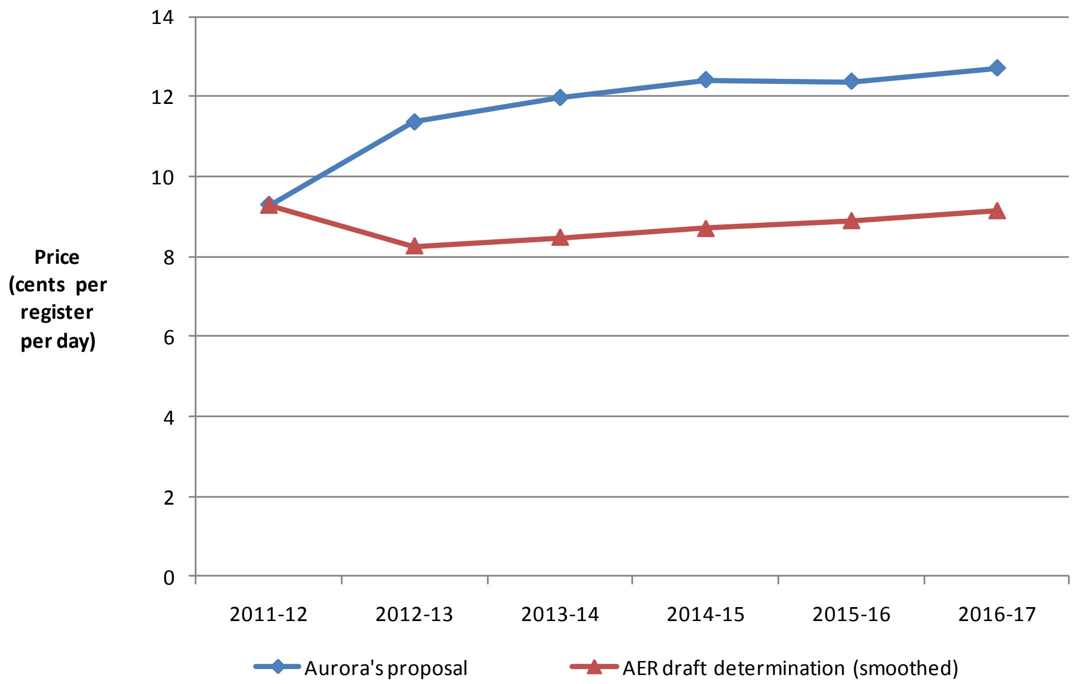
11.3 Prices

This section contains the AER's draft determination prices for some common metering and public lighting services. Appendixes C, D and E contain the AER's complete draft determination prices for alternative control services.

11.3.1 Metering prices

The AER's draft determination on metering services has resulted in price caps that are on average 29 per cent below those proposed by Aurora. Further, the AER prices are on average 6 per cent below those approved by OTTER for 2011–12 (in nominal prices). The AER has determined smoothed prices to reduce the variability of the price path over the forthcoming regulatory period. Figure 11.1 shows the weighted average metering prices for meter types.

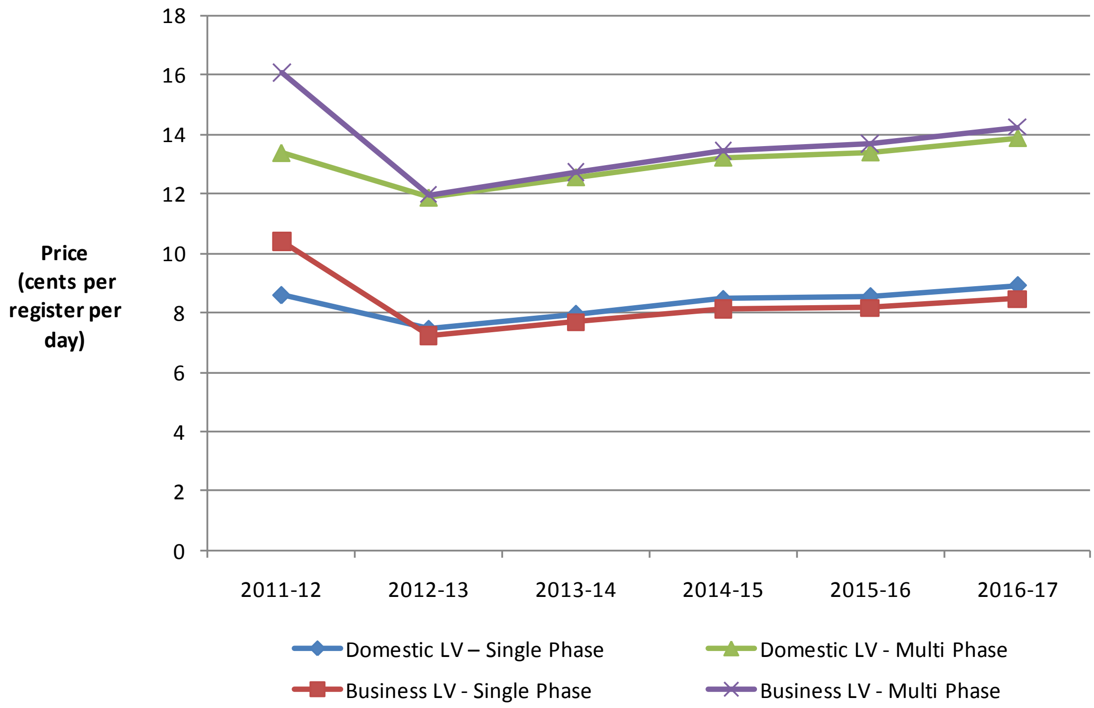
Figure 11.1 Weighted average metering prices for all meter types ($nominal)



Source: AER analysis.

Figure 11.2 shows the AER draft determination prices for common metering services, and Table 11.1 lists the prices for these meter types.

Figure 11.2 Current and AER draft determination prices for common metering services ($nominal)



Source: AER analysis.

Table 11.1 AER draft determination prices for common metering services ($nominal, cents per register per day)

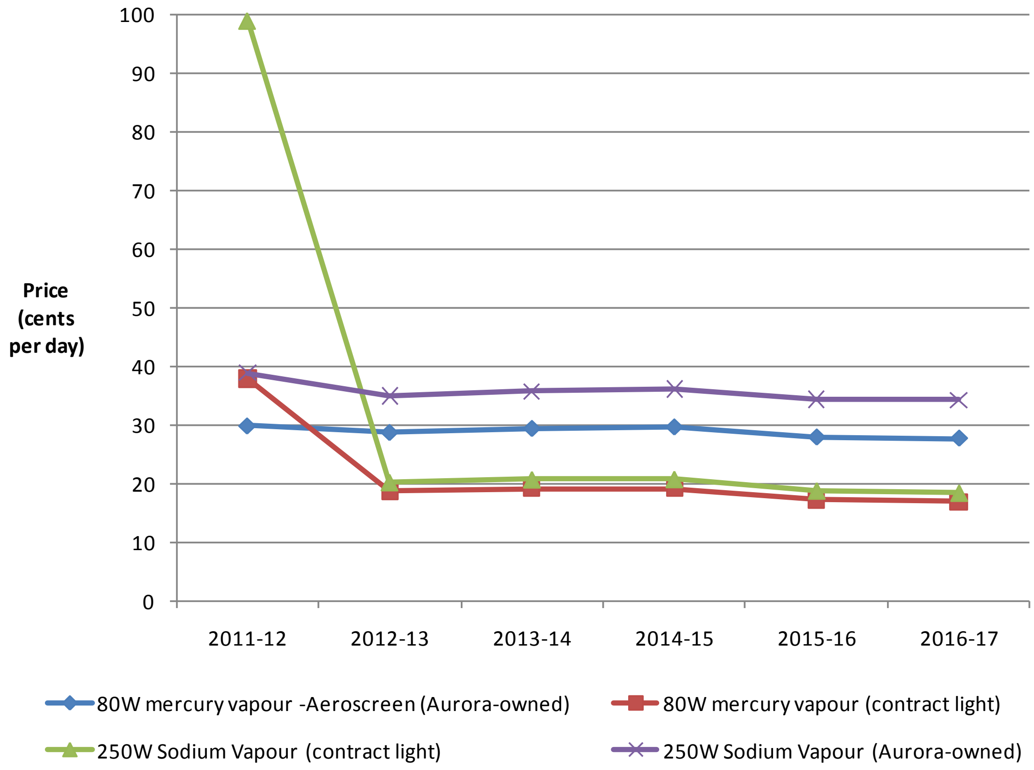
	2012-13	2013-14	2014-15	2015-16	2016-17
Business LV - Single Phase	7.600	7.769	7.945	8.075	8.268
Business LV - Multi Phase	12.720	13.006	13.286	13.671	14.024
Domestic LV – Single Phase	7.819	8.031	8.248	8.431	8.674
Domestic LV - Multi Phase	12.631	12.859	13.082	13.404	13.695

Note: 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.

11.3.2 Public lighting prices

The AER's draft 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 11.3 compares current prices with AER draft determination prices for Aurora's common public lighting services.

Figure 11.3 Current and AER draft determination prices for common public lighting assets ($nominal)



Source: AER analysis.

Table 11.2 compares the AER's draft determination price caps for 2012–13 with Aurora's proposed price caps for common public lighting assets. The AER's draft determination on public lighting services has resulted in price caps that are on average 19 per cent below those proposed by Aurora.

Table 11.2 Comparison of AER draft determination price caps and Aurora proposed price caps for 2012–13 for common public lighting assets ($nominal, cents per day)

	Aurora's proposed price cap for 2012–13	AER draft determination price cap for 2012–13	% difference between AER draft determination and Aurora's proposal
80W mercury vapour (private contract)	23.03	18.65	-19%
80W mercury vapour (Aurora owned)	36.49	28.71	-21%
250W sodium vapour (private contract)	24.80	20.29	-18%
250W sodium vapour (Aurora owned)	42.87	34.93	-19%

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

Attachments

1 Classification of Aurora's distribution services

The AER is required to make a decision on the classification of Aurora's distribution services.[127] A departure from the framework and approach classifications is only allowed in certain circumstances.[128]

The AER set out its likely approach to the classification of distribution services for Aurora in its framework and approach paper.[129] The AER proposed to group Aurora's distribution services into the following categories:

- network services;
- metering services;
- public lighting services;
- fee-based services;
- connection services; and
- quoted (non-standard) services.

1.1 Draft determination

The AER considers the classification of Aurora's distribution services should be in accordance with the classifications set out in the AER's framework and approach paper and therefore removes the inclusion of the service 'new connection–install service & meters' from Aurora's alternative control services.

1.2 Aurora's proposal

Aurora accepted the AER's proposed classification of distribution services in its regulatory proposal.[130] However, Aurora also proposed prices for an alternative control service ('new connection – install service & meters')[131], which is inconsistent with Aurora's acceptance of the AER's classification of connection services as standard control services.

1.3 AER approach

The AER is required to make a decision on the classification of the services to be provided by Aurora during the course of the regulatory control period.[132] The AER must adopt the classification of distribution services as set out in the framework and approach paper unless the AER considers, in light of Aurora's regulatory proposal and submissions received, there are good reasons for departing from the classifications proposed.[133]

[127] National Electricity Rules (NER), clause 6.12.1(1).
[128] NER, clause 6.12.3(b).
[129] AER, *Final framework and approach paper for Aurora Energy*, November 2011, Chapter 2. (AER, *Framework and approach paper*, Nov 2011)
[130] Aurora, *Energy to the people: Regulatory Proposal*, 31 May 2011, pp. 65–67 (Aurora, *Regulatory proposal*, May 2011)
[131] Aurora, *Regulatory proposal*, May 2011, p. 243.
[132] NER, clause 6.12.1(1).
[133] NER, clause 6.12.3(b).

The AER's assessment of the classification of services does not determine how costs associated with the services will be recovered; that is discussed in the relevant control mechanisms chapters.[134]

The AER's approach is to adopt the classifications of the framework and approach paper, but provide further clarity for connection services.

1.4 Reasons for determination

The AER does not consider there are good reasons for departing from the classifications proposed in the framework and approach paper because nothing in Aurora's proposal or submissions received suggests the AER framework and approach classifications are inappropriate.[135]

However, Aurora's proposal is ambiguous in relation to connection services, so the AER has addressed this ambiguity.

In 2007, the Office of the Tasmanian Economic Regulator (OTTER) declared new connection services as 'special services'[136], and proposed to regulate them under a price cap.[137] Although OTTER subsequently removed the cost of services for new connections from the special services price cap in 2008, Aurora still provides various new connection services for a fixed fee.[138]

One such service is Aurora's 'standard' new connection service (install service wire and meters)—a special service—but the fee is $0[139] because Aurora actually recovers the cost of these connection services through distribution use of system (DUOS) charges.[140] For this reason, the AER classified standard connection services as standard control services in its framework and approach paper.[141] However, the AER also classified all special services as alternative control services.[142]

The AER considers connection services should be classified as standard control services, and considers 'new connection–install service & meters' should be removed from Aurora's alternative control services to avoid confusion. The AER's decision to classify Aurora's distribution services is made on the basis of the following information provided by Aurora:

- Aurora confirmed that the inclusion of 'new connection–install service & meters' as part of Aurora's alternative control services was an administrative error, and that it is not intending to charge the proposed prices. Aurora also updated the relevant models to remove the costs that had been erroneously allocated to this new service.[143]
- Aurora confirmed that it had accepted the AER's framework and approach classification of connection services as standard control services.[144]

The AER's classification of Aurora's distribution services is displayed in Table 1.1.

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134 See Attachment 2 for standard control services and Attachment 15 for alternative control services.
135 In accordance with NER, clause 6.12.3(b).
136 Special services are services for which Aurora charges on the basis of either a fixed fee or a quote. OTTER regulates some of these services under a price cap, and monitors the prices set by Aurora for the remainder.
137 OTTER, *Statement of Reasons*, Jan 2007, p. i; p. 16.
138 Aurora, *Prices for the provision of Distribution Special Services for the period 1 July 2011 until 30 June 2012*, April 2011, p. 8 (Aurora, *Distribution Special Services prices 2011–2012, April 2011*).
139 Aurora, *Distribution Special Services prices 2011–2012, April 2011*, p. 8.
140 This is discussed further in AER, *Framework and approach paper*, Nov 2011. See p. 46.
141 AER, *Framework and approach paper*, Nov 2011, p. 53.
142 AER, *Framework and approach paper*, Nov 2011, p. 45.
143 Aurora, *Response to information request AER/012* (follow up request of 5 August 2011), received 9 August 2011, p. 3.
144 Aurora, *Response to information request AER/012 of 21 July 2011*, received 22 July 2011, pp. 3-4.

1.5 Revisions

The AER has made one revision to Aurora's proposed classification of services.

Revision 1.1: The AER has removed the fee-based service 'new connection – install service & meters' from Aurora's alternative control services.

Table 1.1 The AER's classification of Aurora's distribution services

Service category	Direct control services: standard control	Direct control services: alternative control	Negotiated distribution services	Unregulated services
Network services	Standard network services			
Metering services		Type 5–7 metering services		Type 1–4 metering services PAYG metering services provided by Aurora Retail
Public lighting services		All public lighting services (except new public lighting technology and alteration and relocation of public lighting assets)	New public lighting technology	
Connection services	Standard connection services and connections requiring augmentation			Capital contributions component of connections requiring augmentation
Fee based services		All fixed fee special services **except** 'new connection–install services & meters'		
Quoted services		All quoted (non-standard) services including above standard network and metering services Alteration and relocation of public lighting assets		

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

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.[145] The AER will make constituent decisions on:

- the control mechanism (including the X factor) for standard control services[146]
- how the distribution network service provider (DNSP) is to demonstrate compliance with the relevant control mechanism[147]
- how the DNSP is to report to the AER on its recovery of transmission use of system (TUOS) charges[148] for each regulatory year, and adjustments to be made in pricing proposals in subsequent years to account for TUOS over or under recoveries[149]

2.1 Draft determination

The AER's framework and approach paper for Aurora Energy (Aurora) decided a revenue cap control mechanism would apply to Aurora's standard control services in the forthcoming regulatory control period.[150] The AER decided that the control mechanism will:

- be of the prospective CPI-X form (or some incentive-based variant)
- accord with Part C of the NER
- have a basis as specified in the AER's draft and final distribution determinations.

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 over and under recoveries on a two year lagged basis.

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

- trunk mobile radio (TMR) levy
- the full retail contestability charges (FRC)

[145] NER, clause 6.2.5(a).
[146] NER, clause 6.12.1(11).
[147] NER, clause 6.12.1(13).
[148] Representing the avoided customer TUOS charges referred to in the designated pricing proposal charges definition under the NER, clause 6.12.1(19).
[149] NER, clause 6.12.1(19).
[150] AER, *Framework and Approach*, November 2011, pp. 62–85.

- excess guaranteed service level (GSL) costs (GSLse and GSLcap)

To close out the revenue adjustments from the control mechanism of the current regulatory control period that will not be non-ongoing into the forthcoming regulatory control period, the AER will use a transitional factor (defined in the revenue control formula in section 2.5 below). The transitional parameter will also include final NEM participation costs incurred by Aurora that will finish in the current regulatory control period. The transitional parameter will close out all of these non-ongoing revenue adjustments, lapsing no later than 2013-14.

The revenue cap formula is outlined in detail in section 2.5.1 below.

2.2 Aurora's proposal

Aurora has proposed a revenue cap control mechanism but with a number of specific adjustments to the generic form. Figure 2.1 is the form of control for standard control services proposed by Aurora to apply in the forthcoming regulatory control period.

Figure 2.1 Aurora's proposed revenue cap[151]

$$MAR_t = AR_{t-} \times (1 + \Delta CPI_t) \times (1 - X_t) + [(ESISC_t + NEMC_t + TMR_t + GSLse_t) \times (1 + CPI_t)]$$
$$+ NEM_t + FRC_t + GSLcap_t + unders\ \&\ overs_t$$

As outlined in Figure 2.1, Aurora proposed a revenue cap inclusive of a large number of revenue adjustment mechanisms. Aurora proposed the continuation in the forthcoming regulatory control period of the following revenue adjustment mechanisms from the current regulatory period[152]:

- GSL
- TMR levy
- FRC
- ESISC
- under and over recoveries from prior period revenues (unders & overs)
- NEMC

Aurora also proposed a method for calculating the adjustment of under or over recovery of TUOS charges as required by the NER.[153]

In addition, Aurora proposed a new revenue adjustment mechanism for unfunded shared network events.[154] Unfunded shared network events are significant projects taking place during the regulatory control period that are not known about when preparing the regulatory proposal. Such projects involve a new large customer seeking to be supplied and requiring the construction of new connection assets and a need to augment the existing network.[155]

151 AER's formulaic presentation of Aurora's proposal based on the control formula in Aurora Energy, Calculation of the maximum annual revenue for distribution network services for the period from 1 Jul 2011 to 30 Jun 2012 (Period 5), p. 1.
152 Aurora, *Regulatory Proposal*, May 2011, pp. 225–227.
153 NER, clause 6.12.1(19).
154 Aurora, *Regulatory Proposal*, May 2011, p. 229.
155 Aurora, *Regulatory Proposal*, May 2011, p. 229.

In relation to side constraints, Aurora proposed it be allowed to recover adjustments associated with the under or over recovery of revenue over two consecutive regulatory years and that it not be subject to side constraints.[156]

2.3 Assessment approach

The AER issued a regulatory information notice (RIN) to Aurora prior to lodgement of its regulatory proposal. In that RIN, the AER required Aurora to state its position on the precise form of the revenue cap.

In deciding on a control mechanism for standard control services, the AER assessed all of Aurora's proposed revenue adjustment mechanisms in light of the factors in clause 6.2.5(c) of the NER. For those revenue adjustments the AER decided should not apply during the forthcoming regulatory control period, a transitional parameter was applied to close out the effect of these. This is set out in section 2.5 below.

2.4 Reasons for draft determination

The AER accepts Aurora's proposal that the control mechanism for standard control services be a revenue cap. The AER also accepts:

- the proposed DUOS unders and overs mechanism
- the proposed NEMC charge cost revenue adjustment mechanism
- the ESISC revenue adjustment mechanism, in the event Aurora wins the tender to provide these services in the forthcoming regulatory control period.

The AER however does not consider that some of Aurora's proposed revenue adjustment mechanisms should from part of the control mechanism on the basis they are not consistent with clause 6.2.5(c) of the NER. An assessment of each of the components of the control mechanism proposed by Aurora in light of clause 6.2.5(c) of the NER is detailed below.

2.4.1 Revenue adjustment mechanisms

Excess GSL costs revenue adjustment mechanisms

Aurora proposed the continuation of two GSL revenue adjustment mechanisms [GSL Cap (GSLcap) and Excess GSL Payments (GSLse)].[157]

The AER considers the two GSL cost revenue adjustment mechanisms should not form part of the control mechanism for standard control services in the forthcoming regulatory control period. The AER will account for the adjustment of GSL revenue costs occurring in the last year of the current regulatory period through the transitional parameter in the revenue cap formula (defined in section 2.5.1 below).

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

[156] Aurora, *Regulatory Proposal*, May 2011, p. 229.
[157] Aurora, *Regulatory Proposal*, May 2011, p. 227.

bottom line.[158] AER calculations indicate Aurora has not breached this cap during the current regulatory period.

The excess 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 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.[159] The remaining half contributes to calculations of whether Aurora has reached the cap for GSL payments over the period.[160]

These adjustment mechanisms are not part of the jurisdictional GSL scheme, and will not continue to apply unless specified in the control mechanism for standard control services. Aurora stated the continuation of these adjustments (and other proposed continued adjustments) are consistent with clause 6.4.3 of the NER.

The AER considers:

- The GSL revenue adjustment mechanisms protect Aurora from the financial consequence of extreme weather events. However, they also weaken the incentive for Aurora to efficiently invest in or undertake activity to reduce the likelihood and severity of events that are within its control as they limit Aurora's financial exposure to GSL payments more generally. This weakened incentive should not be part of Aurora's control mechanism as it results in a lower incentive to minimise outages than would occur in the absence of the adjustment mechanisms and is not consistent with the national electricity objective.[161]
- Tasmania is the only jurisdiction in the NEM where these GSL revenue adjustment mechanisms in the control mechanism exist.
- Aurora is also seeking to limit its financial exposure by proposing separate pass through events for natural disasters, bushfires and storms.[162] The question of whether Aurora should bear the risk of extreme weather events has been considered in the AER's review of Aurora's proposed pass through events.[163]
- Under the GSL scheme widespread interruptions related to rare events can be excluded if approved by the regulator.[164]

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 outweighed maintaining consistency with Aurora’s previous regulatory arrangements. Consideration of these factors is outlined in Table 2.1 below.

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

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

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

161 NEL, section 7.

162 Aurora, *Regulatory Proposal*, May 2011, p. 209.

163 The AER accepts natural disasters as a nominated pass through event. See page 2 of attachment 14.

164 OTTER, *Guideline - Guaranteed Service Level Scheme*, December 2007, pp. 2–6.

Table 2.1 NER factors and GSL revenue adjustment mechanisms

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	There are no additional administrative costs to Aurora in implementing these mechanisms as they exist in its current control mechanism. The impact on the AER's administrative costs would be small.
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.[165] Weakened incentives to minimise GSL payments and reduce outages is not consistent with the NEO as they do 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.

Trunk mobile radio

Aurora proposed the continuation of a revenue adjustment mechanism relating to its involvement in the joint government departmental cost of running the trunk mobile radio (TMR) communications network within Tasmania for emergency services.[166] This charge is levied upon Aurora by the Police and Emergency Management Department each financial year.[167]

The AER does not accept that the TMR revenue adjustment mechanism should form part of the control mechanism for standard control services in the forthcoming regulatory control period. However, forecast TMR costs should be (and are) included in Aurora's opex. The AER will account for the adjustment of TMR revenue costs occurring in the last year of the current regulatory period through the transitional parameter in the revenue cap formula (defined in section 2.5.1 below), lapsing in 2013-14.

The AER considers:

- Absent a legal obligation on Aurora to participate in the TMR, the decision to continue to participate in the TMR and incur costs associated rests with Aurora.[168] Where the TMR is used in the provision of the electricity distribution services by Aurora, it can include the costs of this service in its forecasts of the costs of providing direct control services. The TMR expenditure would then be assessed by the AER in reviewing Aurora's proposed opex for direct control services.

165 NEL, sections 7 & 7A.
166 Aurora, *Regulatory Proposal*, May 2011, p. 227.
167 Aurora, *Regulatory Proposal*, May 2011, p. 227.
168 Aurora, *Response to information request AER/019 of 29 July 2011*, received 8 August 2011, p. 3.

- The current regulatory arrangements were established by OTTER due to uncertainty of these costs during OTTER's 2007 determination.[169] OTTER decided a revenue adjustment mechanism would balance this uncertainty.
- While there has been a discrepancy between forecast and actual expenditure on TMR in the current regulatory period, this does not indicate Aurora would not be able to more accurately forecast this cost for the forthcoming regulatory control period.[170] Indeed, the absence of the revenue adjustment mechanism would provide it with an incentive to forecast more accurately and incur costs more efficiently. This incentive is consistent with the NEO and RPP.[171]

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 2.2 below:

Table 2.2 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 will not affect the efficiency of tariff structures.
Administrative costs	There are no additional administrative costs to Aurora in implementing the TMR mechanism as it exists in its current control mechanism. 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 take what steps it can to ensure that it incurs TMR 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.

Full retail contestability costs

Aurora proposed the continuation of a revenue adjustment mechanism relating to the implementation of full retail contestability costs (FRC).[172] The first five tranches of retail contestability have been progressively undertaken.

169 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: Final report and proposed maximum prices*, September 2007, p. 167.
170 Aurora, *Response to information request AER/019 of 29 July 2011*, received 8 August 2011, p. 3.
171 NEL, sections 7 & 7A,
172 Aurora, *Regulatory Proposal*, May 2011, p. 227.

A new tranche of contestability was introduced on 1 July 2011 for business customers that use between 50MWk and 150MWh of electricity per year.

The decision on the final rollout, of FRC to residential customers, is still with the Tasmanian Government, with no indication of likely commencement or timing.

The AER does not accept the FRC revenue adjustment mechanism should form part of the control mechanism for standard control services in the forthcoming regulatory control period. The AER considers:

- Aurora will incur costs only if the Tasmanian Government decides to implement FRC.
- If incurred, it is more appropriate to assess these costs as a pass through event under the NER.[173] This approach is consistent with the AER's treatment in other jurisdictions where the costs and timings of new requirements are unknown.[174]
- There exists the possibility of additional administration costs in treating the FRC under a pass through event to both the AER and Aurora instead of under a revenue adjustment.[175] However, these costs are only incurred in the event further tranches of customers are made contestable during 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. In deciding that the FRC revenue adjustment mechanism should not be included in the control mechanism, the AER considers that desirability for a consistent regulatory approach across jurisdictions outweighed maintaining consistency with Aurora's previous regulatory arrangements. Consideration of these factors is outlined in Table 2.3 below:

Table 2.3 NER factors and the FRC revenue adjustment mechanism

NER Factor	AER consideration
Efficient tariff structures	The inclusion of the FRC mechanism into the control mechanism for standard control services would not affect the efficiency of tariff structures.
Administrative costs	There are no additional administrative costs to Aurora in implementing the FRC mechanism as it exists in its current control mechanism. The impact on the AER's administrative costs would be small.
Previous regulatory arrangements	The FRC revenue adjustment mechanism is part of the control mechanism applied in the current regulatory period.
Desirability for a consistent regulatory approach	A FRC revenue adjustment mechanism is not present in the control mechanism established by the AER for any other DNSP in the NEM. Similar costs for other DNSPs across the NEM have been accepted as nominated pass through events by the AER.[176]
Any other relevant factor	There are no other relevant factors.

173 NER, Chapter 10.

174 See for example smart meters in Queensland. AER, *Final Decision: Queensland distribution determination, 2010-11 to 2014-15*, p. 310.

175 NER, clauses 6.2.5(c)(2) and (3).

176 See for example smart meters in Queensland. AER, *Final Decision: Queensland distribution determination, 2010-11 to 2014-15*, p. 310.

Unfunded shared network events

Aurora proposed a new revenue adjustment mechanism for unfunded shared network events.[177] Aurora stated where a new large customer seeks to be supplied from Aurora's distribution system, this often requires both the construction of new connection assets and a need to augment the network.[178]

The AER does not consider the unfunded shared network events revenue adjustment mechanism should be included in the control mechanism for standard control services. Aurora did not propose, and the AER has not made any allowance for the costs of these events in its draft determination on capital expenditure (capex).

This adjustment would allow Aurora to recover the costs for any significant new projects that take place during the forthcoming regulatory control period but were not known when Aurora prepared its regulatory proposal. Aurora stated this mechanism is required to:

- recover the cost of connection assets from the particular large customer
- recover the cost of augmentation from all customers who use the shared network assets[179]

Aurora noted its forecast capex does not provide for these costs, and proposes it be able to amend its revenue cap on an ex post basis to allow for a return on, and of, any such new assets.[180]

The unfunded shared network events revenue adjustment mechanism is broadly comparable to the risk sharing mechanism established by OTTER's 2007 determination. This risk sharing mechanism allowed Aurora to recover financial costs and depreciation on investment in excess of OTTER's allowance on operational and service connection assets, up to a capped level of expenditure. The cap is based on the Wilson Cook (OTTER's technical consultant) ‘prudent’ levels of expenditure (adjusted for the OTTER's wage and productivity assumptions).[181]

The AER considers:

- Aurora is only exposed to the risk of not recovering the financing costs of this expenditure (depreciation and WACC). All capex is rolled into the regulatory asset base (RAB) under the NER.
- While there may be uncertainty in forecasting this expenditure, the uncertainty would be greater for events toward the end of the regulatory control period. However, the financial consequence of forecasting uncertainty is lower for expenditure in the later years of the regulatory control period.
- Allowing the financing costs of unfunded shared network events to be passed through would reduce Aurora's incentive to incur these costs efficiently. For this expenditure, should Aurora propose unfunded shared network expenditure it would be unable to benefit from underspending its forecast, and would face no financial risk of overspending the forecast.
- The absence of these costs in Aurora's forecast of capex would mean the efficiency of these costs would not be reviewed by the AER.

177 Aurora, *Regulatory Proposal*, May 2011, p. 229.
178 Aurora, *Regulatory Proposal*, May 2011, p. 229.
179 Aurora, *Regulatory Proposal*, May 2011, p. 229.
180 Aurora, *Regulatory Proposal*, May 2011, p. 229.
181 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: Final report and proposed maximum prices*, September 2007, p. VIII.

- The revenue adjustment mechanism would create an incentive for other capex to be categorised as unfunded shared network events. The ability to re-categorise capex associated with unfunded shared network events might also reduce Aurora's incentive to efficiently incur that capex.

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 unfunded shared network events revenue adjustment mechanism should not be included in the control mechanism, the AER considers that the high administrative costs of such a mechanism, the desirability for a consistent regulatory approach across jurisdictions and the possible perverse 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 unfunded shared network event mechanism

NER Factor	AER consideration
Efficient tariff structures	The inclusion of the unfunded shared network event mechanism into the control mechanism for standard control services will not affect the efficiency of tariff structures.
Administrative costs	The administrative costs to the AER of the unshared network events would be high as the AER would need to satisfy itself the proposed amounts truly related to unfunded shared network events.
Previous regulatory arrangements	While a risk sharing mechanism was established by OTTER's 2007 determination, there are significant differences between the operation of this mechanism and the unfunded shared network event mechanism.
Desirability for a consistent regulatory approach	There are no unfunded shared network event mechanisms in the control mechanisms established by the AER for NEM DNSPs.
Any other relevant factor	The NEO and RPP are relevant to the question of whether the unfunded shared network should be in the control mechanism for standard control services. The unfunded shared network revenue adjustment mechanism eliminates Aurora's incentives to incur unfunded shared network costs efficiently. These incentives do 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.

Electrical safety inspection service levy

Aurora proposed the continuation of a revenue adjustment mechanism for its involvement in undertaking electrical inspection services. Aurora undertakes these services on behalf of Workplace Standards Tasmania (WST) in accordance with the *Electricity Industry Safety and Administration Act 1997 (EIS&A Act)*.[182] WST is responsible for providing these services, and tenders out for the contract to provide these services on behalf of WST.

A mechanism exists under the *Electricity Supply Industry Act 1995 (ESI Act)* for the Minister to estimate and require an electricity entity to pay for the electrical safety inspection service charge (ESISC).[183] OTTER's 2007 determination provided for an adjustment mechanism to account for any discrepancies between the forecast allowance and the actual allowance for the ESISC.

182 Aurora, *Regulatory Proposal*, May 2011, p. 226.
183 Clause 121B(2) and 121B(4) of the EIS&A Act.

However, Aurora's contract expires on 30 June 2012 and WST will go out to tender for a provider of these services from 1 July 2012. Whether or not Aurora wins the tender to provide these services, the Minister has the ability to require Aurora to pay the electrical service inspection charge.

The AER does not consider that the ESISC revenue adjustment mechanism should be included in the control mechanism for standard control services if Aurora does not win the contract starting 1 June 2012. The AER considers:

- The provision of an electrical safety inspection service falls within the definition of a cost incurred in providing standard control services but Aurora will only incur these costs if it wins the contract to provide these services post 1 July 2012. If Aurora does not win the contract, Aurora will not incur costs in providing standard control services. In this instance, the ESISC should not be part of the control mechanism for standard control services.
- If Aurora wins the contract, the treatment of these costs as a revenue adjustment mechanism is appropriate. This is because it will not impact on Aurora's incentive as it does not have any control over the amount of the ESISC as it is determined by the Minister under the *EIS&A Act.*
- An allowance will be made in the forecast opex and the proposed revenue adjustment mechanism will balance the difference between the actual and forecast charge.
- If Aurora does not win the contract, then these costs should not be part of Aurora’s control mechanism for standard control services.

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 making its decision on the ESISC revenue adjustment mechanism, the AER considered that the desirability for consistency across jurisdictions and the impact of the mechanism on Aurora’s incentives would outweigh maintaining consistency with Aurora’s previous regulatory arrangements if it did not win the contract. Consideration of these factors is outlined in Table 2.5 below:

Table 2.5 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.
Administrative costs	There are no additional administrative costs to Aurora in implementing the ESISC mechanism as it exists in its current control mechanism. 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 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.

National electricity market charge

Aurora proposed a revenue adjustment mechanism for the pass through of costs relating to Tasmania's costs of funding the Australian Energy Market Commission (AEMC). Clause 121.2 of the ESI Act provides for the Minister to determine an electricity entity to be subject to the charge, and determine the amount of the charge.

The AER accepts the NEMC revenue adjustment mechanism. The AER considers:

- While Aurora incurs these costs in the provision of standard control services, the amount of this charge is entirely beyond its control. These costs are incurred by the AEMC and its contribution to this cost is determined by the Minster under the ESI Act.
- As the amount of these costs are not within the control of Aurora, there is no impact on Aurora's incentives.
- An allowance will be made in the forecast opex and this revenue adjustment mechanism will balance the difference between the actual and forecast charge.

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 light of the uncontrollable nature of these costs and the presence of the parameter in the current control mechanism, on balance, the AER considers that the NEM levy revenue adjustment mechanism should be included in the control mechanism for standard control services. Consideration of these factors is outlined in Table 2.6 below:

Table 2.6 NER factors and the NEMC

NER Factor	AER consideration
Efficient tariff structures	The inclusion of the NEMC revenue adjustment mechanism in the control mechanism for standard control services will not affect the efficiency of tariff structures.
Administrative costs	There are no additional administrative costs to Aurora in implementing the NEM mechanism as it exists in its current control mechanism. The impact on the AER's administrative costs would be small.
Previous regulatory arrangements	The NEM charge revenue adjustment mechanism is part of the control mechanism applied in the current regulatory period.
Desirability for a consistent regulatory approach	No other DNSP in the NEM has applied for a NEMC revenue adjustment mechanism in their control mechanism. These costs are included in base opex in other DNSPs in the NEM. However clause 121.2 of the Tasmanian ESI Act provides for the Minister to determine an electricity entity to be subject to the charge, and determine the amount of the charge.
Any other relevant factor	The NEO and RPP are relevant to the question of whether the NEMC should be in the control mechanism for standard control services. As Aurora has no control over the NEMC, the NEMC revenue adjustment mechanism will not impact on Aurora's incentive to incur costs efficiently.

NEM participation costs

Aurora's costs of participating in the NEM in the current regulatory period are now fully absorbed into the base opex. However, because the revenue adjustment mechanism in the current regulatory period operates with a two year lag, the last two years of the current regulatory period will be accounted for as part of the transitional parameter in the revenue cap for the forthcoming regulatory control period, lapsing in 2013-14. This is discussed in section 2.5.

2.4.2 Under and over recovery mechanism of TUOS and DUOS

TUOS under and over recovery mechanism methodology

TUOS charges are recovered from distribution customers through the pricing proposal.[184] Aurora's proposed unders and overs mechanism, uses a two year lag before the difference between actual and forecast costs are accounted for in the pricing proposal.

Under this approach the difference between the charges for transmission services and the amount recovered through distribution prices for transmission services in a given year are incorporated into distribution prices two years later.

Aurora uses a different approach to account for the under and over recovery of DUOS charge. For DUOS, instead of waiting two years before incorporating the under or over recovery into prices, Aurora uses an estimate (based on nine months of data) into the calculation of the under or over recovery. The inclusion of this estimate has the effect of smoothing the impact of the under or over recovery into prices.

The AER has decided to apply a TUOS under and over recovery mechanism consistent with Aurora's DUOS under and over recovery mechanism. The AER considers:

- Aurora's proposed approach uses a two year lag of actual data reconciled against forecast data. This approach can result in undesirable price impacts because the impact of an under or over recovery takes two years to be realised and is not moderated by the incorporation of an estimate.
- An approach similar to Aurora's DUOS under and over recovery mechanism is more appropriate because the likelihood of undesirable price shocks is reduced. This approach uses Aurora's TUOS approach but also incorporates estimated and forecast data for the year in between. This method creates a smoothing of the TUOS under and over recovery because it provides more updated and accurate estimated and forecast data in the middle year.

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 TUOS unders and overs mechanism should operate in the same way as Aurora’s DUOS unders and overs mechanism, the AER considered that the impact on efficient tariff structures and the desirability for a consistent regulatory approach TUOS and DUOS unders and overs outweighed maintaining consistency with Aurora’s previous regulatory arrangements. Consideration of these factors is outlined in Table 2.7 below:

184 These avoided customer TUOS charges are referred to in the designated pricing proposal charges definition under the NER, clause 6.18.2(b)(6).

Table 2.7 NER factors and the TOUS unders and overs mechanism

NER Factor	AER consideration
Efficient tariff structures	The AER considers efficient tariff structures should reflect the efficient costs of providing services. Mechanisms where changes in tariffs do not reflect underlying changes in the costs of providing services distort the ability of tariffs to send appropriate signals to consumers. Such distortions are not consistent with the need to set efficient tariff structures.
Administrative costs	There are no additional administrative costs associated with Aurora's proposed approach to accounting for TUOS under and overs.
Previous regulatory arrangements	The TUOS unders and overs revenue adjustment mechanism is part of the control mechanism applied in the current regulatory period.
Desirability for a consistent regulatory approach	Aurora and the Queensland DNSPs are the only DNSPs subject to revenue caps in the NEM. The Queensland DNSPs account for TUOS under and over recovery in the same way as proposed by Aurora. The transitional provisions in the NER allowed Queensland DNSPs to continue with this approach to TOUS unders and overs mechanism used by the Queensland Competition Authority. No such transitional provisions apply in Tasmania.
Any other relevant factor	There are no other relevant factors.

DUOS over and under recovery

The AER has decided to apply Aurora's proposed DUOS under and over recovery mechanism to smooth the impact of over and under recovery into prices year on year. The AER's reasons are the same for the TUOS under and over recovery as set out above.

Side Constraints

Aurora proposed any revenue adjustment associated with under or over recovery of revenues not be subject to the side constraint set out in clause 6.18.6 of the NER.[185] The AER rejects this proposition in Aurora's proposal.

The AER considers the application of the unders and overs in the side constraint formula provides for the appropriate treatment of these revenue adjustments in keeping with clause 6.18.6 of the NER.

2.5 Control mechanism formulas

Aurora as part of its pricing proposals must submit to the AER proposed tariffs and charging parameters which lead to expected revenues consistent with the MAR formula set out below plus any unders and overs adjustment needed to move the balance of their DUOS unders and overs account to zero

2.5.1 Revenue cap formula

Figure 2.2 is the form of control for standard control services for Aurora to apply in the forthcoming regulatory control period.

185 Aurora, *Regulatory Proposal*, May 2011, p. 226.

Figure 2.2 AER's draft 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[186]
  - 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[187]
- $passthrough_t$ is the approved pass through amounts with respect to regulatory year t, as determined by the AER
- ESISC is the actual overs or unders from the estimated ESISC costs in regulatory year t-1 if Aurora wins the contract to undertake the electrical safety inspection services
- NEMC is the actual overs or unders from the estimated NEMC costs in regulatory year t-1
- Transitional is the remaining under or over non-ongoing revenue adjustments to be made for TMR and GSL in 2012-13, and for FRC and NEM in 2013-14, in relation to unders or overs from the last year of current regulatory period as defined in section 2.5.5 below.

2.5.2 Side constraints

Aurora will be required to demonstrate in their 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:

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

187 In the formulas in the STPIS 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.

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

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
- $passthrough_t$ 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 overs or unders from the estimated ESISC costs in regulatory year t-1
- NEMC is the actual overs or unders 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 a transitional factor revenue adjustments from the current regulatory period that will not be ongoing in the forthcoming regulatory period

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).

2.5.3 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 ($ESISC_y$):[188]

$ESISC_y = (ESISCa_{y-1} - ESISCf_{y-1})x(1+WACC)$

where,

- $ESISCa_{y-1}$ is the actual charge for the period previous to the relevant period
- $ESISCf_{y-1}$ is the forecast charge for the period previous to the relevant period

188 Aurora, *Regulatory proposal*, Other Revenue Adjustments Appendix, May 2011, p. 5.

- WACC is the Weighted Average Cost of Capital for a full year

2.5.4 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 ($NEMC_y$):[189]

$NEMC_y = (NEMCa_{y-1} - NEMCf_{y-1})x(1+WACC)$

where,

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

2.5.5 Transitional parameter

The AER will account for revenue adjustments from the current regulatory period that will not be part of the control mechanism for the 2012-2017 period through the transitional parameter in the revenue cap formula. The transitional parameter will lapse no later than 2013-14. Where required, the following illustrates how each individual adjustment will be calculated:

Trunk mobile radio

The adjustment for the difference between the actual trunk mobile radio network charge and the forecast charge for the previous period (TMR_y) is calculated on the following basis:[190]

$TMR_y = (TMRf_{y-1} - TMRa_{y-1}) \times (1 + WACC)$

where,

- $TMRa_{y-1}$ is the actual trunk mobile radio charge for the period previous to the relevant period
- $TMRf_{y-1}$ is the forecast trunk mobile radio charge for the period previous to the relevant period
- WACC is the Weighted Average Cost of Capital for a full year

Full retail contestability charges (FRC)

The adjustment for the difference between the actual revenue allowance and the forecast revenue allowance in prior periods for costs attributable to full retail contestability (FRC_y) is calculated on the following basis:[191]

$FRC_y = (FRCa_{y-2} - FRCf_{y-2})\ x+ (1 + WACC_{y-2}) \times (1 + WACC_{y-1})$

where,

[189] Aurora, *Regulatory proposal*, Other Revenue Adjustments Appendix, May 2011, p. 6.
[190] Aurora, *Regulatory proposal*, Other Revenue Adjustments Appendix, May 2011, p. 7.
[191] Aurora, *Regulatory proposal*, Other Revenue Adjustments Appendix, May 2011, p. 12.

- $FRCf_{y-2}$ is the forecast revenue in relation to the implementation of FRC for the period prior to the previous period
- $FRCa_{y-2}$ is the actual revenue in relation to the implementation of FRC for the period prior to the previous period
- $WACC_{y-1}$ is the Weighted Average Cost of Capital in the period previous to the relevant period
- $WACC_{y-2}$ is the Weighted Average Cost of Capital in the period prior to the previous period
- $FRCf_{y-2}$ is calculated on the following basis:
    - $FRCf_{y-2} = RAB_f \times WACC + DEPN_f + OM_f$

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 ($GSLse_y$) is calculated on the following basis:[192]

$GSLse_y = GSL_{y-1} \times (1 + WACC)$

where,

- GSL_{y-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_{y-1} is calculated on the following basis:
- $GSL_{y-1} = \sum_{events} ({}^{P}/_{2} \times 80)$

where,

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

GSLcap

$GSLCap_y$ is the adjustment to the AARR calculated as follows:[193]

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

192 Aurora, *Regulatory proposal*, Other Revenue Adjustments Appendix, May 2011, p. 8.
193 Aurora, *Regulatory proposal*, Other Revenue Adjustments Appendix, May 2011, p. 15–16.

- 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 y-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_y) is calculated on the following basis:[194]

$NEM_y = (NEMa_{y-2} - NEMf_{y-2}) \times (1+ WACC_{y-2}) \times (1+WACC_{y-1})$

where,

- $NEMf_{y-2}$ is the forecast revenue in relation to NEM and retail contestability costs for the period prior to the previous period

- $NEMa_{y-2}$ is the actual revenue in relation to NEM and retail contestability costs for the period prior to the previous period

- $WACC_{y-1}$ is the Weighted Average Cost of Capital in the period previous to the relevant period

- $WACC_{y-2}$ is the Weighted Average Cost of Capital in the period prior to the previous period

- $NEMf_{y-2}$ is calculated on the following basis:

  - $NEMf_{y-2} = RAB_f \times WACC + DEPN_f + OM_f$

2.5.6 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 distribution use of system (DUOS) unders and overs account. Aurora must provide information on this account to the AER as part of their annual pricing proposal under clause 6.18.2(b)(7) of the NER.

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[195]

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 weighted average cost of capital (WACC). No such interest charge applies to the opening balance for year t

[194] Aurora, *Regulatory proposal*, Other Revenue Adjustments Appendix, May 2011, p. 12.

[195] 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.

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 maximum allowed revenue (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 2.8. 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 should 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 2.8 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	49,564
Less under/over adjustment approved by the regulator for year t–2	800[a]	na	na
Less MAR for the relevant year	34,365	46,694	50,000
Allowed revenues (AR_t)	34,100	46,554	49,895
Transitional ($Transitional_t$)	240[b]	100	80
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	1,856	-2,933	-166
DUOS unders and overs account			
Nominal WACC	8.08%	8.08%	na
Opening balance	1,000[f]	3,087	166
Interest on opening balance	81	249	na
Under/over recovery for regulatory year	1,856	-2,933	-166[h]
Interest on under/over recovery for regulatory year	150	-237	na
Closing balance	3,087	166[g]	0[i]

(a) In this example, the regulator agreed the DNSP could over recover its revenues by $800,000 in year t–2 due to under recoveries in year t–3.
(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 than was forecast for that year. 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 dependant on Aurora applying for pass throughs.
(f) The opening balance for year t–2 is based on any DUOS under/over recoveries prior to year t–2 that have not been returned to (or recovered from) customers yet.
(g) This figure will be the 'under/over adjustment approved by the regulator for year t–2 for the annual price approval process in two year's time.
(h) This figure will be the 'under/over adjustment approved by the regulator for year t-1 for the annual price approval process in three year's time.
(i) This figure should be discounted by one year's WACC to provide the opening balance for the DUOS unders and overs account for the price approval process next year.

2.5.7 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 transmission use of system (TUOS) unders and overs account. Aurora must provide information on this account to the AER as part of their annual pricing proposal under clause 6.18.2(b)(7) of the NER.

The AER's approach to the TUOS under and over recovery account is a departure from Aurora's proposal. The AER considers a method similar to that of the DUOS method is more 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 weighted average cost of capital (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 weighted average cost of capital (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 2.9. 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 2.9 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	37,866
Less under/over adjustment approved by the regulator for year t–2	1,000[a]	na	na
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	1,856	-934	-1,334
TUOS unders and overs account			
Nominal WACC	8.08%	8.08%	na
Opening balance	0	2,006	1,159
Interest on opening balance	0	162	na
Under/over recovery for regulatory year	1,856	-934	-1,159[c]
Interest on under/over recovery for regulatory year	150	-75	na
Closing balance	2,006	1,159[b]	0

(a) In this example, the regulator agreed that the DNSP could over recover its revenues by $1 million in year t–2 due to under recoveries in year t–3.

(b) This figure will be the 'under/over adjustment approved by the regulator for year t–2 for the annual price approval process in a year's time.

(c) This figure will be the 'under/over adjustment approved by the regulator for year t-1 for the annual price approval process in two years time.

2.6 Revisions

Revision 2.1: The AER does not accept Aurora's proposed revenue adjustments for TMR, GSL, FRC and unfunded share network costs.

Revision 2.2: The AER does not accept Aurora's proposed two year lag of TUOS unders and overs adjustment and to instead apply the unders and overs adjustment mechanism proposed for DUOS overs and unders.

Revision 2.3: The AER does not accept Aurora's proposal that side constraints not be applied and instead will apply side constraints as per clause 6.18.6 of the NER.

3 Demand forecasts

In making its determinations on Aurora's forecast capex and opex, the AER is required under the National Electricity Rules (NER) to have regard to a realistic expectation of demand.[196] 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:[197]

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

The AER accepts Aurora's forecasts of net new customer connections but does not consider Aurora's forecasts of maximum demand and gross new customer connections to be realistic. The AER's view of a realistic expectation of demand is shown in Table 3.1. The basis of the AER's adjustments to Aurora's forecasts is detailed in section 3.3 below.

Table 3.1 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)	1,082	1,098	1,115	1,132	1,149	1,165	1,182

Source: AER analysis using data from Aurora's regulatory proposal, 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.

3.1 Aurora's proposal

Aurora forecast total maximum demand to grow on average by 1.54 per cent per year from 1095 megawatts (MW) in winter 2010 to 1218 MW in winter 2017 (assuming a long-run median temperature).[198]

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

197 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.

198 Note that this is temperature-corrected maximum demand – that is, the level of demand assuming the long-run median temperature level is experienced. Actual temperature may vary and this will influence actual demand. Also, individual parts of Aurora's network may experience higher or lower growth in maximum demand that the network in total. AER analysis using data sourced from: Aurora, *2010 Distribution Network Connection Maximum Demand Forecast*, December 2010, p. 39.

Aurora forecast 3000 net new customer connections and 4040 gross new customer connections on average per year from 2010–11 to 2016–17.

Aurora's forecasts are shown in Table 3.2.

Table 3.2 Aurora's proposed demand forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17
Net new customer connections (#)[199]	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Gross new customer connections (#)[200]	3,984	4,051	4,068	3,896	3,942	4,129	4,233
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Maximum demand (MW)[201]	1,152	1,159	1,165	1,177	1,189	1,203	1,218

Source: ACIL Tasman, Aurora.

Aurora used an econometric methodology to forecast new customer connections. This approach requires the estimation and testing of statistical relationships between number of new connections and the underlying drivers that influence the number of new connections. Aurora assumed the number of new buildings as the main driver of new residential and commercial connections. Aurora used forecasts of new buildings developed by the Construction Forecasting Council. Aurora assumed historical growth rates to be the main driver of new irrigation connections.[202]

To develop forecasts of maximum demand, Aurora's approach was to develop forecasts at each connection point with the transmission network. Maximum demand forecasts for each zone substation and each feeder were developed by taking the current demand on the zone substation / feeder and then applying the forecast growth rate from the relevant connection point that supplies the zone substation / feeder.

To develop connection point forecasts, Aurora started with historical maximum demand as metered at each connection point. This actual, metered demand was likely influenced by the temperature that occurred at the time, but these temperatures are unlikely to be replicated exactly in the future. To account for this, Aurora calculated the long-run average temperature for each connection point and assumed this average temperature would occur in the future.

To develop connection point forecasts commensurate with the average temperature, Aurora adjusted the actual metered demand for past years to a level that Aurora estimated would have been experienced had the average temperature occurred.

Aurora then also adjusted the past demand data for individual loads that Aurora knows to be transient, discontinued or otherwise unlikely to be representative of the future.

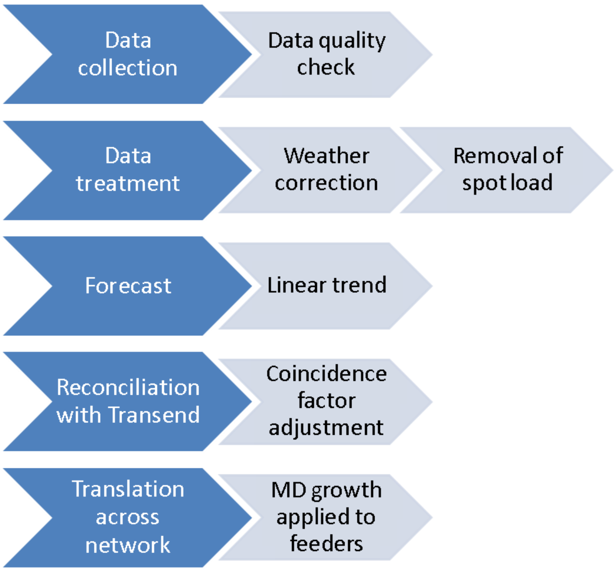
Aurora then used linear trends of the adjusted and temperature-corrected historical data to create forecasts. Future transient loads and loads that Aurora knew will begin in the future were then added to the linear trend forecasts.

199 Aurora, *Regulatory Information Notice*, template 6.7.
200 ACIL Tasman, *Aurora new customer connections forecasts*, Prepared for Aurora Energy, February 2011, pp. 24–25.
201 Aurora, *Regulatory Information Notice*, template 6.3.
202 Aurora, *Energy to the People: Aurora Energy Regulatory Proposal 2012–17*, 31 May 2011, p. 75.

The linear trend forecasts for each connection point were then summed into a total system forecast. Aurora's linear-trend-based total system forecast was then compared to state maximum demand forecast of the Tasmanian transmission network operator, Transend. Aurora's linear-trend-based total system forecast was increased to reconcile to Transend's forecast. Aurora's total system forecast was then disaggregated back into individual connection point forecasts, with the amount added to the total system forecast for reconciling to Transend's forecast pro-rated to each connection point.

The rate of growth in the reconciled connection point forecasts is then applied to the zone substations[203] and feeders[204] supplied by the connection points.

Figure 3.1 Aurora’s method of forecasting maximum demand



3.2 Assessment approach

The NER requires the AER to have regard to a realistic expectation of demand when determining whether Aurora’s proposed capex or opex reasonably reflects the costs required to achieve the capex or opex objectives.[205]

Statistical techniques are widely used by NSPs and other businesses for developing an expectation of future demand. Statistical techniques typically identify relationships between various economic variables (such as between temperature and energy consumption) and develop forecasts from historical data. The AER’s approach is typically to review the statistical techniques used by NSPs, and/or compare results from those techniques to those used in the AER’s own analysis.

Statistical demand forecasting techniques generally involve identifying potential drivers of demand, estimating the relationship between the drivers and final demand (the model specification), and testing the statistical significance of the drivers and model specification as well as the accuracy of the forecasting model. As statistical forecasting techniques are used widely in business and academia, the AER is able to refer to current best-practice techniques.

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203 ACIL Tasman, *Winter model NW#30185879*, template recon sys coin ZS forecasts.
204 Aurora, *Feeder Loading NW-#30201055-v1-2010*, template 2010 Fdr Loads – v3.
205 NER, clause 6.5.7(c)(3), 6.6.6(c)(3).

The AER considers that to develop realistic expectations of the future, forecasting techniques should include the following characteristics:

- Accuracy and unbiasedness of data – an unbiased forecast of demand should include careful management of data (removal of outliers, data normalisation), data quality and forecasting model construction (choosing a model based on sound theoretical grounds that closely fits the sample data).
- Transparency and repeatability – as evidenced by good documentation, including documentation of the use of judgment, which ensures consistency and minimises subjectivity in forecasts.
- Appropriate incorporation of key drivers (inputs) of demand and exclusion of spurious drivers.
- Model validation and testing – including, where appropriate, assessment of statistical significance of explanatory variables, goodness of fit, in-sample forecasting performance of the model against actual data, diagnostic checking of the old models, out of sample forecast performance.
- Accuracy and consistency of forecasts at different levels of aggregation – affects the overall reasonableness of the forecasts, as accuracy at the total level may mask errors at lower levels that cancel each other out.
- Use of the most recent input information.

3.3 Reasons for AER view

Maximum demand forecasts are important for identifying network capacity constraints and consequent capex to address those constraints. Forecasts of maximum demand growth are discussed in section 3.3.2.

In coming to its view, the AER considers the general basis of Aurora's methods of forecasting demand was appropriate and consistent with principles outlined in section 3.2. However, the AER does not accept Aurora's application of its methods with respect to:

- Weather correction
- Calculation of coincidence factors
- Reconciliation with Transend's state maximum demand forecast
- Translation of Terminal station demand growth to feeders

Given the interdependence of each element to the overall forecast of demand, the AER has estimated the total materiality of simultaneously revising all the elements of Aurora's methodology.

The AER has developed substitute demand forecasts by using Aurora's methods and revising the application, where appropriate, to create more realistic forecasts. The AER's substitute demand forecast is, on average, 4.1 per cent lower in each year of the forthcoming regulatory period.

New customer connections are important for forecasting capex and opex. The number of customer connections represents the size of Aurora's network, which is a key driver of opex (see section 6.4.4 of attachment 6). New customer connections are also a main driver of capex required to facilitate these new connections. Forecasts of new customer connections are discussed in section 3.3.1.

3.3.1 New customer connections

New customer connections[206] 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.

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 (see section 5.4.2 of the capital expenditure attachment 5). Net new connections are considered a measure of overall change in network size, which is an important driver of Aurora's opex (see section 6.4.3 of attachment 6).

Aurora's forecasts of gross new customer connections were separated into residential, residential subdivision, commercial and irrigation customers.[207] Residential customer connections account for approximately 82 per cent of Aurora's total connections while commercial and irrigation customers account for the remaining 18 per cent.[208] On the basis that most of Aurora's customer connections are residential, the AER considers that dwelling / household growth is a significant driver of new customer connections (net and gross).

New commercial and irrigation customers

For new non-residential customer connections, Aurora forecast a constant net growth. Aurora's historical data for non-residential customer connections shows an erratic historical trend, and therefore the AER considers it difficult to determine whether Aurora's forecast is consistent with historical trends. However, the AER notes that Aurora's net new customer connection forecast is broadly in line with historical trend at the total level. The AER therefore considers Aurora's proposed net growth in customer connections in total to reasonably reflect a realistic expectation of future demand.

Aurora forecast residential connections to make up 82 per cent of forecast net new customer connections in each year except 2010–11, in which it forecast residential connections to comprise 56 per cent of the net new connections. Aurora did not provide a justification for the forecast compositional change. The AER considers that the most realistic expectation would be for a relatively constant composition, and that Aurora's forecast composition for 2010–11 results in a forecast of net new non-residential connections that is too high. The AER has therefore accepted Aurora's forecasts of total customer connections with a revised composition for 2010–11.

New residential and residential subdivision customer connections

The AER considers Aurora's forecasts of net new customer connections to be realistic, but Aurora's forecasts of gross new residential customer connections are too high. Accordingly, the AER has estimated a substitute forecast of gross connections by taking Aurora's forecast of net new residential customer connections, adjusted for the forecast rate of demolitions. The AER considers that Aurora's

206 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 (NMI)'s [see: Aurora, *Response to information request AER/017 of 27 July 2011*, received 3 August 2011, p. 4]. Aurora considered that one NMI should reflect one connection, and presumed an average of one NMI per connection site [see: Aurora, *Response to information request AER/017 of 27 July 2011*, received 3 August 2011, pp. 3–4].

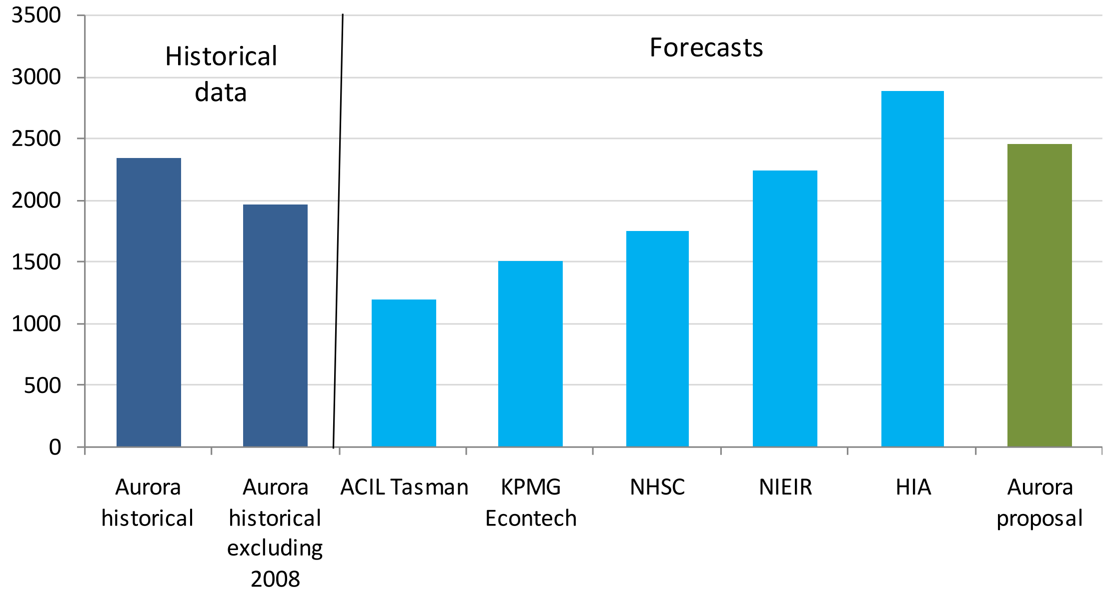
207 ACIL Tasman, *Aurora new customer connections forecasts*, February 2011, p. 16.

208 SKM-MMA, *Review of Aurora Energy's customer number forecasting methodologies in its 2012–2017 regulatory proposal*, 26 September 2011, p. 1.

proposed net new residential connections are reasonable when compared to the forecast change in Tasmania's dwelling stock. The AER has calculated new gross residential customer connections from Aurora's net residential customer estimates plus an amount for the portion of dwellings that have been demolished and require a new connection to be established.

Aurora proposed growth in net residential customer connections consistent with growth rates forecast by various institutions and historical data. This is shown in Figure 3.2.

Figure 3.2 Average annual change in net residential customer connections – actual measures and proxies – historical data and forecasts by various institutions



Source: NIEIR[209], NHSC[210], HIA[211], KPMG Econtech[212], Attachments to Aurora's regulatory proposal[213], information provided by Aurora in response to AER request.[214]

Explanatory notes:

Aurora historical data – new residential customers – 2001 to 2010
Aurora historical data – new residential customers – 2001 to 2010, excluding 2008
ACIL Tasman – forecast of new residential customers – 2010 to 2017 – used in forecast energy consumption report prepared for Aurora
KPMG Econtech forecast – net growth in households – 2009 to 2017
National Housing Supply Council forecast – net housing growth – 2010 to 2017
National Institute of Economic and Industry Research forecast – net change in housing stock – 2010 to 2017
Housing Industry Association forecast – housing starts – 2003 to 2013
Aurora proposed new residential customers – 2010 to 2017

In examining Aurora's forecast growth against historical trends, the AER considers the measure of net customer connections growth from 2006–07 to 2007–08 to be an outlier. As shown in Figure 3.3,

209 National Institute of Economic and Industry Research, *Electricity sales and maximum demand forecasts for Tasmania to 2042*, May 2011, dwelling stock, p. 7.

210 National Housing Supply Council, *2nd state of supply report*, 2010 and associated tables.

211 Housing Industry Association economic group, *dwelling starts by financial year*, 2011, retrieved 8 August 2011, http://economics.hia.com.au/media/July%202011%20%20Forecasts.pdf.

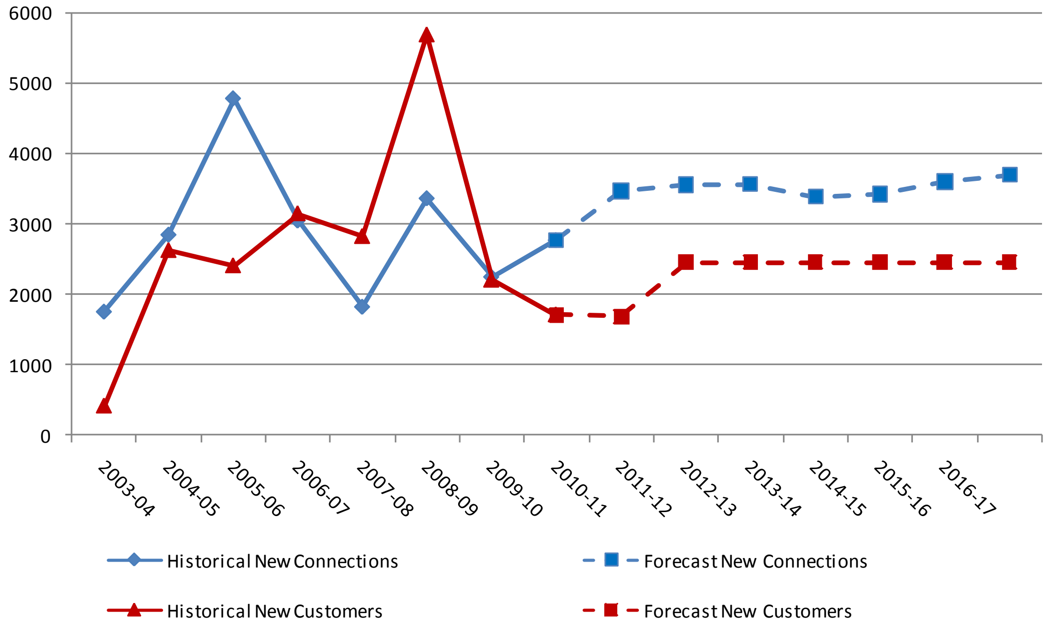
212 KPMG Econtech, *Stage 2 report: Economic scenarios and forecasts 2009-10 to 2029-30,* 2010, retrieved 8 August, http://www.aemo.com.au/planning/esoo2010.html.

213 ACIL Tasman, *Energy consumption forecasts*, June 2011, pp. 34, 43.

214 Aurora, *Response to information request AER/037, of 30 August 2011,* received 1 September 2011, -NW-#-30187142 template customer numbers methodology.

Aurora's historical data indicates Aurora experienced 10,949 net new customer connections in 2007–08, while the next highest annual net growth was 4,010.

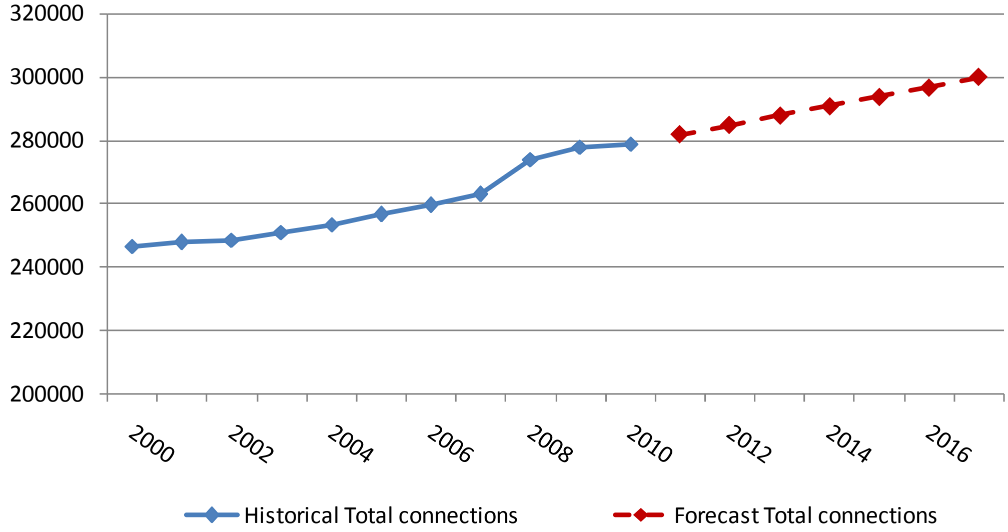
Figure 3.3 Aurora's forecast net and gross new customer connections



Source: ACIL Tasman[215], RIN.[216]

Figure 3.4 depicts Aurora's total historical and forecast customer numbers and demonstrates the anomalous increase in total customer numbers of 4.1 per cent from 2006–07 to 2007–08.

Figure 3.4 Aurora's historical and proposed forecast total net customer connections



Source: ACIL Tasman[217], RIN.[218]

215 ACIL Tasman, *Aurora new customer connections forecasts*, February 2011, p. 16.
216 Aurora, *Regulatory Information Notice*, template 6.7.

When requested to explain the significant and anomalous increase from 2006–07 to 2007–08, Aurora stated:[219]

> Aurora is unable to clearly explain the apparent anomalous large (4.1%) increase in total customers during 2006/07 – 2007/08, however it may be related to the migration of data from the Retail Billing System to the Network Billing System.

The AER assumed that the growth in net customers prior to 2007–08 is reliable and has developed adjusted historical customer connections using 2007–08 total net customer numbers and historical net new customer connection growth.

Aurora's proposed forecast of net new residential customer connections is significantly higher than the forecast used by ACIL Tasman in developing Aurora's proposed energy consumption forecasts. The two appear to be internally inconsistent.[220] Despite this inconsistency, Aurora's proposed net new residential customer connections appear consistent with historical trends and the range of appropriate growth expectations[221] shown in Figure 3.3, although at the higher end of the range.[222]

To assess Aurora's forecast gross new residential customer connections, the AER compared it against Aurora's forecast for net connections growth grossed up for connections that are replaced, upgraded or otherwise removed.[223] The AER used the National Housing Supply Council's (NHSC) demolitions forecast as a proxy for connections that are replaced, upgraded or otherwise removed.[224] The AER also compared Aurora's gross new connections forecast to net connections forecasts from other institutions also grossed up for demolitions. This is shown in Figure 3.5.

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217 ACIL Tasman, *Aurora new customer connections forecasts*, February 2011, p. 16.

218 Aurora, *Regulatory Information Notice*, template 6.7.

219 Aurora, *Response to information request AER/017 of 27 July 2011*, received 3 August 2011, p. 3.

220 When asked to comment on this, Aurora stated that they were forecast using different methods:

> The difference in forecast residential new connections is due to the difference in forecasting methods: Aurora extrapolates actual connections data; ACIL Tasman have linked the number to forecast population growth — See: Aurora, *Response to information request AER/017 of 27 July 2011*, received 3 August 2011, pp. 3–4.

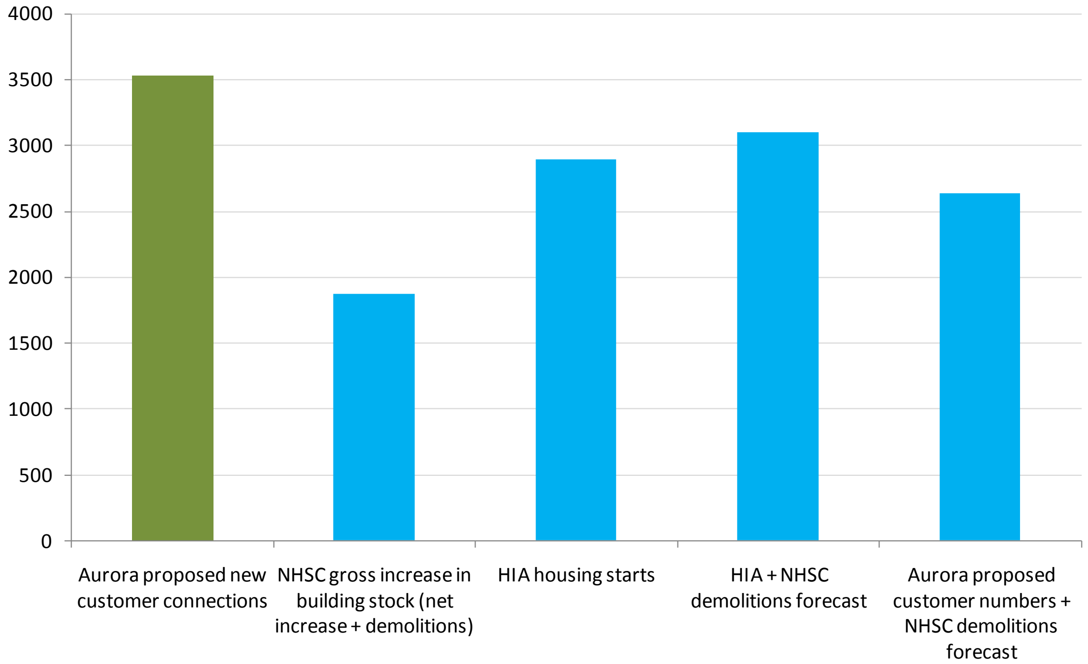
221 The Housing Industry Association (HIA) forecast in 0 appear high compared to KPMG Econtech forecast estimates. The KPMG Econtech household growth is likely to be understated compared to dwelling growth as it does not take into account empty dwellings. Indeed, the KPMG Econtech forecast of household growth is some 8-10% lower than the National Institute of Economic and Industry Research forecast of dwelling numbers.

222 The Energy Users Association of Australia also considered that Aurora's forecasts are at the high end of a range of reasonable expectations after consideration of population growth comparisons to other NEM states. See: Energy Users Association of Australia, *Submission to the Australian Energy Regulator on Aurora Energy's Regulatory Proposal on Distribution Prices For 2012–2017*, August 2011, p. 10.

223 This is consistent with Aurora's forecasting method which assumed construction value as a key driver – construction value includes value of new dwelling stock as well as the value of replacements and upgrades to existing dwelling stock — See ACIL Tasman, *Aurora new customer connections forecasts*, February 2011, p. 16.

224 SKM-MMA, *Review of Aurora Energy's customer number forecasting methodologies in its 2012–2017 regulatory proposal*, September 2011, pp. 17–20.

Figure 3.5 Average annual gross change in residential customer connections – Aurora's forecast and forecasts proxied from net growth forecasts



Source: AER analysis, NHSC,[225] HIA,[226] Attachments to Aurora's regulatory proposal, information provided by Aurora in response to AER request.[227]

The NHSC forecast a rate of demolitions of 6.7 per cent per year.[228] Aurora's forecast of gross change in residential customer connections implies an annual average rate of demolitions of 33 per cent per year. That is, Aurora forecast 33 per cent of new residential customer connections to be upgrades or alterations to existing connections (given Aurora's forecast of total customer connections). As shown in Figure 3.5, Aurora's forecast gross new residential connections is significantly higher than its net forecast grossed up for demolitions. The AER's forecast of gross new residential connections is also significantly higher than the highest independent forecast of net new connections grossed up for demolitions.[229] The AER therefore considers that Aurora's implied forecast of demolitions is too high, and given the AER's view on total customer connections, the AER concludes that Aurora's forecast of gross change in residential customer connections is too high.

The AER adopted a substitute forecast based on Aurora's forecast of net change in residential connections and the NHSC's forecast of demolitions of 6.7 per cent per year on average. The AER's substitute forecast is shown in Figure 3.6. The AER considers this forecast to be more consistent with historical trends, as well as Aurora's[230] and the EUAA's expectation of subdued economic activity to

225 National Housing Supply Council, *2nd state of supply report*, 2010 and associated tables.

226 Housing Industry Association economic group, *dwelling starts by financial year*, 2011, retrieved 8 August 2011, http://economics.hia.com.au/media/July%202011%20%20Forecasts.pdf.

227 Aurora, *Response to information request AER/037, of 30 August 2011,* received 1 September 2011, -NW-#-30187142 template customer numbers methodology.

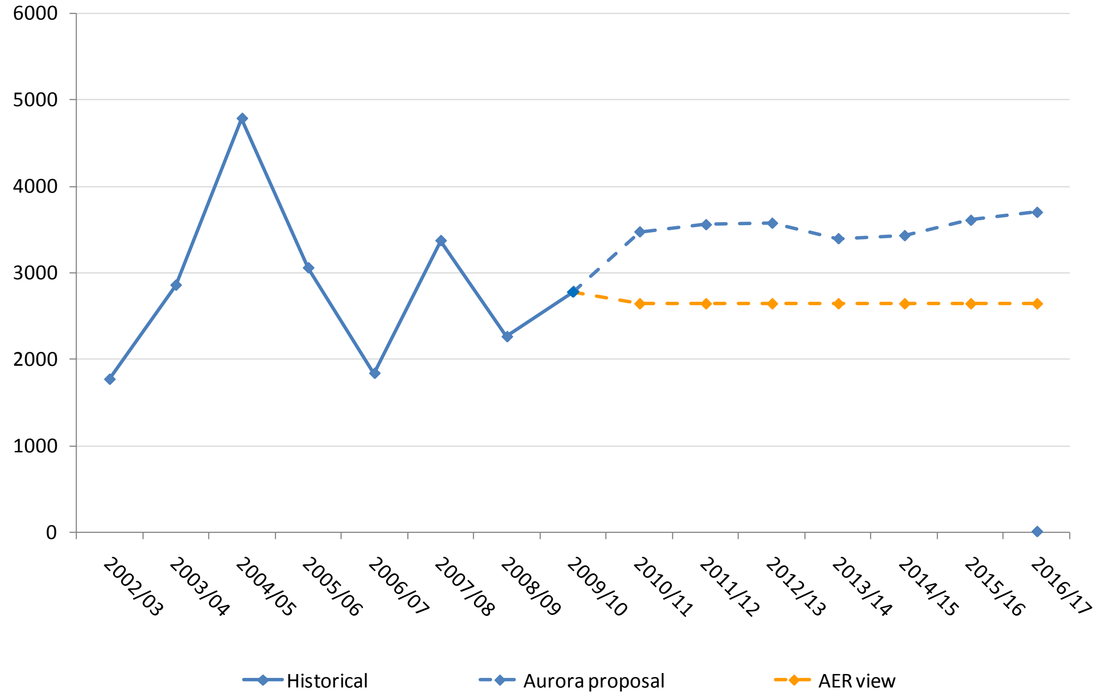
228 National Housing Supply Council, *2nd state of supply report*, 2010 and associated tables.

229 Aurora's forecast of gross change in residential customer connections is also higher than the NHSC's forecast of gross additions to the Tasmanian residential building stock and the HIA's forecast of housing starts. As mentioned above, the HIA's forecast of housing starts is likely to overstate net additions to the dwelling stock, and Aurora's forecast of gross change in customer connections is also significantly (14 per cent) higher than the demolitions-adjusted HIA forecast.

230 Aurora stated: *whilst over the past 4 – 5 years there has been significant increases in the CICW volumes and expenditure levels, the current econometric drivers and influencing trends in Tasmania indicate these activities are not expected to increase from the currently experienced growth levels of investment over the 5 year period to 2017*. Aurora, *Customer-initiated capital works management plan*, March 2011, p. 3. Revised management plan to replace Attachment

prevail in Tasmania throughout the forthcoming regulatory period.[231] The AER's forecast is also consistent with forecast dwelling stock changes and demolition statistics.

Figure 3.6 New residential customer connections (gross) – Aurora's forecast and AER's forecast



Source: AER analysis, Attachments to Aurora's regulatory proposal; information provided by Aurora in response to AER request.[232]

Aurora's forecasts for gross change in commercial connections and irrigation connections are in line with historical trends, as shown in Table 3.3. These forecasts could be expected to be lower given subdued economic activity expected in the future. However, the AER considers Aurora's forecasts of gross change in commercial and irrigation connections to be a reasonable reflection of a realistic demand expectation (although potentially at the high end of the range of realistic expectations).

Table 3.3 Average annual gross change in commercial and irrigation connections – historical and Aurora forecast

Average annual new connections	2003 to 2010	2010 to 2017
New commercial connections	334	330
New irrigation connections	180	181
Total	514	511

Source: AER analysis, Attachments to Aurora's regulatory proposal.[233]

AE032 to Aurora, Regulatory proposal 2012–2017, 31 May 2011. Provided in *response to information request AER/016 dated 26 July 2011*, received 11 August 2011.

231 Energy Users Association of Australia, *Submission to the Australian Energy Regulator on Aurora Energy's Regulatory Proposal on Distribution Prices for 2012–2017*, August 2011, p. 7.

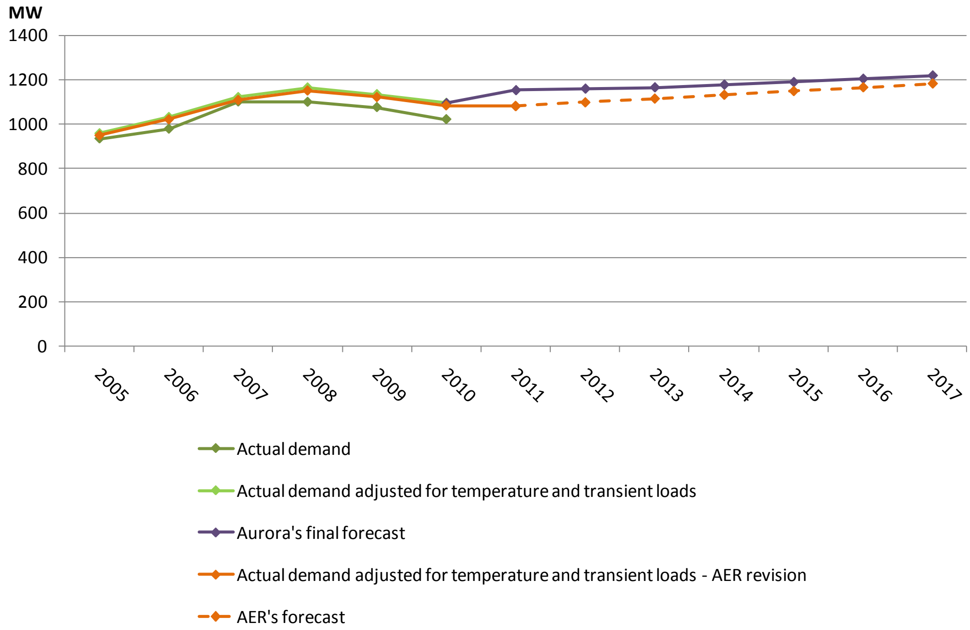
232 Aurora, *Response to information request AER/037, of 30 August 2011,* received 1 September 2011, -NW-#-30187142 template customer numbers methodology.

3.3.2 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.[234] The AER has therefore focused its review of demand forecasts largely on maximum demand forecasts at the total system level.[235]

The AER considers that Aurora's total system maximum demand forecast is too high, and has developed a substitute forecast as shown in Figure 3.7. The AER's substitute forecast provides an annual average growth rate of 1.11 per cent from 2010 to 2017, while Aurora's forecast provides an annual average growth rate of 1.54 per cent over the same period. In applying the total system growth rate to various assets, the AER also considers that Aurora's method of estimating current demand does not result in realistic forecasts, and the AER has developed substitute forecasts at the individual asset level.

Figure 3.7 Total system maximum demand: AER view and Aurora's forecasts



Source: AER analysis, Attachments to Aurora's regulatory proposal,[236] information provided by Aurora in response to AER request.[237]

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233 Aurora, *Response to information request AER/037 of 30 August 2011,* received 1 September 2011, -NW-#-30187142 template customer numbers methodology.

234 ACIL Tasman, *Terminal and zone substation winter maximum demand forecasting tool*l. — see Aurora, *Response to information request AER/003 of 1 July 2011*, received 8 July 2011.

235 Aurora routinely develops and revises forecasts of maximum demand as part of its ongoing network planning.[235] Consequently, the forecasts used by Aurora to develop its proposed capex were revised prior to Aurora submitting its regulatory proposal [Aurora, *Response to information request AER/014 of 22 July 2011*, received 27 July 2011]. While the growth rate for Aurora's distribution system in total from Aurora's original forecast was reasonably comparable to the revised forecast, the growth rates for individual connection points, zone substations and feeders varied significantly. Seventeen connection points had revised forecasts more than 5 per cent higher than the original forecasts, and sixteen connection points have revised forecasts more than 5 per cent lower than the original forecasts [SKM-MMA, *Review of Aurora Energy's maximum demand forecasting methodologies in its 2012–2017 regulatory proposal*, 26 September 2011, p. 7].

236 Aurora, *Regulatory Information Notice*, template 6.7.

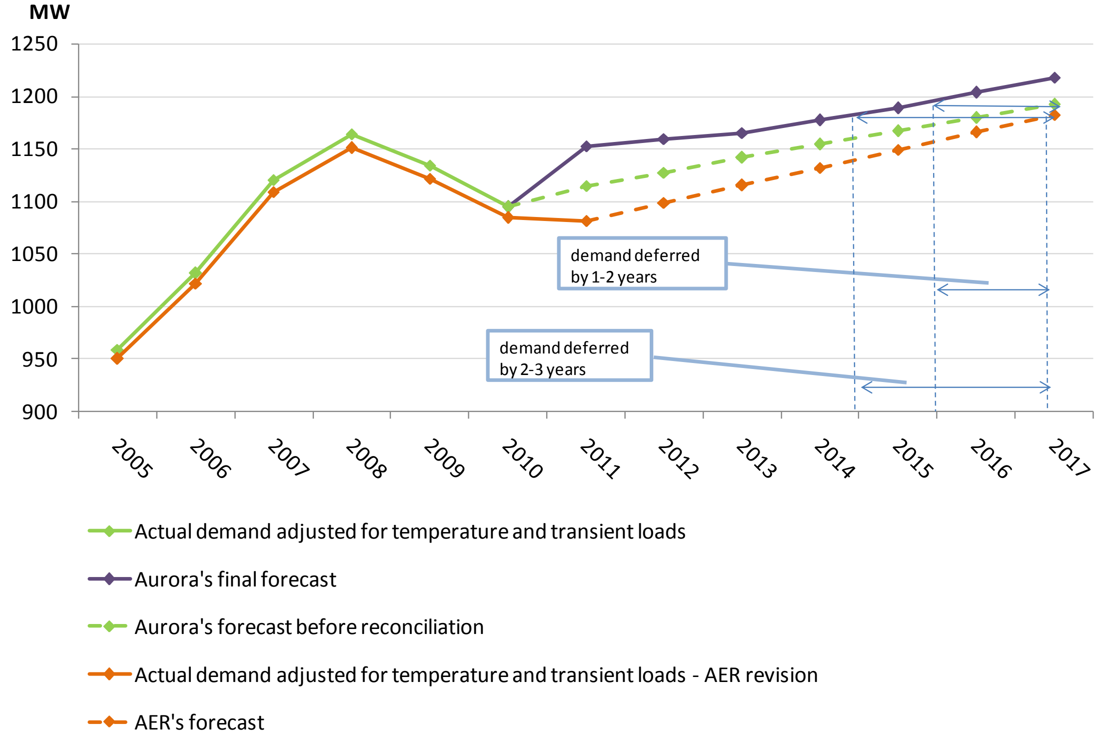
In coming to its view, the AER considers that the general basis of Aurora's method of forecasting maximum demand is appropriate and consistent with current industry standard practices.[238] However, the AER disagreed with the application of this method in a number of areas:

- Reconciling to Transend's state maximum demand forecast
- 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

These are discussed in turn below.

As shown in Figure 3.8, the impact of addressing the reconciliation issue results in lower demand growth such that the level of maximum demand achieved in 2016–17 is the same level that Aurora forecast to occur 1 to 2 years earlier. The impact of addressing both the reconciliation and temperature-related issues results in lower demand growth such that the level of maximum demand achieved in 2016–17 is the same level that Aurora forecast to occur 2 to 3 years earlier.

Figure 3.8 Impact of AER revisions to maximum demand forecasts



Source: AER analysis, Attachments to Aurora's regulatory proposal,[239] information provided by Aurora in response to AER request.[240]

237 Aurora, *Response to AER information request sent on the 23 June 2011: NW-#30195655-v1-Transend_NIEIR_System_forecast_2009*, sheet 2 template.

238 SKM-MMA, *Review of Aurora Energy's maximum demand forecasting methodologies*, September 2011, pp. 31–32.

239 Aurora, *Regulatory Information Notice*, template 6.7.

240 Aurora, *Response to AER information request sent on the 23 June 2011: NW-#30195655-v1-Transend_NIEIR_System_forecast_2009*, sheet 2 template.

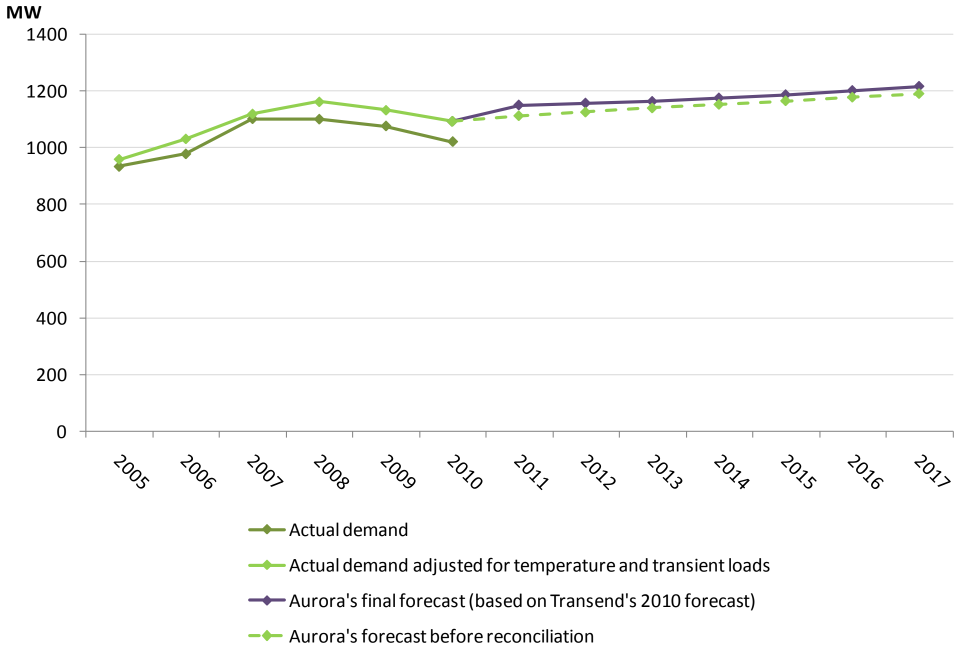
Reconciling to Transend's forecast

Aurora developed forecasts for each of its connection points to the transmission network, which were then adjusted[241] to reconcile to a forecast developed by Transend.[242] Aurora stated it made these reconciliation adjustments because:[243]

> Reconciliation…has the advantage of allowing the methodology to incorporate the impacts of broader macroeconomic and demographic aggregates, as well as the impacts of new policy initiatives which are better modelled at the system level. System level data is also smoother and more amenable to the fitting of econometric models which can be used to generate more accurate system level forecasts.

Reconciliation of Aurora's forecasts to Transend's results in a significant initial increase in the maximum demand forecasts,[244] although the subsequent rate of growth in maximum demand is comparable, particularly from 2013 onwards. This is shown in Figure 3.9.[245] Aurora's forecast before reconciliation shows a 1.83 per cent increase in maximum demand from 2010 to 2011, while Aurora's reconciled forecast shows a 5.28 per cent increase.

Figure 3.9 Historical maximum demand and Aurora's forecasts



Source: AER analysis, Attachments to Aurora's regulatory proposal,[246] information provided by Aurora in response to AER request.[247]

[241] ACIL Tasman, *Outline of Aurora's spatial demand forecasting methodology*, Proposed demand forecasting methodology for Aurora's 44 connection points and 16 zone substations, September 2010, p. 5.

[242] Aurora, *2010 Distribution Network Connection Maximum Demand Forecast*, December 2010, p. 18.

[243] ACIL Tasman, *Outline of Aurora's spatial demand forecasting methodology*, ,September 2010, p. 5.

[244] Note that the reconciliation adjustment required to reconcile Aurora's forecast before reconciliation to Transend's 2010 total system forecast is overstated due to Aurora's coincidence factors, but understated by Aurora's method of temperature correction (that is, the assumed absence of a warming trend and greater than 50 POE adjustment method).

[245] Note that Figure 1.8 shows Aurora's trend-based forecasts using Aurora's proposed co-incidence factors. The AER has concerns with Aurora's use of 2010 co-incidence factors for each forecast year. The AER considers it more appropriate to use an average of past co-incidence factors for aggregating forecast maximum demand. Use of average co-incidence factors will decrease the trend-based forecast, increasing the adjustment required to reconcile to Transend's total system forecasts.

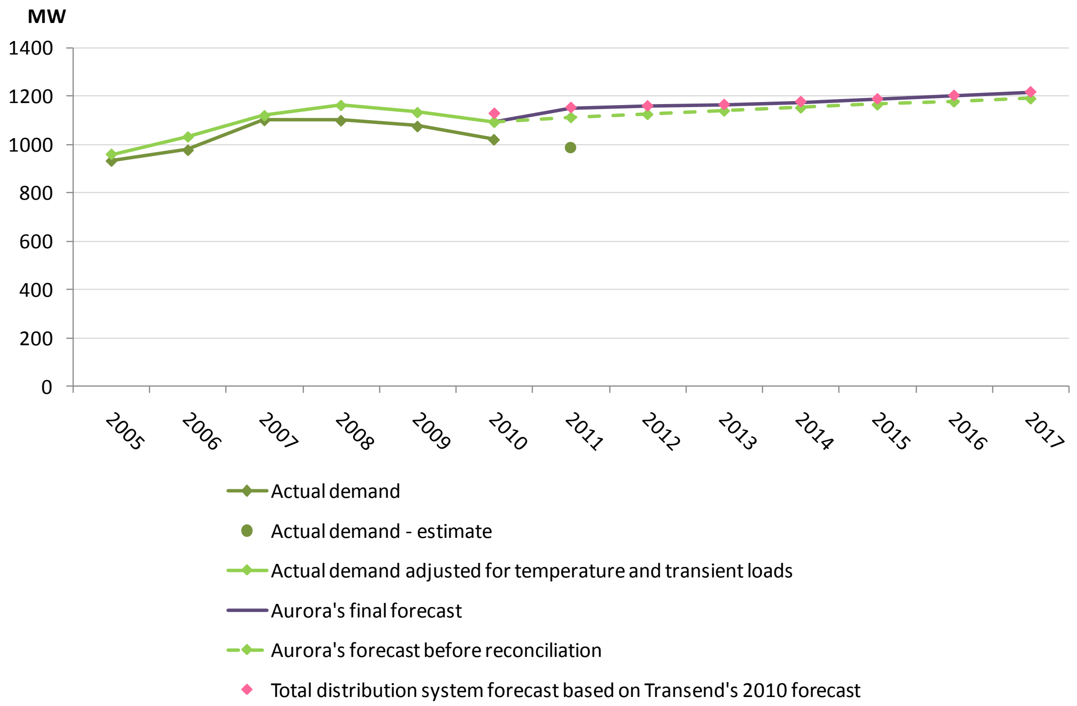
[246] Aurora, *Regulatory Information Notice*, template 6.7.

[247] Aurora, *Response to AER information request sent on the 23 June 2011: NW-#30195655-v1-Transend_NIEIR_System_forecast_2009*, template sheet 2.

The AER considers that the initial increase in maximum demand from 2010 to 2011 was too high, but that the subsequent growth rate was reasonable given historical trends and forecasts of demand drivers such as gross state product and population growth.

The AER considers that the initial increase in maximum demand forecast by Aurora may be due to the timing of Transend's forecasts – they were developed in May 2010 while Aurora's forecasts were developed in December 2010.[248] Consequently, Aurora's forecast before reconciliation accounted for the actual demand experienced in 2010, while Transend's forecast did not. As shown in Figure 3.10, actual demand decreased from 2009 to 2010, and Transend's 2010 forecast is significantly higher than Aurora's temperature adjusted demand for 2010.

Figure 3.10 Historical maximum demand, Aurora's forecasts and Transend's 2010 forecast



Source: AER analysis, Attachments to Aurora's regulatory proposal,[249] information provided by Aurora in response to AER request.[250]

Although the AER considers the reconciliation is generally appropriate to incorporate the impact of broader macroeconomic and demographic factors, it did not consider it appropriate to reconcile to a forecast that is out-dated and shown to be significantly divergent from realised demand (for 2010).

Due to Transend's forecasts being developed in May each year, the AER obtained Transend's recent (May 2011) forecasts[251] that were not available to Aurora at the time Aurora submitted its regulatory proposal. Distribution system maximum demand based on Transend's 2011 forecasts is shown in

248 Aurora, *2010 Distribution Network Connection Maximum Demand Forecast*, December 2010, p. 14; National Institute of Economic and Industry Research, *Electricity sales and maximum demand forecasts for Tasmania to 2039*, May 2010; National Institute of Economic and Industry Research, *Electricity sales and maximum demand forecasts for Tasmania to 2042*, May 2011.

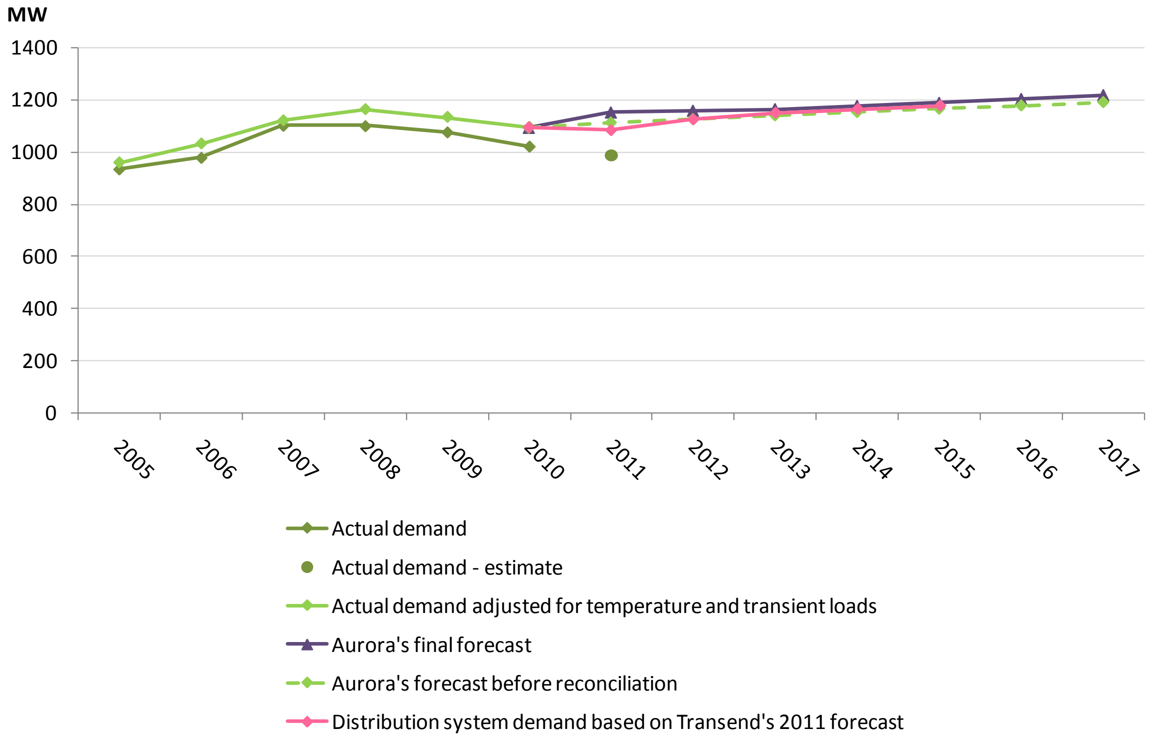
249 Aurora, *Regulatory Information Notice*, template 6.7.

250 Aurora, *Response to AER information request sent on the 23 June 2011: NW-#30195655-v1-Transend_NIEIR_System_forecast_2009*, template sheet 2.

251 National Institute of Economic and Industry Research, *Electricity sales and maximum demand forecasts for Tasmania to 2042*, May 2011.

Figure 3.11. These forecasts benefit from the availability of 2010 actual demand (as do Aurora's forecasts before reconciliation). As expected from the trend of decreasing demand since 2007 and decreases realised from 2009 to 2010, distribution system maximum demand based on Transend's 2011 forecast was lower than that based on Transend's 2010 forecast. Transend's 2011 forecast shows a significantly altered growth rate, notably a forecast decline from 2010 to 2011 and a subsequent growth rate higher than its previous 2010 forecast.[252]

Figure 3.11 Historical maximum demand, Aurora's forecasts and Transend's 2011 forecast



Source: AER analysis, Attachments to Aurora's regulatory proposal,[253] information provided by Aurora in response to AER request,[254] Transend 2011 annual planning report.[255]

The AER has obtained an estimate of 2011 actual maximum demand from Aurora, which is shown in Figure 3.11.[256] This estimate, although not adjusted for temperature effects, appears to suggest a decrease in maximum demand from 2010 to 2011, and the AER considers that this could result in a lowering of the growth expectations compared to Transend's 2011 forecast.

The AER also notes that Transend's forecasts were based on assumptions about future Tasmanian gross state product which were inconsistent with those used by Aurora in developing its forecasts. Aurora assumed gross state product would grow on average by 2 per cent per year from 2010 to

252 AER analysis using data sourced from: National Institute of Economic and Industry Research, *Electricity sales and maximum demand forecasts for Tasmania to 2039*, A report for the Transend Networks Pty Ltd, May 2010; National Institute of Economic and Industry Research, *Electricity sales and maximum demand forecasts for Tasmania to 2042*, A report for the Transend Networks Pty Ltd, May 2011; Aurora, *Response to information request of 23 June 2011*, received 1 July 2011, attachment titled 'NW-#30195655 -v1-Transend_NIEIR_System_forecast_2009_(Version_2).xls'.

253 Aurora, *Regulatory Information Notice*, template 6.7.

254 Aurora, *Response to AER information request sent on the 23 June 2011: NW-#30195655-v1-Transend_NIEIR_System_forecast_2009*, template sheet 2; Aurora, *Response to information request AER/025 of 15 August 2011*, received 31 August 2011, template daily total system demand input.

255 Transend, *Transend networks annual planning report*, June 2011, p. 105.

256 Actual data validated through appropriate data audits was not available at the time of the AER's analysis.

2017.[257] Transend's forecasts were derived based on assumed average growth in gross state product over the same period by 2.4 per cent per year in its 2010 forecast[258] and by 2.5 per cent per year in its 2011 forecast.[259] Nonetheless, the AER considers that the forecast average growth rates in maximum demand across the period 2011 to 2017 from Transend's 2010 forecast, Transend's 2011 forecast and Aurora's forecast before reconciliation are all within range reflecting a realistic expectation of demand growth.

Based on this analysis, the AER considers that no reconciliation is required to develop realistic demand forecasts. Aurora's forecast before reconciliation provided average growth rates in maximum demand across the period 2011 to 2017 that are reasonably reflective of those in Transend's 2010 forecast and Transend's 2011 forecast. The AER also considers that Aurora's forecast before reconciliation provides an appropriate starting point for forecast demand, as it reflects recent demand data. Accordingly, the AER has developed its substitute maximum demand forecasts without reconciliation to Transend's total system forecast but instead reconciled to an alternative total system forecast. The AER has derived the alternative total system forecast from a seven year linear trend that is weather corrected using the AER's simulation methodology.

Measuring the impact of temperature on maximum demand

In developing its forecasts, Aurora started with historical maximum demand as metered at each connection point. This actual, metered demand was likely influenced by the temperature that occurred at the time. These temperatures are unlikely to be replicated exactly in the future. To account for this, Aurora calculated the long-run average temperature for each connection point and assumed this average temperature would occur in the future.

Typically, assumed temperature levels are chosen for planning purposes – planning for contingencies (temperatures) that can be expected to occur at a given probability. Aurora submitted that an average temperature (that is, one that would be exceeded 50 years out of every 100 – a 50 per cent probability of exceedance (POE)) is used for the identification of network capacity limitations and therefore planning for investment to alleviate these limitations.[260]

The AER notes that Transend's total system forecast[261] was based on the assumed existence of a trend of warming temperatures,262 but that Aurora's forecasts were not (other than to the extent they were reconciled to Transend's forecasts).[263] As limited information is available about how Transend's total system forecasts were derived, the AER is unable to assess how Transend had come to its assumed warming trend. From examining the temperature data from the relevant weather stations used by Aurora in adjusting for temperature effects, the AER considers there is sufficient evidence to suggest that winter temperatures have become milder over the past twenty years.[264]

257 ACIL Tasman, *Energy consumption forecasts*, Energy consumption forecast for Aurora Energy covering six customer classes, Prepared for Aurora Energy, June 2011, pp. 19, 43.
258 National Institute of Economic and Industry Research, *Electricity sales and maximum demand forecasts for Tasmania to 2039*, A report for the Transend Networks Pty Ltd, May 2010, p. 18.
259 National Institute of Economic and Industry Research, *Electricity sales and maximum demand forecasts for Tasmania to 2042*, A report for the Transend Networks Pty Ltd, May 2011, p. 6.
260 Aurora, *Response to information request of 23 June 2011*, received 1 July 2011, p. 8.
261 Both Transend's 2010 and 2011 forecasts.
262 National Institute of Economic and Industry Research, *Electricity sales and maximum demand forecasts for Tasmania to 2039*, A report for the Transend Networks Pty Ltd, May 2010, p. 24.
263 ACIL Tasman, *Terminal and zone substation winter maximum demand forecasting tool*, developed for Aurora Energy—see Aurora, *Response to information request AER/003 of 1 July 2011*, received 8 July 2011.
264 Analysis can be found at: SKM-MMA, Review of Aurora Energy's maximum demand forecasting methodologies in its 2012–2017 regulatory proposal, 26 September 2011, pp. 22–24.

To estimate the long-run median temperature, Aurora used daily temperature data for relevant weather stations going back up to fifty years (where data was available).[265] Given that winter temperatures have become milder, the AER considers that using averaging periods of up to fifty years may result in an average temperature that is too low, temperature adjustment that is too large, and therefore demand forecasts that are too high.

There may be numerous means by which a warming trend could be taken into account in the estimation of a long-run median temperature. Greater weight could be placed on more recently observed temperatures, or the sample size could be reduced on the grounds that older observations are no longer representative of current trends. The AER considers that limiting the estimation of long-run median temperature to a maximum of twenty years of temperature data should account for this warming trend in an adequate and administratively simple manner.

In estimating the long-run median temperature, Aurora also excluded data points corresponding to non-business days (weekends and holidays), but included these days when estimating the correlation between demand and temperature.[266] Aurora stated that non-business days should be excluded from the long-run temperature estimation because maximum demand rarely occurs on these days.[267] The AER notes that Transend excluded non-business days from both the long-run temperature estimation and the temperature sensitivity estimation in its total system forecasts for similar reasons.[268]

The AER considers that a consistent approach should be taken. The AER considers that the rationale for excluding non-business days from the long-run temperature calculation is equally valid for the temperature sensitivity calculation.

The AER estimates that the effect of both excluding weekends and using a twenty year series of data to calculate 50 POE temperature will reduce demand across Aurora's network by 1.5 per cent on average across the period 2010 to 2017.[269] The AER has therefore developed its substitute demand forecasts using alternative temperature adjustments calculated using long-run median temperatures based on a maximum 20 year averaging period and temperature sensitivities calculated after the exclusion of non-business days.

Adjusting demand to a level consistent with a median temperature

Aurora's approach to adjusting for temperature effects was to:[270]

1. Estimate the impact of temperature on demand.

2. Calculate the difference between the temperature on the maximum demand day and the long-run median temperature.

265 ACIL Tasman, *Terminal and zone substation winter maximum demand forecasting tool*, developed for Aurora Energy — see Aurora, *Response to information request AER/003 of 1 July 2011*, received 8 July 2011.

266 ACIL Tasman, *Terminal and zone substation winter maximum demand forecasting tool*, developed for Aurora Energy — see Aurora, *Response to information request AER/003 of 1 July 2011*, received 8 July 2011, NW-#30185879-v1-Winter_Aurora_model_v44, template daily winter MD and temp data.

267 ACIL Tasman, *Outline of Aurora's spatial demand forecasting methodology*, Proposed demand forecasting methodology for Aurora's 44 connection points and 16 zone substations, September 2010, p. 3.

268 National Institute of Economic and Industry Research, Electricity sales and maximum demand forecasts for Tasmania to 2039, Report for the Transend Networks Pty Ltd, May 2010, p. 32.

269 AER analysis using data sourced from: ACIL Tasman, *Terminal and zone substation winter maximum demand forecasting tool*, developed for Aurora Energy — see Aurora, *Response to information request AER/003 of 1 July 2011*, received 8 July 2011.

270 ACIL Tasman, *Outline of Aurora's spatial demand forecasting methodology*, *Proposed demand forecasting methodology for Aurora's 44 connection points and 16 zone substations*, September 2010, p. 3.

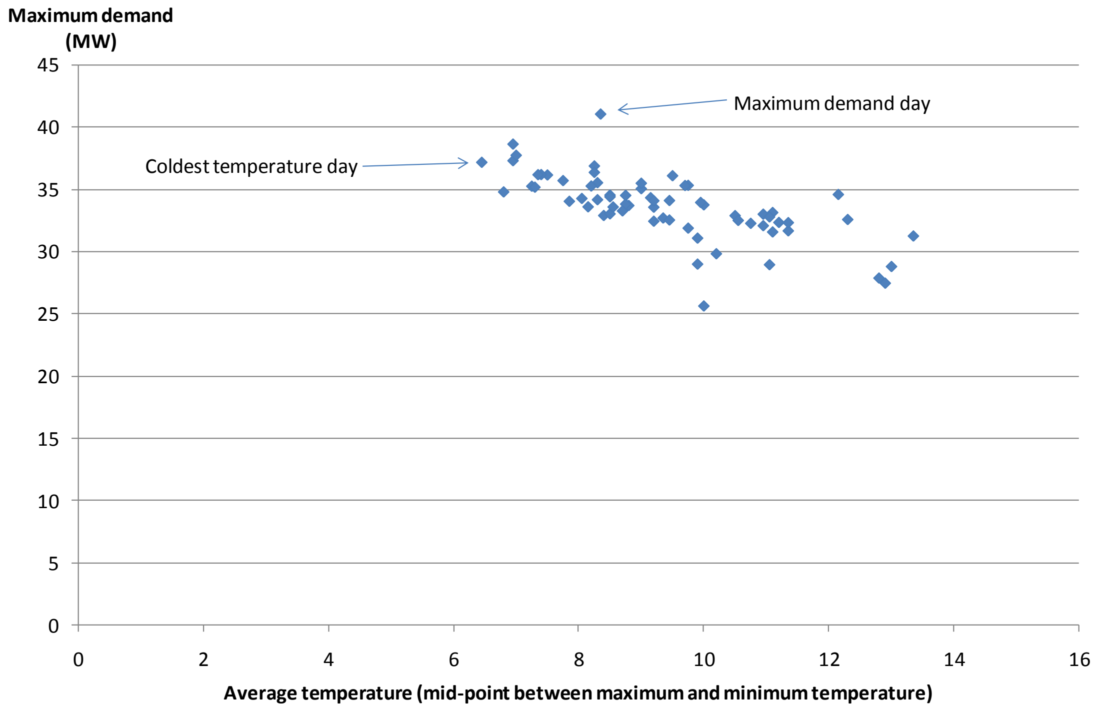
3. Add the estimated impact on demand of this temperature difference to the level of demand experienced on the maximum demand day.

In adjusting for temperature in this way, the AER considers that Aurora's forecasts were not appropriately adjusted to the level of maximum demand that can be expected to be exceeded 50 out of every 100 years (50% POE). This is due to the selection of the maximum demand day on which to add the impact of the 50 POE temperature.

Maximum demand is typically heavily influenced by temperature, but is also likely to be influenced by other factors. The timing of the temperature effects on maximum demand may not be contemporaneous. That is, the largest effect that temperature has on maximum demand and the largest effect that the other factors have on maximum demand may not occur at the same time.

This can be seen in Figure 3.12, which shows the daily maximum demand for Aurora's Chapel Street connection point for each day in 2010, aligned with the temperature that occurred on each day. The maximum demand occurred on a day that was not the coldest. While the reasonably cold temperature on the maximum demand day presumably had some effect, there were clearly other factors that drove the large amount of demand. Conversely, the demand experienced on the coldest day was less than that experienced on the maximum demand day. While temperature effects were presumably greater on this day than on the maximum demand day, the impact of other factors was clearly lower.

Figure 3.12 Historical maximum demand, Aurora's forecasts and Transend's 2011 forecast



Source: AER analysis,information provided by Aurora in response to AER request.[271]

The AER considers that Aurora's method for estimating of a long-run median temperature and the sensitivity of demand to temperature is appropriate to estimate the impact of assuming a median, or

[271] Aurora, *Response to information request AER/003 – NW -#30197215-v1-GB_Chapel_St_example_2010_LF*, template Chapel St.

50 POE, temperature.[272] However, by starting with the level of demand on the maximum demand day when undertaking temperature adjustments, Aurora has also included the level of demand that was driven by other non-temperature factors. Therefore, Aurora's temperature adjusted historical demand in total (that is, the combination of demand driven by temperature factors and demand driven by other factors) does not represent demand at a 50 POE planning level.

To develop alternative temperature adjustments that better reflect a 50 POE level, the AER used a simulation approach to determining the 50 POE level of both the demand driven by temperature factors and demand driven by other factors. The simulation approach uses long-run temperature information and temperature sensitivity estimates from Aurora's original regression analysis. It then generates randomised non-temperature-driven demand values to create simulated, randomised maximum demands. A median (50 POE) value is then derived from these maximum demands.[273] The AER's alternative temperature-adjusted historical demand is shown in Figure 3.8.

To ensure that the forecast demand for all assets is temperature adjusted, the AER applied its alternative temperature adjustment to Aurora's total system maximum demand and reconciled Aurora's forecasts to the AER's forecast. The maximum demand growth rates then included the impact of the temperature adjustment, ensuring that other asset forecasts included the impact of this adjustment when the growth rate is applied to them.

Co-incidence factors

To arrive at its own measure of total distribution system demand (as distinct from Transend's measure), Aurora sums the demand at its connection points. To do so, demand at each connection point must be adjusted by a co-incidence factor that accounts for the timing difference between the time that a connection point is experiencing maximum demand and the time that the system in total is experiencing maximum demand. Since the AER has used Aurora's total system demand forecast in estimating revised temperature adjustment, the AER needs to consider the appropriate co-incidence factors used to develop the total system forecast.

The timing differences, and the resultant co-incidence factors, between connection point maximum demands and total system maximum demand were measured from actual timing differences in past years. Aurora used the co-incidence factors experienced in 2010 to sum demand in all forecast years.[274] The coincidence factors experienced in 2010 are, on average, lower than the coincidence factors experienced in earlier years and lower than the average of the coincidence factors experienced from 2005 to 2010.

A higher co-incidence factor is interpreted as meaning that Aurora's connection point demand maximums are more closely harmonised—that is, the maximum demands at each connection point are occurring closer in time to each other. This increases the maximum demand of the system in total (it is having to deal with more connection point maximum occurring at the same time), but does not increase the individual maximum experienced at each connection point.

The AER considers that Aurora understated the extent to which its connection point maximums are likely to be harmonised in the future, and that an average of multiple past year co-incidence factors

[272] Note that the AER was concerned with the application of Aurora's method, particularly the exclusion of a warming trend and non-business day data.

[273] See: SKM-MMA, Review of Aurora Energy's maximum demand forecasting methodologies in its 2012–2017 regulatory proposal, Final report to the Australian Energy Regulator, 26 September 2011, pp. 43–45.

[274] ACIL Tasman, *Terminal and zone substation winter maximum demand forecasting tool*, developed for Aurora Energy — see Aurora, *Response to information request AER/003 of 1 July 2011*, received 8 July 2011.

would be more appropriate. Using an average would reduce the influence of yearly fluctuations in co-incidence factors on the estimated future co-incidence factors and hence forecast maximum demand. The AER considers that a 5-year historical average would be appropriate to smooth the influence of yearly fluctuations in co-incidence factors. ACIL Tasman, engaged by Aurora to provide advice on its demand forecasts, also recommended using a 3 or 5 year average to estimate co-incidence factors.[275] The AER therefore used 5-year historical averages as estimates of future co-incidence factors in deriving alternative maximum demand forecasts.

Applying growth rates to 'base' demand for individual assets

Aurora derived feeder forecasts by applying the growth rate from the relevant connection point to a base / starting value for the feeder. The starting value for feeder demand forecasts used by Aurora to inform its proposed capex is the median of the last three years of actual maximum demand (2008 to 2010).[276]

The AER considers that the starting value for the forecasts should be the most recent (2010) actual demand figure. This is consistent with the forecasting approach used by Aurora at terminal and zone substations, which Aurora acknowledges is done to avoid a large discontinuity with the historic time series.[277] The AER's substitute maximum demand forecasts for feeders were developed using 2010 temperature-adjusted historical demand as the starting value.

3.4 Revisions

Revision 3.1: The AER has developed substitute forecasts of new customer connections. These are shown in Table 3.1.

Revision 3.2: The AER has developed substitute forecasts of maximum demand. These are shown in Table 3.1.

[275] ACIL Tasman, *Outline of Aurora's spatial demand forecasting methodology*, September 2010, p. 5.

[276] Aurora, *Response to information request AER/003 of 1 July 2011*, received 8 July 2011, attachment titled 'Feeder Max Demand RIN Data - Chapel St 1of2 11kV'.

[277] SKM-MMA, Review of Aurora Energy's maximum demand forecasting methodologies in its 2012–2017 regulatory proposal, 26 September 2011, p. 36.

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 and opex attachments (attachments 5 and 6 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 will not necessarily increase at the same rate as the consumer price index (CPI). Aurora included an allowance for forecast real materials cost increases—that is, cost increases greater than forecast CPI increases—in both its opex and capex forecasts.[278] Aurora proposed that labour costs be escalated by CPI only.[279] However, it also stated that it applied an annual three per cent efficiency factor to the labour rates assumed in its regulatory proposal.[280]

4.1 Draft decision

The AER is satisfied that the real cost escalation included in Aurora's forecast capex, in proportional terms, reasonably reflects increases in Aurora's capex due to real cost increases. The AER has determined the weighted real cost capex escalators in Table 4.1 based on the labour and materials escalation included in Aurora's regulatory proposal.

Similarly, the AER is satisfied that the labour and materials real cost increases, included in Aurora's proposed total opex, reasonably reflects the opex criteria.[281] The AER has applied the weighted opex real cost escalators in Table 4.1 to determine Aurora's total opex.

The AER is also satisfied that the labour and materials real cost increases, included in Aurora's proposed expenditure for alternative control services, is consistent with the National Electricity Objective[282] and revenue and pricing principles in the National Electricity Law.[283]

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278 Aurora, *Regulatory Proposal*, May 2011, pp. 162–164.
279 Aurora, *Regulatory Proposal*, May 2011, p. 165.
280 Aurora, *Regulatory Proposal*, May 2011, p. 14.
281 NER, clause 6.5.6(c)
282 NEL, s7
283 NEL, s7A.

Table 4.1 AER conclusion on weighted real cost escalators (per cent, real)

	2012-13	2013-14	204-15	2015-16	2016-17
Aurora's proposal					
Opex	0.4	0.5	0.6	0.5	0.4
Capex	0.6	1.4	0.9	1.0	0.1
AER draft determination					
Opex	0.8	0.9	0.4	–0.3	–0.5
Capex	0.6	1.4	0.9	1.0	0.1
Difference					
Opex	0.4	0.4	–0.2	–0.8	–0.9
Capex	0.0	0.0	0.0	0.0	0.0

Source: AER analysis.

4.2 Aurora's proposal

Aurora proposed that the labour proportion of its capex and opex forecasts be escalated by CPI. That is, Aurora forecast that its labour costs would not increase in real terms over the forthcoming regulatory control period. It stated that it was confident of achieving efficiencies in its labour costs over the forthcoming regulatory control period and did not consider that an increase in labour costs over and above CPI was reflective of efficient costs.[284] Aurora also stated that to deliver operational efficiencies, it applied an annual three per cent efficiency factor to the labour rates assumed in its regulatory proposal.[285]

Aurora proposed that real cost escalation be applied to its materials inputs. It engaged Sinclair Knight Merz (SKM) to provide expert advice.[286] SKM considered the escalation rates in Table 4.2 represented the underlying drivers of network infrastructure plant and equipment costs specific to Aurora.[287]

284 Aurora, *Regulatory Proposal*, May 2011, p. 165.
285 Aurora, *Regulatory Proposal*, May 2011, p. 165.
286 Aurora, *Regulatory Proposal*, May 2011, p. 162.
287 SKM, *Annual Material Cost Escalation Factors 2013–17*, 15 April 2011, p. 5.

Table 4.2 Aurora proposed real cost escalators (per cent, real)

	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16
Aluminium	17.02	–1.07	–1.12	–2.98	–2.69	–2.08
Copper	17.79	–6.04	–7.69	–10.45	–10.76	–10.86
Steel	13.30	–2.53	–1.40	–3.05	–2.76	–2.15
Oil	8.73	–4.76	8.71	–3.33	–8.88	1.09
Construction costs	–0.26	–2.95	–1.60	1.05	2.79	2.91
CPI	2.75	3.00	2.50	2.50	2.50	2.50

Source: Aurora.[288]

To estimate the impact of these cost changes on capex in the forthcoming regulatory control period, SKM assigned individual cost component weightings for each project component. It then modelled the annual movement in the cost of network assets by applying weightings to each component, and applying the forecast movements input costs.[289] For example, SKM forecast the change in the cost of distribution equipment by applying weightings to the forecast movement in aluminium, copper, steel, oil and construction costs.

SKM used the same approach to forecast the change in the cost of 'distribution equipment'. Aurora applied this escalation rate to the materials component of its opex forecast.[290]

4.3 AER approach

Real cost escalation is a key input into Aurora's capex and opex forecasts. Attachments 5 and 6 outline the AER's approach to assessing Aurora's total capex and opex forecasts, including the approach to applying real cost escalators. The AER must accept Aurora's opex and capex forecasts if satisfied the total forecasts reasonably reflect the opex and capex criteria.[291]

The criterion particularly relevant to real cost escalation is the requirement that total forecast opex and capex reasonably reflect a realistic expectation of the cost inputs required to achieve the opex and capex objectives.[292] The efficient costs of a prudent DNSP depend on what happens in the labour and materials markets over the forthcoming regulatory control period. For the AER to be satisfied Aurora's opex and capex forecasts reasonably reflect all the opex and capex criteria, it must be satisfied those forecasts reasonably reflect a realistic expectation of these costs.

The AER engaged Deloitte Access Economics to develop forecasts of labour cost changes.[293] For materials, the AER developed its own forecasts of materials price changes. Where possible, it forecast price changes from prices traded in futures markets, such as for contracts traded on the London Metal Exchange. Where these were unavailable, the AER took forecasts from Consensus

288 Aurora, *Regulatory Proposal*, May 2011, pp. 162.
289 Aurora, *Regulatory Proposal*, May 2011, pp. 162–3.
290 Aurora, *Regulatory Proposal*, May 2011, p. 163.
291 NER, clauses 6.5.6(c) and.6.5.7(c).
292 NER, clauses 6.5.6(c)(3) and.6.5.7(c)(3).
293 Deloitte Access Economics, *Forecast growth in labour costs: Queensland and Tasmania*, 15 August 2011.

Economics, which provides forecasts derived from an average of forecasts from a number of economic forecasters.[294]

4.4 Reasons for decision

The AER considers that labour cost increases over the forthcoming regulatory control period will not necessarily match movements in the CPI. On balance, the AER is satisfied the impact of Aurora's proposed real cost escalators reasonably reflects a realistic expectation of labour and materials cost increases over the forthcoming regulatory control period.

The AER notes that its forecast labour cost increases, produced by Deloitte Access Economics, are greater than the CPI increases forecast by Aurora. It has considered the likely magnitude of any difference from CPI based on the view that:

- labour price increases due to labour productivity growth do not increase labour costs
- the LPI adjusted for productivity provides a more realistic expectation of labour cost changes than does changes in average weekly ordinary time earnings (AWOTE) adjusted for productivity.

Aurora applied an annual three per cent efficiency factor to the labour rates assumed in its regulatory proposal as a means of reducing total expenditure.[295] 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 did not apply an efficiency factor to the Aurora's labour rates for forecast opex because it made efficiency adjustments to Aurora's base year expenditure.

However, Aurora's lower labour cost escalators were counterbalanced by higher materials cost escalators, forecast by SKM. SKM's description of its forecasting model is largely consistent with the AER's own model. However, the AER is not satisfied with the:

- currency of SKM's forecasts, which were produced in April 2011
- exchange rate forecasts used by Aurora to convert SKM's forecasts from US dollar terms to Australian dollar terms.

4.4.1 Opex real cost escalators

The AER considers the weighted opex real cost escalators in Table 4.1 represent the increases in Aurora's opex due to real cost increase.

The AER has been unable to apply its forecast of real cost movements to forecast opex using the same method as Aurora because it did have the weightings required to forecast the weighted distribution equipment real cost escalators.

The AER forecasts of labour cost increases, forecast by Deloitte Access Economics, average 3 per cent, in cumulative real terms, over the forthcoming regulatory control period.[296] By comparison Aurora proposed that its labour costs be escalated by CPI increases only.[297] For materials, the real cost escalators forecast by the AER are lower than those forecast by SKM. On balance, the AER is

294 Consensus Economics, *Energy and metals consensus forecasts*, July 2011.
295 Aurora, *Response to information request AER/046,of 5 October 2011*, received 13 October 2011, p. 3.
296 Deloitte Access Economics, *Forecast growth in labour costs: Queensland and Tasmania*, 15 August 2011, p. 72.
297 Aurora, *Regulatory Proposal*, May 2011, p. 165.

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.

To determine weighted opex real cost escalators using Aurora's labour and materials escalators, the AER first determined the composition of Aurora's forecast opex (Table 4.3). It applied SKM's distribution equipment escalators to the materials proportion and no real escalation (that is, CPI only) to the remainder, to generate the weighted real cost escalators in Table 4.1.

Table 4.3 Composition of forecast opex (per cent)

	2010-11	2011-12	2012-13	2013-14	204-15	2015-16	2016-17
Labour—in-house	35.1	32.9	30.8	31.0	30.5	30.1	30.0
Materials	34.4	31.1	30.7	30.7	30.7	30.9	31.5
Overheads	14.7	17.4	15.8	15.4	15.3	14.9	14.1
Unallocated	15.8	18.6	22.6	23.0	23.5	24.1	24.4

Source: AER analysis; Aurora, RIN template.

4.4.2 Capex real cost escalators

Real cost escalation accounts for less than one per cent of Aurora's forecast capex. The AER has been unable to apply its forecast of real cost movements to forecast capex using the same method as Aurora for two reasons:

1. the AER has been unable to forecast the cost impact of real materials price changes on asset costs because SKM did not disclose the weightings it assumed in deriving its weighted real cost escalator for capex assets
2. the AER has been unable to determine how Aurora applied its proposed efficiency factor to its labour rates.

By applying an efficiency factor to its labour rates, Aurora has assumed that labour costs will decrease over the forthcoming regulatory control period. Deloitte Access Economics forecasts that real labour costs over the forthcoming regulatory control period, adjusted for labour productivity improvements, will on average increase by 3 per cent in cumulative real terms.[298]

However, the real materials cost escalators forecast by the AER are lower than those forecast by SKM for Aurora (see attachment 5). On balance, the AER is satisfied that the real cost escalation included in Aurora's forecast capex, in proportional terms, reasonably reflects a realistic expectation of labour and materials cost increases over the forthcoming regulatory control period. The AER's conclusion on weighted capex real cost escalators is in Table 4.1.

4.4.3 Alternative control real cost escalators

The AER has been unable to apply its forecast of real cost movements to alternative control costs using the same method as Aurora because it did have the weightings required to forecast the weighted metering and street lighting real cost escalators.

[298] Deloitte Access Economics, *Forecast growth in labour costs: Queensland and Tasmania*, 15 August 2011, p. 72.

The AER forecasts of labour cost increases, forecast by Deloitte Access Economics, average 3 per cent, in cumulative real terms, over the forthcoming regulatory control period.[299] By comparison Aurora proposed that its labour costs be escalated by CPI increases only.[300] For materials, the real cost escalators forecast by the AER are lower than those forecast by SKM. On balance, the AER is satisfied that the impact of the real cost escalators applied by Aurora to its proposed alternative control costs reasonably reflects a realistic expectation of labour and materials cost increases over the forthcoming regulatory control period.

4.4.4 Treatment of labour productivity effects

Labour price changes, agreed in negotiated wage agreements, can be described by both productivity effects and other effects. Productivity effects drive labour price changes since more productive labour receives higher wages. Other effects include CPI increases and any price changes driven by labour market supply/demand imbalances.

The AER considers forecast labour price changes should be adjusted for labour productivity changes to forecast the change in labour costs.

It is important to make the distinction between labour prices and labour costs. Deloitte Access Economics (DAE) stated:

> … labour costs will rise at a different rate [than labour prices] due to the effects of labour productivity growth. Effectively, labour productivity measures the number of units of output an individual employee can produce in a given time period. The more units of output each worker can produce, the fewer workers are required to create a given level of industry output. If productivity is rising, the total cost of labour (the price of each employee multiplied by the number of employees) will rise less rapidly than the individual employee's price.[301]

Broadly labour price changes can be described by three effects:

1. Composition productivity effects reflect increases in workforce productivity due to changes in the skill composition of the workforce. For example, an increased share of high skill workers will increase average workforce productivity and average wage rates per worker.[302] However, because average workforce productivity has increased, fewer workers are required to produce the same amount of output, and any increase in labour costs will be less than the increase in the average labour price.

2. Worker productivity effects are increases in workforce productivity due to increases in the productivity of individual workers. For example, workers may become more productive from working with better capital equipment.[303] Again, because average workforce productivity has increased, fewer workers are required, and any increase in labour costs will be less than the increase in the average labour price.

3. Other effects unrelated to productivity. For example, wage increases due to CPI increases or labour supply or demand imbalances.[304] Because these effects are unrelated to productivity, the same amount of labour is required to produce a given amount of output, and the change in labour price results in a corresponding change in labour costs.

[299] Deloitte Access Economics, *Forecast growth in labour costs: Queensland and Tasmania*, 15 August 2011, p. 72.
[300] Aurora, *Regulatory Proposal*, May 2011, p. 165.
[301] Deloitte Access Economics, *Forecast growth in labour costs: Queensland and Tasmania*, 15 August 2011, p. 102.
[302] Prof. J Borland, Labour cost escalation report for Envestra Limited, 2011, p. 2.
[303] Prof. J Borland, Labour cost escalation report for Envestra Limited, 2011, p. 2.
[304] Prof. J Borland, Labour cost escalation report for Envestra Limited, 2011, p. 2.

Thus to the extent that labour prices are rising due to increased labour productivity (either compositional productivity or worker 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 to produce a constant level of output, the price impacts of both composition productivity effects and worker productivity effects should be removed from the labour price measure used.

Aurora proposed that the labour proportion of its capex and opex forecasts be escalated by CPI only.[305] However, Aurora also stated that to deliver operational efficiencies, it applied an annual three per cent efficiency factor to the labour rates assumed in its regulatory proposal.[306] At first glance these two statements could appear contradictory. One interpretation is Aurora has assumed that the *labour price* will increase by CPI only during the forthcoming regulatory control period. That is, the salary of a worker that remains at the same job classification level and pay step will increase by CPI only. But labour productivity will improve by three per cent per annum. Thus the labour rates within Aurora's unit rates, that is, *labour costs*, will decrease by three per cent per annum in real terms.

However, Aurora's forecast labour productivity improvements are best described as an aspirational target. Aurora has assumed productivity improvements to achieve its long term objective of ensuring 'no increase to customer prices as a result of its efforts'.[307] That is, Aurora has applied the labour efficiencies across all expenditure as a means of reducing total expenditure.[308] Consequently, the AER does not consider the efficiency factor proposed by Aurora to be a robust forecast of labour productivity improvements.

4.4.5 The choice of labour price measure

Different labour price measures are available, including average weekly earnings (AWE) and the labour price index (LPI).[309] The different measures have been developed for different purposes and it is important to use the appropriate measure. Aurora did not propose a specific measure be used to forecast its labour prices. However the AER has considered the appropriateness of different labour price measures in estimating its own forecast of labour cost changes.

The AER considers forecast growth in AWOTE does not reasonably reflect a realistic expectation of the change in labour costs. It considers LPI forecasts, adjusted for productivity effects, most reasonably reflect labour costs during the forthcoming regulatory control period.

AWOTE measures average employee earnings from working the standard number of hours per week. It is not strictly a price index (that measures the pure price effect) because the composition of labour is not held constant. It captures composition productivity effects, worker productivity effects and other effects. In contrast the LPI is a Laspeyres type price index that measures the change in the labour costs, with the quantity and quality of work performed held constant.[310] LPI measures the pure price effect, showing how much the same quantity of labour costs in the current period, relative to the base period. The weights used are for the base period and are updated annually to represent job distribution.[311]

305 Aurora, *Regulatory proposal*, May 2011, p. 165.
306 Aurora, *Regulatory proposal*, May 2011, p. 165.
307 Aurora, *Regulatory proposal*, May 2011, p. 167.
308 Aurora, *Response to information request AER/046 of 5 October 2011*, received 13 October 2011, p. 3.
309 References to LPI refer to the specific ABS index rather than labour prices indices generally.
310 To the extent that some quality changes in the work performed are unquantifiable, the price change would incorporate some of the quality change effect. However, the magnitude of this effect is generally negligible.
311 ABS, *Labour Price Index: concepts, sources and methods*, Catalogue number 6351.0.55.001, 2004, p. 12.

Conceptually at least, either labour price measure can quantify the change in labour costs. However, it is important when measuring the impact on labour costs of labour price changes that the labour price and productivity measures match.[312] Labour, capital and multifactor productivity measures are the most commonly used productivity measures published by the ABS. The labour productivity measures are published annually for the market sector as a whole, as well as at the industry division level (for example, the electricity, gas and water industry). They indicate value added per hour worked. This conventional measure of labour productivity is the appropriate labour productivity measure for adjusting AWOTE.

A quality adjusted measure of labour productivity, on the other hand, is the appropriate measure to adjust the LPI.[313] The ABS recently developed quality adjusted measures of labour input and labour productivity. It released experimental estimates for 1982-83 to 1999-2000 in 2005, and since published yearly statistics from 1994-95.[314] The measure of labour captures the change in the aggregate quality of labour due to compositional changes such as higher education, or longer work experience, so the effect is not ascribed to productivity. Generally, the quality adjusted labour productivity index increases at a slower rate than the conventional labour productivity index, implying improved labour force skill levels over time.

As relative input prices change over time, efficient NSPs will respond with a (new) cost minimising combination of inputs. There is no need to explicitly capture cost changes and productivity changes associated with labour input change because the labour input requirement is endogenous to the production function. To this end, the AER prefers the LPI (adjusted for quality adjusted labour productivity) to AWOTE (adjusted for labour productivity) because:

- the LPI provides a more accurate measure of labour price change (by holding labour composition fixed) than does AWOTE
- the quality adjusted labour productivity index provides a better measure of labour productivity because the effective quantity labour input accounts for changes in the skill composition of the labour force.

Regarding the first bullet point, the AER has previously noted the AWOTE data series shows greater volatility than the LPI, partly due to the changing composition of the workforce (Figure 4.1).[315] While it is possible to remove the volatility from the AWOTE data series (by using a moving average, for example) this still leaves the end point problem.[316] The end point problem exists because there is insufficient data at the end of the series to apply a symmetric filter.[317] For a centred moving average, for example, it is not possible to calculate the average for the last term of the series because the next data point is required, and it is not yet known.

312 Deloitte Access Economics, *Response to Professor Borland: comments prepared for the AER*, 15 April 2011, p. 3.

313 The AER recognises that its productivity adjusted LPI forecasts, produced by Deloitte Access Economics, are not adjusted using a quality adjusted labour productivity measure. However, Deloitte Access Economics advised that this was appropriate because of their forecasting approach. For details see Deloitte Access Economics, *Productivity measures to adjust LPI and AWOTE*, 8 November 2011, pp. 9–10.

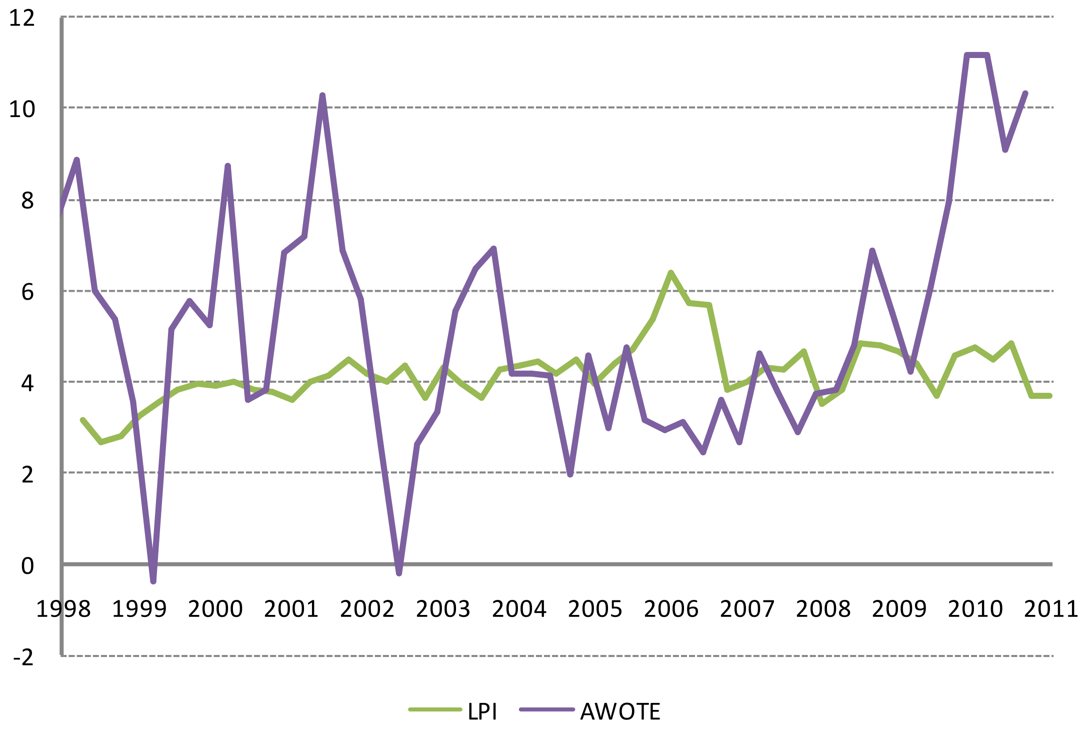
314 ABS, *Quality-adjusted labour inputs*, Research paper, Catalogue number 1351.0.55.010, November 2005.

315 AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, Appendix K, 2010, p. 246.

316 Deloitte Access Economics, Response to Professor Borland: comments prepared for the AER, 15 April 2011, p. 5.

317 ABS, *Time series analysis: The process of seasonal adjustment*, viewed 10 October 2011, www.abs.gov.au/websitedbs/d3310114.nsf/4a256353001af3ed4b2562bb00121564/5fc845406def2c3dca256ce100188f8e!OpenDocument.

Figure 4.1 Annual growth in LPI and AWOTE, EGW industry, Australia (per cent)



Source: ABS.[318]

However, using the LPI has its own difficulties because of the limited availability of quality adjusted labour productivity index data. While the ABS publishes unadjusted labour productivity statistics for the electricity, gas, water, and waste services (EGWWS) industry, its quality adjusted labour productivity index is available only at the overall market sector level. The AER considers, however, the problems with using AWOTE are greater than those with using the LPI. Having to account for these labour composition effects, and the resultant volatility, makes AWOTE unreliable for forecasting labour costs for the utilities industry. The greater stability of the LPI data series makes it preferable for forecasting labour cost growth.

4.4.6 Currency of forecasts

Cost forecasts will change as they are updated to reflect changing market data. The AER considers that forecasts reflecting the most current market data, most reasonably reflect a realistic expectation of labour cost inputs.

The AER considers Access Economics' labour cost growth forecasts, produced in August 2011 for the AER, reasonably reflect a realistic expectation of the labour cost inputs required to achieve the opex and capex objectives. It will update its labour cost growth forecasts for its final determination (to be made in April 2012) to reflect subsequent changes to labour market conditions.

The AER considers its materials and land cost growth forecasts, produced in September 2011, reasonably reflect a realistic expectation of the labour cost inputs required to achieve the capex objectives. It will update these cost growth forecasts for its final determination.

318 ABS, catalogue 6302.0, table H; ABS, catalogue 6345.0, table 9b; AER analysis.

The NER requires capex and opex forecasts to reasonably reflect a realistic expectation of the cost inputs required to achieve the capex and opex objectives.[319] The macroeconomic outlook, including key market factors, has changed since SKM's materials cost forecasts were prepared in April 2011.[320] The AER considers, therefore, the forecasts proposed by Aurora no longer reflect the current market outlook, and do not reasonably reflect a realistic expectation of labour, materials and land cost inputs. The AER has adjusted forecast capex and opex to reflect the AER's forecasts of real cost changes (see attachments 5 and 6 respectively).

Materials cost forecasts require forecasts of both the movement in the price of commodities (such as copper and steel) as well as exchange rate forecasts to convert commodity prices into Australian dollars. To the extent possible, these two forecasts 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.

4.4.7 Foreign exchange rate forecasts

Both the AER and SKM forecast movements in aluminium, copper and steel prices using forward prices on the London metal exchange (LME) and Consensus Economics long term price forecasts.[321] Both of these are denominated in US dollars and require forecast exchange rates to convert to Australian dollar terms.

The AER considers the exchange rate forecasts in Table 4.4, based on rates in the forward market, are the most realistic expectation of exchange rates during the forthcoming regulatory control period.

Table 4.4 AER's conclusion on USD/AUD foreign exchange forecasts

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17
AER forecast	1.00	1.04	1.00	0.96	0.93	0.90	0.88
Aurora's proposal	0.81	0.73	0.73	0.73	0.73	0.74	0.74

Source: AER analysis, Bloomberg, SKM, Aurora.[322]

Aurora's proposed materials cost escalators were forecast by SKM, which converted US dollar denominated input prices to Australian dollars using exchange rates forecast by KPMG Econtech.[323] The forecasts included in SKM's December 2010 report, include actual rates through to August 2010 (as shown in the report's table four, despite the report stating that actual RBA rates were used through to June 2010).[324] Beyond August 2010, SKM forecast exchange rates by interpolating Econtech's exchange rate forecasts from the AER’s May 2010 final decision for Ergon and Energex.[325] It is unclear if SKM updated these exchange rate forecasts in preparing the materials cost forecasts included in its April 2011 report and were used by Aurora to develop its capex and opex

319 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).
320 SKM, *Annual Material Cost Escalation Factors 2013-17*, April 2011.
321 SKM, *Aurora Energy annual material cost escalators 2013–17*, 22nd December 2010.
322 Aurora, Annual material cost escalators 2013–17, 22nd December 2010, pp. 18–19.
323 SKM, *Aurora Energy annual material cost escalators 2013–17*, 22nd December 2010, p. 18.
324 SKM, *Aurora Energy annual material cost escalators 2013–17*, 22nd December 2010, pp. 18–19.
325 SKM, *Aurora Energy annual material cost escalators 2013–17*, 22nd December 2010, p. 18.

forecasts. The AER compared these rates to the average rate available in the forward market during the month of August, and noted that the proposed rates were lower (Table 4.4).

The AER has used forward rates from the month of August because this is close to the date that the long term forecasts from Consensus Economics were released (25 July 2011). As discussed in section 4.4.6, the AER considers that US dollar materials cost forecasts should be converted to Australian dollars using exchange rates forecast at the same time. The most recent forecasts available from Consensus Economics at the time the AER prepared its materials price forecast were those of 25 July 2011.The AER notes that the Australian dollar fell in September but have since risen again.

Exchange rates are difficult to forecast, particularly in the short term.[326] Despite this, the AER is not satisfied that the exchange rate forecasts proposed by Aurora reasonably reflect a realistic expectation of its costs. The exchange rate forecasts provided by Aurora were calculated prior to May 2010 and need to be updated to reflect changed market conditions. Because of this the exchange rates proposed by Aurora are significantly lower than the rates available in the forward market.[327] Given the difficulty in forecasting exchange rates, the AER considers the use of forward exchange rates is reasonable. The use of forward market rates for foreign currency is consistent with the approach adopted by both the AER and SKM to forecast real cost increases of materials. Both the AER and SKM forecast real cost increases in aluminium, copper and steel using forward prices where available.[328]

Consequently, the AER considers that the monthly average forward exchange rates as at August 2011 produce materials cost forecasts that reasonably reflect the opex and capex criteria. The AER will update these rates in its final determination to reflect the most current rates available at that time.

4.4.8 Labour and materials real cost forecasts

Having considered the above matters, the AER has forecast the real cost escalators in Table 4.5. The labour cost forecasts were prepared for the AER by Deloitte Access Economics.[329]

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326 See, for example, Meese, R, Rogoff, K, 'Empirical exchange rate models of the seventies: do they fit out of sample?', *Journal of International Economics*, volume 3, 1983, pp. 3–24. More recently, Rogoff, K, *The Failure of Empirical Exchange Rate Models: No Longer New but Still True*, www.economics.harvard.edu/files/faculty/51_EP_Web2001.pdf, accessed 24 October 2011, October 2001.

327 Forward rates reflect the current spot rate and interest rate differentials between the two countries. According to the forward rate unbiasedness hypothesis, if market participants are assumed to be rational and risk neutral, then the forward rate is an unbiased predictor of the expected future spot rate. However, results of empirical testing of the hypothesis have been mixed. See Natalya Delcoure et al, 'The forward rate unbiasedness hypothesis reexamined: evidence from a new test', *Global finance journal*, volume 14, May 2003, pp. 83–93.

328 SKM, *Aurora Energy annual material cost escalators 2013–17*, 22nd December 2010, pp. 24–31.

329 Deloitte Access Economics, *Forecast growth in labour costs: Queensland and Tasmania*, 15 August 2011.

Table 4.5 AER determined real cost escalators (per cent, real)

	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17
Labour—internal	3.1	1.7	0.8	–0.8	–1.2	–2.1	–1.5
Aluminium	1.8	–3.9	4.9	4.8	–0.3	2.0	1.0
Copper	11.6	–1.6	0.8	–2.6	–11.8	–7.2	–4.6
Steel	3.8	1.4	3.1	1.4	–1.8	–2.2	0.2
Oil	2.1	–6.9	4.8	2.8	1.7	0.8	–0.7
Construction costs	–0.3	–1.0	–3.2	–2.3	–0.2	1.3	1.9

Source: Deloitte Access Economics,[330] AER analysis, Australian Construction Industry Forum.[331]

330 Deloitte Access Economics, *Forecast growth in labour costs: Queensland and Tasmania*, 15 August 2011, p. 72;

331 Australian Construction Industry Forum, Construction aggregates, www.acif.com.au/forecasts/construction-aggregates, retrieved 4 October 2011.

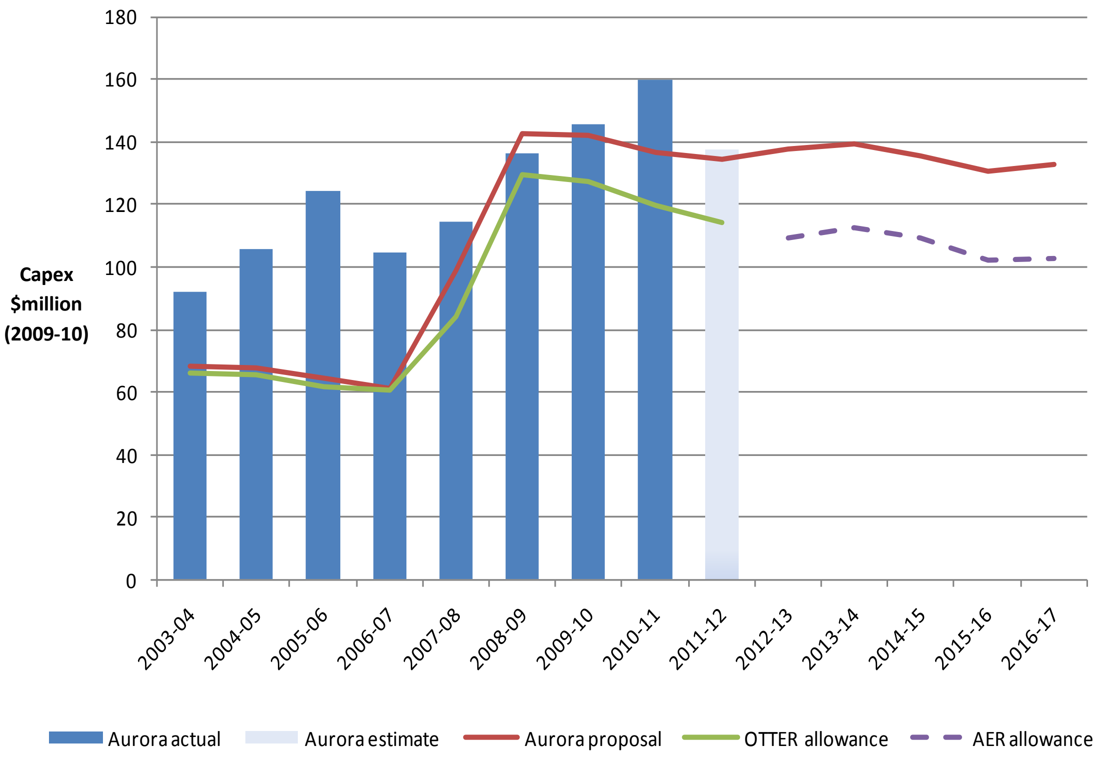
5 Capital expenditure

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 $675.4 million ($2009–10) for 2012–13 to 2016–17.

5.1 AER draft 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.[332] Figure 5.1 compares Aurora's past and forecast total capex with proposed and approved capex.

Figure 5.1 Comparison of Aurora's past and future total capex and AER draft determination ($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. As required by the NER, this estimate reduces Aurora's proposal of total forecast capex only to the extent necessary to comply with the NER.[333] Overall, the AER estimates a total forecast capex of $535.8 million ($2009–10) over the forthcoming regulatory control period. This equates to a reduction of approximately $136.5 million ($2009–10), or 20 per cent of Aurora's proposed total capex.

332 NER, clause 6.5.7(c). Clause 6.5.7(a) specifies the capex objectives.
333 NER, clause 6.12.3(f).

The AER's estimate of the capex allowance required by Aurora for the 2012–13 to 2016–17 regulatory control period that reasonably reflects the capex criteria is displayed in Table 5.1.[334]

Table 5.1 AER draft 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
Adjustment	-27.5	-25.9	-25.4	-28.0	-29.6	-136.5
AER's estimate	109.4	112.6	109.3	102.2	102.3	535.8

Source: Aurora, Revised PTRM, submitted 30 June 2011, AER analysis.

The AER considers that much of the capex proposed by Aurora is consistent with the requirements of the NER. However, the AER considers that several elements of Aurora’s total forecast capex proposal are overstated. The quantum of each concern excludes 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. Aurora has not sufficiently justified an increase in the replacement volumes of some programs from historical levels. The AER considers a reduction of $32.7 million ($2009–10) (4.8 per cent of Aurora’s total forecast capex proposal) is required to address this concern.
- Aurora’s forecast for new residential connections are too high. The AER has developed a substitute forecast of new residential connections. The AER estimates the impact of this substitute forecast, using unit costs as proposed by Aurora, should reduce Aurora’s forecast capex by $30.1 million ($2009–10) (4.5 per cent of Aurora’s total forecast capex proposal).
- Aurora’s forecast unit costs for new connections are also too high. The AER considers more realistic unit costs, derived from historical trends, should reduce Aurora’s forecast capex by an additional $5.1 million ($2009–10) (0.8 per cent of Aurora’s total forecast capex proposal).
- $24.6 million ($2009–10) (3.6 per cent of Aurora’s total forecast capex proposal) is for reliability improvement investment. The AER considers this expenditure 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 should be 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 $12.0 million ($2009–10) (1.8 per cent of Aurora’s total forecast capex proposal) is required to address these concerns.
- Approximately $30.8 million ($2009–10) (4.7 per cent of Aurora’s total forecast capex proposal) appears to be primarily directed at achieving operational efficiencies or reliability improvements. The AER considers this expenditure is not required to achieve the capex objectives in a manner that reasonably reflects the capex criteria.

334 NER, clause 6.12.1(3)(ii).

5.2 Aurora's proposal

Aurora proposed total forecast capex of $675.3 million ($2009–10) for 2012–13 to 2016–17 as shown in Table 5.2.[335]

Table 5.2 Aurora's proposed total forecast capex ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Total capex	139.9	138.5	134.7	130.3	131.9	675.3

Source: Aurora, Revised PTRM, submitted 30 June 2011.

Aurora's proposed total capex for the period 2012–13 to 2016–17 is slightly less than capex incurred over the period 2007–08 to 2011–12.[336]

In its 2007 Pricing Investigation, the Office of the Tasmanian Economic Regulator (OTTER) forecast a significant increase in Aurora's capex for the period 2008 to 20011–12 compared to the period 2004 to 2007. Aurora stated this expenditure was largely driven by the need to ensure the performance of the electricity infrastructure could keep up with Tasmanian economic growth and more stringent reliability and safety standards.[337] Notwithstanding the significant increase forecast by OTTER, Aurora overspent this forecast. This is shown in Figure 5.2.

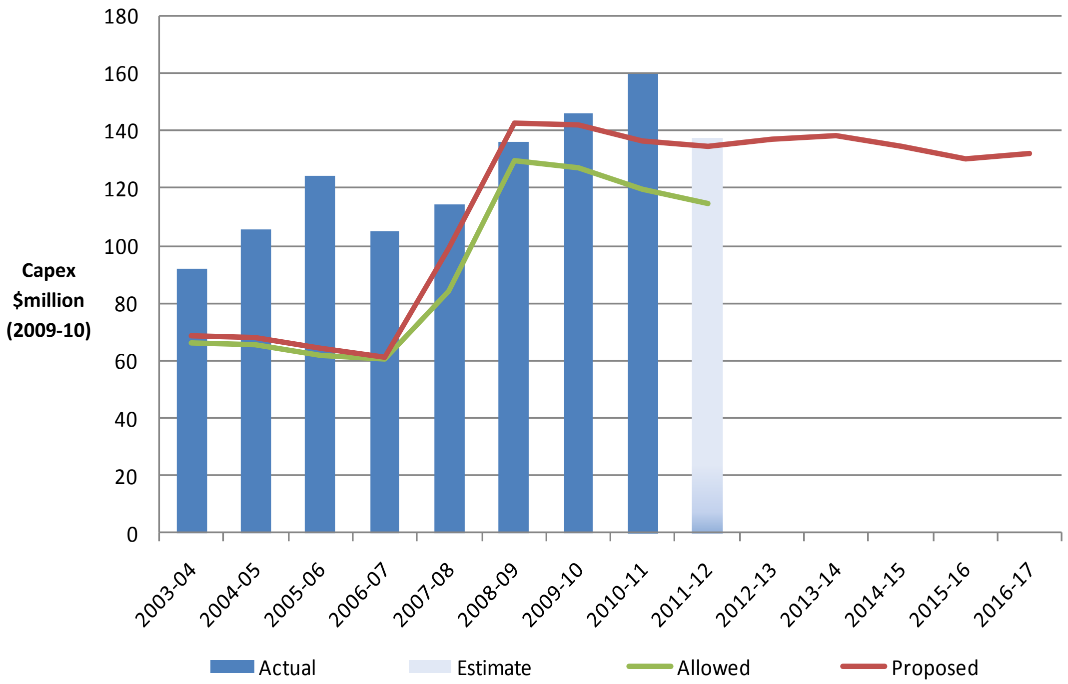
Aurora stated this additional expenditure was due to:[338]

- significant increases in customer generated work driven by buoyant economic conditions
- major supply upgrades
- the rollout of the broken neutral detector device to Tasmanian households
- the need to implement targeted reliability programs
- storm related events throughout 2009 and 2010.

Aurora stated it now has a strong and resilient network, delivering a level of reliability and system security commensurate with the needs of the Tasmanian community.[339] Aurora therefore developed its capex proposal for the forthcoming regulatory control period from the position that investment in its distribution network is now at an appropriate level so that consolidation can occur.[340]

335 Aurora, *Regulatory proposal*, May 2011,p. 124.
336 Aurora's current regulatory period is actually from 1 January 2008 to 30 June 2012 and the previous period is from 1 July 2003 to 31 December 2007. However, for a more meaningful comparison, the AER has treated the 'current regulatory period' as the past five years (2007–08 to 2011–12). The previous period is therefore 2003–04 to 2007–08.
337 Aurora, *Regulatory proposal*, May 2011, p. 3.
338 Aurora, *Regulatory proposal*, May 2011, p. 3.
339 Aurora, *Regulatory proposal*, May 2011, p. 3.
340 Aurora, *Regulatory proposal*, May 2011, p. 3.

Figure 5.2 Comparison of Aurora's past and future total capex ($million, 2009–10)



Source: AER analysis.

Aurora developed its total forecast capex using a 'thread management' approach.[341] The 'thread management' approach means that each asset class used by Aurora has a 'thread' associated with it. A 'thread' comprises staff involved in the planning, design, construction and maintenance for each asset class. Aurora used the threads as a mechanism for grouping assets for planning and expenditure allocation.[342]

Aurora's total forecast capex includes amounts for capitalised overheads and operating costs, input price changes and equity raising costs. Equity raising costs are discussed in sections 5.3.4 and 5.4.7. The AER has assessed capitalised overheads and input price changes separately in attachment 6 (opex) and attachment 4 (real cost escalation). The AER's discussion of these components of capex in this attachment (sections 5.4.8 and 5.4.9) is limited to their impact on total capex. The AER has assessed components of Aurora's total forecast capex excluding capitalised overheads and input price changes. Figure 5.3 shows a break down of Aurora's total forecast capex over each year of the period 2012–13 to 2016–17.

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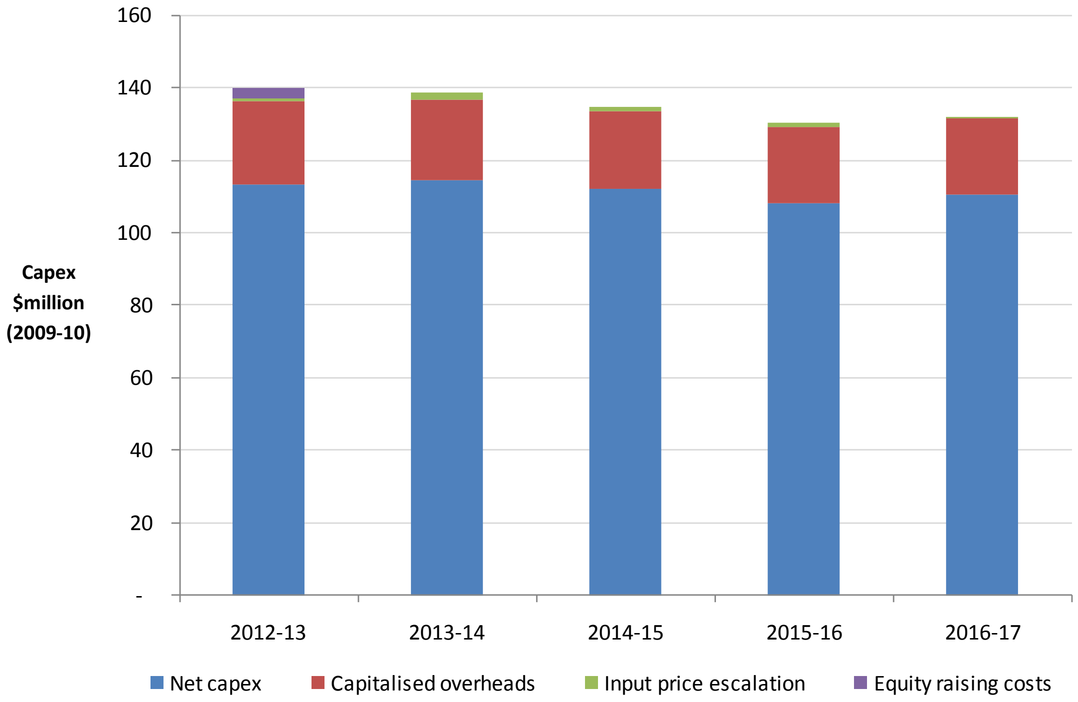
341 Aurora, *Regulatory proposal*, May 2011, p. 32.
342 Aurora, *Regulatory proposal*, May 2011, p. 32.

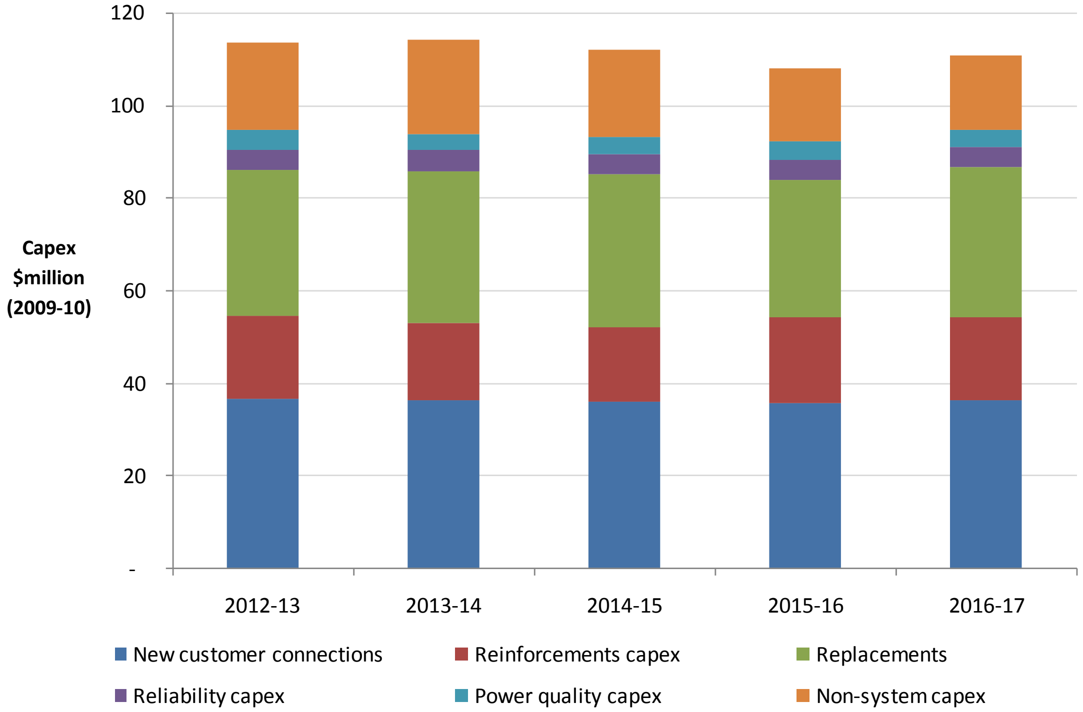
Figure 5.3 Break down of Aurora's proposed total forecast capex ($million, 2009–10)



Source: AER analysis of Aurora's PTRM and RIN response.

Figure 5.4 shows Aurora's capex excluding capitalised overheads and operating costs, equity raising costs and input price changes and separated by purpose categories. Together, replacements capex and new customer connections capex comprise half (50.4 per cent) of Aurora's total forecast capex on average over the period 2012–13 to 2016–17.

Figure 5.4 Aurora's proposed total forecast capex by purpose categories ($million, 2009–10)



Source: AER analysis of Aurora's PTRM and RIN response.

5.3 AER approach

The NER requires Aurora to submit a building block proposal to the AER that includes a total forecast capex for the 2012–13 to 2016–17 regulatory period.[343] The AER is required to assess this forecast to decide whether it:[344]

- accepts the total forecast capex, or
- does not accept it. In this case, the AER must estimate the total amount of capex it considers Aurora's requires that reasonably reflects the capex criteria. The AER's estimate must be based on Aurora's proposal, and amended only to the extent necessary to comply with the NER.[345]

To make this decision, the AER must form a view on Aurora's proposed total forecast capex as a whole, not as individual projects or programs.[346] However, because the total forecast capex can be separated into expenditure components, the AER assesses projects and programs of these components to inform its decision on the total amount.

The AER must accept Aurora's proposed total forecast capex if satisfied it reasonably reflects the capex criteria. That is, the forecast must reflect the efficient costs that a prudent operator in Aurora's circumstances would need to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the capex objectives.[347] The AER considers efficient costs are the

343 NER, clause 6.8.2(2). Clause 6.4.3(b) details the building blocks.
344 NER, clause 6.12.1(3).
345 NER, clause 6.12.3(f).
346 NER, clause 6.5.7(c).
347 NER, clause 6.5.7(c). Clause 6.5.7(a) specifies the capex objectives.

costs that a prudent operator is expected to incur, not a premium above otherwise efficient costs to balance risk.[348]

In deciding whether Aurora's proposed total forecast capex reasonably reflects the capex criteria, the AER must have regard to the capex factors.[349] Although the AER has considered each capex factor when assessing Aurora's proposed total forecast capex, not all factors are relevant for assessing each capex component. Therefore, the AER has made its determination by examining:

- the amount of forecast capex that it considers would reflect the efficient costs of achieving the capex objectives
- whether Aurora's proposed forecast capex reasonably reflects the AER's forecast of efficient capex (in total)
- those item(s) of Aurora's proposed forecast capex that do not appear to reflect the AER's forecast.

Capex is often non-recurrent in nature, and may to some extent be driven by factors beyond Aurora's control. Such factors include maximum demand, asset age, and new customer connections. The effect of the non-recurrent nature of capex is that it may often deviate from forecasts. The deviation of Aurora's actual capex from its forecasts is demonstrated in Nuttall Consulting's technical report, which shows Aurora's forecasting accuracy.[350]

The non-recurrent nature of capex means the AER cannot apply the same assessment approach for total capex as it has for total opex. The AER has used the following assessment techniques to assess whether Aurora's total capex is based on a realistic expectation of demand forecast and cost inputs:[351]

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

The AER has used the revealed cost approach and benchmarking to determine whether Aurora's total capex reasonably reflects an efficient forecast.[352] The AER has also considered the impact of its substitute maximum demand forecasts on Aurora's total capex. The AER's assessment of demand is discussed in attachment 3 (demand forecasts).

348 Some distribution network service providers posited the 'Prudency Premium' hypothesis during the 2011–15 Victorian Electricity Distribution Review. See AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015,* October 2010, pp. 396–398.

349 NER, clause 6.5.7(d). Clause 6.5.7(e) specifies the capex factors.

350 Nuttall Consulting, *Report—-Principle Technical Advisor: Aurora Electricity Distribution Revenue Review—A report to the AER—Final Report*, October 2011, pp. 21–22 (Nuttall Consulting, *Aurora Revenue Review*, October 2011).

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

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

5.3.1 Unit cost comparative analysis

The AER has examined Aurora's new customer connections capex[353] as average unit costs (average cost per connection) to account for the impact of demand for new customer connections. This approach is based on Aurora's customer-initiated capital works management plan. This plan states Aurora's approach to developing forecast new customer connections capex is to apply a unit rate to its forecast volumes.[354] Aurora has not provided any further information on how it derives or applies unit costs. The AER therefore considers it is appropriate to examine the average unit costs for new customer connections derived from Aurora's regulatory proposal. The AER's unit costs are based on connection type, and adjusted for the potential effects of scale and capacity constraints.[355]

The AER has also conducted comparative analysis of other unit costs Aurora has used to develop its capex forecast. In particular, the AER has undertaken high level benchmarking of a selection of Aurora's unit costs against similar unit costs of the Victorian DNSPs.[356] The AER also compared the results of its unit cost benchmarking with the results of a benchmarking report prepared for Aurora by Parsons Brinckerhoff.[357]

5.3.2 Replacement modelling

The AER used its replacement expenditure (repex) model to assist with forecasting age-related capex required to replace assets that have come to the end of their useful life. The repex model is a high level model that forecasts replacement needs at the asset category level based on the age and unit costs of a DNSP's asset base. The repex model is therefore suitable for assessing types of activity with correlation to the age of assets.

At a high level, the repex modelling process for Aurora involves[358]:

1. populating the repex model with the quantity of assets installed in each year (age profiles), asset replacement lives, and asset unit replacement costs

2. generating a 'calibrated model' from Aurora's historical replacement volumes and actual replacement expenditure to simulate future replacement needs

3. generating a 'benchmark model' using the average of the calibrated asset lives and unit costs of Aurora and the Victorian DNSPs, except CitiPower[359].

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353 The AER considers new customer connections capex to be capex that is primarily directed at facilitating the connection of new customers to Aurora's distribution network. The (largely uncontrollable) demand for new customer connections clearly drives the need to incur this capex.

354 Aurora, *Customer-initiated capital works management plan*, March 2011, pp. 14, 16-19. Revised management plan to replace Attachment AE032 to Aurora, Regulatory proposal 2012–2017, 31 May 2011. Provided in *response to information request AER/016 dated 26 July 2011*, received 11 August 2011.

355 Aurora forecast demand for new customer connections and new customer connections capex by connection type – residential, commercial, residential subdivision and irrigation connections. However, Aurora did not provide information (historical or forecast) that separates demand for new customer connections capex by complexity of the capital works. Accordingly, the AER was unable to assess unit costs separated by complexity. Aurora, *Customer-initiated capital works management plan*, March 2011, pp. 12, 14. Revised management plan to replace Attachment AE032 to Aurora, *Regulatory Proposal*, May 2011. Provided in response to Aurora, *information request AER/016 dated 26 July 2011*, received 11 August 2011.

356 Aurora's unit cost categories were selected from Aurora's program of works to ensure that a large portion of Aurora's proposed capex is captured. Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 4.2.

357 Parsons Brinckerhoff, *Capex and opex benchmarking study*, March 2011. Attachment AE061 to Aurora, *Regulatory Proposal*, May 2011, p. 32.

358 A detailed explanation of the repex model and calibration techniques is discussed in Nuttall Consulting's technical report Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 6.3.2.

359 Due to CitiPower's large level of underground assets, its calibrated lives are generally much longer than that of the other DNSPs, which could bias analysis too strongly against Aurora.

This approach to assessing replacement expenditure enables the AER to use data provided by Aurora to estimate future replacement volumes, and in turn, the likely cost of this replacement. Essentially, the repex model uses recent actual replacement volumes and unit costs, taking into account past risks, asset management practices and replacement costs, to forecast likely future replacement needs.

The AER has used the repex model in conjunction with other analysis to inform its decision on the minimum necessary adjustment to Aurora's total forecast capex proposal. The AER's approach is therefore to use the repex model to:

- benchmark Aurora against itself (for example, to compare past replacement volumes and costs with Aurora's proposal)
- benchmark Aurora against the Victorian DNSPs (for example, to compare age profiles and repex model outputs)
- compare with information provided by Aurora in support of its regulatory proposal to identify asset categories that required detailed review

The repex model combined with related analysis provides the AER with an indication of the likely level of replacement and cost required by Aurora to achieve the capex objectives.[360] It follows that the AER can then determine whether the replacement expenditure proposed by Aurora forms part of a total forecast capex that reasonably reflects the capex criteria.[361]

5.3.3 Sampling approach for demand driven capex

The need to incur demand driven capex is typically and predominately driven by growth in maximum demand for electricity—a predominantly uncontrollable driver. The amount of expenditure to address the need may also be driven to some extent by the following other uncontrollable drivers: [362]

- input price changes
- regulatory obligations or requirements
- Aurora’s particular circumstances (for example, Tasmanian topology).

Determining the scope of the efficient response to the need to undertake demand driven investment activity is generally complex due to the influence of multiple material drivers.[363] Aurora is also different to other NEM DNSPs because its network has a relatively small amount of sub-transmission and zone substation assets.[364]

360 This combination of analysis tools provides the AER with an indication of the level of replacement capex required by Aurora to maintain the quality, reliability and security of supply of standard control services (NER, clause 6.5.7(a)(3)), and maintain the reliability, safety and security of the distribution system. NER, clause 6.5.7(a)(4).

361 As required by clause 6.5.7(c)(1) and (2) of the NER.

362 The AER acknowledges that for most of these uncontrollable drivers, Aurora may have some level of control, but there is also an underlying uncontrollable element. For example, Aurora could strive to manage demand for energy supply by altering tariff structures to encourage usage to occur at different times of the day. However, Aurora may have little influence over the reaction of customers to the new tariffs.

363 The scope of reinforcement expenditure is more heavily driven by network configuration than other expenditure categories. This means that the same kind of augmentation as one that occurred in the past, even if for the same network segment/area, may have a different scope due to changes to network configuration over time. Reinforcement projects also often tend to be less frequent than other projects and programs – such as replacements and inspections. This is because of long asset lives and high up front fixed costs resulting in the building in of excess capacity to address demand growth.

364 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 35.

Typically, a large portion of a DNSP's reinforcement capex proposal is for major projects associated with zone substation or sub-transmission development, which can be estimated and assessed at a high level.[365] However, Aurora's proposal mainly comprises a large number of distribution level feeder augmentations, developed through a bottom up process.[366] Solutions to specific feeder issues are difficult to review by typical desktop approaches because there may be several influencing factors for a single feeder augmentation.[367]

As a result, the AER conducted a targeted review of a sample of projects and programs that Aurora considers underpins its forecast.[368] Specifically, the AER has reviewed the documentation provided by Aurora with its regulatory proposal and identified four planning areas of Aurora's network for a targeted review: Hobart East, Hobart West, North West and North Coast.[369] The AER considers these areas contain a large level of planned augmentations, and include a range of large and small projects, as well as a range of load growths.[370]

The AER has grouped 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.[371] The AER has then inferred the average finding of the sampled projects within a group to be the overall finding for the group.[372] The AER has inferred findings for the projects in the sample as findings for projects outside the sample, but only where the AER considers there is a likelihood that concerns with the in-sample projects will also exist in the out-of-sample projects.

Due to concerns that a large proportion of the Aurora's proposed demand driven capex is not required to maintain service levels, the AER has also determined the proportion of all reinforcement capex projects and programs that:

- is required to achieve the capex objectives by maintaining service levels in light of forecast growth in demand (demand component)
- is not required to achieve the capex objectives because it is driven by opex and/or reliability improvements (efficiency benefit component).

The AER has determined this split for assessment of the projects in its sampled review and for the additional programs reviewed. In determining the demand component, the AER has determined an allowance so Aurora can meet growth in demand. Further detail of this sampling approach is contained in Nuttall Consulting's technical report.[373]

365 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 35.
366 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 35.
367 For example, assessing the appropriate solution to a specific HV feeder constraint may require detailed knowledge of existing feeder arrangements including loading, switching arrangements and topology. Nuttall Consulting, Consulting *Aurora Revenue Review*, October 2011, p. 35.
368 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 39.
369 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 39.
370 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 39.
371 The AER’s groupings are: HV feeders, zone substation projects involving non-network solutions and other zone substation projects.
372 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 5.6.
373 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 5.6.

5.3.4 Cash flow analysis for equity raising costs

In assessing Aurora's proposal for equity raising costs, the AER has relied on an approach based on the 2004 Allen Consulting Group (ACG) report commissioned by the ACCC.[374] Under this method the allowance for equity raising costs is based on a hierarchy of three methods for raising equity:

- First, firms should use retained earnings as a source of equity
- Second, firms use dividend reinvestment plans. The amount of equity raised through this method is capped at 30 per cent.
- Third, firms use seasoned equity offerings (SEO) encompassing both rights issues and placements.

The AER has assigned the following transaction unit cost for each form of equity funding:

- Retained earnings – 0 per cent
- Dividend reinvestment plans – 1 per cent of total dividends reinvested
- SEOs – 3 per cent of total external equity required.

The AER's method applies a cash flow analysis in the post-tax revenue model (PTRM) to determine the benchmark amount of equity raising required:

- retained earnings are equal to the internal cash flow less dividends to shareholders. This is then deducted from the equity portion of forecast capital expenditure to determine the amount of external equity required
- dividends are assumed to be sufficient to distribute 70 per cent of the imputation credits assumed in the PTRM, and 30 per cent of dividends paid is returned to the business via a dividend reinvestment plan
- The requirement for SEOs is the difference between the forecast capital expenditure and the net cash flow (retained earnings) that is available for capital expenditure.

The AER amortises benchmark equity raising costs allowance is over the weighted average standard life of the regulatory asset base (RAB). As such, the amount calculated from the steps above is added to the RAB for the purposes of providing an allowance for equity raising costs associated with forecast capex. The AER considers that this method represents the approach that an efficient and prudent operator would apply in raising equity, given its particular capital raising requirements.[375] In particular, the operator will first exhaust the cheapest sources of funding through the use of internal cash flows before using more expensive external sources of equity financing.

5.3.5 Revealed cost approach

The revealed cost approach considers information revealed by the past performance of a DNSP. Under the ex ante regime, DNSPs are rewarded for spending less capex than allowed by the regulator. This incentive enables the AER to place some reliance on the historical costs of a DNSP

[374] ACG, *Debt and equity raising transaction costs - Final Report*, December 2004. The AER has applied this approach to assess equity raising costs in all its determinations.
[375] NER, clause 6.5.7(c).

when reviewing its forecast capex. Importantly, using the DNSP's historic expenditure ensures the total capex forecast reflects the expenditure of a DNSP in its circumstances.[376]

The revealed cost approach is an accepted industry practice. Many DNSPs, including Aurora, have used this approach to forecast expenditure proposals.[377] The AER has also used the revealed cost approach in past reviews.[378]

Given the non-recurrent nature of capex, the AER uses revealed costs in conjunction with other assessment tools to examine the relationships between revealed costs and their drivers. For example, the AER assesses when Aurora has replaced assets to determine the historical relationship between asset age and replacement expenditure. The AER can then examine whether Aurora's forecast expenditure is consistent with its forecast asset profile.

5.3.6 Benchmarking

The AER uses benchmarking to compare Aurora's past performance and forecasts with other DNSPs, as a reference for assessing Aurora's efficiency. Where this benchmarking indicates that Aurora's capex may not be efficient, the AER undertakes a detailed review of Aurora's proposal. The AER's detailed review involves consideration of relevant documentation and the impact of factors expected to differ from the past and/or from other DNSPs. The AER forms its judgement after considering submissions from Aurora, other interested parties, and the AER's own analysis.

The AER recognises that forecast efficient costs may legitimately depart from those revealed through past performance, and compared with other DNSPs. For example, DNSPs may discover more efficient processes over time. DNSPs may propose they can best achieve the capex objectives by incurring expenditure to implement new, more efficient processes, and include such expenditure in their proposed forecast capex. For Aurora, the AER has assumed that operating processes would only be changed (from revealed, or otherwise efficient processes) if they are likely to result in efficiency gains (in the absence of any information to suggest other reasons for the change). Where the AER considers that future cost savings should result from capex investments, the AER has taken this into consideration in determining Aurora's opex allowance.

5.3.7 Capex factors

In reviewing Aurora's capex proposal, the AER had regard to the capex factors.[379] The AER's consideration of the capex factors is summarised in Table 5.3.

376 NER, clause 6.5.7(c).

377 Aurora has assumed historical expenditure and volumes are a valid basis for forecasting. Aurora *Regulatory Proposal*, May 2011, p. 2. Other DNSPs that have used this approach include the Victorian DNSPs (although United Energy did not use this as a basis to forecast its opex proposal).

378 See, for example, AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, October 2010, p. 401.

379 NER clause 6.5.7(e).

Table 5.3 AER consideration of capex factors

Capex factor	AER approach
The information included in or accompanying the building block proposal.	The AER has reviewed Aurora's regulatory proposal and supporting documentation. Among other things, this includes asset management plans, justification documentation, models and responses provided to AER information requests.
Submissions received in the course of consulting on the building block proposal.	The AER has considered submissions in response to Aurora's regulatory proposal.
Analysis undertaken by or for the AER and published before the distribution determination is made in its final form.	The AER has undertaken extensive analysis of Aurora's regulatory proposal and supporting documentation, and analysis of previous regulatory reviews conducted by the AER. The AER has also engaged independent expert technical consultants to assist with its review.
Benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period.	The AER has benchmarked Aurora against itself and other NEM DNSPs to assess whether its forecast capex is efficient. The AER has undertaken this benchmarking analysis for total capex and specific components of capex as well as for unit costs.
The actual and expected capital expenditure of Aurora during any preceding regulatory control periods.	As part of its analysis, the AER has reviewed Aurora's actual and expected capex for preceding regulatory periods.
The relative prices of operating and capital inputs.	The AER has assessed capital inputs such as Aurora's unit costs and materials and labour costs as part of this review.
The substitution possibilities between operating and capital expenditure.	The AER has inherently considered capex and opex substitution possibilities through detailed project review. The AER has considered options to address needs, including the substitution of opex to defer capital projects, or capital projects to remove the need for opex. Part of the AER's review is also to consider how Aurora has considered these possibilities when preparing its forecast. The AER has accounted for substitution possibilities in its estimate of substitute forecasts for total capex and total opex.
Whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period.	The AER has developed a substitute capex allowance that is sufficient to allow Aurora to achieve the capex objectives in the forthcoming regulatory control period.
The extent the forecast of required capital expenditure of Aurora is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms.	This factor is not applicable to Aurora as it does not deal with any related parties.
The extent Aurora has considered, and made provision for, efficient non-network alternatives.	Aurora proposed non-network alternatives in its capex forecast. The AER has considered these as part of its review. In particular, the AER considered these in the detailed project reviews and review of Aurora's forecast methodology.

5.4 Reasons for determination

This section outlines how the application of the AER's assessment approach has lead the AER to:

- not accept Aurora's proposed forecast capex as reasonably reflective of the costs required to achieve the capex objectives given the capex criteria, and
- develop a substitute forecast capex based on amendments to Aurora's proposed forecast capex.

The AER has a number of concerns with Aurora's proposed total capex. Similar concerns have been raised by the Energy Users Association of Australia (EUAA) in its submission on Aurora's regulatory proposal.[380] The AER's concerns are summarised in Table 5.4. The AER's considerations of each issue in Table 5.4 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. The AER has developed a substitute forecast capex based on these amendments to Aurora's proposed capex.

Table 5.4 AER's adjustments to Aurora's proposed forecast capex ($million, 2009–10)

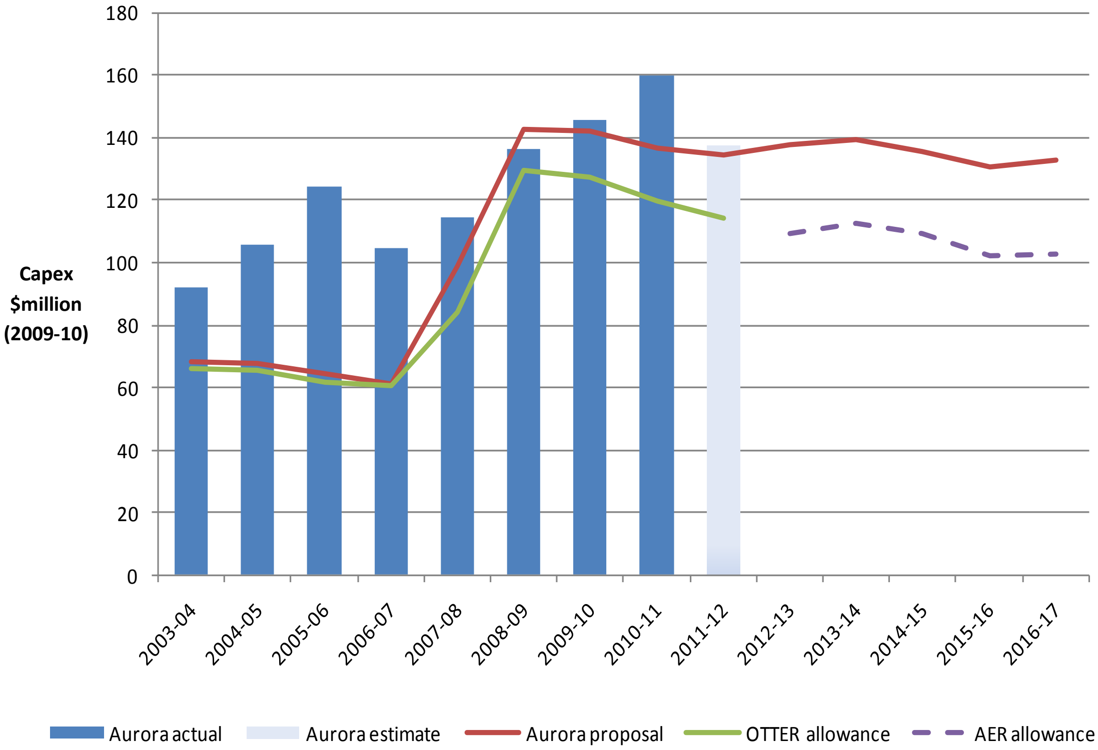
Issue	Amount
Replacement costs that are too high	29.6
Forecast of customer connection volumes that are too high	30.1
Forecast of customer connection unit costs that are too high	5.1
Capex for reliability improvements that are not required to achieve the capex objectives	24.6
Capex projects to address maximum demand growth that are driven by efficiency benefits and are not required to achieve the capex objectives	29.7
Capex projects to address maximum demand growth that are too extensive in scope and too high relative to benchmarks	12.0
Capex to maintain power quality that is not required to achieve the capex objectives	4.2
Equity raising costs that are too high given realistic capital requirements	2.7
Input price changes that are too high	0.2

Source: AER analysis.
Note: Amounts exclude capitalised overheads and input price changes.

The AER has estimated a substitute total capex forecast for Aurora that the AER considers reasonably reflects the capex criteria, having regard to the capex factors. This estimate reduces Aurora's proposal of total forecast capex only to the extent necessary to comply with the NER.[381] Overall, the AER estimates a total forecast capex of $432.5 million ($2009–10) (excluding capitalised overheads and input price changes)[382] over the forthcoming regulatory control period. The AER's estimate is $139.0 million ($2009–10) 24 per cent lower than Aurora's forecast excluding capitalised overheads and input price changes ($571.5 million ($2009–10)).

[380] EUAA, *Submission to the Australian Energy Regulator on Aurora Energy's Regulatory Proposal on Distribution Prices for 2012–2017,* August 2011, pp. i, 7–14.
[381] NER, clause 6.12.3(f).
[382] All amounts referred to in section 5.4 exclude capitalised overheads and input price changes unless specified otherwise.

Figure 5.5 Comparison of Aurora's past and future total capex and AER draft determination ($million, 2009–10)



Source: AER analysis, Aurora's RIN template.

The AER has reviewed the following categories of Aurora's capex proposal:

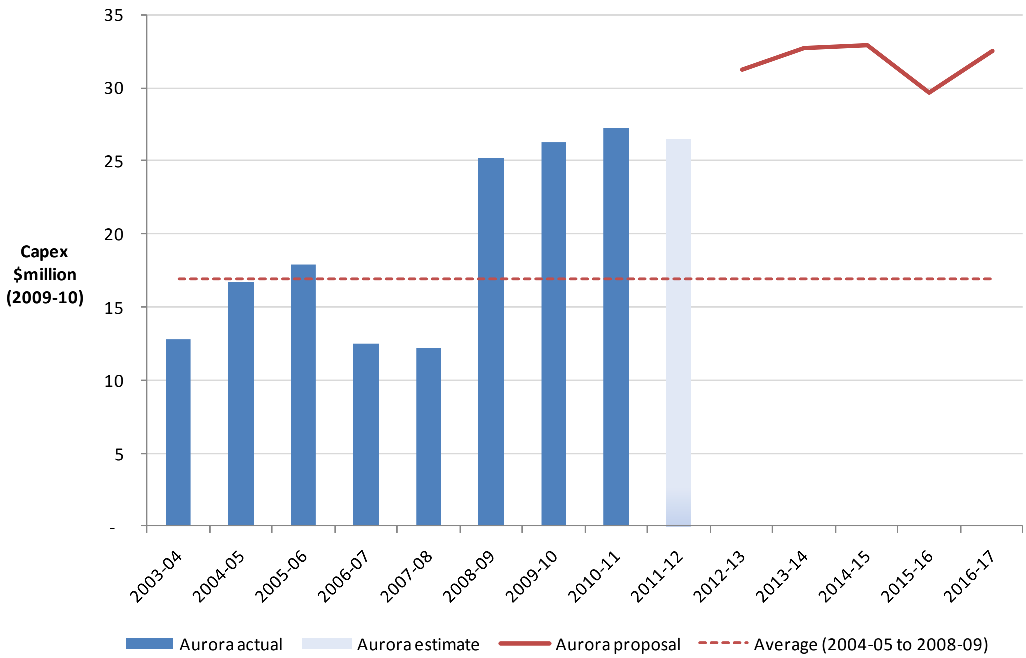
- age or condition-based replacement
- new customer connections
- reliability improvement
- capex to address maximum demand growth (reinforcement)
- power quality issues
- non-system investment
- equity raising costs
- capitalised overheads
- real input price changes.

The AER's analysis of these categories is presented below.

5.4.1 Age or condition-based asset replacement

Aurora's proposed replacement expenditure for the forthcoming regulatory control period totals approximately $159.1 million ($2009–10).[383] This amounts to 23.6 per cent of Aurora's total forecast capex proposal. Figure 5.6 shows that Aurora has forecast total replacement capex to increase significantly from current and past levels.

Figure 5.6 Aurora's historical and forecast replacement capex ($million, 2009–10)



Source: AER analysis.

Despite this, the AER considers that most of Aurora's proposed replacement capex is required to achieve the capex objectives, particularly for maintaining reliability, safety and security of the distribution system.[384] However, the AER considers that some of Aurora's asset management practices result in inefficient replacement volumes (and hence higher costs) than those required to maintain the network or otherwise achieve the capex objectives. The AER also considers some of the increased capex may result in offsetting reductions in opex.

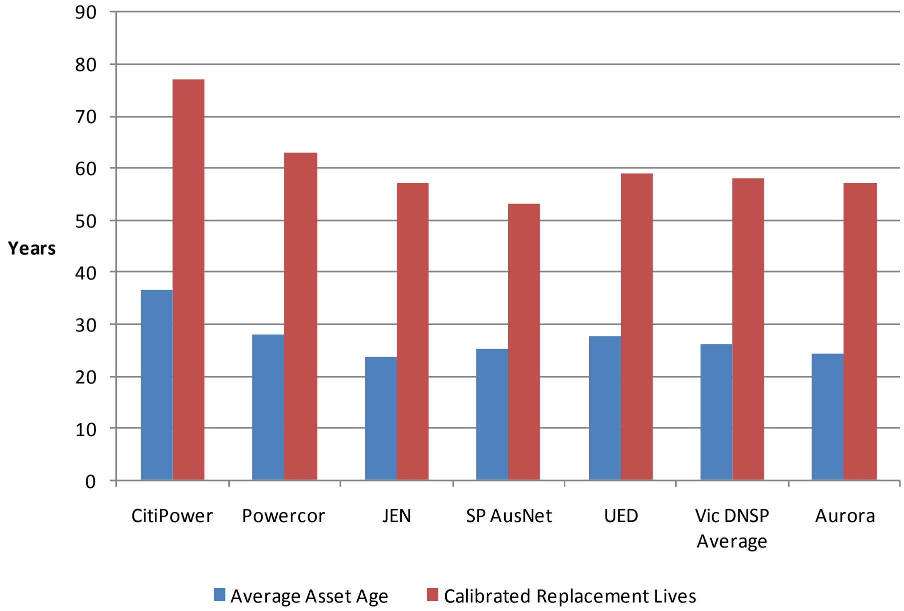
Therefore, the AER considers Aurora's forecast replacement capex is in excess of the expenditure required to form part of a total forecast capex that will enable Aurora to achieve the capex objectives. The AER considers an adjustment of approximately $29.6 million ($2009–10) to Aurora's total forecast capex proposal is required to comply with the NER. This amounts to a reduction of 18.6 per cent of Aurora's proposed replacement capex. The AER's analysis of Aurora's replacement capex is below.

A large proportion of Aurora's proposed replacement capex is correlated with asset age, so the AER used the repex model as a basis for the assessment of this expenditure. The repex model generates likely future replacement needs based on Aurora's past replacement volumes and unit costs.

383 AER analysis of Aurora's RIN response and Aurora's Capex by work category spreadsheet.
384 NER, clause 6.5.7(a)(4).

Aurora's asset age profile and calibrated replacement lives indicate that Aurora has a relatively young network compared to the Victorian DNSPs[385], but on average, replacement lives are shorter (Figure 5.7).[386]

Figure 5.7 Comparison of asset age and replacement lives



Source: AER analysis. Victorian DNSP results are taken from Nuttall Consulting, *Report—Capital Expenditure: Victorian Electricity Distribution Revenue Review-—A report to the AER—Final Report,* Appendix H, 4 June 2010. This report was published as part of the Victorian draft distribution determination.

Note: CitiPower is included for comparative purposes, but was not used for benchmarking. The Victorian DNSP average excludes CitiPower.

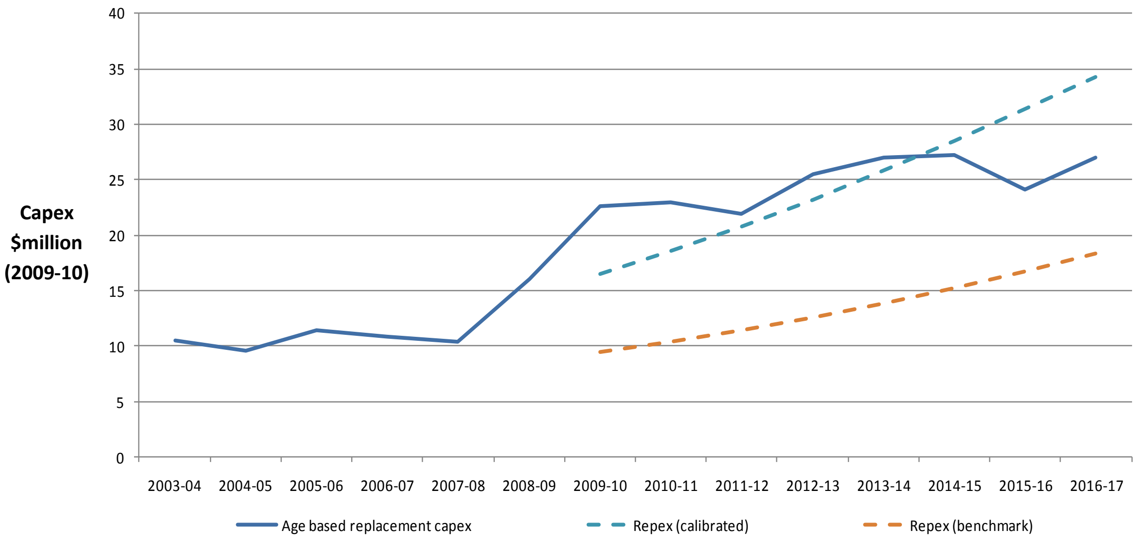
The calibrated repex model output (dashed blue line in Figure 5.8) forecasts similar capex to Aurora in the early half of the next regulatory control period and more in the later half, but this should be viewed as the upper limit when compared with the benchmark repex model.[387] This is because the calibrated repex model uses Aurora's volumes and unit costs (which may not be efficient), but the benchmark repex model also includes the Victorian DNSPs' volumes and unit costs).

385 CitiPower is excluded from the Victorian DNSP average. Due to CitiPower's large level of underground assets, its calibrated lives are generally much longer than that of the other DNSPs, which could bias analysis too strongly against Aurora.

386 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 75–76.

387 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 75–76.

Figure 5.8 **Aurora's age based replacement capex compared to repex model outputs ($million, 2009–10)**



Source: AER analysis of Aurora's capex by work category spreadsheet; repex model.

The benchmark repex model output (dashed orange line in Figure 5.8) suggests that Aurora's current asset management practices and/or its forecasting methodologies may be overstating the prudent investment needs of its network.[388]

Detailed review with the repex model

The AER has conducted a detailed review of Aurora's work categories in conjunction with the repex model assessment. Through this further analysis, the AER has confirmed that some of Aurora's current asset management practices are resulting in volume forecasts that are inefficient. For example, Aurora's pole condemnation forecasting approach: [389]

- results in replacement levels above the long term average currently achieved with similar pole populations and inspection procedures on the mainland
- implies service lives of between 19 and 25 years when 30 to 50 years is more appropriate given that the majority of Aurora's poles are steel, concrete or treated hardwood
- suggests Aurora's pole lives are (on average) shorter than those of the Victorian DNSPs.

The AER considers that Aurora's forecasting approach is generally appropriate. However, where Aurora has been unable to justify why its management practices are reasonable, and, in the AER's assessment, they result in inefficient forecasts, the AER has given greater weight to historical information and benchmark analysis.

Whilst it is open to Aurora to continue its current asset management practices, the AER considers it appropriate to reduce total forecast capex as necessary, given its concern.

The AER has also found that some replacement volumes for volume based replacement programs are forecast to increase above historical levels. However, Aurora has not provided fault data or

388 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 75–76.
389 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 80–82.

condition information to support the increased expenditure. This is specifically the case with some distribution transformer, switchgear and underground cable replacement programs.[390] In the absence of such justification, the AER considers historical replacement volumes (supported by the benchmark repex model) provide a more reasonable indication of Aurora's replacement needs. As a result, a minor reduction in total forecast capex is required.

Although the benchmark repex model often supports a reduction in Aurora's expenditure, there are a large number of programs that the AER considered ought to be allowed despite this. The AER's detailed review has established that parts of Aurora's network pose safety risks. Aurora has claimed confidentiality over the specific risks. These are listed in Appendix H.

The AER considers that Aurora has clearly justified the need to address these safety risks in order to maintain the reliability, safety and security of its network. The higher than benchmark volumes are reasonable given the safety risks. In several cases, the problems identified by Aurora are similar to those faced by other DNSPs, who are currently addressing them, or have already addressed them.[391] On the whole, the AER did not find any significant issues with the proposed costs of these programs. However, given that some of the replacement is to address older and poorer condition assets, there should be associated opex savings and/or reliability improvements as a result.[392] These are discussed further below.

Detailed review without the repex model

The AER has been unable to use the repex model as an assessment tool for some of Aurora's replacement forecasts. Generally, this is due to either: [393]

- insufficient volume data
- lack of correlation with asset age
- lack of historical aged-based replacement activity.

For these programs, the AER has assessed Aurora's justification documentation, historical averages, historical trends and benchmarking (where possible), and other supporting information. The AER has examined historical data over the past two regulatory periods (from 2003–04).

The AER is generally satisfied that the programs proposed by Aurora are reasonably required for Aurora to maintain the reliability, safety and security of its distribution network. The majority of the programs are required to address safety issues or comply with existing obligations.[394] As with some programs assessed with the repex model, some non-repex modelled programs are for safety issues that most other DNSPs have already addressed, or are currently addressing.[395] The AER has also found that Aurora has, on the whole, justified the volumes and unit costs, but some opex savings and/or reliability improvements may arise as a result of the replacements. These are discussed further below.

390 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 89, 97, 105–106.
391 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 86–87, 105.
392 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 94, 108.
393 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 87–88, 94, 103–104,108, 111, 115–116.
394 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 88, 102–103, 107–108, 109–110, 119.
395 For example, replacement of cast iron potheads, fibreglass substation doors and live line clamps. Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 107, 117–118.

However, the AER disagrees with a series of programs to address aging transformers in some of Aurora's zone substations. The AER considers that Aurora's current asset management practices for transformers are resulting in forecast replacements earlier than necessary.[396] The AER considers a more prudent approach is to defer replacement until the assets reach the end of their useful lives, and ensure the existing assets are appropriately maintained. This can be achieved by:[397]

- continued condition monitoring
- oil reconditioning for the transformers in poorer condition
- purchasing a spare transformer.

The AER's decision on these programs does not prevent Aurora from continuing its current asset management practices. However, the AER does not consider it is prudent to allow the capex to replace these transformers when there is not an obvious need and there are more cost-effective solutions available.

Opex savings and reliability improvements

The AER considers some of Aurora's proposed replacement capex programs may result in future opex savings and/or reliability improvements, particularly where the program is for targeted replacement. Examples include Aurora's CONSAC[398] cable replacement program[399] and some distribution transformer replacement programs.[400]

The AER has considered the potential opex savings and reliability improvements from these replacement programs in light of its proposed adjustments to total forecast capex and total forecast opex.[401] The AER considers an adjustment to Aurora's total opex is not required as a result of these replacement programs for two reasons.

First, although the AER has allowed these replacement programs (which should reduce opex), the AER has also not allowed capex for other programs because it is more efficient for Aurora to spend opex instead of capex. An example of the latter is Aurora's zone substation transformer replacement program.[402]

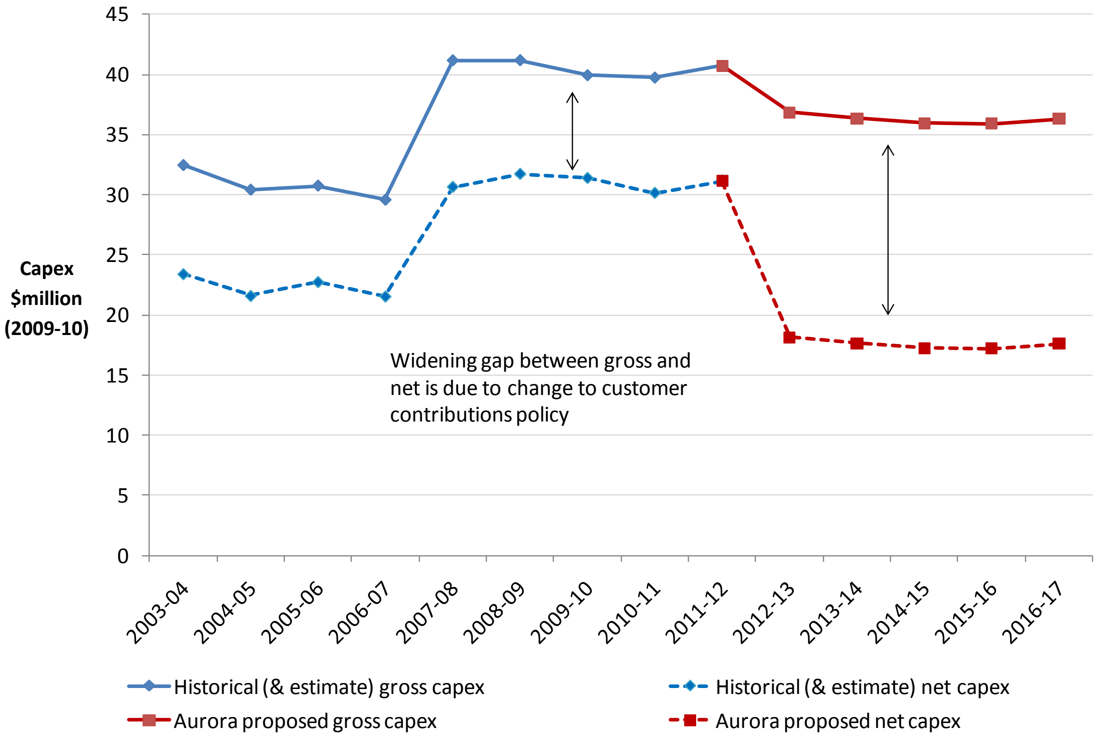
Second, the AER has not allowed Aurora's proposed non-demand driven reliability improvement capex (see section 5.4.3), or other capex that appears to be driven primarily by opex savings and/or reliability improvements (see sections 5.4.4 and 5.4.5) because the AER considers it is not required to achieve the capex objectives in a manner that reasonably reflects the capex criteria.[403] This capex totals $22.2 million ($2009–10) and is 3.3 per cent of Aurora's proposal. One of the reasons for not allowing the non-demand driven reliability improvement capex is because of the replacement programs that should also result in reliability improvements (such as the distribution transformer and CONSAC programs mentioned above). In light of the reductions to capex, the AER considers that the magnitude of opex savings from Aurora's replacement program should not be significant. On balance, a reduction to Aurora's opex is therefore not required.

396 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 111–114.
397 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 114–115.
398 Concentric neutral, solid aluminium conductor.
399 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 105–106.
400 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 93–94.
401 NER, clauses 6.5.6(e)(7) and 6.5.7(e)(7) require the AER to consider the substitution possibilities between opex and capex.
402 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 111–114.
403 NER, clause 6.5.7(a).

5.4.2 Forecast of new customer connections

Aurora has proposed approximately $181.4 million ($2009–10) for customer connections capex. This amounts to approximately 26.9 per cent of Aurora's proposed total capex forecast. The AER's considerations of a realistic expectation of demand for new connections are outlined in the demand attachment (attachment 3). Aurora's forecasts of new customer connections are separated into residential, commercial, irrigation and residential subdivision connections. Aurora's total historical and proposed customer connections capex is displayed in Figure 5.9.

Figure 5.9 Aurora's historical and proposed customer connections capex ($million, 2009–10)



Source: AER analysis.
Note: Net capex excludes customer capital contributions.

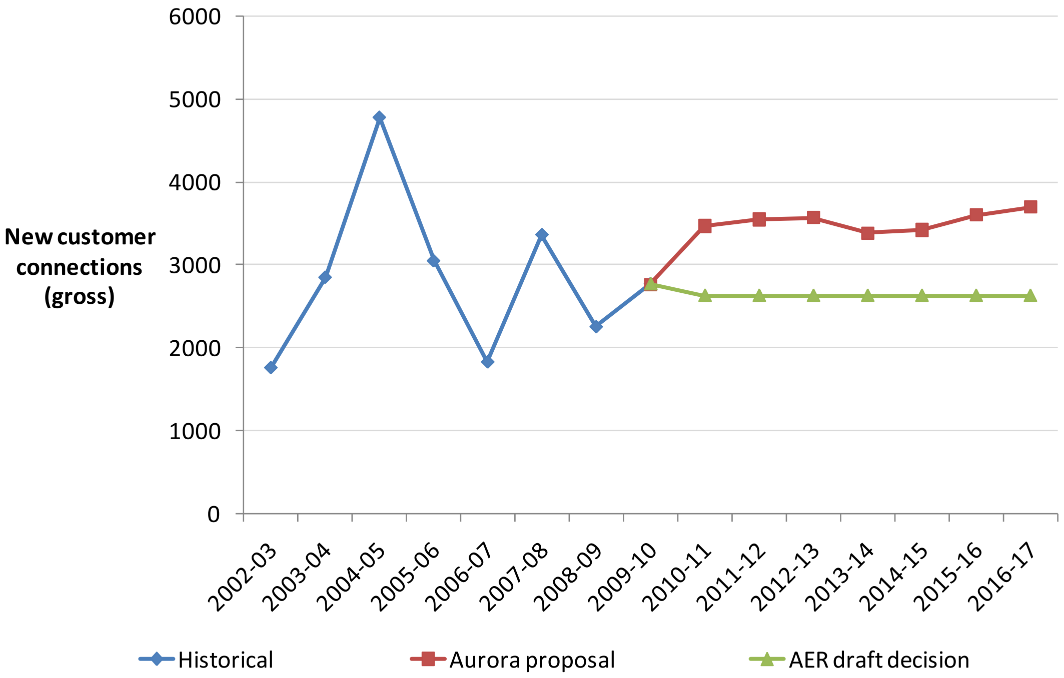
The AER considers Aurora's forecast volumes for new residential (including residential subdivision) connections are too high compared to historical trends and a range of forecasts from independent institutions. The AER therefore considers a reduction of $30.1 million ($2009–10) (16.6 per cent) to total connections capex is required to address this issue.

The AER also considers Aurora's proposed unit cost for new commercial connections is too high. The AER's substitute unit cost results in a $5.1 million ($2009–10) (2.8 per cent) reduction to Aurora's proposed total connections capex. The AER's adjustments to Aurora's connections capex will also affect Aurora's capital contributions requirement. The AER's analysis of Aurora's customer connections capex is below.

Volumes of new customer connections

The AER has accepted Aurora's forecast volumes of new commercial and irrigation connections as a realistic expectation of demand. However, the AER considers Aurora's forecast volumes for new residential (including residential subdivision) connections are too high compared to historical trends and a range of forecasts from independent institutions. Consequently, the AER has developed a substitute forecast of new residential connections. The AER's substitute forecast is discussed in attachment 3 (demand forecasts). Figure 5.10 compares Aurora's forecast with the AER's forecast.

Figure 5.10 New residential customer connection volumes (gross) – Aurora's forecast and AER's forecast



Source: AER analysis.

To estimate the impact of the AER's lower residential connection volumes on new customer connections capex, the AER has multiplied its substitute volume forecasts by Aurora's proposed unit costs This results in a reduction of $30.1 million (16.6 per cent) to total connections capex of $181.4 million over the period 2012–13 to 2016–17. This reduction represents 25 per cent of Aurora's proposed residential new customer connections.

Unit costs for new customer connections

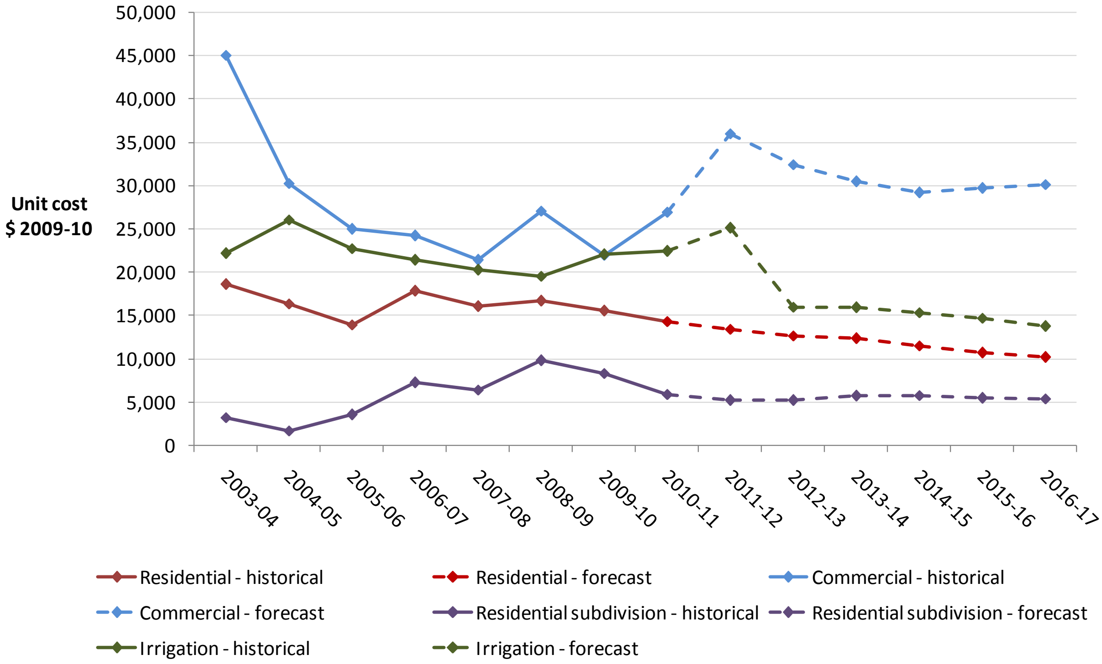
The AER has also examined the reasonableness of Aurora's unit costs of facilitating new customer connections. With the exception of Aurora's commercial connections unit cost, the AER considers that Aurora's proposed unit costs are largely reasonable because:

- they are in line with historical trends
- they decrease over the forthcoming regulatory control period, and

- historical values generally benchmark adequately against average unit cost proxies, particularly in light of the rural nature of Aurora's distribution network and the impact of rural connections on unit costs. [404]

Figure 5.11 displays Aurora's proposed unit costs. The adjustments referred to in Figure 5.11 have been made by Aurora for the purpose of smoothing prices and minimising the cost of customer initiated capital works to customers.[405]

Figure 5.11 Aurora's proposed unit costs ($2009–10)



Source: AER analysis.

Unit cost benchmarking

Due to limitations in the comparability of volume data across each DNSP within the NEM the AER has undertaken benchmarking on a state-by-state basis using two proxies for new connection volumes:[406]

- construction value added (used by Aurora as a main driver of new customer connection volumes)[407]
- dwelling units completed.

There are two limitations with these proxies. Construction value may be influenced by property type and property value, which may weaken correlation between construction value and the unit cost of a

404 Aurora, *Regulatory proposal,* May 2011: *Attachment AE061 Parsons Brinckerhoff, Capex and opex benchmarking study, March 2011, p. 18.*

405 Aurora, *Regulatory Proposal*, May 2011: *Attachment AE032 - Management Plan 2011 - Customer Initiated Capital Works*, p. 19.

406 Australian Bureau of Statistics, *Building activity, Australia*, cat. no. 8752.0, retrieved 21 October, 2011, http://www.abs.gov.au/ausstats/abs@.nsf/mf/8752.0.

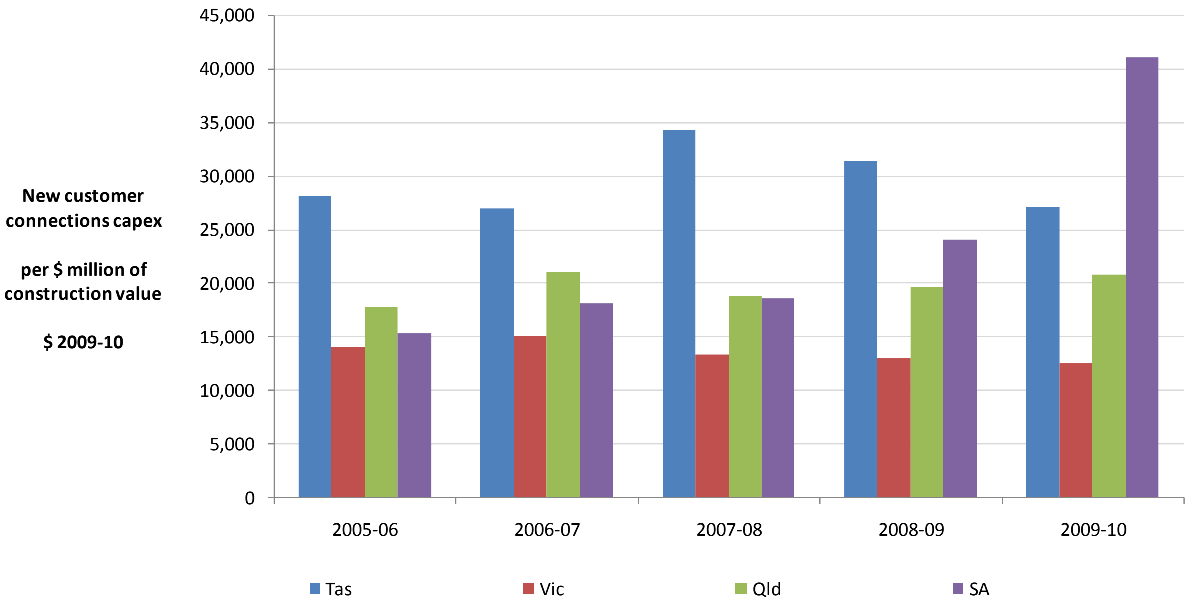
407 Residential construction value for residential and residential subdivision connections, and non-residential construction value for commercial connections. Construction value was not used as a volume driver for irrigation connections. ACIL Tasman, *Aurora new customer connection forecasts*, February 2011, p. 16. Attachment AE058 to Aurora, *Regulatory proposal* , May 2011.

new connection.[408] Dwelling unit data includes only residential dwellings. To mitigate these issues, the AER has concurrently considered the benchmarking results of both unit cost proxies to inform its decision on customer connections capex.

The AER's benchmarking analysis is shown in Figure 5.12 to Figure 5.15. The figures illustrate standardised measures of connections capex across jurisdictions. Historical total state connections capex is weighted by the number of new dwellings completed and the value (per $ million) of construction. The analysis indicates:

- Aurora compares poorly for new customer connections capex per million dollars of construction value
- Aurora compares favourably for new customer connections capex per dwelling unit completed, but remains above the Victorian average
- after accounting for the potential effects of scale and capacity constraints on these measures, Aurora remains above the Victorian average but is comparable to the industry average.

Figure 5.12 New customer connections capex per million dollars of construction value

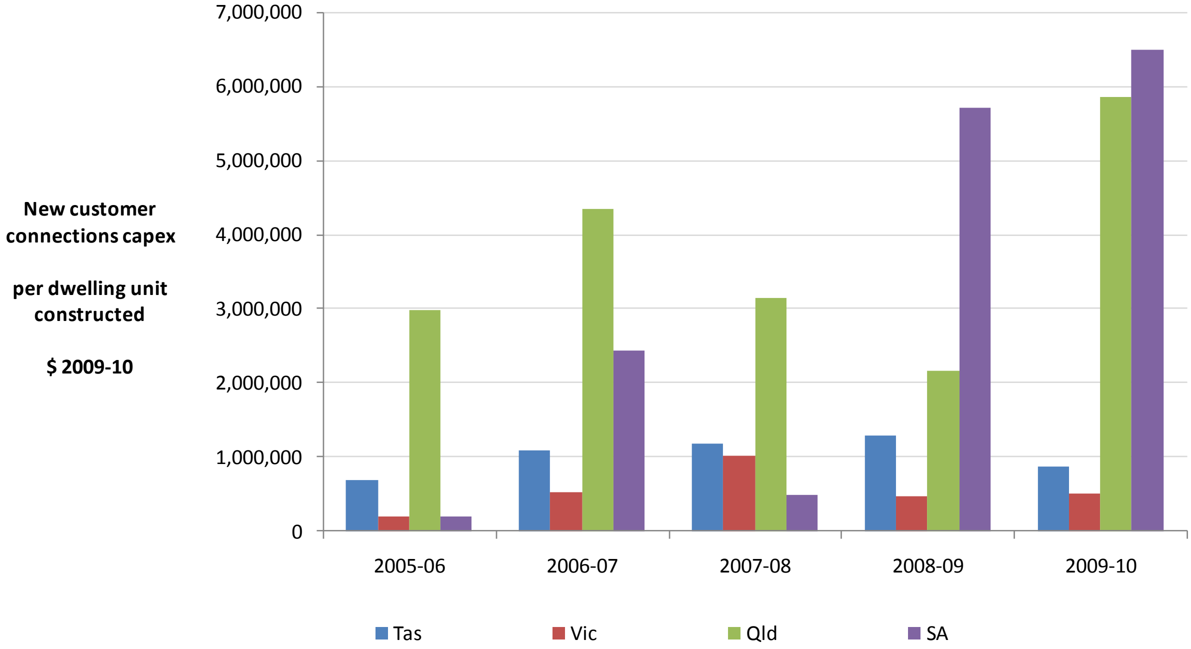


Source: AER analysis.[409]

408 Which may be likely to have a more pronounced effect in cross-sectional data then in time series data (as used by Aurora for forecasting new customer connections).

409 The 2008–09 and 2009–10 values for Queensland and South Australia are derived from estimates of capital expenditure from each of the DNSPs as reported to the AER.

Figure 5.13 New customer connections capex per dwelling unit completed

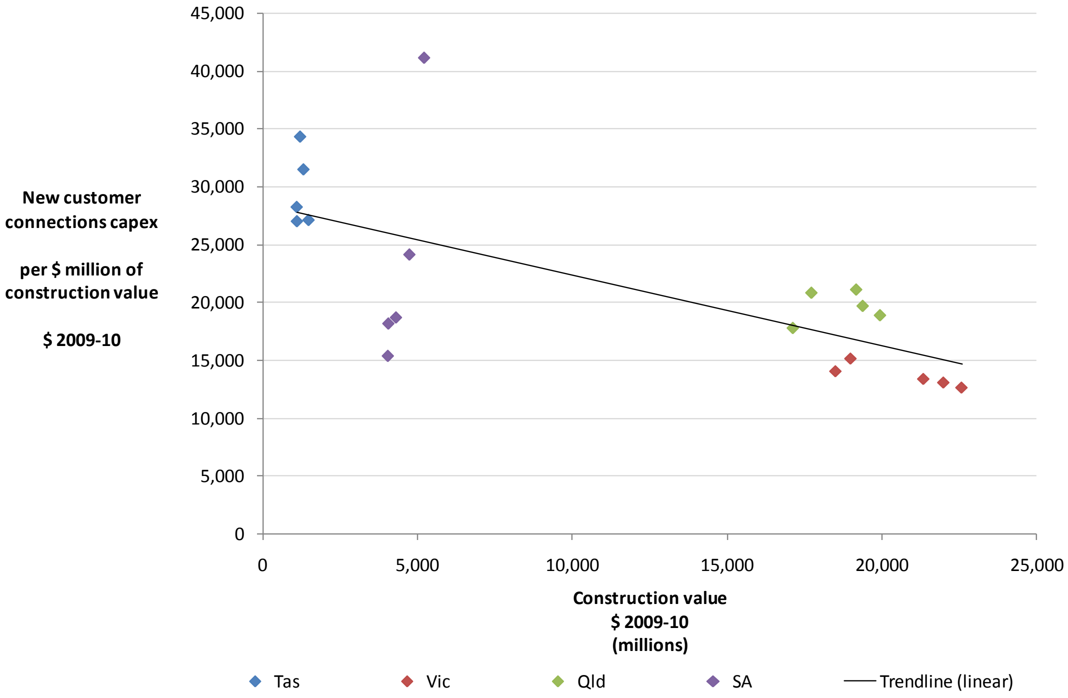


Source: AER analysis.[410]

In addition, the AER has considered the impact of scale—that is, the amount of construction value added and the number of dwelling units completed—on the unit cost proxies. Figure 5.14 shows the relationship between construction value and the unit cost proxy, and Figure 5.15 shows the relationship between dwelling units completed and the unit cost proxy. The five squares for each DNSP represent the connections capex per $million of construction value for each year from 2005–06 to 2009–10.

[410] The 2008–09 and 2009–10 values for Queensland and South Australia are derived from estimates of capital expenditure from each of the DNSPs as reported to the AER.

Figure 5.14 Relationship between construction value and new customer connections capex per million dollars of construction value



Source: AER analysis.[411]

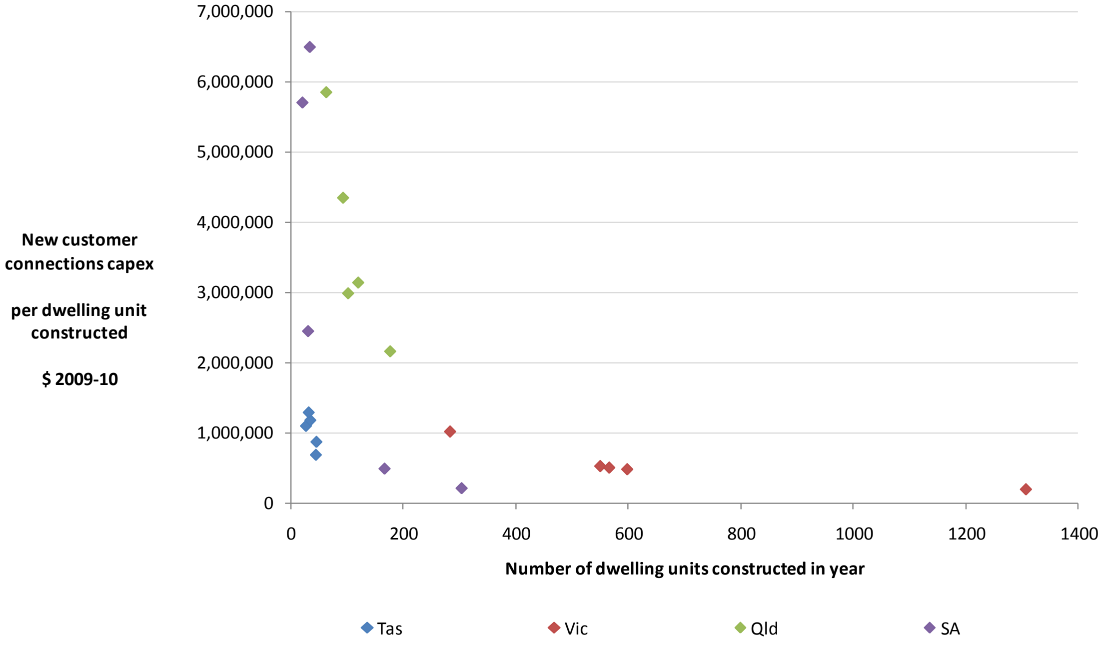
This analysis indicates Aurora's historical performance is generally in line with the industry average but not as efficient as the Victorian average. This is consistent with the findings of benchmarking undertaken by PB for Aurora[412] and the total capex benchmarking the AER has undertaken.[413]

411 The 2008–09 and 2009–10 values for Queensland and South Australia are derived from estimates of capital expenditure from each of the DNSPs as reported to the AER.

412 Parsons Brinckerhoff, *Capex and opex benchmarking study*, March 2011, p. 18. Attachment AE061 to Aurora, *Regulatory proposal*, May 2011.

413 Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 3.

Figure 5.15 Relationship between dwelling units completed and new customer connections capex per dwelling unit completed



Source: AER analysis.[414]

The AER considers movements in the volume of new customer connections are unlikely to materially alter forecast unit costs from historical trends because Aurora's forecasts and the AER's substitute forecast are not materially different from historical volumes.[415] The one exception is irrigation connection volumes, which Aurora has forecast to steadily increase from 145 new connections in 2009–10 to 209 new connections in 2016–17. Aurora submitted that this is reflective of the Tasmanian Government's 'Food Bowl' policy of establishing irrigation systems.[416]

However, Aurora's proposed unit costs for new irrigation connections for the period 2012–13 to 2016–17 are substantially lower than historical trend. As Aurora has not provided justification for the level of its proposed unit costs, the AER has presumed that any scale effects associated with new irrigation connections have been factored into Aurora's relatively low proposed unit costs.

The AER also considers changes in network utilisation and instances of capacity constraints are unlikely to materially alter forecast unit costs from historical trends because:

- Aurora's proposed augmentation capex and the AER's forecast augmentation capex are not materially different from historical trend.[417]

414 The 2008–09 and 2009–10 values for Queensland and South Australia are derived from estimates of capital expenditure from each of the DNSPs as reported to the AER.

415 Aurora experienced an annual average of 3349 new customer connections between 2002–03 and 2009–10, representing 1.2 per cent of Aurora's total connections as at 30 June 2010. The AER forecast an annual average of 3148 new customer connections from 2009–10 to 2016–17, representing 1.1 per cent of Aurora's total connections as at 2009–10.

416 Aurora, *Regulatory Proposal*, May 2011, *Attachment AE032 – Management Plan 2011 – Customer Initiated Capital Works*, p. 3. Revised version provided in response to *information request AER/016 of 26 July 2011*, received 11 August 2011.

417 Aurora incurred an annual average of $17.7 million ($2009–10) of reinforcement capex 2003–04 to 2010–11. The AER forecast Aurora would be required to incur $8.6 million ($ 2009-10) of reinforcement capex on average per year from 2012–13 to 2016–17.

- Aurora's network reliability has improved from 2007–08 to 2010–11 (see attachment 12), indicating that capacity constraints (or issues arising from them) may be easing.[418]

Therefore the AER accepts Aurora's proposed unit costs for new residential, residential subdivision and irrigation connections. However, the AER considers that Aurora's proposed unit cost for new commercial connections is too high.

Unit costs for commercial connections

In examining historical trends, the AER has found that unit costs for commercial connections decline over the forthcoming regulatory control period, but:

- are above historical trend
- are above the 2010–11 value in every year due to the substantial initial increase from 2010–11 to 2011–12.
- other than movements in the number of new commercial connections,[419] Aurora did not provide any justification for the increase from 2010–11 to 2011–12.

The AER has developed a substitute unit cost for commercial connections based on the unit cost experienced by Aurora in 2010–11. The AER has used this substitute because:

- The 2010–11 value is comparable with the historical trend if the 2003–04 unit cost value is excluded. The significantly higher unit cost experienced in 2003–04 disproportionately distorts the trend and is the most out-dated value.
- The 2010–11 value incorporates current levels of input costs.

The AER's revised forecast unit cost, shown in Figure 5.16, is likely to be at the upper end, given:

- The unit cost for 2010–11 is above the historical trendline.
- The historical trend suggests unit costs are declining over time,[420] while the AER has adopted a constant unit cost over the forthcoming regulatory control period.[421]
- Aurora also forecast commercial connection unit costs to decrease over the forthcoming regulatory control period.

The adjustments displayed in Figure 5.16 have been made by Aurora for the purpose of smoothing prices and minimising the cost of customer initiated capital works to customers.[422]

418 The AER also considered that although constraints in particular localised areas of the network may arise, the general improvement in reliability across Aurora's network should indicate that there is sufficient 'room' for Aurora to implement solutions to these localised issues (which may include bearing an increase in GSL payments) without materially increasing the overall cost of facilitating new customer connections capex.

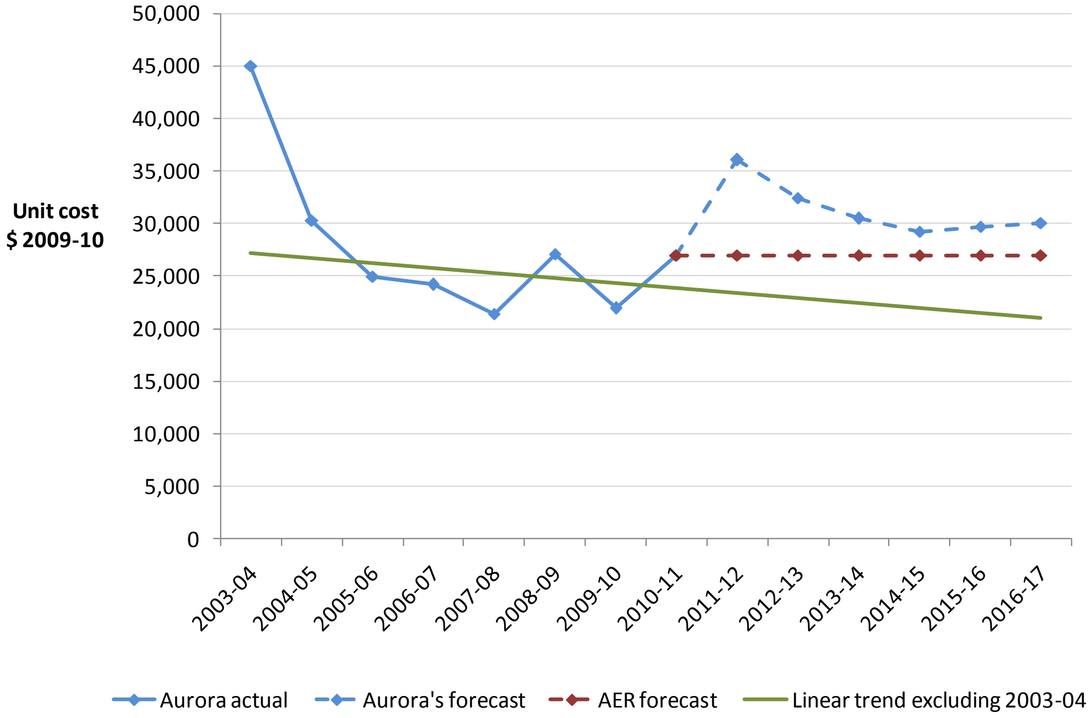
419 Aurora, *Customer Initiated capital works management plan*, March 2011, p. 3.

420 Note: the historical trend inclusive of the 2003–04 unit cost suggests a steeper decline than the historical trend excluding 2003–04.

421 That is, constant in real 2009–10 dollar terms.

422 Aurora, *Regulatory proposal*, May 2011: *Attachment AE032 - Management Plan 2011 - Customer Initiated Capital Works*, p. 19.

Figure 5.16 Unit cost for new commercial connections – Aurora and AER forecasts ($2009–10)



Source: AER analysis.

The impact of the AER's substitute unit cost for new commercial connections on forecast total (gross) new customer connections capex is a reduction of approximately $5.1 million ($2009–10), or 2.8 per cent.

Customer contributions towards capital works

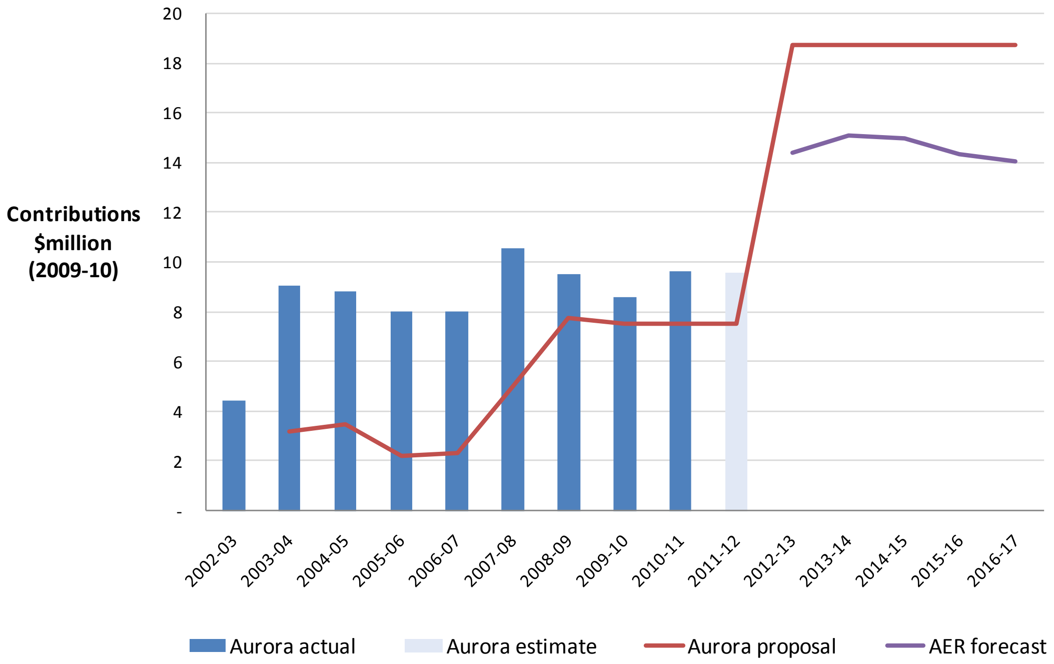
The NER provides that a DNSP may require a customer to contribute to the cost of a new connection or modification in service for an existing connection.[423]

Just as new customer connections capex is driven by forecast volumes of new customer connections, so are customer contributions towards this capex. Aurora has revised its customer contributions policy towards a greater contribution from customers towards new customer connections works.[424] This is shown in Figure 5.17.

Since the AER considers that Aurora's forecasts of connections volumes are overstated, it follows that Aurora's proposed capital contributions are also overstated. Using the same average contribution per connection as proposed by Aurora, the AER's revised forecast of connection volumes results in the forecast of capital contributions is shown in Figure 5.17 and Table 5.5.

423 NER, clause 6.21.1.
424 Aurora, *Regulatory proposal*, May 2011, p. 77.

Figure 5.17 Capital contributions – actual, Aurora's proposal and AER forecast ($million, 2009–10)



Source: AER analysis.

Table 5.5 Impact of AER revisions on Aurora's proposed capital contributions for new customer connections ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17
Aurora’s proposal	18.7	18.7	18.7	18.7	18.7
Aurora’s proposal: with AER substitute volumes	14.4	15.1	15.0	14.3	14.0

Source: AER analysis.

5.4.3 Capex to improve reliability

The capex objectives broadly reflect expenditure that Aurora requires to provide standard control services to maintain current service levels, or comply with associated regulatory obligations or requirements. Expenditure that improves service levels may therefore not be required to achieve the capex objectives in a manner that reasonably reflects the capex criteria.[425]

As part of its review, the AER has analysed Aurora's work categories and supporting documentation. The AER has assessed that Aurora has forecast work categories relating to reliability improvements to continue into the forthcoming regulatory control period.[426] However, in its regulatory proposal, Aurora has treated the associated expenditure as expenditure to maintain (rather than improve) its network.[427] This approach to allocating capex may be misleading, and may have caused stakeholders to question why Aurora requires so much expenditure to maintain its network.[428]

The AER considers that $24.6 million ($2009–10) (3.6 per cent) of Aurora's proposed capex for the period 2012–13 to 2016–17 is for reliability improvements.[429] The majority of this capex relates to either local reliability programs or remote control and protection programs.[430] Local reliability capex is to address issues in specific areas where customers are subject to the worst performance.[431] The protection and control capex is to enhance reliability in urban areas and ensure good industry practice.[432] Aurora proposed that these programs are required to maintain reliability and comply with reliability obligations under the Tasmanian Electricity Code (TEC).[433]

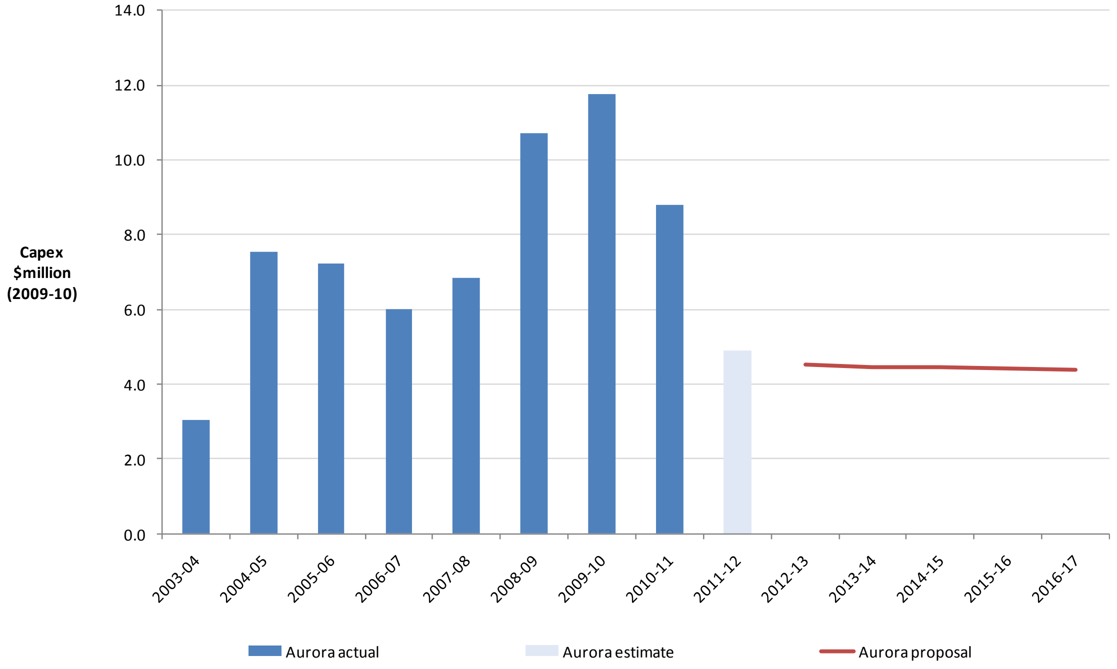
The TEC requires Aurora to use 'reasonable endeavours' to meet various minimum reliability standards. Aurora also operates a guaranteed service level (GSL) scheme that provides payments to customers when reliability falls below defined parameters.[434] The AER's analysis of Aurora's reliability improvement capex is below.

Historically, Aurora has been provided with capex to improve reliability. In particular, in January 2007 Aurora proposed a 60 per cent increase in service improvement capex specifically to meet the TEC reliability standards by the end of the current regulatory period.[435] OTTER approved this increase.[436] This can be seen in Figure 5.18, where Aurora spent a significant amount of reliability capex between 2007–08 and 2009–10. The AER therefore considers Aurora has already received sufficient capex to improve reliability in the current regulatory period.

Aurora has forecast reliability capex closer to 2003–04 levels,[437] stating the aim for the period 2012–13 to 2016–17 is to maintain reliability and target the worst performing parts of the network.[438]

425 The capex objectives are specified in clause 6.5.7(a) of the NER.
426 For example, work category codes including (but not limited to) PRFLT, PRREH, PRSEC and REOTC.
427 Aurora did not forecast any reliability and quality improvement expenditure for the forthcoming regulatory control period. Aurora, *Regulatory proposal*, May 2011, pp. 119, 203.
428 See, for example, EUAA, *Submission to the Australian Energy Regulator on Aurora Energy's Regulatory Proposal on Distribution Prices for 2012-2017*, August 2011, pp. 12–13.
429 AER analysis of Aurora's RIN response and Capex by work category spreadsheet.
430 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 124–125.
431 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 124–125.
432 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 124–125.
433 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 124–125.
434 TEC, S8.6.11.
435 OTTER, *Draft Report — 2007 Electricity Pricing Investigation*, July 2007, p. 94.
436 OTTER, *Final Report — 2007 Electricity Pricing investigation*, September 2007, p. 109.
437 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 126.
438 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 124.

Figure 5.18 Aurora's historical and forecast reliability improvement capex ($million, 2009–10)



Source: AER analysis.

The AER is proposing to allow a significant increase in replacement expenditure above historical levels (see section 5.4.1). The AER considers this increased asset replacement should be sufficient to address reliability issues because some programs will improve reliability where the assets are in poor condition. For example, some replacement programs address assets with a high failure history.[439] As a result, although Aurora's reliability improvement programs may seem reasonable in principle, the AER considers the capex for these programs is beyond what is required to maintain reliability of supply or otherwise achieve the capex objectives. In this sense, the proposed expenditure does not reasonably reflect the efficient costs needed by a prudent operator to achieve the capex objectives.

Although the TEC requires Aurora to use 'reasonable endeavours' to meet minimum GSL targets, the GSL compensation scheme exists because funding Aurora to meet its TEC reliability standards in every circumstance would be inefficient. Supply reliability is one of the many obligations Aurora must comply with as a DNSP and Aurora must manage its risk to balance these obligations. The 'reasonable endeavours' requirement and the GSL scheme provide Aurora with a balanced incentive to maintain reliability, but do not require Aurora to invest inefficiently in its network.

The AER considers its total capex allowance reflects the efficient funding required for Aurora to maintain supply reliability, meet its TEC obligations and otherwise achieve the capex objectives.[440]

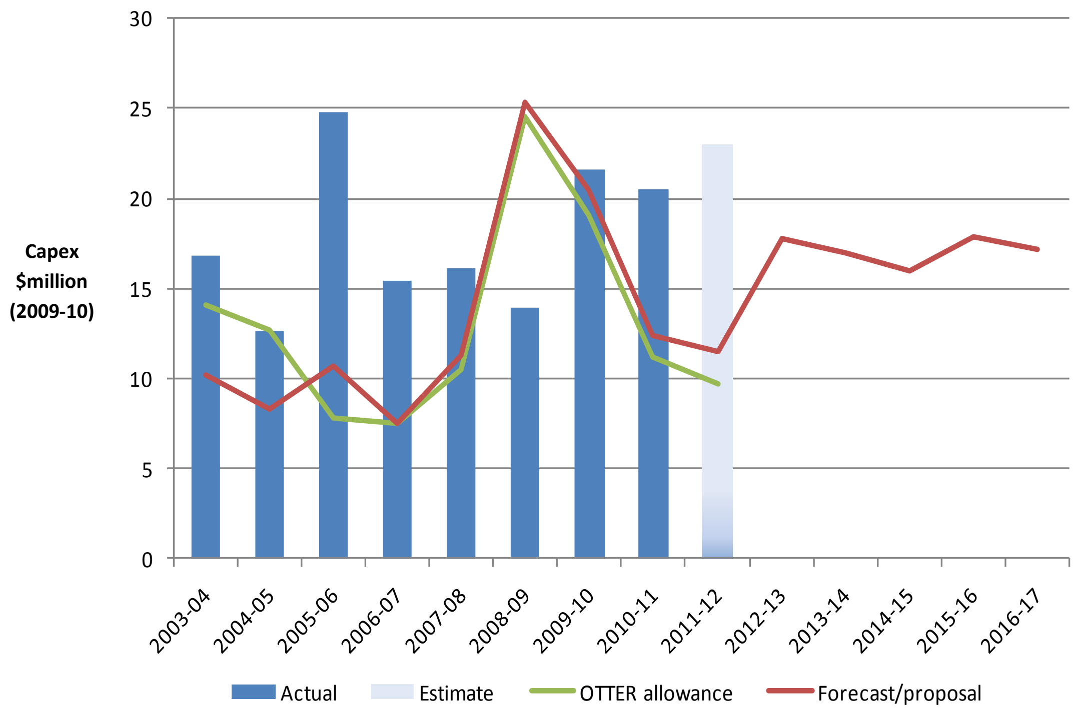
439 Such as the CONSAC replacement program and some distribution transformer replacement programs. See section 5.4.1.
440 TEC, section 8.6.11.

5.4.4 Capex to address maximum demand growth (reinforcement capex)

Reinforcement capex is primarily driven by growth in maximum demand for electricity.[441] It is required to augment or increase the capacity of the distribution network to ensure forecast growth in maximum demand will not adversely affect the supply of standard control services. It does not include capex to facilitate growth in customer connections.[442]

Aurora has forecast reinforcement capex in 2012–17 to total approximately $87.1 million ($2009–10).[443] This amounts to approximately 12.9 per cent of total forecast capex. Aurora's forecast for 2012–17 is generally in line with average historical spend, although the trend in historical spend has varied.[444] This is shown in Figure 5.19. The majority of Aurora's proposed reinforcement capex relates to HV feeder and zone substation augmentation. A small portion (10.4 per cent) is for distribution substations and LV feeders.

Figure 5.19 Aurora's actual, allowed and forecast reinforcement capex ($million, 2009–10)



Source: AER analysis.

Overall, the AER considers the methodology Aurora has applied to produce its forecast of reinforcement capex would be appropriate to identify possible needs and strategic solutions.[445] To a reasonable degree, this process aligns with the actual planning processes Aurora applies in its normal planning activities.[446] However, 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.[447] The AER

441 Maximum demand is the highest load on the overall distribution system at a given point in time. This is discussed further in the demand attachment.
442 Except for facilitating connections for embedded generators. The demand for this is strongly correlated with growth in maximum demand.
443 Aurora, *Regulatory proposal*, May 2011, p. 115.
444 The lumpy nature of this capex is usually due to zone substation development, which tends to be high cost.
445 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 42.
446 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 42.
447 As required by NER, clause 6.5.7(a)(1). Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 42.

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.[448] The AER also considers that in some cases Aurora has not adequately demonstrated that its proposed solution to address demand growth reasonably reflects the efficient costs of achieving the capex objectives.

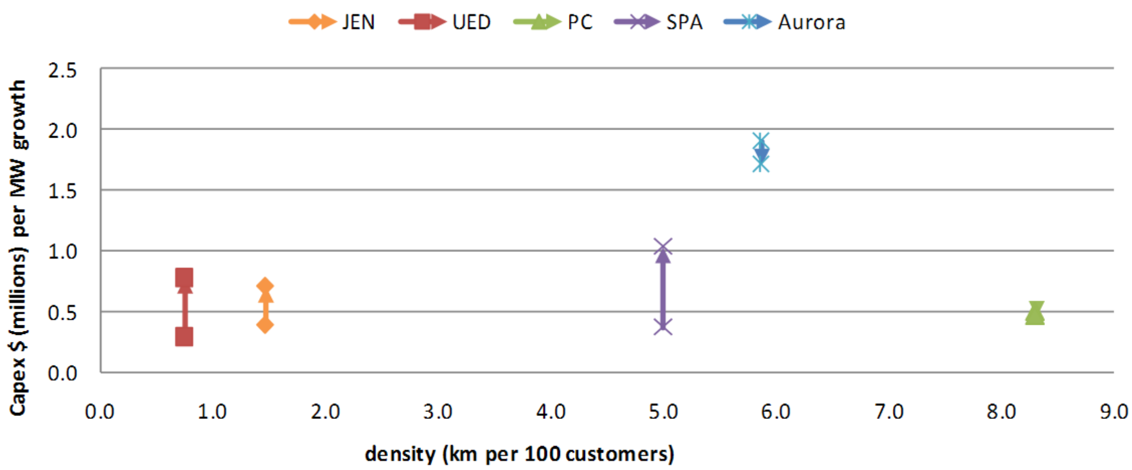
Therefore, the AER considers Aurora's forecast reinforcement capex proposal for the forthcoming regulatory control period is more than required to form part of a total forecast capex that reasonably reflects the capex criteria. An adjustment of approximately $44.1 million ($2009–10) (or 50.6 per cent of Aurora’s proposed reinforcement capex) to Aurora's total forecast capex proposal is the AER's estimate of reinforcement capex that would comply with the NER.

The AER has come to this view on the basis of benchmark analysis and detailed review. Since Aurora's proposal mainly comprises a large number of distribution level feeder augmentations[449], the AER has conducted a detailed review of a sample of planned projects and programs that Aurora considers underpins its forecast.[450] This approach is discussed further in section 5.3. In addition to the targeted sample review, the AER has also conducted a broad review of the methodology and rationale for a selection of other projects and programs. The AER’s analysis of reinforcement capex is below.

In the current period[451], Aurora's reinforcement capex per megawatt (MW) of growth in peak demand is $1.9 million ($2009–10), which is almost five times higher than the Victorian DNSP average[452] for the 2006 to 2010 regulatory period ($0.4 million ($2009–10)).[453] For the forthcoming regulatory control period, although the AER allowed the Victorian DNSPs a significant increase in reinforcement capex, Aurora's forecast ($1.7 million ($2009–10)) is still over twice the Victorian DNSP 2011 to 2015 average ($0.8 million ($2009–10)).[454] This is shown for each DNSP in Figure 5.20. The direction of the arrows indicates the change from current to forecast capex.

448 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 42.
449 For example, Aurora has proposed 422 line items for HV feeders. Aurora, *Regulatory proposal*, May 2011, p. 115.
450 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 34–35.
451 The current period for Victoria is the five years from 2006 to 2010. The forthcoming period is the five years from 2011 to 2015. The AER has referred to the five year period from 2007-08 to 2011-12 as Aurora's current period and 2012-13 to 2016-17 as Aurora's forthcoming period for a more meaningful comparison.
452 CitiPower's predominantly urban network means it is not a suitable comparator and may unduly bias against Aurora. The AER has therefore excluded CitiPower from the Victorian DNSP average.
453 Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 5.2.
454 Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 5.2.

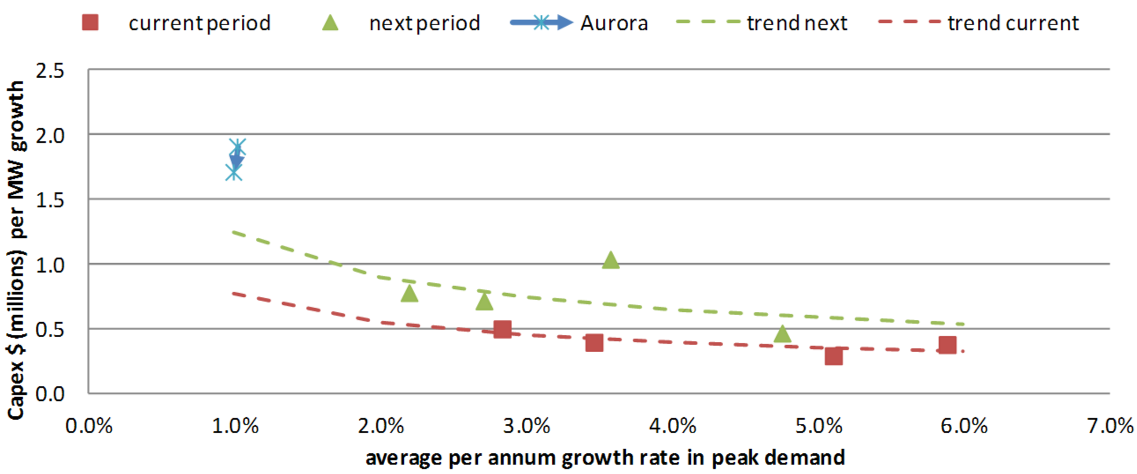
Figure 5.20 Reinforcement capex high level benchmark analysis



Source: Victorian DNSP data for 2006 to 2010 is taken from their regulatory proposals for the 2011 to 2015 regulatory period. Forecast data is the AER's allowance in AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015,* October 2010. Aurora data is sourced from its regulatory proposal.

Moreover, the Victorian DNSPs have experienced, and are expecting, higher peak demand growth than Aurora. Aurora's growth rate in the current regulatory period is 1 per cent, and is forecast to be slightly less than 1 per cent in the forthcoming period.[455] The Victorian DNSPs, on the other hand, have experienced growth from between about 3 and 6 per cent in the current period, and are expecting growth in the forthcoming period of approximately 2 and 5 per cent.[456] Higher growth rates may mean that the Victorian DNSPs can find some scale efficiencies when optimising larger capital programs to cater for this growth.[457] To address this issue, the AER has estimated the likely capex levels for the Victorian DNSPs for a 1 per cent growth rate. This is displayed in Figure 5.21.

Figure 5.21 Reinforcement capex relationship with demand growth



Source: AER analysis.

[455] Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 5.2.
[456] Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 5.2.
[457] Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 5.2.

With this adjustment, Aurora still compares unfavourably with the Victorian DNSPs. Aurora's capex is still more than twice the Victorian DNSP average for the current period, and forecast to be about 40 per cent greater in the forthcoming period.[458]

A mitigating factor for Aurora is that its reinforcement capex spend may be somewhat tied to Transend's development. For example, new state-based reliability obligations for Transend have resulted in the development of new substations in the current period. This meant that Aurora had to develop the distribution network to allow Transend's substations to be connected and to ease some of the load from Transend's existing substations.[459]

However, the additional substations and associated feeders should reduce feeder overloads that would have occurred if the need to develop the distribution network was not addressed by Aurora.[460] This should mean Aurora would expect greater gains in the forthcoming regulatory control period. The AER has not seen evidence of this in Aurora's proposal.[461]

The AER conducted benchmarking at a high level (total reinforcement capex) so aggregation may disguise capacity limitations and legitimate reinforcement needs. Nonetheless, the AER considers the magnitude of the findings sufficient to indicate it unlikely that Aurora is currently operating at efficient levels, supporting the need for detailed review.

Detailed review of sampled projects

As part of its detailed review, the AER has reviewed a significant number of projects and programs in three categories[462] to assess the reasonableness of Aurora's forecast. For projects associated with demand loading issues at zone substations, the AER's sample includes 6 of the 9 projects. This equates to 68 per cent of the $19.6 million ($2009–10) capex over the forthcoming regulatory control period.[463] This sample includes a mix of zone substations with non-network solutions, and zone substations with network solutions.

For projects to address HV feeder limitations, the AER's sample includes 10 of the 17 projects. This amounts to 83 per cent of the $12.5 million ($2009–10) capex proposed by Aurora over the forthcoming regulatory control period.[464] Further analysis and detail of these projects can be found in Nuttall Consulting's technical report.

In general, the AER considers Aurora's proposal is reasonable and an appropriate response to the identified network limitations, based on sound methodology. However, the AER's review has revealed three issues.

First, a large portion of the sampled capex does not appear to be required to achieve the capex objectives under current operating practices. Instead, it appears to be primarily directed at achieving operational efficiencies and/or improving reliability beyond that which would reasonably reflect the capex criteria. Although Aurora's proposed capex may appear reasonable from the perspective of

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458 Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 5.2.
459 Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 5.2.
460 Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 5.2.
461 Nuttall Consulting, *Aurora Revenue Review*, October 2011, section 5.2.
462 Zone substation projects involving non-network solutions, zone substation projects involving network solutions, HV feeder projects.
463 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 5.3.
464 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 5.3.

those technically responsible for managing the network, it does not seem to be economically justifiable when assessed against the requirements of the NER.[465]

The AER takes into account various factors in assessing whether expenditure reasonably reflects the capex criteria. For example, the AER takes into account factors such as future opex savings or reliability improvements (efficiency benefits) when considering whether the expenditure reasonably reflects the efficient costs of achieving the capex objectives.[466] However, Aurora does not appear to have quantified any efficiency benefits (such as, opex savings or reliability improvements), or provided justification that this capex is an otherwise efficient and prudent solution to achieving the capex objectives.[467]

Therefore, Aurora must demonstrate to the AER that this capex reasonably reflects the capex criteria having, regard to the capex factors. In particular, Aurora should identify the substitution possibilities between opex and capex and quantify any opex savings and reliability improvements. The AER will then make any necessary adjustments to Aurora's opex allowance and reliability targets to ensure net benefits result from the capex in a manner consistent with the NER.

To calculate the forecast opex savings, the AER will convert the amount of capex resulting in opex savings into an annuity, where the annuity has the same term as the asset life of the proposed capex and where the net present value (NPV) of the total annuity payments equals the NPV of the proposed capex.

The AER will use a straight-line depreciation approach to convert the proposed capex into the opex savings annuity. The AER recognises that not all opex savings may be realised in the forthcoming regulatory control period and will account for this by equating the term of the annuity with the asset life of the proposed capex.

Table 5.6 identifies the split between capex the AER has assessed as required to meet or manage expected demand, and capex that is not so required but might otherwise result in efficiency benefits.

Table 5.6 Proportions of sampled capex attributable to demand and capex that ought to result in efficiency benefits

Category	Demand component	Efficiency benefit component
Zone substation projects involving non-network solutions	100%	0%
Remaining zone substation projects (network solutions)	46%	64%
HV feeder	65%	34%

Source: AER analysis.

The percentages indicate the average proportions the AER has calculated for the projects in each of the three categories assessed in the sample. The AER has used these averages to adjust Aurora's capex for the equivalent projects in the areas it did not review.[468] The AER has inferred findings for the projects in the sample as findings for projects outside the sample, but only where the AER

465 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 42.

466 The substitutability between capex and opex is a factor the AER must consider in determining whether Aurora's capex and opex proposals reasonably reflect the capex and opex criteria. NER, clause 6.5.6(e)((7) and 6.5.7(e)(7). Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 42.

467 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 42.

468 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 56.

considers there is a likelihood that concerns with the in-sample projects will also exist in the out-of-sample projects. Further detail is discussed in Nuttall Consulting's technical review which the AER accepts as a sound basis for assessing whether proposed capex reasonably reflects the capex criteria.

The AER considers its findings are consistent with benchmarking results. For example, the large proportion of capex that should result in efficiency benefits explains why Aurora's proposed capex to address demand growth is much higher than that of the Victorian DNSPs.

Second, in some cases, Aurora has not adequately demonstrated that the proposed solution to address demand growth reasonably reflects the efficient costs of achieving the capex objectives. The AER considers Aurora could adopt lower cost solutions if more rigorous analysis is undertaken. For example, the proposed Sandford sub transmission project network solution.[469] The AER considers Aurora could develop a much lower cost short term network solution, potentially involving some further voltage support and/or the use of mobile generation during peak periods.[470] The AER has adjusted Aurora's total forecast capex where Aurora's proposal has not been justified as reasonably reflecting the efficient costs of achieving the capex objectives.

Third, Aurora proposed a number of non-network projects to address maximum demand growth, but has not substantiated some of the capex in light of the capex criteria. Aurora's demand management plan summarises individual broad based and location-specific projects and programs.[471] Aurora has also provided a study performed by an independent consultant (the Futura report) in support of its demand management plan.[472]

The AER considers the process applied by Aurora and methodology applied by Futura seem reasonable. The Futura analysis represents a level of detail and thoroughness consistent to that seen in other regulatory reviews of NEM DNSPs.[473] For the location-specific projects discussed, the Futura report shows that the cost of the non-network solution should be lower than the deferral value of the preferred network solution. The AER considers these projects are a good example of efficient opex spending to defer capex solutions.

However, some of Aurora's expenditure for these projects is higher than that recommended by the Futura analysis. Aurora has not substantiated this departure.[474] Therefore, the AER considers the capex beyond that recommended by Futura should not be allowed unless Aurora can provide justification.

Detailed review of non-sampled projects

The AER has reviewed a number of projects and programs outside the sample discussed above. These are projects and programs outlined under the following work programs in Aurora's capacity management plan:[475]

- mobile generation

469 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 173–174.
470 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 173–174.
471 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 5.5.
472 Futura Consulting, *Identification of non-network initiatives for the 2012-17 EDPR*, July 2010. Attachment AE055 to Aurora, *Regulatory proposal*, May 2011.
473 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 51.
474 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 51–53.
475 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 44–45.

- operations (HV phasing, switching, security and transfer)
- developments
- conversion

These projects generally address common industry issues faced by DNSPs, such as management of load under planned or unplanned outages in light of maximum demand growth and network capacity.[476]

The AER considers the needs and proposed solutions for these programs seem reasonable. Aurora's proposed solutions are 'good practice' approaches to addressing the issues.[477] However, the projects appear to be primarily driven by attempts to improve operating practices and reliability rather than non-compliance issues resulting from forecast increase in demand.[478]

The AER therefore does not consider the majority of the capex for these programs is prudent or required to achieve the capex objectives (or, for that matter, 'best practice'), unless they result in sufficient operational cost savings and/or reliability improvements (efficiency benefits) in a manner that reasonably reflects the capex criteria.[479] Aurora does not appear to have provided any substantial analysis to demonstrate that this portion of the capex is an efficient solution to achieve the capex objectives, or quantified any efficiency benefits.[480]

Accordingly, the AER considers this capex is not required to achieve the capex objectives, absent further information from Aurora. Further detail of these programs is contained in Nuttall Consulting's technical report which the AER accepts as a sound basis for assessing whether proposed capex reasonably reflects the capex criteria.[481]

Distribution substation and LV feeder capex

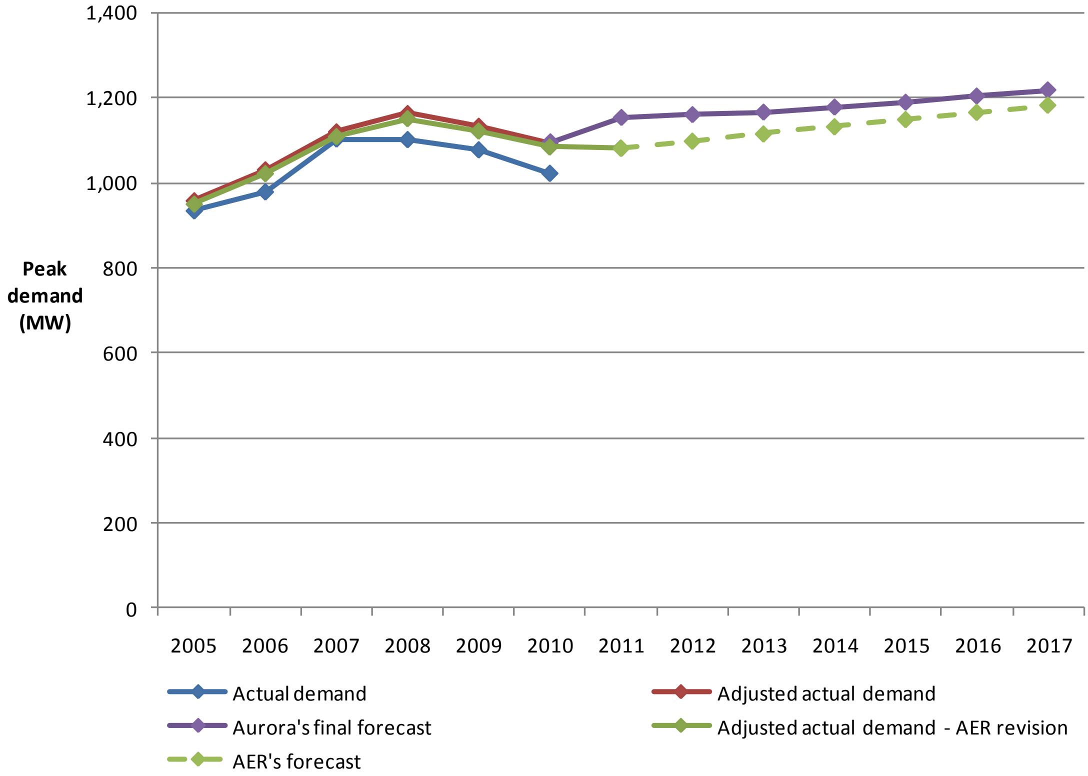
Aurora has proposed approximately $7.9 million ($2009–10) for the forthcoming regulatory control period for distribution substation and LV feeder capex programs.[482] This capex consists of several projects and programs for minor augmentations of large volume assets. Aurora has developed forecasts from broad-based forecasting methods or reactive programs. The AER considers that Aurora's proposed capex reasonably reflects an efficient amount required to address demand-driven network limitations in these assets. Aurora's proposed expenditure is close to the long term historical average (2004–05 to 2009–10) and its methodology is sound and similar to other NEM DNSPs.[483]

Adjustment for demand forecasts

Since demand is a significant driver of reinforcement capex, the AER's forecast of maximum demand for the forthcoming regulatory control period affects the capex allowance. As outlined in attachment 3 (Maximum demand), the AER's forecast of maximum demand is lower than Aurora's forecast. This is demonstrated in Figure 5.22.

476 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 44–45.
477 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 44–45.
478 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 44–45.
479 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 44–45.
480 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 44–45.
481 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 44–45.
482 Aurora, *Regulatory proposal,* May 2011, pp. 115–116.
483 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 46–48.

Figure 5.22 Total system maximum demand: AER view and Aurora's forecasts



Source: AER analysis.
Note: Adjustments to actual demand are for weather and transient loads.

The AER's forecasts of maximum demand for HV feeders are lower both in terms of the growth rate and the starting point for demand (at the beginning of the forthcoming regulatory control period). The growth in the aggregate maximum demand of the HV feeders over the next period is approximately 38 per cent less than the equivalent forecast used by Aurora.

The AER considers, based on its demand forecasts, that on average,a significant portion of the HV feeder projects could be deferred by around 3 to 4 years.[484] Overall, the AER considers that the lower substitute forecasts of maximum demand means that Aurora's proposed reinforcement capex should be adjusted by approximately $44.1 million ($2009–10) (50.6 per cent of Aurora's proposed reinforcement capex). This amount represents a $4.9 million ($2009–10) (11.1 per cent) addition to the AER's adjustment before accounting for the impact of lower demand forecasts ($39.2 million ($2009–10)).[485]

The AER has not made any adjustment for the reinforcement programs that do not appear to be driven by growth in maximum demand.[486] The AER also has not made an adjustment for LV network reinforcement, since Aurora's forecasting method for this program was based on historical trends rather than maximum demand growth.[487]

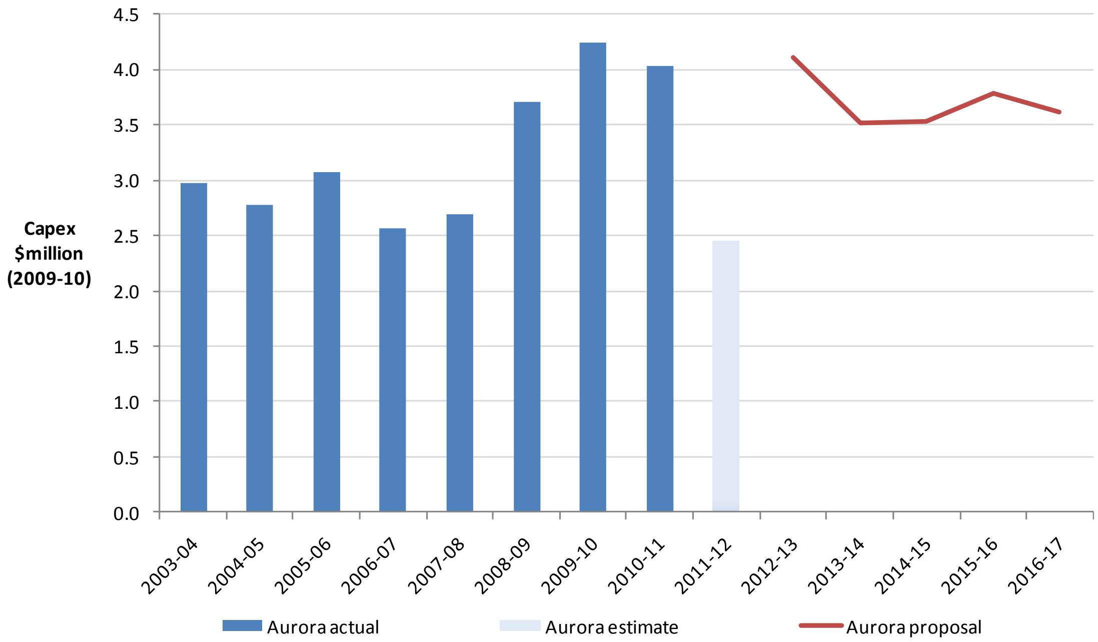
484 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 59, 63.
485 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 58, 64.
486 Demand management capex, mobile generation, embedded generation, and system fault level capex. Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 63–64.
487 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 63–64.

5.4.5 Power quality issues not driven by demand or asset age

Aurora proposed approximately $18.6 million (3.3 per cent of Aurora's total capex proposal) over the forthcoming regulatory control period for capex to comply with various state and NEM-wide obligations associated with power quality.[488] The majority (90 per cent) of this proposal relates to reactive programs intended to upgrade the network in response to voltage complaints from customers. Aurora also proposed capex for proactive programs, the introduction of new technology, and surveys and studies.

As seen in Figure 5.23, overall power quality capex was relatively constant prior to 2008–09, and increased significantly between 2008–09 and 2010–11; peaking in 2009–10. Aurora's forecast for the next regulatory control period is broadly in line with a linear trend excluding 2009–10.

Figure 5.23 Aurora's historical and forecast power quality capex ($million, 2009–10)



Source: AER analysis.

The AER's review of power quality expenditure is based on detailed review of Aurora's asset management plans and justification documentation. Overall, the AER accepts that these programs are required to maintain compliance with power quality obligations.[489] However, the AER considers Aurora's forecast costs for the reactive programs are based on a trend that does not reflect a realistic historical average. The AER also considers that expenditure on the proactive and new technology programs does not reasonably reflect the capex criteria. The programs are primarily driven by improvements to operations at a cost that is not efficient and more than required by a prudent operator to achieve the capex objectives.[490]

488 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 6.4.
489 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 6.4.
490 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 6.4.

Reactive programs

Aurora's proposed reactive programs are mainly associated with upgrading distribution transformers and LV conductors, but also include smaller amounts for HV conductor upgrades and voltage regulator installation.[491] In principle, the AER considers Aurora's reactive programs are a prudent and efficient approach to managing power quality issues, which are essential to maintaining the quality and reliability of supply.

However, the AER disagrees with Aurora's inclusion of the 2009–10 year in its forecast.[492] That year saw a peak in reactive power quality expenditure and Aurora has not sufficiently justified why this peak should continue in the future. In the absence of such justification, a more realistic trend is the five year average from 2004–05 to 2008–09.[493] The AER considers a reduction of $3.1 million ($2009-–10) (16.6 per cent of Aurora's power quality capex proposal) is required to take this into account.[494]

Proactive and new technology programs

Primarily, the proactive program capex is for installing power quality metering equipment on the network. This equipment would reduce costs associated with the reactive programs including opex associated with responding to customer complaints; and improve capital efficiency.[495]

Aurora considers the new technology programs will also improve capital efficiency via the deferral of more costly augmentations. These programs involve using low voltage regulators and upgraded automatic voltage regulators in ground mounted substations.[496]

In principle, the AER does not disagree that such programs may be appropriate and could represent a prudent and efficient approach to managing future power quality issues. However, Aurora has not presented evidence for the net benefits for these programs. In particular:[497]

- Aurora has not demonstrated that its current reactive approach is inappropriate, or provided documentation that suggests customers are unhappy with current service standards
- a reactive approach to power quality issues is common among other NEM DNSPs
- a prudent solution should result in a realisation of benefits in the forthcoming regulatory control period, but Aurora has not anticipated opex savings until later
- Aurora has already begun to roll out power quality meters in the current period, so effective implementation should result in opex savings in the next regulatory control period anyway.

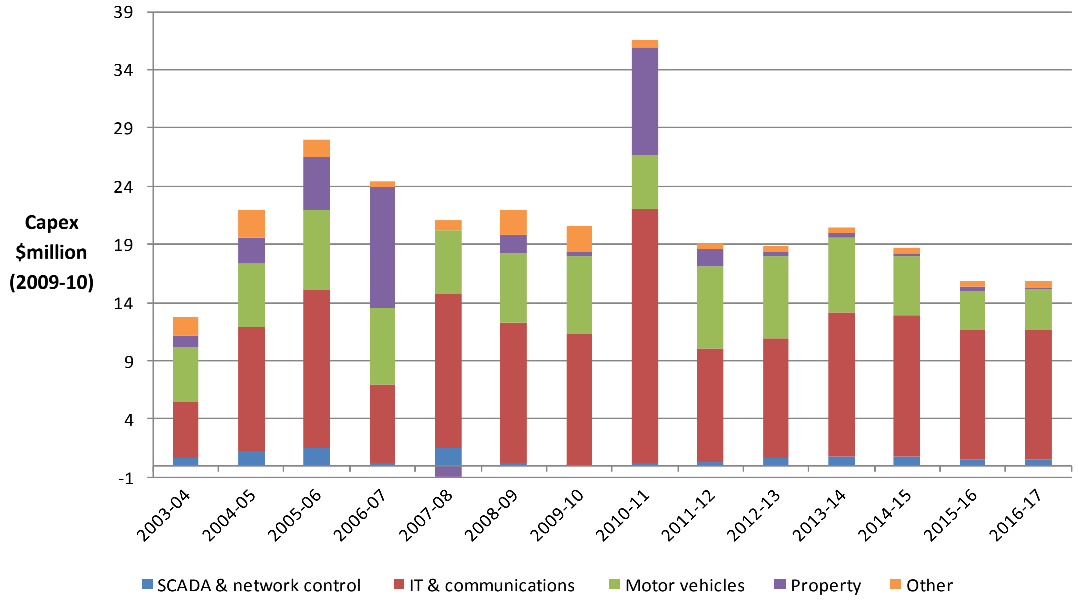
The AER therefore considers that this capex should not be allowed because it is beyond what is required for Aurora to achieve the capex objectives in a manner that reasonably reflects the capex criteria. This results in an additional reduction of approximately $1.1 million ($2009–10) (6.1 per cent of Aurora's power quality capex proposal). As with reinforcement capex, Aurora must demonstrate to the AER that this capex reasonably reflects the capex criteria. In particular, that it is the efficient costs a prudent operator would require to achieve the capex objectives.

491 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 6.4.
492 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 6.4.
493 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 6.4.
494 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 6.4.
495 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 6.4.
496 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 6.4.
497 Nuttall Consulting, *Aurora Revenue Review*, October 2011, Section 6.4.

5.4.6 Investment in non-system assets

Aurora proposed approximately $89.9 million in forecast non-system capex for the next regulatory control period (15.7 per cent of Aurora's total capex proposal).[498] Aurora's proposal is at lower levels than past actual expenditure. Figure 5.24 shows Aurora's proposed non-system capex broken down into the main components: SCADA and network control[499], IT and communications, motor vehicles, property and other.

Figure 5.24 Non-system capex by category ($million, 2009–10)



Source: AER analysis.

In general, the AER considers Aurora's non-system capex proposal is reasonable, and required to support Aurora's provision of standard control services. With the exception of SCADA and network control and IT and communications capex, non-system capex is trending down from the current regulatory period. Some of Aurora's supporting information is not entirely clear, but on balance, the AER is prepared to accept Aurora's proposal.

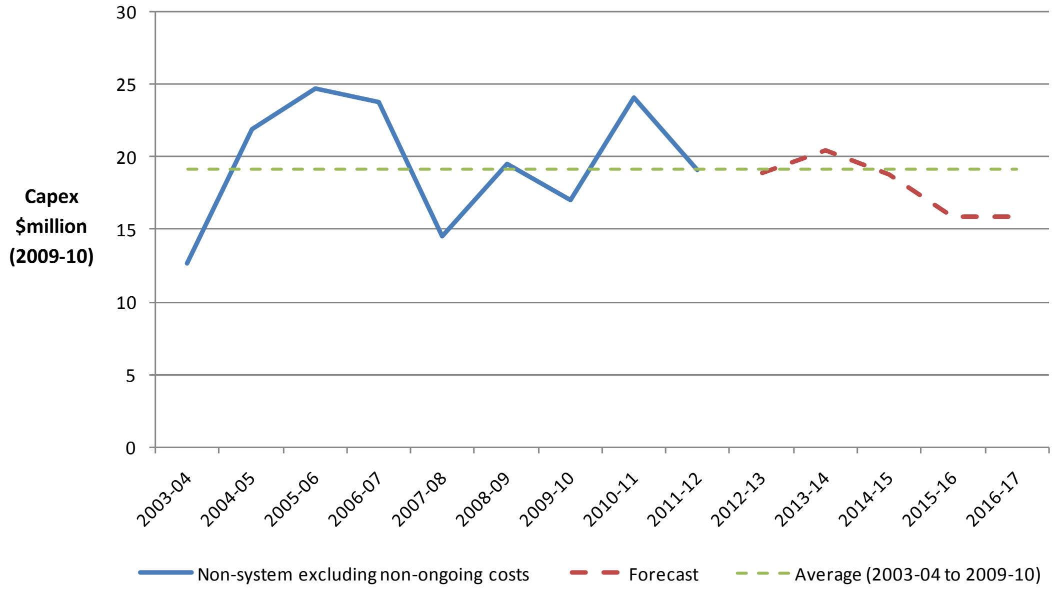
In aggregate, Aurora's non-system capex is lower than the past. As shown in Figure 5.25, this is still the case when adjusted for non-recurrent expenditures[500] and when compared to the 2003–04 to 2009–10 average (which also excludes non-recurrent capex). The AER has identified no material issues at the aggregate level, but the AER has further assessed non-system capex by reviewing the individual components. The AER has not identified any significant issues as a result of this review.

498 Aurora, *Regulatory proposal*, May 2011, p. 124.

499 Aurora's proposal included 'smart grid' IT expenditure that was allocated to SCADA and network control. The AER has assessed this expenditure as IT and communications, since it is clear that this expenditure is IT-related. Aurora, Distribution Network IT Strategy 2012–17, 15 March 2011 (confidential), attachment AE013 to Aurora, *Regulatory Proposal*, May 2011; Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 131–132.

500 IT capex to support further retail contestability tranches and NEM activity. Aurora, *RIN Response Part B - Capital Expenditure*, p. 161.

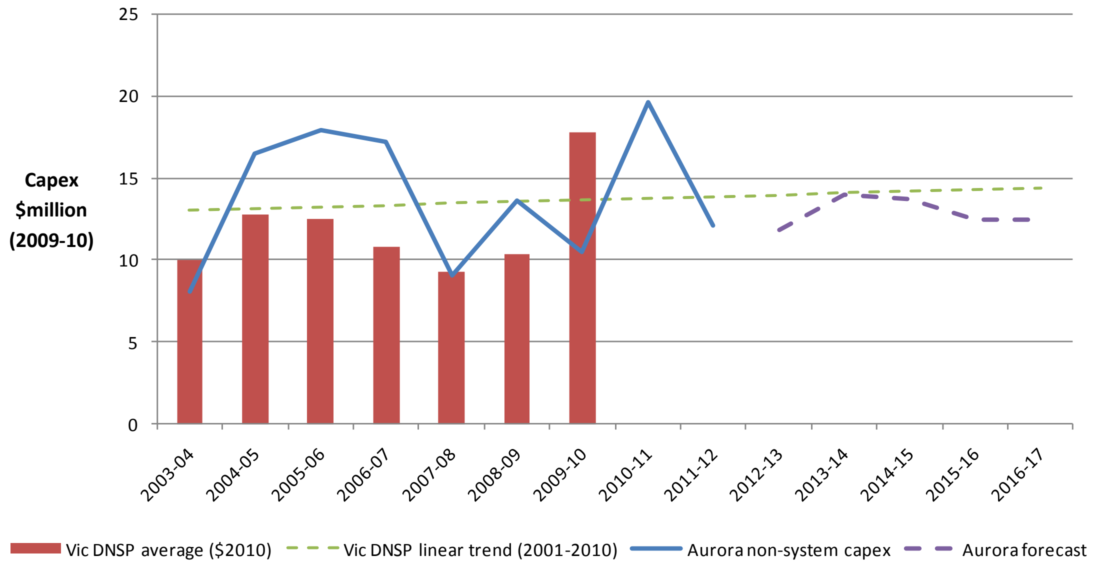
Figure 5.25 Comparison of forecast and adjusted actual non-system capex ($million, 2009–10)



Source: AER analysis.

Aurora's aggregate non-system capex forecast (excluding non-recurrent costs) also compares favourably with the equivalent Victorian DNSP historical average and long run trend (Figure 5.26).

Figure 5.26 Comparison of total non-system capex with the Victorian DNSPs ($million, 2009–10)



Source: AER analysis.

The AER has excluded motor vehicles capex from this comparison because with the exception of one DNSP, the Victorian DNSPs have spent very little motor vehicle capex.[501] The AER understands that

501 AER analysis of Victorian DNSP RIN templates (confidential).

Aurora is one of the few DNSPs who purchases its motor vehicles.[502] The AER's position on non-system capex has been informed by a review of each of the components. These are summarised in Table 5.7.

Table 5.7 The AER's consideration of Aurora's non-system capex proposal

Category	Proposed ($2009-10, million)	Considerations
IT & communications	57.8	Currently, Aurora's IT environment is complex, with a significant number of small and relatively independent IT systems.[503] Proposed IT capex is to consolidate, and simplify Aurora's IT systems into a more efficient tier-one platform that will significantly streamline Aurora's operating environment over 10 years.[504] Based on review of Aurora's documentation, the AER considers Aurora has clearly demonstrated the need for a significant improvement in IT infrastructure and services.[505] The AER acknowledges stakeholder concern that the development of 'smart network' technology may be inhibited by the current operational boundary between Aurora and Transend, providing little benefit to Tasmanian customers.[506] However, Aurora considers its planning for the introduction of smart network capabilities is insufficiently advanced to confirm whether or not this would be the case. [507] The operational boundary between Transend and Aurora is beyond the scope of the AER's review of Aurora's regulatory proposal (as noted by the stakeholder). Proposed IT capex is marginally lower than actual IT capex spent in the current regulatory period. Aurora's past and forecast IT capex is higher than the Victorian DNSPs on a per customer basis, but its forecast is reasonably comparable to the Victorian DNSP average spend.[508] Actual IT capex has been significantly greater than originally proposed in the current regulatory period, but this is primarily due to joining the National Electricity Market and retail contestability obligations.[509] Further, Aurora has estimated capex and opex efficiencies over the forthcoming regulatory control period as a result of the proposed IT program.[510] The AER has considered the efficiencies from this IT capex as part of its determination of total forecast opex and capex.
Motor vehicles	25.3	The AER considers Aurora has access to competitive prices for large volume vehicles because Aurora uses State government contract for purchasing vehicles and individual contracts for trucks and special equipment.[511] Aurora's Strategic Fleet Asset Management Plan for 2011–16 identifies a sound methodology and approach to the management of fleet assets. [512] Aurora's forecast is 14.5 per cent lower than actual expenditure between 2007–08 and 2011–12. [513]

[502] Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 140–141.
[503] Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 135.
[504] Aurora, *Regulatory proposal*, May 2011, p. 121.
[505] Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 136.
[506] David Asten (Charted Professional Engineer), *Submission to the AER*, 12 August 2011.
[507] Aurora, *Response to information request AER/028 of 18 August 2011*, received 25 August 2011.
[508] Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 134–135.
[509] Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 133–134.
[510] Aurora, *Distribution Network IT Strategy 2012–17*, 15 March 2011, p. 3 (confidential), attachment AE013 to Aurora, *Regulatory Proposal*, May 2011.
[511] Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 115.
[512] Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 115.
[513] Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 117.

SCADA & network control	2.6	Forecast expenditure relates to installation of high voltage feeder controls, data acquisition and communications.[514] According to expert engineering opinion, these are standard SCADA and network control works.[515] Benchmarking with the Victorian DNSPs shows Aurora's expenditure in this category is lower than the Victorian average historical actual expenditure. This is expected as Aurora is a smaller utility than the average Victorian DNSP in terms of assets, customers and energy delivered.[516] Forecast expenditure is similar to historical levels.[517]
Other	2.7	The AER understands that this category relates to the purchase of minor assets (such as tools), and is a continuation of a historical program.[518] Aurora has forecast this expenditure at constant levels across the forthcoming regulatory control period, derived from an average of historical actual expenditure.[519] Aurora's forecast is marginally lower than previous levels, and the AER is prepared to accept Aurora's forecast as reasonable.
Property	1.5	Forecast expenditure is significantly less than actual expenditure between 2007–08 and 2011–12. Increased expenditure in this period was due to consolidation of Aurora's accommodation into Kirksway Place, divestiture of its existing Moonah site and purchase of land for a data centre in Moonah.[520] Aurora considers its current accommodation setup will largely remain unchanged.[521] Given these considerations, Aurora's forecast seems reasonable to maintain its properties.

5.4.7 Equity raising costs

Aurora has proposed $3.0 million ($2009–10) (0.44 per cent of total capex) for the forthcoming regulatory control period as capitalised equity raising costs.[522] Such costs include legal fees, marketing costs and other transaction costs associated with raising new equity capital.

Aurora has applied the AER's preferred method to calculate an allowance for equity raising costs (see section 5.3.4). Accordingly, the AER considers that Aurora's proposal satisfies the requirements of the NEL and NER.

The AER’s approach is to amortise the allowance for benchmark equity raising costs over the weighted average standard life of Aurora's RAB to provide the equity raising cost allowance associated with forecast capex in the next regulatory period.[523]

Aurora proposed standard asset life of 41.2 years for equity raising costs in its PTRM. This value is very close to the weighted average standard life accepted by the AER in previous determinations.[524]

514 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 130–132.
515 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 130–132.
516 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 130–132.
517 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 130–132.
518 Aurora, Response to information request AER/010 of 20 July 2011, received 29 July 2011, p. 4.
519 NW-#30201284-v1-Minor_Assets_NS_trend_and_forecasts_(2012-13_to_2016-17), received on 22 July 2011 as an attachment to Aurora’s response to information request AER/010.
520 Nuttall Consulting, *Aurora Revenue Review*, October, pp. 118–119.
521 Aurora, *Facilities Management Plan*, May 2010, p. 3.
522 Aurora, *Response to AER correspondence regarding equity raising costs of 29 June 2011*, received 30 June 2011.
523 This is consistent with the AER's previous approach. See for example AER, Draft decision, *South Australia distribution determination 2010–11 to 2014–15*, pp. 165–166.
524 Based on its calculation, the AER considers that a weighted standard asset life of 42.5 years is appropriate. See AER, Final decision, *South Australia distribution determination 2010–11 to 2014–15*, p. 167.

The AER considers this value to be appropriate and will accept Aurora's proposal and amortise the allowance for equity raising costs over the standard asset life of 41.2 years.

Aurora also proposed a tax standard life of 33.2 years for equity raising costs. The AER notes that an ATO determination requires equity raising costs to have a tax standard life of 5 years.[525] The AER will therefore apply a tax standard life of 5 years for equity raising costs in Aurora's PTRM for tax purposes.

Based on the AER's analysis, the benchmark cash flow indicates that Aurora does not require any external equity raising. Accordingly, an allowance for equity raising costs has not been included in this draft decision. The cash flow analysis for Aurora's equity raising cost is shown in Table 5.8. The AER will update this analysis again for the final decision based on the final capex allowance to be determined at that time.

Table 5.8 AER's cash flow analysis for Aurora's equity raising costs

Cash flow analysis	Amount ($million, nominal)	Notes
Dividends	143.3	Set to distribute imputation credits assumed in the PTRM (70 per cent)
Dividends reinvested	43.0	Capped at 30 % dividends paid
Cost of dividend reinvestment plan	0.43	Dividends reinvested multiplied by benchmark cost (1%)
Capex funding requirement	514.3	Forecast capex funding requirement (not the capex value that includes half year WACC adjustment)
Debt component	181.1	Set to equal 60% of RAB
Equity component	333.2	Residual of capex funding requirement and debt component
Retained cash available for reinvestment	390.9	Include dividends reinvested
External equity required	-57.7	Equals equity component less retained cash flows
External equity raising costs	-1.7	External equity requirement multiplied by the benchmark cost (3%)
Total equity raising costs	-1.3	
Total equity Raising costs ($million, 2009–10)	0	To be added to the RAB at the start of the regulatory control period

Source: AER analysis.

525 ATO, *Guide to depreciating assets 2001-02: Business» related costs - section 40-880 deductions, ATO reference; NO NAT7170.*

5.4.8 Capitalised overheads

Aurora proposed approximately $98.5 million ($2009–10) (14.6 per cent of total capex including overheads) in capitalised overheads for the forthcoming regulatory control period.[526] The AER has reviewed these overheads as part of its shared costs review in the operating expenditure attachment (attachment 6). As explained in attachment 6, the AER has developed an alternative forecast using a base year approach. Aurora's forecast is significantly less than the AER's forecast, and its historical overheads. The AER has therefore accepted Aurora's forecast.

5.4.9 Real input price changes

Aurora's proposed real cost escalation of $5.3 million ($2009–10) accounts for less than one per cent of Aurora's total forecast capex (including real cost escalation).[527] To determine its substitute capex forecast, the AER has applied real cost escalation to the components of capex that it considers would increase in cost at a different rate than CPI. The AER has determined a weighted real cost escalator from the proportions of labour and materials in Aurora's capex forecasts and the forecast real cost increases in labour and materials. The AER's assessment of real cost escalation is discussed in attachment 4.

As discussed in attachment 4, on balance, the AER is satisfied that the real cost escalation included in Aurora's forecast capex, in proportional terms, reasonably reflects a realistic expectation of labour and materials cost increases over the forthcoming regulatory control period. In absolute terms, the AER's forecast results in a reduction of approximately $0.20 million ($2009–10) to Aurora's total forecast capex. The AER's conclusion on weighted capex real cost escalators is in Table 5.9.

Table 5.9 AER conclusion on weighted capex real cost escalators ($million, 2009–10)

	2012-13	2013-14	204-15	2015-16	2016-17	Total
Aurora's proposal	0.8	1.9	1.2	1.3	0.1	**5.3**
AER adjustment	-0.2	-0.2	0.2	-0.1	0.1	**-0.1**
AER draft determination	0.6	1.6	1.5	1.1	0.3	**5.2**

Source: AER analysis.

5.5 Revisions

Revision 5.1: The AER has revised Aurora's total forecast capex for the forthcoming regulatory control period by $139.2 million. The AER's substituted forecast is $535.8 million.

526 Aurora, *Regulatory proposal*, May 2011, p. 113.
527 Aurora, *Regulatory Information Notice*, template 3.5.

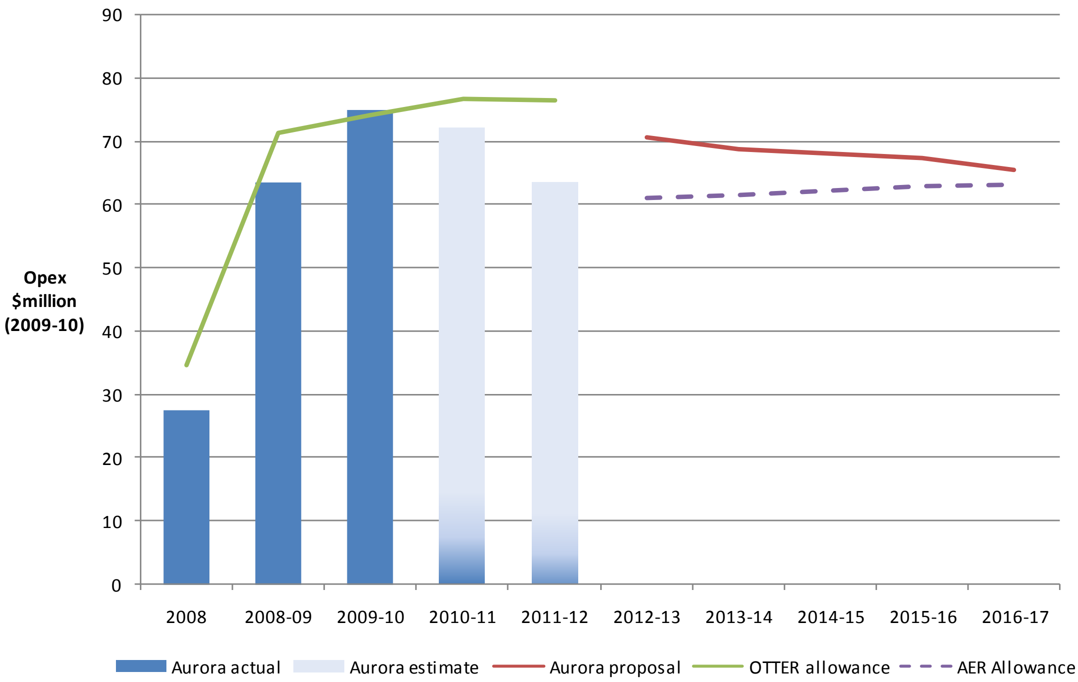
6 Operating expenditure

This attachment sets out the AER's decision on Aurora's proposed total forecast operating expenditure (opex). Opex refers to the operating, maintenance and other non-capital costs a distribution network service provider (DNSP) incurs in providing standard control services.

6.1 Draft determination

The AER is not satisfied Aurora's proposed total forecast opex reasonably reflects the opex criteria. The AER considers Aurora's opex forecast exceeds its requirements for recurrent opex adjusted for network growth and economies of scale. Figure 6.1 compares Aurora's past and forecast total opex with proposed and approved opex.

Figure 6.1 Comparison of Aurora's past and future total opex and AER draft determination ($million, 2009–10)[528]



Source: Aurora,[529] AER analysis.

The AER has estimated a substitute total forecast opex for Aurora using a base year opex forecast that it considers reasonably reflects the opex criteria, taking account of the opex factors. This estimate reduces Aurora's proposal of total forecast opex to the minimum extent necessary so that the AER may approve Aurora's total forecast opex in accordance with the NER.[530] Overall, the AER estimated a total forecast opex of $311.0 million[531] over the forthcoming regulatory control period—a 5.5

528 The first period (2008) in the current regulatory period only extended for a duration of six months. This explains the significant increase in opex from 2008 to 2008-09. 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.

529 Aurora, *Regulatory proposal*, May 2011, pp. 129–145.

530 NER, clause 6.12.3(f).

531 Includes debt raising costs and Aurora's demand management incentive allowance.

per cent reduction[532] (in real terms) on expenditure incurred by Aurora over the current regulatory period.

Table 6.1 AER draft determination on Aurora's operating and maintenance expenditure ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Aurora's proposed forecast opex	70.6	68.6	68.1	67.3	65.4	340.1
AER draft determination	61.1	61.6	62.3	62.9	63.2	311.0

Source: AER analysis. Includes debt raising costs and demand management incentive allowance.

6.2 Aurora's proposal

Aurora proposed total opex of $340.1 million ($2009-10) over the forthcoming regulatory control period (Table 6.2). Aurora stated its proposal represents a real decrease of 5.0 per cent on actual expenditure in the current regulatory period.[533]

Table 6.2 Aurora's proposed total forecast opex ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Operating costs						
Network management	15.7	15.5	15.7	15.9	16.0	78.8
Non-network management	11.5	11.4	11.4	11.3	11.3	56.8
Operating costs—other	4.5	4.6	4.6	4.6	4.6	22.9
Maintenance costs						
Routine maintenance	16.6	16.3	16.0	15.7	15.2	79.9
Non-routine maintenance	21.4	20.5	19.9	19.0	17.5	98.4
Demand management						
Demand management	0.9	0.4	0.5	0.7	0.8	3.3
Total	**70.6**	**68.6**	**68.1**	**67.3**	**65.4**	**340.1**

Source: Aurora.[534]
Note: Numbers may not add due to rounding.

Aurora's direct opex forecasts have been calculated using a program of work that sums each of the operating and maintenance projects it considers will occur in the forthcoming regulatory control period. The opex forecasts for each proposed project have been developed by multiplying estimated volumes and unit costs for that project.[535] The forecasts of the unit costs and volumes for each project

532 The current regulatory control period has been normalised to represent a five year period for this calculation.
533 Data for the current regulatory period data has been normalised to cover a five year period, to enable comparison with Aurora's proposal for the forthcoming regulatory control period. The current regulatory period is four and a half years.
534 Aurora, *Regulatory proposal*, May 2011, p. 145.
535 Aurora, *Regulatory proposal*, May 2011, p. 133.

have been derived by Aurora's thread managers in accordance with Aurora's policies and procedures.[536]

In its asset management activities, Aurora uses a 'thread management' approach whereby activities are broken down into programs called 'threads'.[537] A 'thread' comprises staff from Network and Network Services divisions involved in the planning, design, construction and maintenance of the asset class.[538] The methodology for forecasting volumes of works depends on the individual thread category and is developed by the thread manager. The unit rates currently incurred by Aurora, and reflected in the current average costs of works, have been utilised as the basis for future unit rates. For instance, the unit costs of undertaking vegetation management maintenance are based upon Aurora's actual costs in 2010-11.[539] Aurora's unit rates have been determined using a bottom up approach by aggregating the following:

- estimated labour time required to undertake the task multiplied by the hourly rate of the skill sets utilised
- materials
- plant and equipment.[540]

The individual forecasts of Aurora's unit rates are developed in Aurora's unit rates model. Where project scopes are known and defined, the projects are estimated using a bottom up methodology. Where projects are undefinable, the units rates are calculated using historical data.[541] The methodology to develop forecasts projects for each work category has been presented in Aurora's management plans.[542]

Aurora applied an annual three per cent efficiency factor to opex labour rates to deliver operational efficiencies.[543] The efficiency factor was applied across all opex as a means of reducing total expenditure.[544] Aurora considered this a prudent method to drive cost reductions across all expenditure via a top down approach. As highlighted in Aurora's regulatory proposal it has adopted this methodology for forecasts as it is yet to fully substantiate the individual projects that will be decreased under a typical engineering solution.[545] This efficiency factor results in a real reduction within the labour rates in excess of 10 per cent over the duration of the forthcoming regulatory control period.[546] As Aurora's labour rates are applied to both capex and opex, the efficiencies are applied in the forecasting of both.

Aurora's reasoning for selecting capital or operating projects are presented in Aurora's management plans.[547]

In addition to direct costs, Aurora's total forecast opex also included shared costs. Aurora used its indirect cost allocation model (ICAM) to allocate corporate and shared services costs between Aurora's divisions and subsidiaries. Aurora then used its cost allocation method (CAM), as approved

536 Aurora, *Regulatory proposal*, May 2011, p. 32.
537 Aurora, *Regulatory proposal*, May 2011, p. 32.
538 Aurora, *Regulatory proposal*, May 2011, p. 32.
539 Aurora, *Management plan 2011 vegetation management*, 19 February 2011, p.21-22 (confidential).
540 Aurora, *Regulatory proposal*, May 2011, p.167.
541 Aurora, *Units rates model procedure*, Version 2.0, 16 May 2011.
542 Aurora, *Regulatory proposal*, May 2011, p. 133.
543 Aurora, *Regulatory proposal*, May 2011, p. 165.
544 Aurora, *Response to information request AER/046 of 5 October 2011*, 11 October 2011, p. 3.
545 Aurora, *Response to information request AER/046 of 5 October 2011*, 11 October 2011, p. 3.
546 Aurora, *Regulatory proposal*, May 2011, p. 14.
547 Aurora, *Regulatory proposal*, May 2011, pp. 147–148.

by the AER, to allocate costs between various classifications within the distribution business. Forecasts of these costs have generally been developed outside of Aurora's thread management framework using its budgeting and forecasting (BAF) tool.[548]

6.3 Assessment approach

As part of its building block proposal to the AER for the forthcoming regulatory control period, Aurora must submit a total forecast opex it considered is required to achieve the opex objectives.[549] The AER is required to assess this total forecast opex to decide whether it:[550]

- accepts the total forecast opex, or
- does not accept it. In this case, the AER estimates the total amount of Aurora's required opex it considers reasonably reflects the opex criteria.

To make this decision, the AER must form a view on Aurora's proposed total forecast opex as a whole, not individual projects or programs.[551] However, because the total forecast opex can be separated into expenditure components, the AER assesses projects and programs of these components to inform its decision on the total amount.

The AER must accept Aurora's proposed total forecast opex if satisfied it reasonably reflects the opex criteria. That is, the forecast must reflect the efficient costs that a prudent operator in Aurora's circumstances would need to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the opex objectives.[552] The AER considers the opex criteria are complementary, and that efficient costs are the costs a prudent operator is expected to incur, not a 'prudence premium' above otherwise efficient costs to balance risk.[553]

In deciding whether Aurora's proposed total forecast opex reasonably reflects the opex criteria, the AER must have regard to the opex factors.[554] Although the AER considered each opex factor when assessing Aurora's proposed total forecast opex, not all factors were relevant for assessing each opex component. The AER made its decision, therefore, by examining:

- the amount of forecast opex it considered would reflect the efficient costs of achieving the opex objectives
- whether Aurora’s proposed forecast opex reasonably reflected the AER’s forecast of prudent and efficient opex (in total)
- those item(s) of Aurora’s proposed forecast opex that did not appear to reflect the AER’s forecast.

By using a base year approach the AER provides Aurora with a 'reasonable opportunity' to recover at least its efficient costs, as required by section 7A(2) of the NEL. The AER considers the efficient historical costs of operating the network are captured in the base year. Material changes to a DNSP's

548 Aurora, *Regulatory proposal*, May 2011, p. 134.
549 NER, clause 6.5.6(a).
550 NER, clause 6.12.1(4).
551 NER, clause 6.5.6(c).
552 NER, clause 6.5.6(c). Clause 6.5.6(a) specifies the opex objectives.
553 Some distribution network service providers posited the 'prudency premium' hypothesis during the 2011–15 Victorian electricity distribution price review in the context of the opex criteria. See AER, Final decision: *Victorian electricity distribution network service providers: Distribution determination 2011–2015*, 2010, p. 313.
554 NER, clause 6.5.6(d). Clause 6.5.6(e) specifies the opex factors.

operating environment are then added through network growth escalation, real cost escalation and step changes.

The base year approach also ensures Aurora is provided with effective incentives that promote economic efficiency with respect to investment in, and use of, a distribution system.[555] Specifically, service providers are provided with incentives to realise opex efficiencies within the regulatory control period (and therefore, in the efficient provision of services and operation of the network). Incentives to seek cost efficiencies are also provided through the operation of the EBSS and the STPIS (to ensure that cost efficiencies are not at the expense of service quality and network performance).

In identifying that level of efficient costs the AER has also had regard to the economic costs and risks of the potential for under and over investment, and the under and over utilisation of Aurora's distribution systems. The AER considers the efficient level of costs it is required to identify leads to efficient prices and maintains the safety, quality and reliability of the distribution network. Accordingly, the AER considers that applying a base year approach is both consistent with the opex criteria[556] and ensures achievement of the National Electricity Objective[557] and Revenue and Pricing Principles.[558]

6.3.1 Base year forecast

The AER has developed an opex forecast using a base year approach to assess Aurora's opex proposal. Under this approach, the AER estimated a forecast total opex, developed in consideration of the opex factors, which it considers reasonably reflects the opex criteria. The AER used this forecast to determine whether it is satisfied Aurora's proposed opex reasonably reflects the opex criteria.

The AER applied this approach in reviewing the operating expenditure of the New South Wales[16], Queensland [17] and South Australian [18] DNSPs. The base year approach was also applied in the recent Victorian electricity distribution price review.[19] Further, the regulatory proposals of all the Victorian DNSPs, with the exception of United Energy Distribution (UED), were prepared in accordance with this approach.[20]

In this circumstance, the AER is concerned Aurora's forecasting methodology may not produce a total forecast opex that reasonably reflects the criteria.

Aurora's forecasting methodology involves the aggregation of a significant number of individual forecasts (Aurora's forecast opex was comprised of 131 work projects in its program of works and 150 forecasts of shared costs). When aggregated, the AER is concerned that these forecasts may not account for the economies of scale and scope a DNSP of Aurora's size would be expected to achieve.

Indeed, Aurora itself has made adjustments to the total forecast opex derived from its forecasting methodology. Aurora applied labour (three per cent) efficiencies across all opex as a means of reducing total expenditure. Aurora considered this was a prudent methodology to drive cost

555 NEL, section 7A(3).
556 NER, clause 6.5.6(c).
557 NEL, section 7.
558 NEL, section 7A.
16 AER, Draft decision, *New South Wales draft distribution determination 2009–10 to 2013–14*, 21 November 2008, p. 170.
17 AER, Draft decision, *Queensland Draft distribution determination 2010–11 to 2014–15*, 25 November 2009, p. 133.
18 AER, Draft decision, *South Australia Draft distribution determination 2010–11 to 2014–15*, 25 November 2009
19 AER, *Final Decision: Victorian electricity DNSPs: Distribution determination 2011–2015*, 2010, pp. 312–319.
20 AER, *Final Decision: Victorian electricity DNSPs: Distribution determination 2011–2015*, 2010, pp. 316.

reductions across all expenditure via a top down approach. Aurora stated that it has adopted this methodology for forecasts as it is yet to fully substantiate the individual projects that will be decreased under a typical engineering solution.[559]

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. Aurora made this adjustment with reference to its strategic objective of structuring the Aurora distribution business with its long-term aspirational objective of ensuring that there is no increase to customer prices as result of its efforts.[560]

Therefore, to assess the extent to which the total forecast opex proposed by Aurora reasonably reflects the opex criteria, the AER has compared Aurora's total forecast opex to a forecast developed using a base year approach.

6.3.2 Base year approach

Given operating costs are largely recurrent, the starting point of a base year forecast is actual expenditure in a base year that reflects the recurrent operating costs of providing standard control services. The AER then adjusted this base year opex to account for changes in Aurora's circumstances that will drive changes in Aurora's operating costs in the forthcoming regulatory control period. These adjustments include:

- removing non-recurrent cost from actual expenditure in the base year
- escalating forecast increases in the size of the network (referred to as 'scale escalation')
- escalating forecast real cost changes for labour and materials (referred to as 'real cost escalation')
- adding step changes for efficient costs not reflected in the base opex, such as costs due to changes in regulatory obligations and the external operating environment.

Using a DNSP's historic expenditure ensures the total forecast opex reflects the expenditure of a DNSP in its circumstances. The AER considers two things to determine whether the historic expenditure reflects efficient costs.[561] First, the AER considers the incentives faced by Aurora. DNSPs in the NEM operate under an ex ante incentive regime that provides them with an incentive to reduce expenditure (because DNSPs can retain any cost savings made during the regulatory control period).

While this incentive to reduce expenditure declines over the period, the application of an efficiency benefit sharing scheme (EBSS) provides DNSPs with a continuous incentive. However, Aurora was not subject to an EBSS (or its equivalent) during the current regulatory period. In the absence of an EBSS, DNSPs may have an incentive to increase their expenditure in the base year for the purpose of increasing their opex allowance in the following regulatory control period. Second, the AER analysed the costs of other DNSPs and benchmarked them against Aurora's base year

[559] Aurora Energy, *Response to information request AER/046 of 5 October 2011*, received 11 October 2011, p. 3.
[560] Aurora Energy, *Regulatory proposal*, May 2011, p. 167.
[561] NER, clause 6.5.6(e)(5).

expenditure.[562] Where this high level benchmarking indicates that Aurora's base year expenditure may not be efficient the AER undertakes a targeted review of Aurora's base year costs.

Further, Aurora likely incurred some non-recurrent costs in the base year that reflect the particular circumstances of that year and would not be expected in the forthcoming regulatory control period. The AER thus assessed Aurora's historical opex trends and removed any non-recurrent opex from the base year expenditure that would not reflect the level of recurrent costs required in the forthcoming regulatory control period. In addition, the AER tested Aurora's historical opex against Aurora's forecast opex in previous regulatory proposals, to infer whether the DNSP's forecasting processes reasonably estimate future needs.[563]

In setting base opex, therefore, the AER had particular regard to Aurora's circumstances, consistent with the NER opex criteria,[564] and to the opex factors.[565] It is reasonable to expect Aurora's circumstances in the forthcoming regulatory control period will differ from those in the base year, leading to a change in Aurora's recurrent costs from the base year. One likely change is the size of Aurora's network. Aurora's network will grow as new customers join the network and as existing customers change their demand. As the size of the network grows, Aurora's opex will increase with the growing number of assets it needs to operate and maintain its network. The AER thus applied scale escalation, to ensure the total forecast opex reasonably reflects (1) the efficient costs of a prudent DNSP in Aurora's circumstances and (2) a realistic expectation of the demand forecast.[566]

Labour and materials costs in the forthcoming regulatory control period may differ (in real terms) from those incurred in the current regulatory period. To ensure the total forecast opex reasonably reflects the cost inputs required to achieve the opex objectives,[567] the AER applied real cost escalation to account for any forecast changes in the cost of these inputs. To account for other anticipated changes in Aurora's circumstances (such as changes to regulatory obligations, or other changes to Aurora's operating environment beyond its control), the AER added step changes to its forecast opex.

For these reasons, the AER considers this base year (or revealed cost) approach provides an appropriate basis for determining whether Aurora's proposed total forecast opex reasonably reflects the opex criteria, having regard to the opex factors. In assessing Aurora's proposal, the AER has also considered the explanations given by Aurora where the AER prefers an alternate approach to determining inputs proposed by Aurora in its forecast of total opex. These considerations combined provide the AER with insight to determine whether Aurora's proposed total forecast opex reasonably reflects the opex criteria.

Where Aurora's proposed total forecast opex is higher, or significantly lower, than the AER's base year forecast the AER cannot be satisfied that it reasonably reflects the opex criteria. If the AER is not satisfied Aurora's proposed total forecast opex reasonably reflects the opex criteria, then it must not accept Aurora's proposed opex.[568] The AER must then substitute Aurora's total forecast opex with an estimate it is satisfied reasonably reflects the opex criteria, accounting for the opex factors.[569] The

562 NER, clause 6.5.6(e)(4).
563 NER, clause 6.5.6(e)(5).
564 NER, clauses 6.5.6(c)(1) and (2).
565 NER, clauses 6.5.6(e).
566 NER, clauses 6.5.6(c)(2) and (3).
567 NER, clause 6.5.6(c)(3).
568 NER, clause 6.5.6(d).
569 NER, clause 6.12.1(4)(ii).

substitute amount must be determined on the basis of Aurora's regulatory proposal and varied only to the extent necessary for it to achieve the opex criteria, having regard to the opex factors.[570]

A proportion of Aurora's operating costs are shared costs. These costs are part of a pool of shared costs that are allocated across the whole of Aurora's direct control services. This includes standard control services, metering services and public lighting services. The AER has separately reviewed the shared costs in Aurora's proposed forecast capex and alternative control services using this methodology. This is because the shared costs have the same source and so the same assessment approach is warranted. Further, as these costs are recurrent in nature, like opex, the approach applied to reviewing opex is also appropriate for shared costs.

In reviewing Aurora's opex proposal, the AER had regard to the opex factors.[571] The AER's consideration of the opex factors is summarised in Table 6.3.

Table 6.3 AER consideration of the opex factors

Opex factor	AER approach
The information included in or accompanying the building block proposal.	The AER has reviewed Aurora's regulatory proposal and supporting documentation. Among other things, this includes asset management plans, justification documentation, models and responses provided to AER information requests.
Submissions received in the course of consulting on the building block proposal.	The AER has considered submissions in response to Aurora's regulatory proposal.
Analysis undertaken by or for the AER and published before the distribution determination is made in its final form.	The AER has undertaken extensive analysis of Aurora's regulatory proposal and supporting documentation, and analysis of previous regulatory reviews conducted by the AER. The AER has also engaged independent expert technical consultants to assist with its review.
Benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period.	The AER has had regard to benchmarking analysis conducted by itself and that submitted by Aurora, particularly in its assessment of Aurora's base year expenditure. The analysis has compared Aurora against other DNSPs in the NEM.
The actual and expected operating expenditure of Aurora during any preceding regulatory control periods.	As part of its analysis, the AER has reviewed Aurora's actual and expected capex for preceding regulatory periods, particularly in its assessment of Aurora's base year and step change costs.
The relative prices of operating and capital inputs.	The AER has assessed the forecast movement of input costs such as labour and materials costs.
The substitution possibilities between operating and capital expenditure.	The AER has inherently considered capex and opex substitution possibilities through detailed project review. The AER has considered options to address needs, including the substitution of opex to defer capital projects, or capital projects to remove the need for opex. Part of the AER's review is also to consider how Aurora has considered these possibilities when preparing its forecast. The AER has accounted for substitution possibilities in its estimate of substitute forecasts for total capex and total opex.

570 NER, clause 6.12.3(f).
571 NER clause 6.5.6(e).

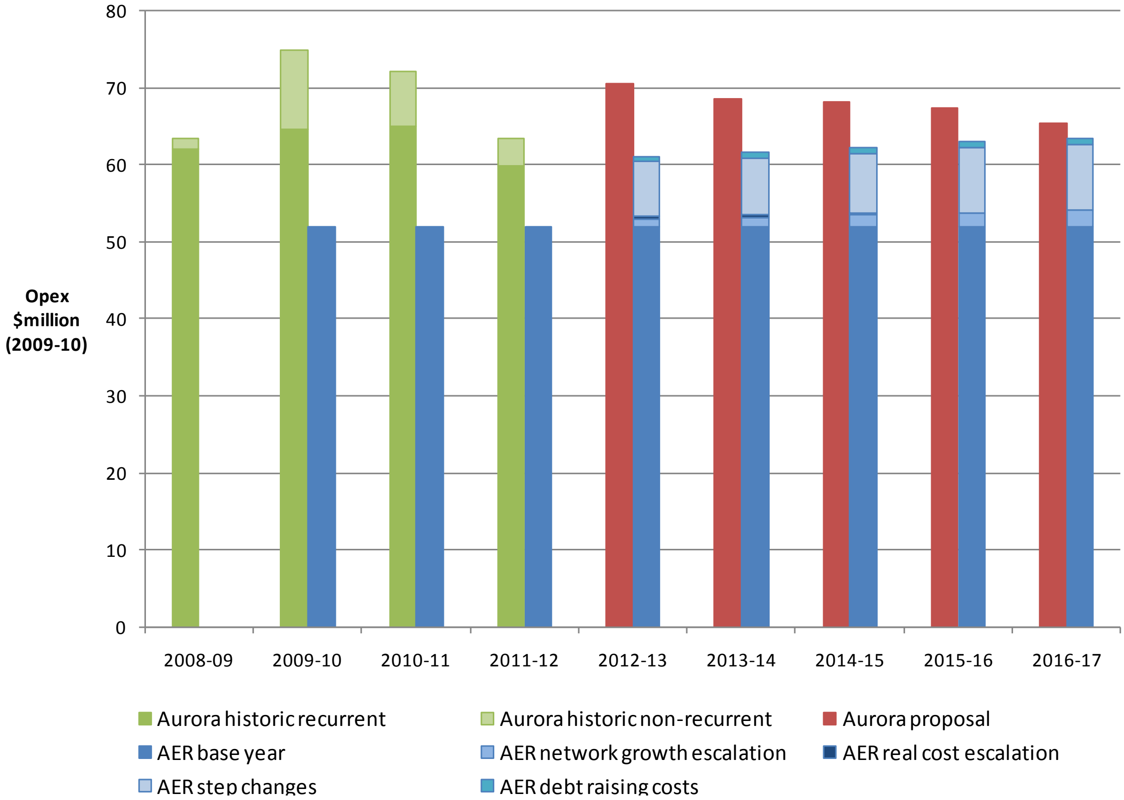
Whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period.	The AER has developed a substitute forecast opex that is sufficient for Aurora to maintain its current levels of service performance in the forthcoming regulatory control period.
The extent the forecast of required capital expenditure of Aurora is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms.	This factor is not applicable to Aurora as it does not deal with any related parties.
The extent Aurora has considered, and made provision for, efficient non-network alternatives.	The AER has had regard to non-network alternatives proposed by Aurora and has included those it considers to be efficient in total forecast opex.

6.4 Reasons for determination

In contrast to the regulatory proposals lodged by most other NEM DNSPs, Aurora did not use a base year approach to forecast its opex over the period 2012 to 2017. It instead produced a bottom up forecast, using the methodology described in section 6.2 above.

The AER does not consider that Aurora's total forecast opex reasonably reflects the opex criteria. In accordance with clause 6.12.1(4)(ii) and 6.12.3(f) of the NER the AER produced an estimate of the total opex for the forthcoming regulatory period. Figure 6.2 presents Aurora's actual and forecast opex and the AER's draft determination total forecast opex. The AER's forecast of $311.0 million ($2009-10) over the forthcoming regulatory control period is 8.6 per cent lower than Aurora's forecast of $340.1 million ($2009-10).

Figure 6.2 Comparison of Aurora's opex proposal with the AER's alternative forecast ($million, 2009–10)



Source: AER analysis, Aurora.[572]

The AER has reached this view after testing Aurora's forecast using two main approaches:

First, the AER reviewed Aurora's recent opex and its circumstances. Taken together, this review suggested that the AER could not rely on Aurora's actual costs alone to calculate a total forecast opex for Aurora. Further analysis of Aurora's opex forecast was required. The AER found that:

- Aurora has not been subject to an EBSS and therefore has not faced a continuous incentive to reduce opex in the current regulatory period
- Aurora has spent close to its OTTER allowance, suggesting that it may not have strongly responded to incentives to reduce costs
- benchmarking suggests that Aurora's opex is slightly higher than its peers.

Second, the AER developed an alternative forecast which placed some reliance on Aurora's recurrent expenditure as a base, but accounted for all factors that the AER expected would affect Aurora's costs over the forecast period. In producing its alternative forecast, the AER:

- used 2009-10 as the preferred base year
- removed non-recurrent expenditure and movements in provisions

572 Aurora, *Regulatory Information Notice*.

- reviewed and adjusted some categories of the base year expenditure that deviated from past expenditure
- adjusted for step changes, network growth and real cost escalation.

The composition of the AER's forecast opex is detailed in Table 6.4 below.

Table 6.4 AER draft determination on Aurora's total forecast opex ($000, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Base opex	51,918	51,918	51,918	51,918	51,918	**259,591**
Network growth escalation	945	1,264	1,585	1,908	2,233	**7,935**
Real cost escalation	438	457	197	-150	-290	**652**
Step changes	7,076	7,155	7,770	8,407	8,555	**38,963**
Debt raising costs	758	769	779	788	798	**3,893**
DMIA	400	400	400	400	400	**2,000**
Total opex	**61,136**	**61,563**	**62,250**	**62,872**	**63,213**	**311,034**

Source: AER analysis. DMIA is the demand management incentive allowance.

This approach yielded a lower forecast than Aurora's forecast. The AER considers that Aurora's forecasting methodology results in a forecast opex that is in excess of the forecast opex that would reasonably reflect the opex criteria.

The divergence between the AER and Aurora's forecast opex is driven by the lower level of expenditure in the base year used by the AER. To the extent that Aurora's forecasting methodology is reliant on historical costs, the high expenditure in 2009-10 and 2010-11 would appear to have contributed to Aurora's higher forecast.

The AER's considers its base year forecast to be a reasonable estimate of the efficient opex a DNSP in Aurora's circumstances would require to achieve the opex objectives. On the basis of the information provided by Aurora in its regulatory proposal and supporting information, the AER has accounted for all circumstances it expects to change Aurora’s total forecast opex over the forthcoming regulatory period. If other matters are expected to change Aurora’s total forecast opex in the forthcoming regulatory control period, and the AER is to consider them in making in final determination, these should be explained in terms of their influence on the elements of the AER’s base year forecast.

The remaining sections of this attachment present how the AER arrived at its base year opex forecast.

6.4.1 Aurora's historical expenditure

The AER reviewed Aurora's expenditure during the current regulatory period to test whether it was appropriate for use as the base year expenditure using a base year forecasting approach.

Base year expenditure should reflect the recurrent costs of providing standard control services for a DNSP in Aurora's circumstances. The recurrent opex in the base year must be sufficient to enable Aurora to achieve the opex objectives.

Some reliance can be placed on Aurora's actual historical costs in deciding the recurrent base opex because Aurora has demonstrated that this level of recurrent opex was sufficient to operate in its circumstances in the past. However, how much weight can be placed on Aurora's historical expenditure depends on the extent to which this expenditure reflected efficient costs.

The AER has considered the appropriateness of Aurora's historical recurrent opex through analysis of its incentives and expenditure benchmarking. The AER notes Aurora did not use a base year approach to forecast opex and as such did not propose an amount for base opex.

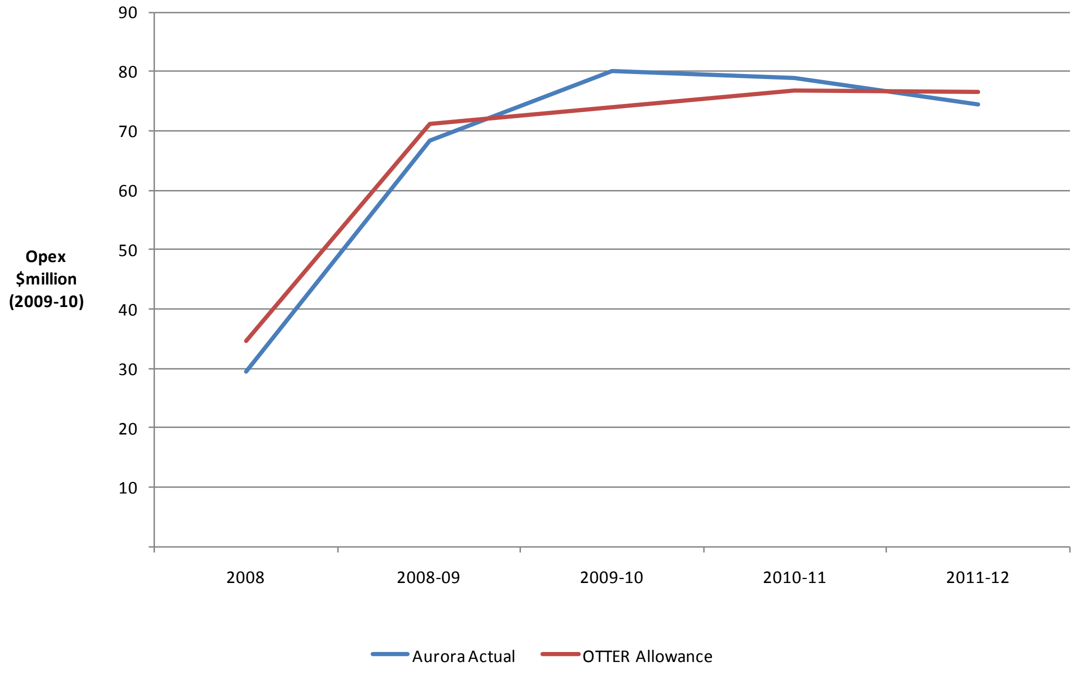
Aurora's current circumstances

In the current regulatory period Aurora is operating under an ex ante incentive regime that rewards it for reducing expenditure below the allowance provided by OTTER. However, unlike other DNSPs in the NEM, Aurora is not subject to an efficiency benefit sharing scheme (EBSS).

In the absence of an EBSS, a NSP's incentive to minimise opex declines as the period progresses. This is because efficiency gains made are clawed back when revenues are set for the subsequent period. Thus as the period progresses any efficiency gains made are not retained for as long and the incentive to make them diminishes. Under an EBSS the NSP is able to retain the efficiency gains made for a further five years, regardless of the year, thus providing it a continuous incentive to make opex efficiency gains. Further, without an EBSS an NSP may have an incentive to increase its opex in a year it expects will be used to set opex in the following period. With an EBSS this incentive is removed because the efficiency loss is carried forward for five years by the scheme.

Figure 6.3 below compares Aurora's actual opex for the period January 2008 to 30 June 2010, and forecast opex for the period 30 June 2010 to 30 June 2012 with the opex allowance determined by OTTER.

Figure 6.3 OTTER's allowance vs Aurora's actual/estimated opex - current regulatory period ($million, 2009–10)



Source: Aurora,[573] AER analysis.

Figure 6.3 shows Aurora expects to spend close to the allowance provided by OTTER in the current regulatory period. Figure 6.3 includes overheads and has been prepared in accordance with the CAM Aurora applied in the current regulatory period (the previous CAM).

This is confirmed in Table 6.5. Aurora expects to slightly underspend its allowed opex based on its most recent forecasts.

Table 6.5 Comparison of actual opex and allowed opex 2008 to 2011–12 (per cent)

	2008	2008-09	2009-10	2010-11	2011-12	Total
Audited actual	–14.94	–4.23	8.23			–1.16
Forecasts				2.86	–2.59	0.14
Full period	–14.94	–4.23	8.23	2.86	–2.59	–0.56

Source: AER analysis.

The AER considers Aurora's historical costs cannot be solely relied upon to provide a starting point for the development of a forecast of opex without further investigation. This is because Aurora has:

- not been subject to an EBSS and therefore has not faced a continuous incentives to reduce opex in the current regulatory period
- spent close to its OTTER allowance, suggesting that it may not have strongly responded to incentives to reduce costs

573 Aurora, *Regulatory proposal*, May 2011, pp. 129–132.

Expenditure benchmarking

Benchmarking Aurora's historic opex against the historic opex of other DNSPs provided some guidance on the relative efficiency of Aurora's historic opex. The AER has considered the two benchmarking reports that Aurora provided in support of its regulatory proposal prepared by (Parsons Brincknerhoff (PB) and Benchmark Economics).[574] Appendix B responds to specific points relevant to this analysis in benchmarking analysis conducted by the EUAA, PB and Benchmark Economics.

However, in interpreting the findings of expenditure benchmarking on Aurora's efficiency the AER must have regard to the comparability of Aurora with the other DNSPs operating in the NEM. The AER has discussed the limitations of benchmarking in previous determinations.[575] These limitations include:

- different licence requirements in the NEM jurisdictions
- differences between purchase and leasing policies
- variations in the network characteristics of DNSPs including the age, size and maturity of their networks and the markets they serve
- different capitalisation, cost allocation and other accounting policies
- different regulated service classifications.

Nevertheless, the AER considers that expenditure benchmarking at an aggregate level combined with analysis aimed at identifying and accounting for the impact of these differences can provide information on the relative efficiency of DNSPs.

A summary of the AER opex benchmarking is presented in Table 6.6. It compares the performance of Aurora against its benchmark peers. Based on its expenditure benchmarking (see benchmarking appendix B), the AER considers Aurora is in the range of, but above, its benchmark peers. Therefore, the AER considers that further detailed review should be conducted to assess the recurrent opex to be included in the base year.

Table 6.6 Summary of AER's opex benchmarking — Aurora's performance compared to benchmark peers (per cent of Aurora)

	ETSA	SP Ausnet	Powercor
Opex / line length	+114	+47	+99
Opex / customer	+20	+14	+22
Opex / electricity distributed	+2	–13	+12
Opex / peak demand	+9	–15	–1
Opex / RAB	+8	–22	–12

Source: AER analysis.

[574] Parsons Brinckerhoff, *Capex and opex benchmarking study: Aurora Energy*, March 2011 and Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011.

[575] AER, *Draft decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, Appendix I, pp. 78–79.

6.4.2 Selection of the base year and detailed review

The AER considers the recurrent opex for use in its base year opex forecast is 51.9 million ($2009-10). This has been derived by excluding non-recurrent costs, and the movement in provisions from Aurora's actual expenditure for 2009-10. To be satisfied the base opex included only efficient recurrent costs the AER also conducted a detailed review of those categories of Aurora's opex that varied significantly from the historical trend.

To help identify the appropriate year to use as a base year, the AER removed non-recurrent expenditure and the movement in provisions from Aurora's actual expenditure during the current regulatory period.

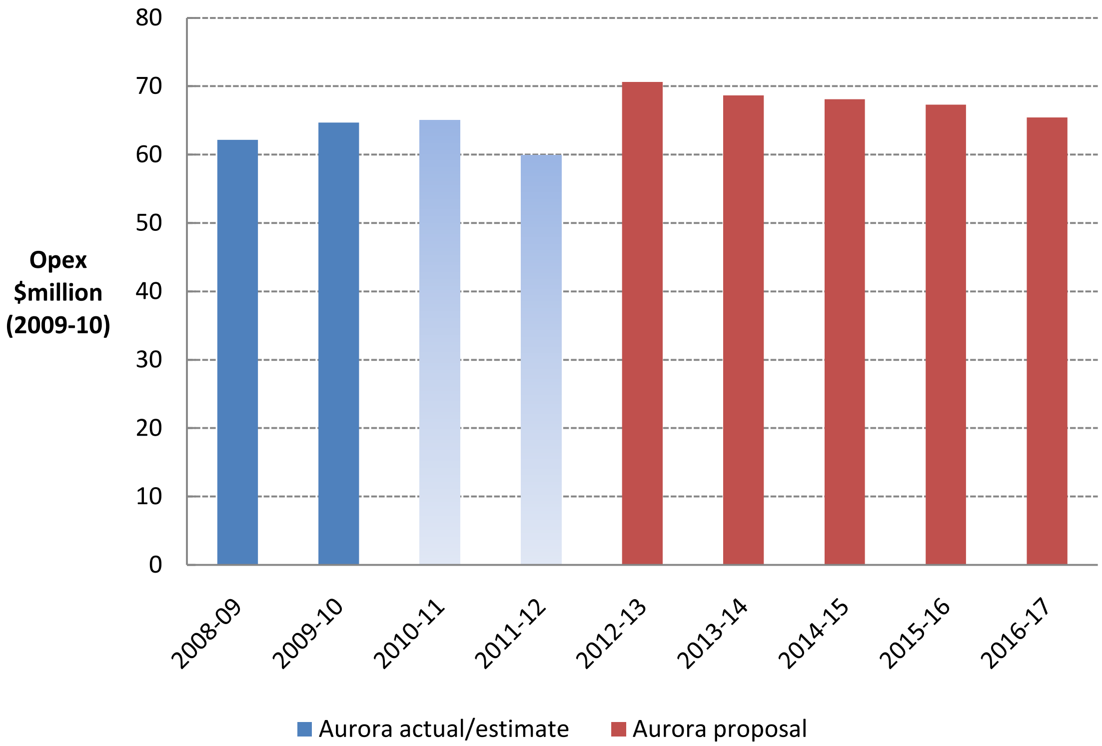
The AER removed non-recurrent costs to calculate Aurora's underlying recurrent costs. For example, regulatory submission costs have been removed because they do not occur evenly throughout the regulatory period. The AER recognises these costs will be incurred in the forthcoming regulatory control period, and an allowance is provided for these costs in the forecast as an opex step change. The process for adding these non-recurrent costs onto the AER's base year opex forecast is outlined in section 6.4.3 below.

The AER also adjusted Aurora's opex to exclude the movement in provisions. Removing the movement in provisions ensures reported opex includes only expenditure actually incurred and represents the underlying economic circumstances of a DNSP. This approach is consistent with that applied by the Essential Services Commission of Victoria in its 2006 electricity distribution price review (EDPR), and applied by the AER in setting the base opex of the Victorian DNSPs in its 2010 final decision.[576]

Figure 6.4 provides Aurora's opex by category excluding non-recurrent costs and adjusted for the movement in provisions for the previous and current regulatory periods. It also presents Aurora proposed total forecast opex.

[576] AER, *Final Decision: Victorian electricity DNSPs: Distribution determination 2011–2015*, 2010, pp. 336–347.

Figure 6.4 **Aurora's proposed opex against Aurora's current regulatory period costs which exclude non-recurrent costs ($million, 2009–10)**



Source: Aurora,[577] AER analysis.

Having assessed Aurora's historical cost, excluding non-recurrent costs and movements in provisions, the AER selected 2009-10 as the base year. The AER often uses the second last year of a regulatory period as the base year for two reasons. Firstly, the second last year is the last year for which the AER has audited regulatory accounts at the time it makes it final determination. Secondly, the EBSS sometimes assumes the second last year is used as the basis for setting opex forecasts.[578] At the time Aurora submitted its regulatory proposal, 2009-10 was the most recent year for which audited data was available. Audited data for 2010-11 only became available in October 2011, a month prior to the release of the draft decision. Because the AER considered it was necessary to conduct a detailed review of components of Aurora's base year expenditure, and audited regulatory accounts were not available at that time, the AER chose 2009-10 as the base year. That said, the AER considers that 2009-10 is a reasonably starting point for developing a base year opex forecast for Aurora for the forthcoming regulatory period.

The AER did not decide to conduct a detailed review of all categories of Aurora's opex. Instead, the AER reviewed those categories of opex where material increases had occurred in 2009-10 compared to the historic average.

The EUAA submission questioned the reasonableness of Aurora's forecast routine and non-routine maintenance opex.[579] The AER considers its detailed review investigated those areas of Aurora's

[577] Aurora, *Regulatory Information Notice.*

[578] The electricity transmission EBSS and previous jurisdictional schemes for the DNSPs in South Australia and Victoria both include this assumption. The AER's electricity distribution EBSS, however, provides more flexibility and allows other years to be used.

[579] EUAA, *Submission to the Australian Energy Regulator on Aurora Energy's regulatory proposal on distribution prices for 2012-17*, August 2011, p. 16.

routine and non-routine maintenance the AER considered were not reflective of the base level recurrent levels in setting its forecast for Aurora for the forthcoming regulatory control period. Specifically, the AER's detailed review investigated the non-routine maintenance category of emergency and unscheduled power system response and repair as well as the categories of vegetation management and other–maintenance which are both routine and non-routine maintenance.

The AER decided to conduct a detailed review of the following categories of opex:

- network management—direct expenditures
- network management—subcontractor expenditures
- emergency and unscheduled power system response and repair
- vegetation management
- other—maintenance.

Having considered these matters the AER has made the following adjustments.

Network management—direct expenditures

The AER considers the level of opex Aurora incurred in 2009-10 is reflective of the opex required for this particular year.[580] However, the AER does not consider the 2009-10 level is reflective of the recurrent levels of opex required for the forthcoming regulatory control period. In 2010-11 Aurora undertook a restructuring of network management services staff. Specifically, it reduced the number of full time equivalent (FTE) staff involved in the provision of network management services by 16 FTEs.[581] The AER considers this change in staff levels should be taken into account in order to set an appropriate base for recurrent costs over the forthcoming regulatory control period. The AER considers the number of FTEs allocated to standard control services for network management purposes after the 2010-11 restructure reasonable.

To determine the base level of recurrent opex, the AER considers an appropriate treatment is to scale the 2009-10 actual opex by the ratio of staffing levels before and after the restructure.[582] The AERs method is based on the assumptions that:

- labour costs are directly proportional to staffing levels
- materials and other costs include 25 per cent fixed costs, with the remaining 75 per cent of costs directly proportional to staffing levels.

Based on this approach the AER considers a reduction of $2.4 million from Aurora's network management expenditures in 2009-10 is appropriate. The AER considers this is reflective of the recurrent levels of network management—direct expenditures. The AER notes this level of opex is consistent with Aurora's estimated 2011-12 levels.

580 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 11–12.
581 Aurora, *Response to information request AER/042 of 27 September 2011*, received 4 October 2011, pp. 10–11.
582 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, p. 15.

Network management—subcontractor expenditures

Aurora identified some subcontractor expenditures relating to one-off expenditures which would not be expected to be incurred recurrently in the forthcoming regulatory control period.[583] The AER considers these one-off expenditures should be removed from its base year.[584]

In addition the AER considered the increased level of expenditure relating to the roll out of Aurora's Cable PI project would be reduced over the forthcoming regulatory control period.[585] Aurora noted the 2009-10 level of this expenditure reflects the increase in reported faults and call outs to address these faults associated with the Cable PI project.[586] Aurora noted it expects this expenditure to be reduced in the forthcoming regulatory control period as these faults are rectified. The AER agrees with this view.[587]

The AER removed the one-off expenditures to determine the recurrent base level opex for network management—subcontractor expenditure.[588] The AER has also reduced Aurora's 2009-10 Cable PI expenditures to reflect Aurora's forecasts of lower level activity for the forthcoming regulatory control period. This reduces Aurora's 2009-10 levels of actual opex for network management—subcontractor expenditures by $1.0 million. The AER considers this is reflective of the recurrent levels required for the forthcoming regulatory control period.

Emergency and unscheduled power system response and repair

Aurora noted the emergency and unscheduled power system response and repair opex has increased due to the increased severity and impact of storms and fires over recent years.[589] Specifically, the peak in 2009-10 expenditure is associated with severe storm activity. The AER notes that even when the costs of severe storm activity are excluded, this category of opex has still been increasing over recent years.[590]

The AER considers there are therefore two drivers of the increases in the 2009-10 actual expenditure:

- storm related activities
- processing issues

Storm related activities

Aurora has identified $4.9 million[591] of one-off costs in 2009-10 relating to non-recurrent storm related activities.[592] These events are considered severe by Aurora as they resulted in opex in excess of $0.5 million.[593] This trigger level has been set by Aurora.[594]

583 Aurora, *Response to information request AER/042 of 27 September 2011*, received 4 October 2011, p. 13.
584 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 19–20.
585 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 19–20.
586 Aurora, Response to information request AER/042 of 27 September 2011, received 4 October 2011, p. 13.
587 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 17–18.
588 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 19–20.
589 Aurora, Response to information request AER/022 of 4 August 2011, received 18 August 2011, p. 10.
590 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, p. 26.
591 The $4.9 million is a combination of Emergency and unscheduled power system response and repair opex and GSL Payment opex.
592 Aurora, *Regulatory Information Notice* templates, Table 2.9.2.
593 Aurora, Response to information request AER/022 of 4 August 2011, received 18 August 2011, p. 8.
594 Aurora, Response to information request AER/042 of 27 September 2011, received 4 October 2011, p. 14.

The AER considers the non-recurrent opex for this category of expenditure should be determined in line with the AER's service target performance scheme.[595] This scheme includes a trigger level for excluding major event days (MEDs). The trigger level is referred to as the 2.5 beta. The 2.5 beta methodology is a national standard and provides an assessment that is probability based.

From information provided by Aurora, the AER developed a probabilistic model to estimate the expected recurrent costs.[596] Based on the model estimates, the AER considers a reduction of $4.3 million should be made to the 2009-10 level of the emergency and unscheduled power system response and repair actual opex.

Processing issues

A major contributing factor to Aurora’s ongoing increases in this category of opex has been its existing process issues.[597] The AER’s analysis of these specific issues relied on confidential information to Aurora. These are discussed in Appendix H.

The AER notes Aurora's planned IT investments in the forthcoming regulatory control period should resolve these existing issues as well as provide the opportunity for improvements in this area.[598] However, the AER does not consider any adjustments should be made to Aurora's 2009-10 actual opex as there is no clear evidence these costs are inefficient.[599]

Vegetation management

Aurora noted the increases in vegetation management opex over the current regulatory period have been driven by work being undertaken for the management of 'overhang' in 'high' and 'very high' fire risk areas.[600]

The AER notes the 2009-10 level of vegetation management opex was the highest level of historical costs and 40 per cent higher then the level incurred in 2007-08.[601] The Energy Users Association of Australia (EUAA) also noted Aurora’s vegetation management opex has been a large proportion of its routine maintenance opex.[602]

In determining the 2009-10 recurrent base level, the AER has reviewed Aurora's:[603]

- vegetation management practices and criteria
- contracting arrangements
- recent cost increases.

Based on the AER's analysis, it considers Aurora's historical management of vegetation has resulted in 2009-10 costs above those which an efficient DNSP would have incurred given similar circumstances.[604] The AER considers Aurora had previously been advised that a change in its

595 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, p. 39.
596 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, Appendix A.
597 Aurora, *Distribution business issues register*, p. 3 (confidential).
598 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 37–38.
599 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 39–40.
600 Aurora, Response to information request AER/022 of 4 August 2011, received 18 August 2011, p. 10.
601 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 41–42.
602 EUAA, *Submission to the Australian Energy Regulator on Aurora Energy's regulatory proposal on distribution prices for 2012-17*, August 2011, p. 16.
603 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 44–54.
604 Nuttall Consulting*, Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 44–54.

vegetation management practices would result in medium to long term cost reductions. However, the AER considers a multiple of factors contributed to these change in practices not occurring. Aurora has claimed confidentiality over these factors. These are discussed in Appendix H.

The AER considers a prudent and efficient DNSP given the same historical circumstances could have incurred a much lower level of vegetation management opex in 2009-10, which would have resulted in a reduction in the order of $5.7 million in 2009-10.[605] However, in light of Aurora's current circumstances, the AER considers this reduction may be too large for Aurora to meet its ongoing obligations in the forthcoming regulatory control period.

The AER therefore considers it is more appropriate to allow Aurora the opportunity to transition to a best practice approach over the forthcoming regulatory control period rather than penalising it for its historical management decisions. Based on this approach, the AER considers a reduction of $0.4 million is reflective of the recurrent opex Aurora requires in accordance with the opex criteria in the forthcoming regulatory control period.[606] This reduction not only provides Aurora the ability to comply with its ongoing obligations but also provides Aurora the ability to achieve future cost reductions.[607]

Other—maintenance

Aurora's other–maintenance category of opex is consequently diverse in nature. The AER has reviewed the main expenditure items of this category of opex:[608]

- Power quality monitoring and investigation
- Oil management
- Repairs to fault indicators

Power quality monitoring and investigation

Aurora noted the power quality monitoring and investigation opex in 2009-10 increased due to increased customer initiated work as a result of Aurora's Cable PI program.[609] The Cable PI program is a proactive approach by Aurora to monitor and address steady state voltage.[610] Aurora noted its customer complaints regarding steady state voltage peaked over the 2009-10 period which resulted in a corresponding increase in network augmentation in response. Aurora's proposed movement from a reactive program to a proactive program in addressing steady state voltage should see a corresponding reduction in customer complaints.[611] However, Aurora has requested an increase in its forecast opex for the forthcoming regulatory control period for increased customer complaints.[612]

Based on the information provided by Aurora, the AER has not been able to justify the additional costs for Cable PI for this draft decision. In the absence of additional supporting information, the AER

605 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 53–54.
606 This reduction is based on GHD's review of Aurora's 2009-10 vegetation management which provides a perspective on Aurora's vegetation management and recommendations on future contracting arrangements. See: Aurora, *Response to information request AER/042 of 27 September 2011*, received 30 September 2011 and Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 53–54.
607 The AER is not able to quantify the cost reductions over the forthcoming regulatory control period by would anticipate Aurora to incur cost savings based on its transition to a best practice approach.
608 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 55–59.
609 Aurora, *Response to information request AER/042 of 27 September 2011*, received 4 October 2011, p. 18.
610 Aurora, *Regulatory proposal*, May 2011, p. 109.
611 Aurora, *Power quality management plan*, 2011, p. 11 (partially confidential).
612 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, p. 56.

has used the historical average for this draft decision. The AER therefore has made a reduction of $0.2 million to the 2009-10 levels of power quality monitoring and investigation actual opex.

Oil management

The AER expects variations in the annual level of oil management category of expenditure due to the differing oil volumes of the asset groups undergoing replacement or rehabilitation.[613] Based on Aurora's assets and Australian standards to dispose of oil and oil-contaminated assets, the AER considers the average expenditure of the previous six years provides for a sound basis for the recurrent level of opex required for the forthcoming regulatory period. The AER therefore has made a reduction of $76,000 to the 2009-10 levels of oil management actual opex.

Repairs to fault indicators and reclosers

The AER notes Aurora is forecasting expenditure relating to the repair of fault indicators and reclosers for years 2010-11 and 2011-12. However, the AER notes there is no separate cost category for these expenditures in Aurora's 2009-10 actual costs.[614] The AER considers as fault indicators and reclosers are relatively standard distribution equipment these assets are already included in Aurora's historic maintenance expenditure. Aurora has not provided any explanation as to why its forecast has separately identified these cost categories or whether these are new or relocated costs.

The AER considers if these are new costs then Aurora should have proposed them as opex step changes. Given Aurora has not requested these as step changes and the insufficient information provided in separately identifying these costs, the AER considers these are already included in Aurora's base year maintenance expenditure. Based on this analysis the AER has not made any further adjustments to the other–maintenance category of expenditure in relation to these costs.

6.4.3 Projecting the base year forward

The AER's base year forecast is $311.0 million ($2009–10) over the forthcoming regulatory control period. This excludes debt raising costs.

The AER has adjusted its starting point of recurrent costs by:

- accounting for network growth
- accounting for real costs escalation
- adding back non-recurrent costs
- adding back step changes.

Accounting for network growth

This section sets out the AER's estimated scale escalation allowance for Aurora. Aurora did not propose a scale escalation allowance in its total forecast opex. It used a bottom up approach to forecast its opex for the forthcoming regulatory control period.[615]

613 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, p. 58.
614 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, p. 58.
615 Aurora, *Regulatory proposal*, May 2011, p. 133.

The scale escalation allowance reflects the additional opex Aurora requires resulting from network expansion. To estimate the scale escalation allowance for Aurora, the AER:

- estimated scale escalators for Aurora based on forecast growth in customer connection numbers, line length, zone substation capacity and number of distribution transformers
- used Aurora's forecast growth rates for customer connection numbers, line length, zone substation capacity and distribution transformer numbers in the Regulatory Information Notice (RIN) to estimate its network growth[616]
- used the average of the Victorian DNSP's economies of scale (EOS) factors as an estimate of EOS for Aurora.

Table 6.7 sets out AER's determinations on Aurora's EOS and net scale escalators. Table 6.8 sets out the AER's estimate of the scale escalation allowance to be included in its forecast of Aurora's opex requirement for the forthcoming regulatory control period.

Table 6.7 AER draft determination on economies of scale and net scale escalator (per cent, per annum)

Expenditure category	Gross scale escalator	Economies of scale adjustment	Net scale escalator
Operating expenditure	1.0	72.9	0.3
Maintenance expenditure	1.2	33.8	0.8
Total	1.1	47.2	0.6

Source: AER analysis.

Table 6.8 AER draft determination on scale escalation ($million, 2009–10)

Expenditure category	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Operating expenditure	0.2	0.2	0.3	0.3	0.4	1.3
Maintenance expenditure	0.8	1.1	1.3	1.6	1.9	6.6
Total scale escalation allowance	0.9	1.3	1.6	1.9	2.2	7.9

Source: AER analysis.
Note: Totals may not add up due to rounding.

The AER must be satisfied the total forecast opex reasonably reflects a realistic expectation of the demand forecast required to achieve the opex objectives.[617] Aurora did not explicitly include a scale escalation allowance in the development of its total forecast opex.

As part of developing an alternative forecast of opex to compare with Aurora's proposal, the AER forecast how much Aurora's opex will need to change in response to changes in the size of the network.

The AER considers the approach of developing an alternative forecast is consistent with the approach adopted in its recent distribution determinations. In the Victorian distribution determination the AER

[616] Aurora has updated its customer connection numbers in the RIN. The AER has used the updated customer connection numbers for the calculation of scale escalation.
[617] NER, clause 6.5.6(c)(3).

estimated a scale escalation allowance for UED who did not explicitly include this allowance in the development of its forecast opex.[618] In terms of EOS adjustment, the AER applied the average EOS of other Victorian DNSPs for Jemena and UED, as they did not propose any EOS adjustment.[619]

The AER calculated gross scale escalators based on the forecast growth rate of Aurora's customer numbers and network size, then adjusted the gross scale escalators for EOS factors. The resultant net scale escalators are then multiplied by the base opex to calculate Aurora's scale escalation allowance. The AER considered this method is consistent with a total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required by a DNSP to achieve the opex objectives. This is because this method takes into account the growth in Aurora's core distribution assets and customer numbers. Therefore, it will likely result in forecast opex that closely reflects the actual growth in opex activity level.

The AER conducted an opex trend analysis to compare Aurora's actual price deflated opex with the historical growth rate of network size. It calculated Aurora's actual price deflated opex using the formula below:[620]

$$\Delta \text{ real opex} = (\Delta \text{ opex price} - \Delta\text{CPI}) + (\Delta \text{ output quantity} - \Delta \text{ opex PFP})$$

Where:

$$\Delta \text{ opex PFP} = \Delta \text{ identified efficiency gains} + \Delta \text{ unidentified efficiency gains}$$

$$= \text{EOS gain} + \text{technology efficiency gain}$$

The AER considers it appropriate to use this formula to examine the relationship between Aurora's actual opex and the size of its network because it identifies a change in actual opex which reflects both changes in net opex prices and changes in net output quantities. Conceptually, the growth in a DNSP's customer numbers, line length, number of transformers and system capacity reflect the growth in the DNSP's network output. In relation to the scale escalation method, the AER referred to these variables as the measurement of a DNSP's network size.

In terms of the impact of growth on the network size, removing the influence of opex input prices means the AER can narrow the resultant change in opex to the growth in the network size net of efficiency gains. The AER then compared the trend of the actual price deflated opex with the trend of the historical growth in network size. The AER noted the Essential Services Commission Victoria (ESCV) used this formula to determine the rate of change in opex for gas distributors.[621] The AER also adopted this formula to analyse opex trend in its Victorian distribution determination.[622]

Opex trend analysis (Figure 6.5) shows the growth rate for Aurora's actual price deflated opex is above the historical average growth rate for Aurora's customer connection numbers, line length, zone substation capacity and distribution transformer numbers. The level of Aurora's actual opex activities is thus growing at a faster rate than its network.

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618 AER, *Draft decision—appendices: Victorian electricity distribution network service providers: Distribution determination 2011–2015,* 2010, pp. 83 and 96; AER, *Final decision—appendices: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, 2011, pp. 176–178.

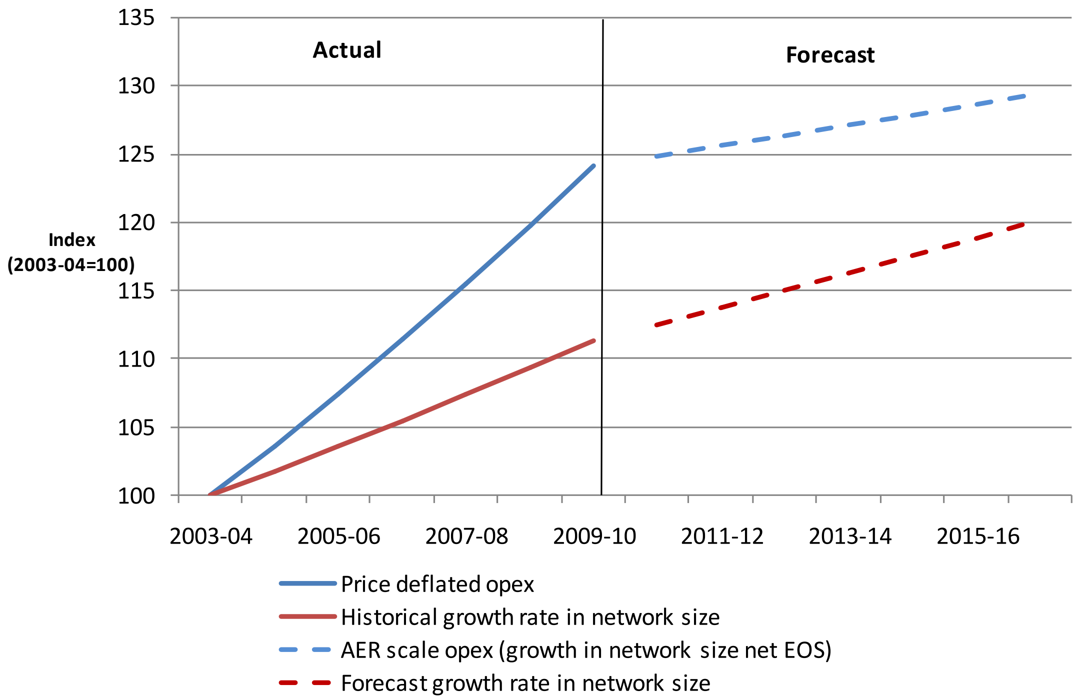
619 AER, *Final decision—appendices: Victorian electricity distribution network service providers: Distribution determination 2011–2015, 2010*, p. 212.

620 Δ opex PFP is the growth in partial factor productivity (PFP) for opex inputs.

621 ESCV, *Final decision—Gas access arrangement review 2008–2012*, March 2008, p. 224.

622 AER, *Final decision: appendices: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, 2010, p. 226.

Figure 6.5 Aurora opex trend analysis



Source: AER analysis.

However, the AER considers scale escalators based on forecast growth in Aurora's customer connection numbers, line length, zone substation capacity and number of distribution transformers is the best estimate of the growth rate for opex activities. The AER considers this approach will also reflect a realistic expectation of Aurora's demand forecast. The AER considers the level of activity required to maintain Aurora's asset base will grow proportionally with the volume and capacity of these core assets. It thus considers a composite scale escalator based on the volume and capacity of these assets provides a good estimate of the growth in Aurora's maintenance expenditure.

Further, the AER considers Aurora's operating activity levels will grow as its customer base expands. It thus considers the growth in Aurora's customer connection number provide a good estimate of the growth in its opex. This approach is consistent with recent AER distribution determinations, including the Victorian distribution determination and the South Australian (ETSA Utilities) distribution determination.[623]

The AER applied the average of Victorian DNSP's EOS determined in the Victorian distribution determination to Aurora. The opex trend analysis in Figure 6.5 indicates Aurora has not achieved any efficiency gains over the period 2003-04 to 2009-10. As discussed above, the actual price deflated opex reveals growth in the network size and any efficiency gains achieved during a particular time period. Given Aurora's actual price deflated opex is growing at a rate above that of its network size, Aurora's efficiency gains during this period have been negative. Benchmark Economics stated few

623 AER, *Final decision: appendices: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, 2010, p. 226 and AER, *Draft decision, South Australia Draft distribution determination 2010–11 to 2014–15*, 25 November 2009, pp. 213–214.

EOS gains may be achievable by Aurora because Aurora's network is relatively small compared with other distribution networks in Australia.[624]

The AER adjusted the gross scale escalators for each expenditure category for EOS in recognition of the cost advantage Aurora will obtain due to network expansion. It calculated the net scale escalators using the following formula:

Net scale escalator = gross scale escalator × (1 – economies of scale)

This formula recognises total forecast opex will grow at a slower rate than the size of the network. This outcome is reflective of the EOS a network business experiences as the size of its network and operations increase.

In its assessment of Aurora's base year expenditure the AER considered which DNSPs were close comparators of Aurora based on network density and size. It considered Powercor and SP AusNet were the closest comparators in the NEM. However, in determining the appropriate EOS to apply to the gross scale escalators, the size of the comparator DNSPs is more significant. As a DNSP grows its fixed costs will comprise a smaller proportion of its total costs, reducing the EOS gains that can be achieved through further expansion. This can be seen in Table 6.9, where the larger DNSPs (Powercor and SP AusNet) have larger EOS factors. Consequently, the AER considers the EOS factors of Powercor and SP AusNet will understate the EOS that can be achieved by Aurora because it is a considerably smaller network.

Aurora is similar in size to CitiPower and Jemena. However, these two DNSPs are significantly denser than Aurora. On average Aurora's network scale and density are comparable to the average network scale and density of the Victorian DNSPs. The AER thus considers an average of the Victorian DNSPs' EOS is the appropriate EOS for Aurora (Table 6.9).

Table 6.9 AER conclusion on economies of scale for Victorian DNSPs (per cent, per annum)

DNSP	Operating expenditure	Maintenance expenditure
CitiPower	72.8	25.1
Powercor	73.0	35.9
Jemena	72.9	33.8
SP AusNet	N/A	40.3
United Energy	72.9	33.8
Average	72.9	33.8

Source: AER,[625] AER analysis.
Note: The AER did not apply any scale escalation to SP AusNet's operating expenditure in the final Victorian distribution determination. Therefore, the average EOS for operating expenditure is based on the EOS for CitiPower, Powercor, Jemena and United Energy.

624 Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, pp. 43–45.
625 AER, *Final decision: appendices: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, 2010, p. 221.

Application of real cost escalators

Aurora's proposed real cost escalation of $1.6 million ($2009–10) accounts for less than one per cent of Aurora's total forecast opex (including real cost escalation).[626] To assess Aurora's proposal and determine its substitute total forecast opex, the AER applied real cost escalation to the components of opex it considers would increase in cost at a different rate than CPI. The AER has determined a weighted real cost escalator from the proportions of labour and materials in Aurora's opex forecasts and the forecast real cost increases in labour and materials. The AER considered that, on balance, the labour and materials escalators proposed by Aurora were reasonable (see attachment 4) and it has applied these to determine the impact of real cost increases in Table 6.10.

Table 6.10 AER draft determination on real cost escalation ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Aurora's proposal	0.4	0.5	0.6	0.5	0.4	
Adjustment	0.4	0.4	–0.2	–0.8	–0.9	
AER draft determination	0.8	0.9	0.4	–0.3	–0.5	

Source: AER analysis.

Non-recurrent costs

The AER considers that some costs included in Aurora's past opex are non-recurrent. These non-recurrent costs are those which are out of Aurora's control or do not occur evenly across the regulatory period.

Table 6.11 presents the AER's draft determination of the non-recurrent costs Aurora should be permitted in the forthcoming regulatory control period.

Table 6.11 AER draft determination of Aurora's non-recurrent opex ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17
GSL Payments	1.868	1.887	1.907	1.927	1.947
ESIS Levy	2.209	2.222	2.235	2.248	2.261
NEM Levy	0.342	0.344	0.346	0.348	0.350
NEM and contestability	2.321	2.334	2.348	2.362	2.375
Regulatory submission	–	–	0.477	0.920	0.928
Movement in provisions	–	–	–	–	–
Debt raising costs	0.758	0.769	0.779	0.788	0.798

Source: AER analysis.
Note: The debt raising costs allowance is discussed below.

[626] Aurora, *Regulatory Iinformation Notice,* template 2.11.

The AER has removed non-recurrent costs from the base year as they are not reflective of future ongoing costs. However, in most cases Aurora will incur some costs in relation to these activities in the future. In recognition of these future costs, the AER has provided an allowance more reflective of their ongoing recurrent levels in its forecast allowance. In most cases the AER undertakes this by using historical averages. Each of these costs is considered individually below.

GSL payments

Due to severe weather and storm events, Aurora experienced an increase in opex in 2009-10 relating to GSL payments. As this increase is not expected to occur in every year, the AER has removed the GSL payments from its base year approach. To recognise the recurrent level of future GSL payments going forward the AER has estimated an allowance based upon a probabilistic model from Aurora's outage and cost data.[627] The AER forecast allowance is $1.9 million ($2009-10) per annum in the forthcoming regulatory control period.

Electrical safety inspection services (ESIS) levy and the national electricity market (NEM) levy

There is a legislative requirement requiring Aurora to pay levies in relation to its involvement in electrical safety inspection services and Tasmania's participation in the national electricity market.[628] As these costs are imposed upon Aurora, it has limited ability to control these costs. Due to the variability of these imposed costs, any given year of actual opex is not necessarily reflective of its future costs.

In recognition of the costs to be incurred by Aurora for these levies in the forthcoming regulatory control period, the AER has provided a forecast allowance based on historical averages and applied growth escalation.[629] The AER notes the draft determination control mechanism for Aurora contains a revenue adjustment mechanism to account for any difference between allowed and actual costs for these opex components. The AER forecast allowance is $2.2 million and $0.3 million ($2009-10) respectively per annum in the forthcoming regulatory control period.[630]

NEM and contestability related costs

Aurora's historical opex includes costs relating to its participation in the NEM and introduction of retail contestability into Tasmania. Aurora groups these cost components together. The AER notes these costs have not been incurred evenly across the previous and current regulatory periods. The level of these costs in the forthcoming regulatory control period is ultimately dependent on the Tasmanian Government's decision regarding the roll out of full retail contestability. As discussed in its control mechanism attachment, the AER's draft determination will not include a revenue adjustment mechanism relating to the additional forecast costs. Rather, if Aurora should incur these additional costs in the forthcoming regulatory control period then Aurora may apply for a general pass through.

Further, the AER considers the recurrent level of these cost components should already be included in Aurora's historical costs. Aurora joined the national electricity market in 2005 and therefore all Aurora's ongoing recurrent costs should already included in the fabric of its day to day business.

627 Nuttall Consulting, *Operating expenditure base-line: A report to the AER*, 28 October 2011, pp. 21–24 and Appendix A.
628 Electricity Supply Industry Act 1995 (Tas) (ESI Act)
629 A five year historical average the electrical safety inspection service and a three year historical average for the national electricity market levy (NEM levy). The NEM levy only uses a four year average as Aurora have only incurred these levies since 2006–07.
630 Based upon information provided in Aurora's regulatory information notice templates.

Retail contestability has been gradually phased in by Aurora over the last two regulatory periods. The AER considers the bulk of these costs should too be included in the fabric of its day to day business.

Based on these factors the AER considers the increase in these costs in 2009-10 is above recurrent levels. Therefore, the AER has removed them from its base year. In recognising the recurrent levels of these costs, the AER has provided a forecast allowance based upon a five year historical average of Aurora's actual costs and applied growth escalation. The AER forecast allowance is $2.3 million ($2009-10) per annum in the forthcoming regulatory period.[631]

Regulatory submission costs

Aurora incurs an increase in opex towards the end of the current regulatory period relating to its preparation of its regulatory submission. As these costs do not occur evenly throughout a regulatory period, the AER has removed them from its base year approach. Aurora has forecast regulatory submission costs of $2.3 million ($2009-10) in the forthcoming regulatory control period. This is more than a million dollars less than Aurora's expected regulatory submission costs in the current period of $3.4 million ($2009-10). These costs benchmark well against those of the Victorian DNSPs. For Victorian DNSPs the AER took into account the benchmark firm and actual costs and determined these reasonably reflected the opex criteria.[632] As such the AER considers Aurora's proposed costs reflect the prudent and efficient costs of providing distribution services. Based on this, the AER has accepted Aurora's forecast costs as a step change.

Movement in provisions

Aurora's opex includes provisions. A provision is a liability of uncertain timing or amount.[633] Provision accounts are used to set aside amounts for the payments of these liabilities for when they arise for settlement. A movement in provision occurs when the annual amount set aside differs to the annual amount paid out. The AER considers the movement in these provisions represent non-recurrent costs and therefore removed them from the base year.

The AER has reversed the movement in provisions relating to Aurora's 2009-10 opex. The reversal of the movement in provisions more appropriately recognises the amount of provisions paid out rather than the amount of provisions Aurora reported. This reversal could be either a negative or positive movement in the base year. The AER considers this necessary in setting its allowances for Aurora on the basis that movement in provisions:

- may be used to represent the reported accounts of Aurora differently from its underlying economic circumstances
- may prevent and distort the comparison of Aurora on a consistent basis from year to year
- can be affected by a change in accounting standards despite expenditure remaining the same.

Based on the above, the AER considers the reversal of the movement in provisions produces a base level of expenditure that is more suitable for regulatory purposes. This is important for calculating EBSS carryover adjustments for Aurora's forthcoming regulatory control period.

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[631] Based upon information provided in Aurora's regulatory information notice templates.
[632] AER, *Final decision: appendices: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, 2010, Appendix L, p. 340–343.
[633] AASB, *137: Provisions, contingent liabilities and contingent assets*, section 10.

Debt raising costs

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 has made an adjustment to remove actual costs from its base year. This adjustment reflects the AER's view on the proportion of the distribution related expenditures Aurora incurs for its debt refinancing. The AER forecast allowance is $3.9 million ($2009-10) per annum in the forthcoming regulatory period. For detail of the cost build up of this benchmark see section 6.4.4 below.

Step changes

In addition to its business as usual activities, Aurora has proposed to undertake a new program of opex in the forthcoming regulatory control period. This opex relates to activities to minimise the impact of peak demand on is distribution network and to defer capital expenditure as a result of increases in system demand.[634] As this is a new program of expenditure it is not reflected in the historical costs in Aurora's base year.

This opex is in addition to the expenditure Aurora proposed to undertake in accordance with the AER's demand management incentive scheme (DMIS). Aurora's expenditure under the DMIS is to gain an insight into non-network opportunities and develop experience in implementing demand management initiatives. Aurora's proposed demand management step change opex is presented in Table 6.12.

Table 6.12 Aurora's proposed for step change opex ($million, 2009–10)

	2012-13	2013-14	2014-15	2015-16	2016-17
Demand management opex	0.891	0.411	0.501	0.746	0.786

Source: Aurora.[635]

Table 6.13 presents the AER's draft determination of Aurora's demand management step change opex allowance.

Table 6.13 AER draft determination of Aurora's step change opex ($million, 2009–10)

	2012–13	2013–14	2014–15	2015–16	2016–17
Step change opex	0.391	0.421	0.511	0.656	0.746

Source: AER analysis.

The AER recognises Aurora may be subject to new (or changed) regulatory obligations or changes in its operating environment (termed 'step changes') impacting on its opex in the forthcoming regulatory control period. As step changes are new requirements, forecasts cannot be based upon historical costs. The AER's approach is to review Aurora's forecasts of step changes individually against the opex criteria taking into account the opex factors.[636] Where the AER considers these step changes meet the requirements of the NER, these specific costs are added to the total forecast opex.

[634] Aurora, *Regulatory proposal*, 31 May 2011, 144.
[635] Aurora, *Regulatory proposal*, May 2011, p. 144.
[636] NER, clause 6.5.6(c). Clause 6.5.6(e) specifies the opex factors.

Demand management step changes

The AER has reviewed Aurora's proposed demand management incentive programs and considers most satisfy the opex criteria and objectives. The majority of these programs are location-specific projects for non-network solutions including capex deferrals, residential and small business load response project and the development of a curtailable/distributed generation program with large commercial and industrial customers.[637]

The AER is satisfied the following proposed expenditure reasonably reflects the efficient costs of a prudent DNSP:

- Residential and small business load response project
- Demand management training
- Blackmans Bay zone substation deferral
- Sandford zone substation deferral
- Curtailable/DG program with large C&I customers
- Community & stakeholder engagement - material and external costs
- Bridgewater/Austins Ferry zone substation deferral
- Wyndard station deferral.

In coming to this view, the AER had regard to the extent Aurora has considered, and made provision for, efficient non-network alternatives and the substitution possibilities between operating and capital expenditure.[638]

However, the AER identified three studies it considers are an extension of Aurora's demand management incentive allowance (DMIA) allowance. These studies are:[639]

- Load control architecture study
- Power factor correction study
- Residential and small business hot water study

Aurora acknowledges the proposal for each of these step changes are additional funding to support studies to be attained through the AER's demand management incentive allowance (DMIA).[640] The AER considers to approve these costs therefore would be to increase the DMIA. The AER notes the DMIA is a capped amount based on the relative size of a DNSP's average annual revenue allowance

637 Aurora, *Management plan 2011: Demand management*, 23 February 2011 and Aurora, *Response to information request AER/011 of 21 July 2011*, received 29 July 2011.

638 NER, clauses 6.5.6(c)(1), (2); 6.5.6(a)(2), 6.5.6(e)(1), (3) and (10).

639 Aurora, *Response to information request AER/011 of 21 July 2011*, received 29 July 2011, pp.2–3.

640 Aurora, *Response to information request AER/011 of 21 July 2011*, received 29 July 2011, pp.2–3.

in the previous regulatory period.[641] The AER considers the DMIA allowance set for Aurora is appropriate based on its view of customer's willingness to pay.[642]

The AER considers the primary source for demand management expenditure should be the forecast opex and capex approved by the AER in a DNSP's distribution determination. The DMIS is provided to DNSPs as a mechanism to encourage the consideration of more innovative, perhaps untested, non-network alternatives and research and development projects. The AER considers these studies fall into this category. As stated, this consideration is supported by Aurora who proposed that these studies are to support the DMIA projects.[643]

Based on this, the AER considers the costs of these studies are in excess of the benchmark opex a DNSP would require in the provision of standard control services.[644] The AER considers these studies are more appropriately provided through the DMIS rather than as a step change to Aurora's forecast opex. Therefore the AER considers these studies do not meet the requirements of the NER.[645]

In addition, the AER notes in attachment 13 that Aurora will incur additional opex in the forthcoming regulatory control period relating to its reporting requirements of its DMIS activities.[646] These costs will not be in Aurora's current or historical costs as this is a new requirement in the forthcoming regulatory control period. The AER considers Aurora's forecast costs relating to these reporting requirements are reasonable. Therefore the AER will provide for these additional costs as a step change.

6.4.4 Debt raising costs

Debt raising costs are costs which are incurred each time debt is raised or refinanced. These costs may include underwriting fees, legal fees, company credit rating fees and other transaction costs. Debt raising costs are a legitimate expense for a benchmark efficient operator and an allowance should be provided to recover these costs.

Aurora proposed a benchmark debt raising unit cost of 9.4 basis points per annum (bppa) to be applied to the debt component of the regulatory asset base (RAB) of $720 million (2009–10). Aurora is required to raise three standard sized bond issues which results in a total allowance of $0.7 million ($2009–10) for debt raising costs.[647]

The AER accepts Aurora’s proposed debt raising costs and the method used to calculate this allowance. The AER has further updated the input costs for debt raising costs. This update results in a benchmark debt raising unit cost of 9.5 bppa.

Table 6.14 AER's draft determination of on debt raising costs ($million, 2009–10)

Unit Rate	2012–13	2013–14	2014–15	2015–16	2016–17	Total
9.5 bppa	0.80	0.81	0.82	0.83	0.84	4.10

Source: AER analysis.

641 AER, *Demand management incentive scheme: Aurora energy regulatory control period commencing 1 July 2012*, October 2011, p. 4.
642 AER, *Final framework and approach paper: Aurora energy pty ltd regulatory control period commencing 1 July 2012*, 29 November 2010, pp. 131–132.
643 Aurora, *Response to information request AER/011 of 21 July 2011*, received 29 July 2011, pp. 2–3.
644 NER, clause(e)(4).
645 NER, clause 6.5.6(c)(1) and (2).
646 Aurora, *Regulatory proposal*, May 2011, pp. 206–207.
647 Aurora, *Information clarification Aurora response to questions raised by the AER*, p. 15, June 2011.

The revenue and pricing principles under the NEL set out that each operator should be provided with a reasonable opportunity to recover at least its efficient costs.[648] Also relevant is the potential for under or over investment, a matter that is particularly relevant to debt raising costs.[649] The opex criteria require that the total forecast opex reasonably reflects the efficient costs and the costs that a prudent operator would require.[650] Further, the forecast opex is assessed with regard to, among other things, the benchmark opex that would be incurred by an efficient operator over the forthcoming regulatory control period.[651]

The AER is required to assess Aurora's proposal for debt raising costs with regard to the relevant criteria and objectives under the NER. In assessing a DNSP's proposal for debt raising costs, the AER has relied on an approach based on the 2004 Allen Consulting Group (ACG) report commissioned by the ACCC.[652]

The ACG method involves two key steps. First, it identifies the types of transaction costs that an efficient and prudent operator would incur in raising debt. Second, it quantifies the level of these costs, taking into account the specific circumstances of the operator, with reference to market rates for the relevant services. The AER considers this method estimates the prudent and efficient debt raising costs likely to be incurred by a benchmark efficient operator. This should, in turn, provide a forecast for debt raising costs consistent with the opex criteria under clause 6.5.6 of the NER and the revenue and pricing principles under the NEL.

The ACG method involves calculating the benchmark bond size, and the number of bond issues required to rollover the benchmark debt share (60 per cent) of the RAB. The allowance for debt raising costs is based on the direct costs of raising debt, such as underwriting fees, legal fees and credit rating fees. The AER's standard approach is to amortise the upfront costs that are incurred using the relevant nominal vanilla WACC over a ten year amortisation period. This is then expressed in bppa as an input into the post tax revenue model (PTRM).

The AER has refined this approach by updating the individual costs over time and using a five year window of up to date bond data to reflect current market conditions. The AER most recently updated the individual costs in the 2009 South Australia and Queensland electricity distribution determinations.[653] For this determination the AER made further updates to certain inputs to reflect current costs.

Benchmark debt raising costs

The AER has applied the updated cost inputs to its method for determining benchmark debt raising costs and has estimated the indicative costs and total allowance for Aurora. The AER has made changes to Aurora's RAB value. As a result, this has changed the debt component of the RAB and Aurora is now required to raise four standard sized bond issues. The unit costs and the benchmark debt raising cost are shown in Table 6.15. As this draft determination is based on indicative rates, the

648 For electricity, this means efficient costs associated with direct control network services and regulatory obligations; see NEL, section 7A.
649 NEL, s.7A(6).
650 NER, clauses 6.5.6(c)(1) and 6.5.6(c)(2).
651 NER, clause 6.5.6(e)(4).
652 ACG, *Debt and equity raising transaction costs - Final Report*, December 2004. The AER has applied this approach to assess debt raising costs in all its determinations.
653 AER, *Draft decision – Appendices South Australia draft distribution determination 2010–11 to 2014–15*, November 2009, p. 527; and AER, *Draft decision – Appendices Queensland draft distribution determination 2010–11 to 2014–15*, November 2009, p. 733.

AER will update this analysis for the final decision based on the debt component of the RAB and WACC to be determined at the time.

Table 6.15 AER's indicative debt raising cost for Aurora based on a nominal WACC of 8.08 per cent

Fee	Explanation	1 issue	2 issue	4 issue
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	6.73	6.73	6.73
Legal and road show	$195,000 upfront per issue, amortised	1.17	1.17	1.17
Company credit rating	$55,000 per annum	2.20	1.10	0.55
Issue credit rating	4.5 basis points upfront per issue, amortised	0.67	0.67	0.67
Registry fees (initial)	$4,000 up front per issue, amortised	0.02	0.02	0.02
Registry fees (annual) (previously labelled Paying Fee)	$9,000 per issue per annum	0.36	0.36	0.36
Total	Basis points per annum	11.2	10.1	9.5

Source: AER analysis.

For the reasons outlined above, the AER considers its preferred method for calculating an allowance for debt raising costs will approximate the prudent and efficient costs likely to be incurred by a benchmark efficient operator. This, in turn, provides a forecast for debt raising costs consistent with the opex criteria under clause 6.5.6 of the NER and the revenue and pricing principles under the NEL. Aurora has applied the AER's preferred method to calculate an allowance for debt raising costs. Accordingly, the AER considers Aurora's proposal satisfies the revenue and pricing principles under the NEL and the relevant criteria under the NER.

The AER has updated certain costs to reflect current market conditions.[654] Applying the draft decision WACC of 8.08 per cent, the AER has estimated a benchmark debt raising unit cost of 9.5 bppa.

The AER considers the benchmark debt raising unit cost of 9.5 bppa reflects the efficient and prudent costs for current market conditions and has applied this value for 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 $3.89 million (2009–10) for debt raising costs.

654 The AER updated legal and road show fees, issue credit rating fees and registry fees.

6.4.5 The AER's forecast of shared costs

This section presents the AER's review of shared costs attributable to alternative control services and capital expenditure. Shared costs are costs that cannot be directly attributed to a single service (direct control and unregulated) that Aurora provides.[655] Before Aurora submitted its regulatory proposal the AER approved Aurora's Cost Allocation Method (CAM).[656] Aurora's CAM specifies Aurora's shared costs and how they are to be allocated to the direct control services that Aurora provides.

The AER has approved Aurora's forecast allowance of total shared costs attributable to alternative control services and capital expenditure.[657]

The NER requires Aurora to prepare forecasts of expenditure for standard control services in accordance with its approved CAM.[658] To comply with this requirement Aurora has forecast its shared costs and allocated them to direct control services accordance with its CAM. Aurora used its budgeting and forecasting system to forecast shared cost line items. Aurora then allocated these forecast line items in accordance with the principles and policies in Aurora's CAM. Figure 6.6 presents Aurora's forecast shared costs for standard control services capex and alternative control services. Aurora's forecast of shared costs for opex has been included in the AER's base year approach analysis. Aurora's forecasts of shared costs allocated to distribution services is about $5 million lower in real terms than actual shared costs in the current regulatory period.

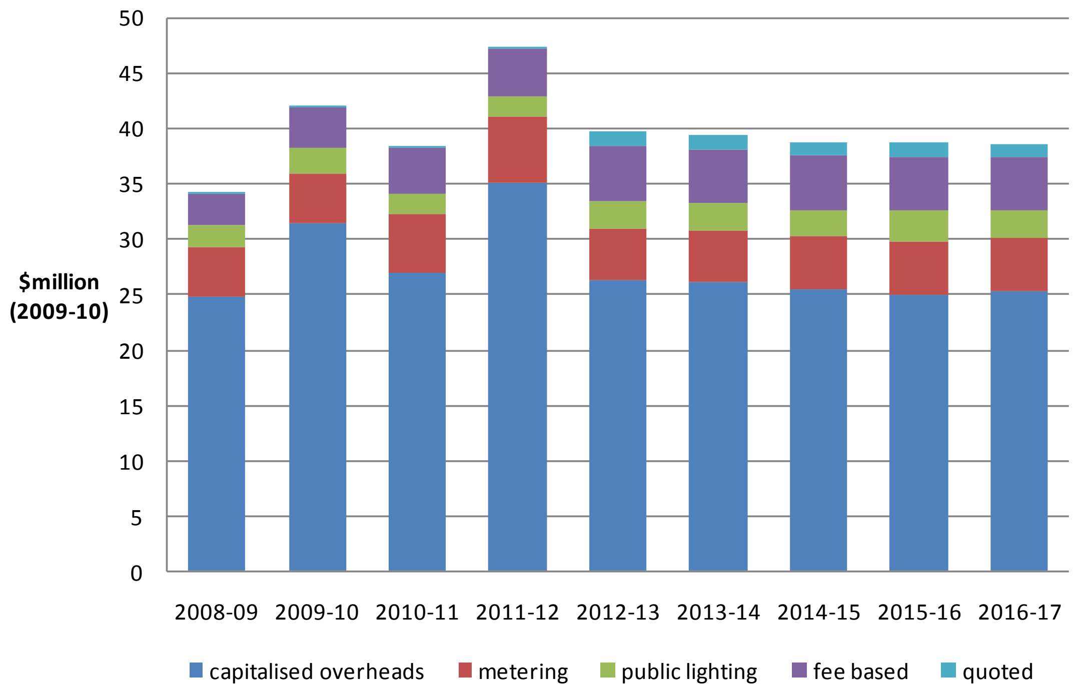
[655] The NER provides that the AER can classify distribution services as being direct control services or negotiated services. Services not classified by the AER are not regulated under the chapter 6 rules. The AER must then classify direct control services as standard control services or alternative control services. The AER must make a building block determination for standard control services whereas the AER has a greater deal of flexibility in regulating alternative control services. Negotiated services not price regulated. The AER classified new public lighting technologies as being negotiated services for Aurora. Aurora has not forecast that it will provide any new public lighting technology in the forthcoming regulatory control period.

[656] AER, *Final decision: Aurora Energy: Proposed Cost Allocation Method amendment*, May 2011.

[657] See attachments 6 (capex) and 17 (alternative control).

[658] Clause 6.5.6(b)(2) and 6.5.7(b)(2) provide that capex and opex forecasts be for expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in the CAM for the DNSP.

Figure 6.6 Aurora's forecast and actual shared costs allocated to capex and alternative control services ($million, 2009–10)



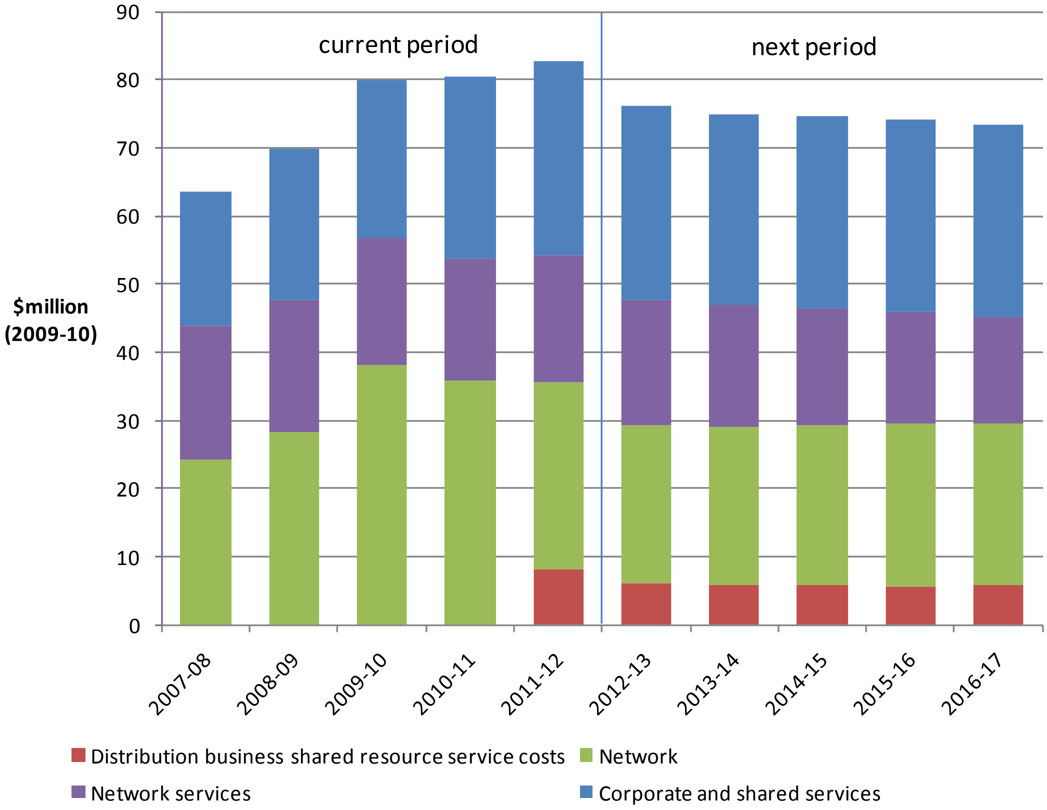
Source: Aurora.[659]

Aurora's proposed forecast total shared costs are presented in Figure 6.7. These forecast shared costs are derived from four different sources:

1. Aurora's corporate and shared services division incorporating:
   - The CEO
   - Commercial services
   - Strategy and corporate affairs
   - People and culture
   - Governance
2. Aurora's network division management costs
3. Aurora's network services division management costs
4. Shared resource costs between network and network services. This is a new business division developed to manage shared costs shared between network and network services.

[659] Aurora, *Regulatory information notice templates,* Aurora, *Response to information request AER/038 spreadsheet of 1 September 2011*, received 7 September 2011.

Figure 6.7 Aurora's Total historical and forecast shared costs by source ($million, 2009–10)



Source: Aurora.[660]

Of the four sources of shared costs, one is attributable to the whole of Aurora's business and three are predominantly attributable to Aurora's network divisions. The corporate and shared services costs are attributable to Aurora's business as a whole. These costs have driven the increase in Aurora's total shared costs in the current regulatory period. Aurora's business has experienced significant change over the previous few years which will have influenced these costs.

While the AER cannot form a view about Aurora's alternative control shared costs and capitalised standard control shared costs in total, it can review shared costs as they relate to Aurora's forecast capex and alternative control service costs. The rules pertaining to proposed capex and opex mirror each other. As such, a review approach that satisfies the opex requirements would also satisfy the capex requirements. The base year approach has been used to review Aurora's forecasts of opex costs. If shared costs are similar in nature to opex costs the same approach will also be appropriate. Both shared costs and opex costs are recurrent costs. Therefore the same approach is appropriate.

Aurora's CAM specifies which costs are attributable to Aurora's direct control services and how they are to be allocated between these services. The AER has previously reviewed and approved Aurora's CAM prior to the submission of Aurora's regulatory proposal.[661] As a result, the AER's review of Aurora's shared costs does not consider whether the costs are attributable to Aurora's direct control services and how these costs are to be allocated.

660 AER, *Response to information request AER/038 of 1 September 2011*, 7 September 2011.
661 AER, *Final decision: Aurora Energy: Proposed Cost Allocation Method amendment*, May 2011.

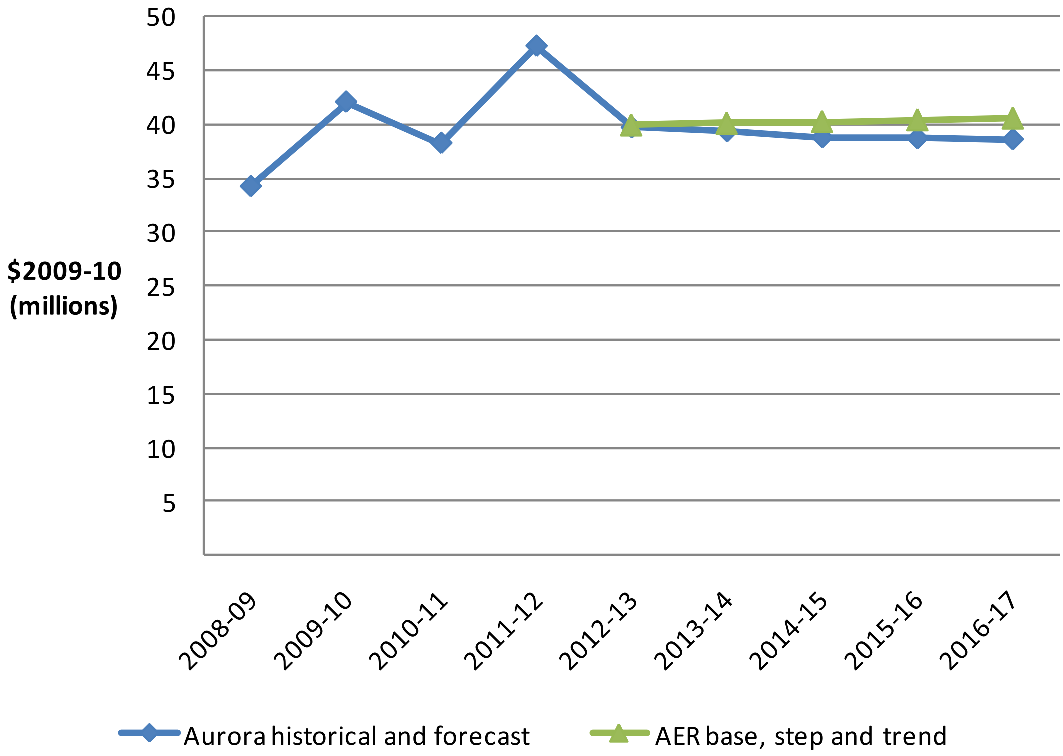
The factors under clause 6.2.5(d) of the NER govern the choice of the form of control for alternative control services and also apply to the basis by which the form of control is calculated. The AER considers a base year approach for alternative control services satisfies the alternative control factors. This approach would generate cost reflective prices for alternative control services as the shared costs are based on actual historical costs incurred. This is discussed in the AER approach section in the alternative control services attachment (attachment 15).

Base year approach to reviewing shared costs allocated to capex and alternative control services

As outlined in section 6.3.2, the AER's approach is to apply the same base year forecast used to assess Aurora's opex to review shared costs allocated to standard control services capex and alternative control services.

The AER's forecast of Aurora's shared costs is presented in Figure 6.8. This demonstrates that Aurora's forecasts of shared costs compare favourably against the base year approach.[662]

Figure 6.8 Aurora's historical and forecast capex and alternative control shared costs compared with base year approach forecasts ($million, 2009–10)



Source: Aurora.[663]

662 The AER applied the same assumptions in forecasting Aurora's shared costs as it did in forecasting Aurora's opex costs using the base year approach. Hence the same base year, input cost escalations and scale escalations have been applied.

663 Aurora, *Response to information request AER/038 of 1 September 2011*, received 7 September 2011.

6.5 Revisions

Revision 6.1: The AER has revised Aurora's total forecast opex for the forthcoming regulatory control period by $29.1 million. The AER's substituted forecast is $311.0 million.

7 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.[664] 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.[665]

7.1 Draft determination

The AER has determined the opening RAB as at 1 July 2012 to be $1439.0 million ($nominal). This differs from Aurora's proposal due to differences in indexation. 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. The AER forecasts the RAB to be $1740.8 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 start of the forthcoming regulatory control period, is shown in Table 7.1. The AER's forecast roll forward of the RAB during the forthcoming regulatory control period is shown in Table 7.2.

[664] NER, clause 6.12.1(6).
[665] NER, clause 6.12.1(18).

Table 7.1 AER conclusion on Aurora's RAB for the current regulatory control period ($million, nominal)

	2006–07	2007–08	2008–09	2009–10	2010–11[a]	2011–12[b]
Opening RAB	908.2	984.1	1,056.7	1,163.4	1,257.9	1,378.7
Capital expenditure[c]	111.7	104.7	127.5	140.3	158.5	141.2
CPI indexation on opening RAB	18.8	29.1	39.0	24.5	33.3	37.9
Straight-line depreciation[d]	–51.3	–61.3	–59.8	–70.3	–71.1	-73.1
Closing RAB	984.1	1,056.7	1,163.4	1,257.9	1,378.7	1,484.7
Difference between forecast and actual capex (1 July 2006 to 30 June 2007)						–21.8
Return on difference for 2006–07 capex						–11.4
Adjustment for shared assets						–12.5
Opening RAB as at 1 July 2012						1,439.0

Source: AER analysis.
(a) Based on estimated capex. The asset base roll forward will be updated for actual capex at the time of the AER final decision.
(b) Based on estimated capex and forecast inflation. The asset base roll forward will be updated for actual CPI at the time of the AER final decision. However, the update for actual capex will be made at the next reset.
(c) Net of disposals and capital contributions, and adjusted for actual CPI and WACC.
(d) Adjusted for actual CPI.

Table 7.2 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	1,439.0	1,497.2	1,554.3	1,613.9	1,675.7
Capital expenditure[a]	104.8	110.1	108.6	104.0	107.2
Inflation indexation on opening RAB	37.7	39.2	40.7	42.3	43.9
Straight-line depreciation	–84.2	–92.2	–89.8	–84.5	–86.0
Closing RAB	1,497.2	1,554.3	1,613.9	1,675.7	1,740.8

(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 has accepted Aurora's proposed approach 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.

7.2 Aurora's proposal

Aurora proposed to use an opening RAB of $908.2 million as at 1 July 2006 to roll forward and establish an opening RAB of $1,447.6 million ($nominal) as at 1 July 2012, the start of the forthcoming regulatory control period. It also forecast the RAB to be $1,894.6 million ($nominal) as at 30 June 2017, the end of the forthcoming regulatory control period.

In its roll forward assessment, Aurora started by adopting the value of $981.1 million ($2006–07) as at 1 January 2008 (in July 2006 dollars), which was set out in the NER.[666] However, Aurora made several adjustments to this value. In particular, Aurora updated forecast capex, disposals and capital contributions for the period 1 July 2006 to 31 December 2007. It also realigned the starting value of the RAB to be based on the regulatory (financial) year, rather than a calendar year value as had been used in the previous regulator's decision. The adjustments are summarised in Table 7.3.

Table 7.3 Aurora's adjustments to the opening RAB for roll forward purposes

July 2006 dollars	$million
Opening RAB - 1 January 2008	981.1
Capex forecast (1 July 2006 to 30 June 2007)	–48.3
Depreciation forecast (1 July 2006 to 30 June 2007)	30.4
Disposal forecast (1 July 2006 to 30 June 2007)	1.2
RAB - 1 July 2007	964.4
Capex forecast (1 July 2006 to 30 June 2007)[a]	–112.6
Depreciation forecast (1 July 2006 to 30 June 2007)	55.5
Disposals forecast (1 July 2006 to 30 June 2007)	0.9
RAB - 1 July 2006	908.2

Source: Aurora[667]
(a) Net of capital contributions.

Aurora's proposed roll forward of its RAB during the current regulatory control period and forthcoming regulatory control period is presented in Table 7.4 and Table 7.5 respectively. This presentation follows that used in the roll forward model (RFM) and post-tax revenue model (PTRM) proposed by Aurora rather than that used by Aurora in its regulatory proposal. The former presentation was chosen to maintain consistency with the AER's standard presentation of the RAB roll forward. In Aurora's regulatory proposal, for example, the closing balance for one year does not match the opening balance for the following year, because Aurora's presentation recognised the indexation of the opening RAB in one year on the first day of the following year.

666 NER, clause S6.2.1.
667 Aurora, *Regulatory proposal*, May 2011, pp. 170–171.

Table 7.4 Aurora's RAB for the current regulatory control period ($million, nominal)

	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12
Opening RAB	908.2	984.1	1,072.2	1,156.6	1,266.6	1,384.8
Capital expenditure[a]	111.7	105.1	128.4	144.0	157.6	141.1
CPI indexation on opening RAB	19.1	44.3	16.1	35.3	31.7	38.1
Straight-line depreciation[b]	–51.6	–61.3	–60.2	–69.3	–71.1	–72.9
Closing RAB	984.1	1,072.2	1,156.6	1,266.6	1,384.8	1,491.2
Difference between forecast and actual capex (1 July 2006 to 30 June 2007)						–21.8
Return on difference for 2006–07 capex						–9.1
Opening RAB as at 1 July 2012						1,460.2

Source: Aurora's proposed RFM.
(a) Net of disposals and capital contributions, and adjusted for actual CPI and WACC.
(b) Adjusted for actual CPI.

In table 92 of its regulatory proposal, Aurora removed an amount of $12.7 million (nominal) relating to "other control services adjustments" in establishing the opening RAB as at 1 July 2012.[668] This explains the difference between the closing RAB as at 30 June 2012 in the RFM and the opening RAB as at 1 July 2012 in the PTRM.[669] The adjustment is to reflect the proportion of shared assets that are expected to be used for non-standard control services over the forthcoming regulatory control period. Aurora also stated it had removed those assets that are to provide other control services directly from the RAB.[670]

Table 7.5 Aurora's proposed RAB for the forthcoming regulatory control period ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17
Opening RAB	1,447.6	1,536.6	1,620.87	1,706.6	1,797.7
Capital expenditure[a]	135.0	136.6	135.0	133.3	138.8
Inflation indexation on opening RAB	37.3	39.6	41.7	43.9	46.3
Straight-line depreciation	–80.3	–91.8	–91.0	–86.3	–88.2
Closing RAB	1,536.6	1,620.87	1,706.6	1,797.7	1,894.6

Source: Aurora's proposed PTRM.
(a) Net of disposals and capital contributions.

668 Aurora, *Regulatory proposal*, May 2011, p. 172.
669 The asset classes affected by this adjustment are; overhead HV lines rural, motor vehicles, minor assets, non-system property, spare parts and NEM assets.
670 Aurora, *Regulatory proposal*, May 2011, p. 172.

Aurora proposed the approach to use depreciation based on actual capex to roll forward the RAB to establish the RAB at the beginning of the 2017–22 regulatory control period.[671]

7.3 Assessment approach

The AER is required to roll forward a DNSP's RAB to establish the opening RAB at the start of a regulatory control period.[672] For Aurora this value was set at $981.1 million as at 1 January 2008 (in July 2006 dollars) in the NER. This value can be adjusted for any differences in the forecast and actual capex, disposals and capital contributions. It may also be adjusted to reflect any changes in the use of the assets, with only assets used in the provision of standard control services to be included in the RAB.[673]

To determine the opening RAB for a distribution determination, the AER has developed an asset base RFM in accordance with the requirements of the NER.[674] A DNSP must use the RFM in preparing its regulatory proposal. The RFM rolls forward the RAB from the beginning of the final year of the previous regulatory control period, through the current regulatory control period, to the beginning of the forthcoming regulatory control period. The roll forward occurs for each year by:

- adding an inflation (indexation) adjustment for the relevant year. This adjustment must be consistent with the inflation factor used in the control mechanism.[675]
- adding capex for the relevant year.[676] Actual capex must be used where available. However, forecasts are typically required for the final year of the regulatory control period. These forecasts are then updated for actual amounts at the next determination. The AER will check actual capex amounts against regulatory accounts data and generally accepts the capex reported in those accounts in rolling forward the RAB. However, there may be instances where adjustments are needed to the regulatory accounting data because it is not fit for purpose due to a particular issue.
- subtracting depreciation for the relevant year. Depreciation based on forecast or actual capex can be used to roll forward the RAB.[677] By default the RFM applies the depreciation approach based on actual capex, although this can be modified to apply a forecast depreciation approach if necessary.
- subtracting any disposals and/or capital contributions for the relevant year.[678] The AER will check these amounts against regulatory accounts data.

These annual adjustments give the closing RAB for any particular year, which then becomes the opening RAB for the following year, during the regulatory control period. Through this process the RFM rolls forward the RAB to the end of the current regulatory control period. The PTRM used to calculate the annual revenue requirement for the forthcoming regulatory control period generally adopts the same roll forward approach as the RFM, although the annual adjustments to the RAB are based on forecasts, rather than actual amounts.

The opening RAB for the 2017–22 regulatory control period can be determined using depreciation based either on forecast or actual capex incurred during the forthcoming regulatory control period. To

671 Aurora, *Response to information request AER/024 of 11 August 2011,* received 17 August 2011, p. 3.
672 NER, clause S6.2.1.
673 NER, clause S6.2.1.
674 NER, clause 6.5.1.
675 NER, clause 6.5.1(e)(3).
676 NER, clause S6.2.1(e)(4).
677 NER, clause S6.2.1(e)(5).
678 NER, clause S6.2.1(e)(6).

roll forward the RAB using depreciation based on forecast capex, the AER would use the forecast depreciation contained in the PTRM for the forthcoming regulatory control period, adjusted for actual inflation. If the approach to roll forward the RAB using depreciation based on actual capex was adopted, the AER would recalculate the depreciation based on actual capex incurred during the 2012–17 regulatory control period. A DNSP can propose a preferred depreciation approach although the AER must decide which approach is appropriate given the circumstances.[679] The AER will make its decision by giving consideration to the incentive properties of the regulatory regime adopted for the DNSP, the nature of the service provided and other factors the AER considers relevant.

7.4 Reasons for draft determination

The AER has determined the opening RAB as at 1 July 2012 to be $1439.0 million, a 0.6 per cent reduction on that proposed by Aurora. The difference reflects changes made by the AER to indexation and the treatment of capitalised provisions.

The AER has forecast the closing RAB as at 30 June 2017 to be $1740.8 million, an 8.1 per cent reduction on that proposed by Aurora. The difference reflecting changes made by the AER to the opening RAB as at 1 July 2012, the inflation forecast for the forthcoming regulatory control period, forecast capital expenditure, and forecast depreciation.

7.4.1 Opening RAB as at 1 July 2012

The AER accepts Aurora's proposed RAB as at 1 July 2006 of $908.2 million as derived from the value of the RAB as at 1 January 2008 set out in the NER[680] and the adjustments set out in Table 7.3. The adjustments in Table 7.3 were reviewed by the AER and found to be appropriate. The forecast amounts removed from the RAB as at 1 January 2008 to derive a mid-year value as at 1 July 2006 were consistent with OTTER's model.

The AER accepts the proposed standard asset lives and remaining asset lives as at 1 July 2006, the actual capex inputs over the current regulatory period, and the other control services adjustments made by Aurora as at 30 June 2012 to account for shared assets over the forthcoming regulatory control period. The AER reviewed the actual capex included in the RFM and found these to be consistent with the regulatory accounts, although forecasts were provided for 2010–11 and 2011–12 and will need to be updated for the final decision. The standard asset lives and remaining asset lives were found to be consistent with those as determined by OTTER. The AER also considers the apportionment of shared assets to non-standard control services is reasonable, being based on the proportion of spending on non-standard control services to the total spend on standard and non-standard control services.[681] The value of this adjustment reduced marginally from that proposed by Aurora due to the indexation issue discussed below.

However, the AER does not accept Aurora's proposed RAB as at 1 July 2012 and has determined the RAB to be $1439.0 million. The AER has made input changes to the RFM submitted by Aurora. The input changes to the RFM relate to the indexation approach to account for inflation and the removal of movements in provisions. These adjustments are discussed further in sections 7.4.2 and 7.4.3 respectively. As part of finalising its decision, the AER will require Aurora to provide an update of the

[679] NER, clause 6.12.1(18).
[680] NER, clause S6.2.1.
[681] Aurora, *Response to information request AER/015 of 22 July 2011*, received 29 July 2011.

forecast capex for 2010–11 in the RFM with actual capex.[682] The latest forecast capex for 2011–12 in the RFM may also be updated at that time.

7.4.2 Indexation approach

The AER considers that Aurora has not indexed its RAB appropriately as part of the roll forward of the RAB during the current regulatory control period. Accordingly, the AER has made two changes to the way actual inflation adjustments were applied by Aurora in the RFM.[683] These changes are:

1. The AER has applied actual inflation over the current regulatory control period based on the change in December to December CPI, consistent with the current control mechanism as required under clause 6.5.1(e)(3) of the NER. Aurora proposed applying June to June CPI.
2. The AER has changed the forecast inflation rate input in the RFM to 3 per cent for the current regulatory control period, consistent with the forecast used by OTTER in its final determination. Aurora proposed a figure of 4.5 per cent. To maintain net present value neutrality, the AER considers that the forecast inflation rate used in the RFM must equal the forecast inflation rate approved by OTTER.[684]
3. The inflation rate for 2011–12 is a forecast. This figure will be updated in the final determination for actual inflation when the December 2011 CPI will be known.

As noted in section 7.4.4, when forecasting the RAB for the forthcoming regulatory control period, the AER updated the forecast inflation rate used in the PTRM to 2.62 per cent per annum. This compares to the 2.58 per cent per annum used by Aurora.[685] This forecast will be further updated for the final determination.

7.4.3 Treatment of provisions

The AER has reduced the capex inputs to the RFM proposed by Aurora by $8.7 million ($nominal) for the movement in capitalised expense provisions. The amounts removed from capex for each year are shown in Table 7.6.

Table 7.6 Movement in provisions – capex ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17
Net movement in provisions – capex	0.4	3.1	4.0	0.4	0.9

Source: Aurora[686]

In its accounts prepared for OTTER, Aurora included provisions for labour expenses such as superannuation and long service leave obligations. These expenses have not been paid but are likely to be incurred at some time (in some cases, many years) in the future. Aurora has capitalised a proportion of these expenses and included this proportion as capex in its RAB.

682 Similarly, the estimated disposals and capital contributions for 2010–11 should be updated for actuals for the final decision.
683 The inflation adjustments for 2005–06 and 2006–07 have been changed to two decimal places. Aurora had rounded the adjustments up to one decimal place.
684 NER, clause 6.5.5(b)(2).
685 The AER's consideration of the inflation forecast to apply over the forthcoming regulatory control period is discussed further in attachment 9.
686 Aurora, *Regulatory Information Notice*, template 2.7 table 2.7.14.

The AER does not accept Aurora's treatment on this matter as being consistent with good regulatory practice, the NEL or NER. This is because allowing a DNSP to earn the return on capital and return of capital for payments that have yet to be made is not efficient or consistent with customers' long-term interests. The AER also considers that clause S6.2.1(e)(1) of the NER only allows capex to enter the RAB on an 'as incurred' basis. '[C]capital expenditure incurred during the pervious control period' does not extend to provisions for costs to be incurred in future years.

If provisioning were allowed, the DNSP would earn a return that is greater than the expense that is ultimately incurred. These additional returns stem from:

- the customers paying a return on capital (through charges) when no capital investment has yet been incurred
- the business using the cash for other investment purposes during the period until the costs are realised.

There can also be some uncertainty as to whether particular expense provisions will materialise. Table 7.7 presents an example of the additional returns resulting from Aurora's proposed treatment of provisions. It assumes an expense of $1 million to be paid in 5 years, and is amortised over 20 years. A real WACC of 7 per cent is also assumed—that is, no inflation is also assumed. The additional returns through charges were calculated by multiplying the real WACC by the capitalised provisions. The additional loss of cash flow was calculated by multiplying the real WACC by the total charges (reflecting both return on and of the capitalised provision) resulting from the provision. The example shows returns are 22 per cent higher with provisioning as opposed to without provisioning.[687]

[687] If provisioning were to be allowed, the $1 million in this example should be discounted before it enters into the asset base. Such a discounting would be the mirror image of the situation for assets that enter the asset base as commissioned. Commissioned assets enter the RAB not only with the costs of construction but also capitalised interest costs (Despite the asset not being used by customers during construction). For provisions it is the additional costs that would have to be removed from the forecast costs. Working out the appropriate discount would be extremely difficult.

Table 7.7 Example: provisions for $1 m expense, due in 5 years time

Year	1	2	3	4	5
Total capitalised provisions	200,000	400,000	600,000	800,000	1,000,000
Total accumulated amortisation	10,000	30,000	60,000	100,000	150,000
Accumulated additional returns (through charges)	14,000	41,300	81,200	133,000	196,000
Accumulated additional returns (loss of cash flow)	1,680	4,991	9,884	16,310	24,220
Costs still to pay when expense becomes due					
With provisioning					850,000
Without provisioning					1,000,000
Total cost to customers					
With provisioning					1,220,220
Without provisioning					1,000,000
Difference					22%

The AER requested Aurora to provide a breakdown of the movement in provisions by asset class. In response, Aurora did not provide a break down of the movement in provisions by asset class. It instead stated no adjustment should be made.[688] Aurora stated that the removal of capitalised expense provisions:

1. is inconsistent with the requirements of Aurora's approved Cost Allocation Method (CAM), noting the CAM makes provision for labour related costs to be included in costing the service provider charges. Aurora quoted footnote 3 of the CAM
2. would result in 'in house' labour costs being treated differently to outsourced labour costs, with Aurora stating that external contractors can recover all labour costs (including any expense provisions)
3. is inconsistent with the treatment of other expenses such as insurance. Aurora stated that insurance costs are recovered prior to an 'event' occurring and this also prevents price shocks from recovering costs as incurred.

The AER does not agree that the CAM allows for expense provisions.[689] The word 'provision' is only used in relation to 'provision of service', which is clearly a different meaning of the word than considered here. The AER accepts that some expenses may be capitalised and the noting of superannuation etc as an expense in footnote 3 of the CAM is not unusual. However, this footnote does not suggest (nor any other statement in the CAM) that expense provisions can be included in

688 Aurora, *Response to information request AER/048 of 10 October 2011,* received 18 October 2011.
689 Aurora, *Aurora's cost allocation method, version 6.3*, May 2011.

the RAB. Accordingly, the AER does not consider that the CAM provides Aurora a basis to include provisions in its RAB.

The AER recognises that excluding provisions from the capitalised expenses would make capitalising of these expenses when incurred more challenging. This is because it would be difficult to divide up such expenses across projects a worker may have been involved in. For example, timesheet records may not go to this level of detail at present or be maintained over a number of years. Therefore, the DNSP may have to maintain more detailed timesheet records, if it chooses to capitalise these expenses when they are actually incurred.

Aurora stated that contractors include provisions for such things as future superannuation payments in their charging. This is difficult to substantiate. In competitive markets it is more typical for expenses to be recovered after they are incurred, not in advance. Even if such charging was standard accounting practice, this does not necessarily mean these practices are consistent with the objectives of the NEL or the requirements of the NER. In this regard, the AER considers that provisioning leads to higher costs and is therefore not efficient or in the long-term interests of customers. As noted above, the AER also considers that clause S6.2.1(e)(1) of the NER does not allow costs that are yet to be incurred to be included in the RAB.

The AER does not consider that insurance payments and provisions are comparable in the way Aurora suggested. While they may both relate to events in the future, premiums paid to insurers are made by the DNSP on an ongoing basis. In contrast, provisions are only paid out by the DNSP when the event occurs.[690] The AER also does not consider the potential lumpiness of future payments as a reason for customers paying in advance. Customers will incur additional costs, as discussed above.[691] In addition, there is no certainty that all provisions will materialise or that they are all likely to be due in the same year. The provision accounts presented in Aurora's RIN suggest the level of expenses being realised out of the provision accounts is relatively constant but rising. However, the change in actual expenses is not considered by the AER to be particularly lumpy.[692] In any event, any lumpiness in these expenses, when they materialise, can be smoothed (as with other expenses) through the calculation of the X factors.

Provisions have also been removed from the base opex amounts used to forecast opex for the forthcoming regulatory control period. This adjustment is discussed in attachment 6. Removing provisions from capex to be included in the RAB is consistent with the adjustments made to opex.

The AER has not removed provisions that may be included in the RAB as at 1 January 2008. As discussed above, Aurora's RAB is rolled forward from the value set out in schedule 6.2 of the NER.[693] Therefore, if this value contains provisions, the AER considers that legally it can not remove such provisions from the RAB. However, the AER considers that the movement in provisions should be removed for the purposes of the roll forward to establish the opening RAB as at 1 July 2012. In the absence of a response from Aurora, the movement in provisions was spread on a pro rata basis

690 Self insurance is a regulatory allowance where a DNSP receives payment in advance of an 'event' occurring. However, these allowances are governed by strict regulatory requirements and are only allowed in circumstances where usual commercial insurance is unavailable or inefficiently cost prohibitive. Provisioning leads to no similar cost savings. The DNSP is also required to commit to meet all expenses that emerge from an 'event' occurring, where as provisions can be reversed.

691 In theory, provisioning of costs could be made neutral to the situation where no provisioning is allowed. However, this would require the future expense being discounted in net present value (NPV) terms. In the example above, even if $1miilions in expense is ultimately incurred, only something less than this amount would be allowed to enter the RAB. There would also need to be a reconciliation between the forecast expense upon which the NPV amount was determined and the actual expense paid. Any difference (in NPV terms) would need to be removed/added to the RAB.

692 Aurora, *Regulatory Information Notice*, template 2.7.

693 NER, clause S6.2.1.

across the asset classes based on the relative proportions of each asset class share of total capex for the relevant year.

7.4.4 Forecast closing RAB as at 30 June 2017

The AER has determined the RAB to be $1740.8 million as at 30 June 2017. The forecast of the 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 7.4.1
- The inflation forecast for the forthcoming regulatory control period, as discussed in section 7.4.2
- Forecast capital expenditure, as discussed in attachment 5
- Forecast depreciation, as discussed in attachment 8.

7.4.5 Depreciation approach to roll forward the RAB

The AER considers that the opening RAB for the 2017–22 regulatory control period should be rolled forward using a depreciation approach based on actual capex.

There can be circumstances where a depreciation approach based on forecast capex may be appropriate for rolling forward the RAB.[694] However, the AER considers that a depreciation approach based on actual capex is the most appropriate approach for DNSPs. This approach discourages a DNSP from overspending its forecast capex allowance, other things being equal. The use of depreciation based on actual capex has been approved by the AER for each of its decisions for DNSPs to date.

7.5 Revisions

The AER requires the following revisions to Aurora's proposal in relation to its RAB.

Revision 7.1: The AER has determined Aurora's opening RAB as at 1 July 2012 to be $1,439.0 million as set out in Table 7.1.

Revision 7.2: The AER has determined Aurora's forecast RAB as at 30 June 2017 to be $1,740.8 million as set out in Table 7.2.

[694] See discussion on the use of forecast capex to determine depreciation for gas pipelines. Final decision; *Envestra Ltd: Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016*, June 2011, pp. 27–28.

8 Depreciation

The AER is required to make a decision in relation to the depreciation schedules submitted by a DNSP.[695] 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.

8.1 Draft determination

The AER accepts Aurora's proposed asset classes, standard and remaining asset lives, and the straight-line method to calculate the regulatory depreciation allowance. The AER considers that Aurora's proposed asset classes and standard asset lives are consistent with those approved by the Office of the Tasmanian economic regulator (OTTER), and reflect the nature and economic lives of the assets consistent with clause 6.5.5(b)(1) of the NER. Aurora's proposed remaining asset lives reflect the relevant assets, the economic lives and the straight-line method of depreciation. Therefore, the AER accepts that Aurora's proposed depreciation schedules satisfy clause 6.5.5(b) of the NER.

The AER does not accept Aurora's proposed forecast regulatory depreciation allowance of $231.9 million ($nominal) for the forthcoming regulatory control period. The AER's adjustments to Aurora's proposed opening RAB, forecast capex and forecast inflation impact the regulatory depreciation allowance under clause 6.5.5(a)(1) of the NER. On the basis of these adjustments the AER has determined Aurora's regulatory depreciation allowance to be $232.9 million ($nominal) as shown in Table 8.1. The increased depreciation allowance from that in Aurora's proposal reflects revisions made to the remaining asset lives as discussed below.[696]

Table 8.1 AER's draft determination on Aurora's depreciation allowance ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Straight-line depreciation	84.3	92.2	89.8	84.5	86.0	436.7
Less: indexation on opening RAB	37.7	39.2	40.7	42.3	43.9	203.8
Regulatory depreciation	46.6	52.9	49.1	42.2	42.1	232.9

Source: AER analysis.

8.2 Aurora's proposal

Aurora proposed a forecast regulatory depreciation allowance of $231.9 million ($nominal) over the forthcoming regulatory control period. To calculate the depreciation allowance Aurora proposed: [697]

695 NER, clause 6.12.1(8).

696 Were the approved remaining asset lives in table 8.3 applied to Aurora's proposed PTRM, depreciation would have been in total $239.9 million ($nominal) over the forthcoming regulatory control period. Compared against this figure, the AER's draft determination depreciation allowance would represent a reduction of around $7 million.

697 Aurora, *Regulatory proposal*, May 2011, p. 179.

- to use the straight-line depreciation methodology employed in the AER's post-tax revenue model (PTRM)
- to depreciate new assets (capex) according to the standard asset lives for each asset class contained in table 97 of its proposal
- to depreciate existing assets based on the values determined in the AER's roll forward model (RFM) over their remaining asset lives
- the standard asset lives and remaining asset lives were adopted in accordance with good engineering practice and its own financial records.[698]
- Aurora's RAB is held within its ring-fenced accounts and Aurora has derived the standard asset lives for each asset class from these accounts.[699] Aurora proposed that the remaining asset life of each asset class as at 1 July 2012 has been calculated by dividing the closing asset values of each asset class by the annual depreciation for each asset class.[700] The AER has reproduced the standard asset lives and remaining asset lives in Aurora's regulatory proposal in Table 8.3.

Aurora's proposed depreciation building block allowance for standard control services for 2012–17 is set out in Table 8.2.

Table 8.2 Aurora's proposed depreciation allowance ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Straight-line depreciation	83.3	91.8	91.0	86.3	88.2	440.7
Less: indexation on opening RAB	37.3	39.6	41.7	43.9	46.3	208.8
Regulatory depreciation	46.1	52.3	49.3	42.3	41.9	231.9

Source: Aurora.[701]

8.3 Assessment approach

The NER requires the AER to determine the regulatory depreciation allowance as a part of a DNSP's annual revenue requirement.[702] The calculation of depreciation in each year is governed by the value of assets included in the RAB at the beginning of the regulatory year and the depreciation schedules.[703] The AER's standard approach to calculating depreciation is to employ the straight line method as set out in the PTRM. The AER considers that the straight-line method of depreciation satisfies the NER requirements in clause 6.5.5(b) because it provides an expenditure profile that reflects the nature of the assets over their economic life.[704] The AER must consider if the proposed depreciation schedules conform to the following requirements:

- the schedules depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets[705]

698 Aurora, *Regulatory proposal*, May 2011, p. 179.
699 Aurora, *Regulatory proposal*, May 2011, p. 179.
700 Aurora, *Regulatory proposal*, May 2011, p. 179. suggests a weighted average approach is used to determine the remaining asset lives as at 1 July 2012. However, this was not in fact the case, as discussed below.
701 Aurora, *Regulatory proposal,* May 2011*, Attachment AE078 - Post tax revenue model*, p. 259.
702 NER, clauses 6.4.3(a)(1) and (b)(3).
703 NER, clause 6.5.5(a).
704 NER, clause 6.5.5(b)(1).
705 NER, clause 6.5.5(b)(1).

- the sum of the real value of the depreciation that is attributable to any asset of category of assets must be equivalent to the value at which that asset of category of assets was first included in the RAB for the relevant distribution system[706]

- the proposed economic life of relevant assets, depreciation method and rates used to calculate the depreciation schedules for the current regulatory period must be consistent with those approved in the previous distribution determination.[707]

To the extent that a DNSP's building block proposal does not comply with the above requirements then the AER must determine the depreciation schedules for the purposes of calculating the depreciation for each regulatory year.[708]

The allowance for regulatory depreciation is an output of the PTRM. The NER requires the AER to determine the reasonableness of Aurora's regulatory depreciation allowance by analysing Aurora's proposed inputs to the PTRM, such as:

- existing assets (opening RAB) and remaining asset life for each asset class

- new assets (capex) and standard asset life for each asset class.

The PTRM inputs include a remaining asset life for each asset class, which the AER uses to calculate the depreciation of the opening RAB as at 1 July 2012. The AER's preferred method to determine the remaining asset lives is the weighted average method. The AER considers the weighted average method provides a better reflection of the mix of assets within an asset class and the economic life of the asset class, which clause 6.5.5(b)(1) of the NER requires.[709] However, the AER recognises that a variety of methods can be employed to calculate the remaining asset lives which also satisfy this clause. The AER has determined the reasonableness of Aurora's proposed depreciation schedules and regulatory depreciation allowance based on clause 6.5.5(b) of the NER, and the above considerations.

8.4 Reasons for draft determination

8.4.1 Regulatory depreciation allowance

The AER's draft determination on Aurora's regulatory depreciation allowance is $232.9 million ($nominal).

The AER accepts Aurora's proposal to use the straight-line method to calculate the regulatory depreciation allowance as set out in the PTRM. However, the AER does not accept Aurora's proposed regulatory depreciation allowance of $231.9 million ($nominal) for the forthcoming regulatory control period under clause 6.5.5(a)(1) of the NER. This is because the AER's determinations regarding other components of Aurora's regulatory proposal impact the proposed regulatory depreciation allowance. These are discussed in other attachments and include:

- the opening RAB (attachment 7)

- forecast capex (attachment 5)

706 NER, clause 6.5.5(b)(2).
707 NER, clause 6.5.5(b)(3).
708 NER, clause 6.5.5(a)(ii).
709 AER, *Explanatory statement, Proposed amendment, Electricity transmission network service providers roll forward model*, August 2010, p. 5.

- forecast inflation (attachment 9).

This attachment sets out the AER's consideration of specific matters that impact on the estimate of regulatory depreciation over the forthcoming regulatory control period. These include the standard asset lives for the purposes of depreciating forecast capex and remaining asset lives for the purposes of depreciating existing assets in the opening RAB.

8.4.2 Standard asset lives

The AER accepts the standard asset lives proposed by Aurora shown in Table 8.3. The proposed standard asset lives are consistent with those Aurora used to calculate the depreciation allowance that OTTER approved in its 2007 determination.[710] The AER considers that Aurora's proposed standard asset lives are comparable with the standard asset lives approved in its previous decisions for other electricity distribution networks.[711] The AER also considers Aurora should use two new asset classes to allocate land and easement expenditures over the forthcoming regulatory control period. No asset lives are associated with these asset classes as they relate to non-depreciating assets.

The AER has reviewed and confirms that the standard asset classes proposed by Aurora are those used to calculate the depreciation allowance approved by OTTER. The AER considers the proposed standard asset lives of Aurora's asset classes are broadly consistent with those accepted by the AER in other distribution determinations. The proposed standard asset life of 'HV metering service connections' is higher than other metering asset classes applied to other DNSPs. However, the 'HV metering service connections' standard asset life is consistent with that approved by OTTER in the previous distribution determination.[712] On balance, and reflecting the general consistency with the decision of the previous regulator, the AER accepts Aurora's proposed standard asset lives. The proposed standard asset lives provide depreciation profiles that reflect the nature of those asset classes over their economic lives, under clause 6.5.5(b)(1) of the NER.

Aurora's asset classes do not separately identify land and easement expenditures, which are non-depreciating assets. The AER considers expenditures for these assets should therefore be allocated to appropriate classes separately from assets subject to the calculation of depreciation in the PTRM. Following a request from the AER, Aurora agreed that it would be appropriate to separate land and easements from depreciable assets.[713] For this draft determination, the AER has used the information Aurora provided to allocate all forecast land and easement expenditures into the respective asset classes for the forthcoming regulatory control period.[714]

8.4.3 Remaining asset lives

The AER accepts Aurora's method for calculating the remaining asset lives as at 1 July 2012 set out in Table 8.3. However, the AER requires Aurora to amend the value of the remaining asset lives to reflect the AER's adjustments to the opening RAB as at 1 July 2011, made as a part of this draft determination.

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710 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania - Draft report and proposed maximum prices*, July 2007, p. 105.

711 AER, *Draft Decision: Queensland distribution determination 2010–11 to 2014–15*, May 2010, pp. 223–225; AER, *Draft decision: Victorian electricity distribution network service providers, Distribution determination 2011–2015*, June 2010, pp. 464–476; AER, *Final decision: Victorian electricity distribution network service providers, Distribution determination 2011–2015*, October 2010, p. 467; AER, *Draft decision: New South Wales distribution determination 2009–10 to 2013–15*, 21 November 2008, pp. 215–219.

712 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania - Final report and proposed maximum prices*, September 2007, p. 117.

713 Aurora, *Response to information request AER/047 of 6 October 2011*, received 11 October 2011, p. 3.

714 Aurora, *Response to information request AER/047 of 6 October 2011*, received 11 October 2011, pp. 3–4.

Aurora proposed that the same asset classes and standard asset lives used in the current regulatory control period apply for the forthcoming regulatory control period. Aurora stated that the weighted average method was used to calculate the remaining asset lives at the commencement of the forthcoming regulatory control period. However, the AER has identified that Aurora employed an alternative to the weighted average method to calculate the remaining asset lives as at 1 July 2012.

The AER's preferred method to calculate the remaining asset lives is the weighted average method.[715] The AER considers the weighted average method better reflects the economic life of an asset class, consistent with clause 6.5.5(b)(1) of the NER.[716] However, the AER recognises that other methods may be employed which satisfy clause 6.5.5(b) of the NER.

The AER has assessed the reasonableness of Aurora's proposed remaining asset lives by comparing them against remaining asset lives derived using a weighted average method. The weighted average method involves weighting within an asset class, the remaining life of each capital stream by the closing capital value of that capital stream as a proportion of the total closing capital value of the asset class.[717] The resulting individual values for each capital stream are then added together to obtain the overall weighted average remaining life of the asset class. In contrast, Aurora's method to calculate its proposed remaining asset lives is to divide the closing written down asset value by the amount of depreciation for the asset class in the following year.[718] The closing written down asset value and depreciation for each asset class were derived from Aurora's modelling of the RAB as at 1 July 2012.[719] The differences in the remaining asset lives between the two approaches are shown in Table 8.3.

Table 8.3 Aurora's proposed standard and remaining asset lives and the AER's draft determination (year)

Asset classes	Aurora's proposed standard asset life	Aurora's proposed remaining asset life	AER's weighted average remaining asset life	AER's approved remaining asset life
Overhead subtransmission lines (urban)	50	31.7	36.9	31.2
Underground subtransmission lines (Urban)	60	38.7	42.6	38.2
Urban zone substations	40	31.5	35.4	31.0
Rural zone substations	40	30.9	34.8	30.8
SCADA	10	2.9	6.0	2.7
Distribution switching stations (ground)	40	33.0	36.4	32.7

715 AER, *Final decision, Amendment to electricity transmission network service providers roll forward model, December 2010,* p. 7.

716 AER, *Explanatory statement, Proposed amendment, Electricity transmission network service providers roll forward model*, August 2010, p. 5.

717 Capital stream refers to the opening asset value or any capex value in each year of the regulatory control period. A worked example is included in the 'Asset lives roll forward' worksheet of the AER's transmission RFM. AER, *Explanatory statement, Proposed amendment, Electricity transmission network service providers roll forward model*, August 2010, p. 5.

718 Aurora, *Response to information request AER/30 of 18 August 2011,* received 23 August 2011.

719 Certain adjustments were made to the closing written down value of Aurora's asset classes to align with its PTRM and the estimated depreciation amounts for the following year were sourced from Aurora's proposed RFM.

Overhead high voltage lines urban	35	24.1	26.4	23.9
Overhead high voltage lines rural	35	20.8	23.8	20.7
Voltage regulators on distribution feeders	40	23.2	24.8	23.0
Underground high voltage lines	60	42.2	44.9	41.9
Underground high voltage lines SWER	60	51.2	52.4	50.9
Distribution substations HV (pole)	40	33.3	33.8	33.2
Distributions substations HV (ground)	40	17.1	19.7	16.9
Distribution substations LV (pole)	40	23.0	25.8	22.8
Distribution substations LV (ground)	40	24.6	27.8	24.4
Overhead low voltage underbuilt urban	35	23.7	25.8	23.5
Overhead low voltage underbuilt rural	35	17.7	20.7	17.6
Overhead low voltage lines urbana	35	23.9	20.5	17.4
Overhead low voltage lines rural	35	26.0	27.4	25.8
Underground low voltage lines	60	38.1	41.1	37.8
Underground low voltage common trench	60	47.2	49.5	46.8
HVST service connections	40	2.1	2.0	2.0
HV service connections	40	28.4	30.3	28.1
HV metering CA service connections	40	11.1	13.8	10.9
HV/LV service connections	40	27.3	29.4	27.0
Business LV service connections	35	13.3	17.4	13.1
Business LV metering CA service connections	25	6.3	12.7	6.2

Domestic LV service connections	35	22.1	25.8	21.8
Domestic LV metering CA service connections	20	4.0	7.4	3.9
Emergency network sparesb	1	0.0	<1.0	1.0
Motor vehicles	6	3.5	4.6	3.5
Minor assets	5	2.7	3.7	2.6
Non-system property	40	20.9	33.8	20.1
Spare partsb	1	0.0	<1.0	1.0
NEM assets	5	2.1	3.5	2.0
Land	n/a	n/a	n/a	n/a
Easements	n/a	n/a	n/a	n/a

Source: Aurora,[720] AER analysis.
(a) Aurora's 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 proposed regulatory depreciation allowance for this asset class.
(b) The proposed remaining life is less than 1 year. For modelling purposes, instead of using the input of zero (as it is not logical to depreciate over zero) a remaining life of 1 year has been used.

The NER is quite broad in that it does not specify a particular approach to be used to calculate depreciation. All things being equal, relatively shorter remaining asset lives will increase the rate of depreciation. Aurora's proposed remaining asset lives provide Aurora with a relatively higher depreciation allowance over the forthcoming regulatory control period compared to the AER's preferred weighted average approach. This is because Aurora's proposed approach uses shorter remaining asset lives. Nonetheless both approaches are generally considered to meet the requirements of clause 6.5.5(b) of the NER.

However, Aurora's proposed remaining asset lives for the asset classes of 'Business LV metering CA service connections' and 'Non-system property' are significantly different to the AER's lives. These differences reflect the sensitivity of Aurora's approach to calculating depreciation with respect to assets nearing the end of their economic life. Aurora has effectively given existing assets (that is, those in existence at the beginning of the current regulatory control period) and new assets acquired during the current regulatory control period equal weight.[721] Generally, existing assets will have shorter remaining asset lives than new assets.

However, the AER considers the impact of the lower remaining asset lives for the 'Business LV metering CA service connections' and 'Non-system property' asset classes upon total revenue are immaterial. This is because these asset classes form a relatively small proportion of the RAB. On balance, the AER considers Aurora's proposed method for calculating remaining asset lives is reasonable and satisfies clause 6.5.5(b)(1) of the NER.

720 Aurora, *Regulatory proposal*, May 2011, p. 180.
721 For example, an existing asset with 1 year remaining life and annual depreciation of $10 million is effectively given the same weight as a new asset with 50 year remaining asset life and annual depreciation of $10 million. The depreciation approach to determining the remaining asset lives would take the closing asset value for this asset class and divide it by $20 million, regardless of the fact that one asset only has 1 year life remaining.

The AER considers Aurora’s proposed depreciation schedules comply with clause 6.5.5(b) of the NER. In accepting the approach employed by Aurora to determining the remaining asset lives, the AER has updated the remaining asset lives to reflect the changes to the opening RAB as discussed in attachment 7. At the time of this draft determination the roll forward of Aurora’s RAB includes forecast capex for 2010–11 and 2011–12. The AER will update these capex figures for its final determination. Therefore, the AER will require a further recalculation of Aurora's remaining asset lives to reflect the updated opening RAB for its final determination.

8.5 Revisions

The AER requires the following revisions to Aurora's proposal in relation to its forecast regulatory depreciation allowance.

Revision 8.1: The AER has determined Aurora's forecast regulatory depreciation allowance to be $232.9 million ($nominal) over the forthcoming regulatory period as set out in Table 8.1.

Revision 8.2: 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 8.3.

9 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 the forthcoming regulatory control period. In making its determination, the AER has to consider whether to apply or depart from a value, method or credit rating level set out in its statement of regulatory intent (SRI).[722] 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.[723] The NER requires the AER to apply the capital asset pricing model (CAPM)[724] to calculate the return on equity for DNSPs.[725]

9.1 Draft determination

The AER has not accepted Aurora's proposed WACC of 10.33 per cent. The AER considers the proposed WACC does not reflect the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by Aurora.[726]

For this draft decision, the AER has determined an indicative WACC of 8.08 per cent for Aurora as set out in Table 9.1. This WACC reflects parameters—such as the nominal risk free rate and debt risk premium (DRP)—estimated over an indicative averaging period and will be updated for the final decision.

In establishing the WACC, the AER has accepted Aurora's proposed averaging period to calculate the nominal risk free rate, and proposed values for the equity beta and gearing. The AER has not accepted Aurora's proposed values for the market risk premium (MRP) and DRP. Aurora proposed an MRP of 6.5 per cent as specified in the SRI. The AER considers that there is persuasive evidence justifying a departure from this value.[727] An MRP of 6 per cent takes account of the available evidence in the current circumstances, which makes the value in the SRI inappropriate. The AER also considers its method to calculate the DRP, based on the average of observed bond yields, appropriately incorporates relevant information from the market. This will contribute to a forward looking rate of return that is commensurate with the prevailing conditions in the market for funds and the risk involved in providing standard control services. The AER has also accepted Aurora's proposed value of the assumed utilisation of imputation credits (gamma), which affects the tax building block allowance.

In addition to bottom-up analysis on the parameter inputs, the AER has also assessed the overall rate of return against market data to ensure that the WACC is appropriate.[728]

[722] NER, clause 6.12.1(5).
[723] NER, clause 6.5.2(b).
[724] 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.
[725] NER, clause 6.5.2(b).
[726] NER, clause 6.5.2(b).
[727] NER, clause 6.5.4(g).
[728] NER, clause 6.5.2(b).

Table 9.1 AER draft determination on WACC parameters

Parameter	AER draft determination
Nominal risk free rate	4.28%
Equity beta	0.80
Market risk premium	6.00%
Gearing level (debt/debt plus equity)	60%
Debt risk premium	3.14%
Assumed utilisation of imputation credits (gamma)a	0.25
Inflation forecast	2.62%
Cost of equity	9.08%
Cost of debt	7.42%
Nominal vanilla WACC	8.08%

(a) The gamma parameter affects the corporate income tax allowance, which is discussed in attachment 10.

9.2 Aurora's proposal

Aurora proposed a nominal vanilla WACC of 10.33 per cent.[729] Table 9.2 sets out Aurora's proposed WACC parameters.

Aurora proposed to apply the three parameters with values set out in the SRI—equity beta, MRP and gearing level—to calculate the WACC.[730] Aurora did not provide any particular reasoning or assessment on these issues. Aurora has not applied the value of gamma specified in the SRI as part of estimating its tax allowance.[731] Instead, Aurora proposed a gamma value of 0.25 based on the findings by the Australian Competition Tribunal (Tribunal) in May 2011.[732]

Aurora's proposed nominal risk free rate is based on an indicative averaging period of 20 business days ending on 25 March 2011. The risk free rate is to be updated based on the agreed averaging period in the future. Aurora's proposed DRP is based on the same indicative averaging period and has been estimated using the Bloomberg BBB rated 7 year fair value curve (FVC), extrapolated to a term to maturity of 10 years.

Aurora proposed an inflation forecast that it stated is consistent with the AER's approach to estimating the expected inflation rate.

729 Aurora, *Energy to the People: Aurora Energy Regulatory Proposal 2012–17 addendum*, June 2011, (Aurora, *Regulatory proposal addendum*, June 2011) , p. 14.
730 Aurora also proposed to use the credit rating of BBB+ as specified in the SRI for the purposes of estimating the DRP.
731 Gamma affects the corporate income tax allowance, which is discussed in attachment 10.
732 Australian Competition Tribunal, *Application by Energex Limited (Gamma) (No. 5) [2011] ACompT 9*, 12 May 2011, paragraph 42.

Table 9.2 Aurora proposed WACC parameters

Parameter	Aurora's proposal
Nominal risk free rate	5.53%
Equity beta	0.80
Market risk premium	6.50%
Gearing level (debt/debt plus equity)	60%
Debt risk premium	4.54%
Assumed utilisation of imputation credits (gamma)a	0.25
Inflation forecast	2.58%
Cost of equity	10.73%
Cost of debt	10.07%
Nominal vanilla WACC	10.33%

Source: Aurora.[733]
(a) The gamma parameter affects the corporate income tax allowance, which is discussed in attachment 10.

9.3 AER approach

The AER completed its review of the WACC parameters (WACC review) as required under the NER in May 2009.[734] As a consequence of the review, the AER issued the SRI adopting the values, methods and credit rating level for DNSPs.[735] The WACC parameter values, methods and credit rating level determined by the AER in the SRI are outlined in Table 9.3.

The SRI applies to Aurora's regulatory proposal because it was submitted after the publication of the SRI.[736] 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.[737]

In deciding whether a departure from a value, method or credit rating level set in the SRI is justified, the AER must consider:[738]

1. the criteria on which the value, method or credit rating level was set in the SRI (the underlying criteria); and

2. 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.

733 Aurora, *Regulatory proposal addendum*, June 2011, p. 14.
734 NER, clause 6.5.4(b).
735 NER, clause 6.5.4(c).
736 NER, clause 6.5.4(f).
737 NER, clause 6.5.4(g).
738 NER, clause 6.5.4(h).

Table 9.3 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
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)[a]	0.65

Source: AER.[739]
(a) The gamma parameter affects the corporate income tax allowance, which is discussed in attachment 10.

The underlying criteria the AER relied on in setting the value, method or credit rating level in the SRI include:[740]

- 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.

To determine the WACC, the values for two parameters (the nominal risk free rate and DRP) must be estimated from recent daily market data. The nominal risk free rate is estimated based on an averaging period as close as practically possible to the commencement of the regulatory control period, using Commonwealth government securities (CGS) data. The DRP is estimated using relevant data sources based on the same averaging period, and in accordance with a BBB+ credit rating and 10 year term.[741]

Ten year term

The AER's approach is to estimate all parameters—including the MRP and DRP—using a 10 year term. This provides internal consistency with the 10 year risk free rate.[742] Throughout the AER's

739 AER, *Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009, p. 7.
740 AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, pp. 175–176.
741 AER, *Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009, p. 7.
742 AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, p. 187.

approach, consideration of short-term conditions is only relevant to the extent that they influence the long-term (10 year) horizon.

Market risk premium

In determining the appropriate estimate of the MRP for Aurora, the AER has to determine, in accordance with the requirements set out in clause 6.5.4 of the NER, whether departing from the value determined in the SRI for the MRP is justified.[743]

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 global financial crisis (GFC) on future market conditions. The AER acknowledged two possible scenarios—a temporary elevation or a structural break—and considered that either option supported an increase in the regulated MRP (though not a significant increase).[744] The AER's approach is to evaluate both of these possible scenarios using the information now available (which was not available in early 2009).

Specifically, the AER's approach takes into account:

- Historical excess returns—Historical excess 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.
    - The AER reviews estimates using two different averaging methods, arithmetic and geometric means.[745] The AER considers that the arithmetic average results in an overestimate and the best estimate of historical excess returns over a 10 year period is likely to be somewhere between the geometric mean and the arithmetic mean of annual excess returns.
- Survey based estimates—Surveys of market practitioners and academics provide information on the expected forward looking MRP and their application in practice.
- Dividend growth models—Cash flow based measures of the MRP generally employ a dividend discount model. One such model is the dividend growth model (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.[746]
- Current market conditions 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 insight into their assessment of economic and financial conditions. Market commentary is primarily relevant to an assessment of whether there has been a structural break as a result of the GFC.

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743 See section 9.3

744 AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, p. 238.

745 An arithmetic mean sums all return observations and divides by the number of observations. A geometric mean multiplies a return observation by one plus the next year's return cumulatively across the period, and then takes the n^{th} root of the cumulative product of returns where n is the number of observations.

746 AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, pp. 216–217.

- 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 volatility to a longer horizon.

The AER's approach is to interpret this information with regard to the limitations of each type of evidence:

- Historical excess returns—Historical excess returns may provide some insight into what these returns will be in the future. However, investors' expectations of their required MRP are unlikely to be solely informed by past excess returns. In estimating the MRP, the AER needs to form a view on investors' expectations of the MRP in the future. It is not sufficient to simply adopt the estimated the excess stock market returns that have been achieved in the past. Further, the AER recognises that the historical estimates are sensitive to the selection of the sampling period. The estimates tend to vary with the addition of more observations.

- Survey based estimates—Survey based estimates may be subjective, though this concern is mitigated as the sample size increases. Their relevance may also be limited by 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. Nonetheless, the AER is of the view that survey based estimates of the MRP are relevant for consideration as they are forward looking and reflect actual market practice.

- Dividend growth models—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.[747] 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.[748] For this reason, the AER has not used the DGM based analysis as the principal basis for estimating the return on equity, and therefore the MRP.

- Current market conditions and economic outlook—Economic and financial conditions have some relevance to the estimation of the MRP. These statements are used as supporting evidence because they rarely extend to direct comments on the most pertinent issues (such as the value of the MRP over the long-term). These comments also need to be understood in the context of the expertise and perspective of the organisation making the statements.

- Implied volatility analysis—Implied volatility varies significantly and provides only a very short-term view of market volatility at any point in time. The assumptions necessary to derive an MRP estimate are contentious.[749] The method only provides a short-term estimate of the MRP (i.e. 12 months or less) and there is no reasonable method to extrapolate to a longer term. Given that the

747 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.

748 For example, CEG used dividend yield for utility stock as a proxy for the market average dividend yield and assumed a dividend growth figure at a rate that is higher than the rate of economy growth. The AER considered that these were inappropriate assumptions. See AER, *Final decision Envestra Access arrangement proposal for the SA gas network 2011–2016*, June 2011, p. 195.

749 For example, the assumption that market risk per unit of implied volatility is constant. This assumption is disputed on theoretical and empirical grounds — See AER, *Draft decision, Envestra Ltd, Access arrangement proposal for the Qld gas network*, February 2011, pp. 282–283.

relevant MRP is the 10 year forward looking rate, the AER places limited weight on the MRP estimate derived on this basis.

The AER's approach to estimating the MRP does not rely on any one type of evidence. Instead, the AER reviews evidence from across all these areas to inform its decision on the appropriate MRP for this draft determination. Each of these five areas of evidence informs the AER's assessment of whether the scenarios identified in the SRI have indeed occurred, and the appropriate forward-looking 10 year MRP.

The AER's approach involves the exercise of appropriate regulatory judgement in the context of complex and conflicting evidence.

Debt risk premium

Under clause 6.5.2(e) of the NER, the AER must estimate the DRP as the margin between the risk free rate and the observed Australian benchmark corporate bond, based on the same term as the risk free rate. The AER's approach to estimate the DRP requires it to make decisions on:

- the benchmark assumptions for the cost of debt set out in the SRI
- the method used to estimate a DRP that conforms to these benchmark parameters, including appropriate data sources.

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+.[750]

The AER's method to estimate the DRP based on these benchmark parameters is to apply a sample based average of observed market data. The AER considers sufficient market data is now available to form a sample of bonds and to use the observed yields from that sample to determine a reasonable estimate of the benchmark DRP. The AER's approach is as follows:

- collate a sample of bonds that meet the following conditions:
  - Australian domestic corporate issuance
  - rated as either BBB, BBB+, or A– by Standard and Poor's
  - between 7 and 13 years remaining term to maturity
  - yield data observed by Bloomberg or UBS during the averaging period[751]
  - fixed interest rate, or floating interest rate where this can be reliably converted into a fixed interest rate equivalent[752]
  - standard bonds (that is, not callable or subordinated debt), or non-standard bond type where this can be reliably converted into a standard bond equivalent

[750] AER, *Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009, p. 7.
[751] Where observed yields are available from both sources, the AER uses an average of the yields; otherwise the AER uses yields from whichever source provides available observations.
[752] The AER derives fixed rate equivalent yields by summing historical floating rate trading margin and swap rate data, sourced from both Bloomberg and UBS.

- there are no strong qualitative grounds to indicate the bond is unrepresentative of a benchmark 10 year, BBB+ rated Australian corporate bond.

- annualise the yields from the sample of bonds and convert to spreads (or DRP) over the estimated risk free rate
- calculate the DRP as the simple average of the spreads.[753]

The AER has included in its bond sample:

- Bonds with remaining terms to maturity between 7 and 13 years—The AER considers that a three year window either side of the benchmark term is wide enough to generate a sufficiently robust sample. This approach yields a sample that is centred on the 10 year benchmark. Also, given the large number of bond issuances with remaining terms of 5–7 years, widening the sample range to include the 5–7 year band would generally result in an average term well below the benchmark of 10 years.
- BBB, BBB+, and A– rated bonds—In the reasons for its decision on the DRP review for Jemena Gas Networks, the Tribunal recognised that bonds within this range of credit ratings can provide useful information regarding the benchmark term of debt.[754] To allow an efficient estimate of the DRP, the AER considers it is appropriate that the sample should, on average, have a BBB+ credit rating. Where there are at least as many BBB rated bonds as A– rated bonds, the distribution of credit ratings in the sample should not result in too low a DRP, to the extent that credit ratings influence yields.
- Floating rate bonds, converted to fixed rate equivalents—The Tribunal has stated that floating rate bonds should be included in analysis of the DRP, and treated as equivalent to fixed rate bonds.[755] In previous decisions, the AER has calculated fixed rate equivalent yields for floating rate bonds as the sum of the trading margins for individual bonds and the daily swap rates.[756] The AER will apply this method to data for floating rate bonds observed from UBS.

The AER has not included in its sample:

- Callable bonds—The Tribunal has stated that it is appropriate to include bonds with non-standard features, such as callable bonds, if the yields on these bonds are able to be reliably adjusted to fixed rate equivalents.757 The AER does not consider that sufficiently reliable adjustments are feasible. Given the scope of adjustments that need to be made, the AER therefore considers it appropriate that callable bonds are excluded from the sample used for this draft decision. In particular, the required adjustments include the following:[758]
    - Conversion of yield-to-call to yield-to-maturity: When callable bond data is published relative to the first call date, the maturity date on a callable bond must be adjusted from the first call

753 The AER has applied a simple average on the basis that credit ratings and terms to maturity are imprecise indicators of expected yield. A simple average will equally reflect the DRPs of bonds deemed comparable to the benchmark. In comparison, a weighted average approach would require certain assumptions about the distribution of bond terms or credit ratings.

754 Australian Competition Tribunal, *Application by Jemena Gas Networks (NSW) Ltd*, June 2011, paragraph 55.

755 Australian Competition Tribunal, *Application by ActewAGL Distribution*, September 2010, paragraph 58.

756 For example, see AER, *Final decision, Envestra Ltd, Access arrangement proposal for the Qld gas network*, July 2011, p. 190.

757 Australian Competition Tribunal, *Application by Jemena Gas Networks (NSW) Ltd*, June 2011, paragraph 57.

758 These adjustments do not apply to 'make-whole' callable bonds, where the bond issuer is required to compensate the bond holder for the present value of future cash flows if the bond is called before the final maturity date. In these circumstances, the bond holder suffers little or no detriment if the bond is called early. See: Oakvale Capital, *Report on the cost of debt during the averaging period: The impact of callable bonds*, February 2011, p. 7.

date to the final maturity, so it can be compared with standard fixed rate bonds. The yield-to-call is the discount factor that equates the current price on a bond to the present value of the coupon payments up until the call date. In contrast, the yield-to-maturity is the discount factor that equates the price on a bond (the same price as in the yield-to-call calculation) to the present value of all coupon payments until maturity. These yields will necessarily be different in most cases.[759] The direction and magnitude of the (vertical) yield adjustment, however, will be dependent on the individual bond characteristics.

- Difference in the risk free rate: When the remaining term on a callable bond is adjusted to the final maturity date, the effective DRP on the bond will be calculated using a higher risk free rate, due to the longer term.[760] Holding other factors constant, this should reduce the implied DRP for that adjusted bond.

- Value of the call option: The call option on callable bonds has a negative value for investors. This is because an investor cannot know in advance when the bond will mature, as this depends on whether the issuer exercises the call option. This in turn depends principally on future debt market conditions. As a result, this creates uncertainty for investors who consequently require a higher yield to hold the debt. Yields on callable bonds must therefore be adjusted to extract this option value, in order to be compared on a like-for-like basis with fixed rate bonds.

- The AER is aware of a method that applies the Bloomberg YASN function to make the adjustments discussed above. However, the AER has had technical issues with the application of the function, and is undertaking further analysis to address these issues. Accordingly, the AER considers the method for adjusting callable bonds is not, in the current circumstances, sufficiently reliable to include these bonds in the sample.

- Subordinated debt—In the event that a debt issuer defaults, subordinated bond holders would have only secondary claims to any outstanding senior (standard) debt. As investors holding subordinated debt are less likely to fully recover their initial investment (in the event of default), the yields on subordinated bonds are higher than the yields on senior debt.[761] Subordinated bonds are also typically more volatile than standard debt.[762]

  - Banks are the most common issuers of subordinated debt within the relevant AER's sample credit ratings band.[763] The RBA, in its September 2011 Financial Stability Review,[764] stated that:

    > Banks have continued to run down their stocks of subordinated debt over recent years, resulting in a decline in Tier 2 capital. They have done so because these instruments in their current form will not be eligible to be included in capital under the Basel III framework after the transition period ends.[765]

759 These yields would only be the same in the specific cases where the yield-to-maturity and the yield-to-call are equal to the coupon rate.

760 For example, the DRP on a bond listed at its call date in 5 years would subtract the 5 year risk free rate from the observed yield. If this is then adjusted to its yield to final maturity, at 10 years term, the DRP would be calculated using a (typically) higher 10 year risk free rate.

761 Oakvale Capital, *Report on the cost of debt during the averaging period: The impact of callable bonds*, February 2011, p. ii.

762 AER, *Final decision, N.T Gas, Access arrangement proposal for the Amadeus Gas Pipeline*, July 2011, p. 169.

763 During Aurora's averaging period, of the 27 subordinated Australian corporate bonds with terms to maturity of 5 to 15 years and credit ratings from BBB to A–, 23 were issued by commercial banks, 2 by an investment bank, and the remaining 2 by an insurance provider.

764 RBA, *Financial Stability Review*, September 2011, p. 34.

765 The Basel III Accord is an agreement formed through the Bank of International Settlements that governs global minimum requirements for bank capital adequacy. Capital adequacy requirements in turn influence the funding practices of banks. One of the key changes is the removal of 'softer forms of capital', such as subordinated debt, from eligible Tier 2 capital.

- The AER considers that this signals a likely long-term reduction in the issuance of subordinated debt from Australian banks, and therefore from the BBB to A– credit rating band.

- In the current circumstances, the AER does not consider it appropriate to include subordinated debt in the sample used for the purposes of this draft decision. Including subordinated debt in the sample without an appropriate adjustment to account for this risk will reduce the robustness of the sample, and will introduce an upward bias to the DRP estimate.

- The Bloomberg BBB rated FVC—The AER has excluded the Bloomberg BBB rated FVC from its sample, for the following reasons:

  - The Bloomberg FVC is an estimate made using a proprietary methodology that is neither transparent nor verifiable. Bloomberg stated that the FVC is not a predictive source of price information.766 It is therefore not consistent with the AER's approach, comprised exclusively of observed bond data.

  - The Bloomberg 7 year BBB rated FVC (the longest BBB rated FVC currently published) does not currently reflect the available market evidence for long dated bonds, or the stated views of other independent market commentators. The AER considers the Bloomberg BBB rated FVC does not reflect the prevailing cost of debt for the benchmark Australian corporate bond.

Expected inflation rate

The expected inflation rate is not a parameter relevant to the determination of the WACC.[767] However, it is used in the post-tax revenue model (PTRM)—for example to index the RAB—and is an implicit component of the nominal risk free rate. For this reason the AER's determination of the expected inflation rate is discussed in this attachment. The AER's approach to determine the best estimate of inflation is to adopt an average inflation forecast over a 10 year period. The AER uses the RBA's short-term inflation forecasts extending out to two years and the mid-point of its target inflation band of 2.5 per cent for the remaining eight years. The averaging of the individual forecasts derives the implied 10 year forecast of the annual expected inflation rate.

9.4 Reasons for draft determination

For this draft determination, the key issues for the AER in determining the WACC are the values of the DRP and MRP. This section discusses the AER's assessment of Aurora's DRP and MRP, and how the values adopted in this draft decision satisfy the regulatory requirements in the NEL and NER.

The AER's considerations in this section set out the following matters:

- WACC parameter values specified in the SRI, including the MRP and gamma

- parameters sampled from daily data—nominal risk free rate and DRP

- overall rate of return

- expected inflation rate.

These requirements are in their transitional phase. National implementation by member countries will commence on 1 January 2013. See: Bank for International Settlements, *Group of governors and heads of supervision announce higher global minimum capital standards*, September 2010, Available at: [http://www.bis.org/press/p100912.htm].

766 Bloomberg, *Letter to the AER*, October 2011, p. 1.

767 The WACC formulation is based on nominal parameters and does not incorporate an explicit inflation rate parameter.

9.4.1 WACC parameter values in the SRI

In the SRI, the AER specified a number of parameter values:[768]

- equity beta of 0.8
- gearing level of 60 per cent
- MRP of 6.5 per cent
- gamma of 0.65.

9.4.2 Equity beta

The equity beta provides a measure of the 'riskiness' of an asset's return compared with the return on the entire market. The equity beta reflects the exposure of the asset to non-diversifiable (systematic) risk, which is the only form of risk that requires compensation under the CAPM. An equity beta of 1.0 implies that the firm's return has the same level of systematic risk as the overall market. An equity beta of less than 1.0 implies the firm's return is less sensitive to systematic risk than the overall market, and vice versa.

For this draft determination, the AER adopts an equity beta value of 0.8 for the purposes of calculating Aurora's WACC. The AER considers that there is not persuasive evidence justifying a departure from the equity beta value specified in the SRI.

Aurora proposed to apply the equity beta specified in the SRI to calculate its WACC.[769]

The AER notes that submissions received as part of this distribution determination process did not comment on whether there was persuasive evidence to depart from the SRI in respect of the equity beta. The AER is also unaware of any persuasive evidence to cause it to depart from the SRI. Given there is no persuasive evidence before the AER to justify a departure from the value of the equity beta specified in the SRI, the AER adopts the SRI equity beta value of 0.8.

9.4.3 Gearing

Gearing is defined as the ratio of the value of debt to total capital (that is, both debt and equity) and is used to weight the costs of debt and equity when formulating the WACC.

For this draft determination, the AER adopts a gearing level of 60 per cent for the purposes of calculating Aurora's WACC. The AER considers that there is not persuasive evidence justifying a departure from the gearing value specified in the SRI.

Aurora proposed to apply the gearing value specified in the SRI to calculate its WACC.[770]

The AER notes that submissions received as part of this distribution determination process did not comment on whether there was persuasive evidence to depart from the SRI in respect of the gearing level. The AER is also unaware of any persuasive evidence to cause it to depart from the SRI. Given there is no persuasive evidence before the AER to justify a departure from the value of gearing specified in the SRI, the AER adopts the SRI gearing of 60 per cent.

[768] AER, *Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009, p. 7.
[769] Aurora, *Regulatory proposal addendum*, June 2011, p. 14.
[770] Aurora, *Regulatory proposal addendum*, June 2011, p. 13.

9.4.4 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.[771] It represents the risk premium 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.

For this draft determination, the AER rejects Aurora's proposed MRP value of 6.5 per cent (the value specified in the SRI). The AER considers that there is persuasive evidence justifying a departure from this value. The AER adopts an MRP value of 6 per cent for the purposes of calculating Aurora's WACC.

The MRP is a parameter within the CAPM. It is forward looking and is not directly observable. In addition, the available evidence that can be used to estimate the MRP is imprecise and subject to varied interpretation. This point is well recognised in academic literature,[772] as well as in reports put forward by regulated entities.[773] As a result, a degree of judgment is required to determine the MRP value that meets the legislative requirements. In particular, the MRP should lead to 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.

In its regulatory proposal, Aurora proposed to adopt the MRP value specified in the SRI.[774] Aurora did not provide any particular assessment or reasoning on this issue.

For the reasons discussed below, the AER considers there is persuasive evidence that justifies a departure from the MRP value specified in the SRI. There has been a material change in circumstances since the SRI was published.

Based on the evidence, the AER concludes that there is persuasive evidence to justify a departure from an MRP of 6.5 per cent to an MRP of 6 per cent. The AER also considers that an MRP of 6 per cent satisfies the requirements of the NER.[775] This MRP value will:

- result in the determination of 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 Aurora.
- 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 the DNSP with a reasonable opportunity to recover at least the efficient costs, and effective incentives to promote economic efficiency with respect to the provision of network services.

771 Assets are classified as risky where there is uncertainty over future return outcomes. See AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, p. 175.
772 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.
773 See for example Officer and Bishop, *Market risk premium, a review paper*, August 2008, pp. 3–4.
774 Aurora, *Regulatory proposal addendum*, June 2011, p. 13.
775 NER, clause 6.5.4(h).

Below is more detail on why the MRP was increased to 6.5 per cent in the WACC review, and why it is now appropriate to return to 6 per cent.

The six per cent consensus

Prior to the 2009 WACC review, Australian regulators consistently applied an MRP of 6 per cent in regulatory decisions.[776] 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.[777] 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 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. Although the AER recognises that the evidence may encompass a range of possible MRP values, in this case the AER has exercised its judgement to set the value of the MRP at 6 per cent.

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.[778]

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.[779]

The 6 per cent consensus is illustrated in Table 9.4, 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.

[776] AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, p. 176.

[777] 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.

[778] AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, p. 236.

[779] AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, pp.100–101.

Table 9.4 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,[780] ICRC,[781] IPART,[782] ESCOSA,[783] QCA,[784] OTTER,[785] ESC[786], ERA[787]
Notes: This list is not exhaustive. Reported decisions were selected to give a spread of years and industry sectors.

The SRI outcome

On 1 May 2009, the AER published its review of WACC parameters in the SRI. The AER reviewed a range of evidence to inform its decision on the best estimate of the forward looking 10 year domestic MRP in accordance with the relevant requirements in the NEL and the NER. This estimate was based on a range of information including historical estimates, survey estimates, cash flow based measures and past regulatory practice. However, the AER acknowledged the uncertainty in the markets at that time. The AER considered one of two scenarios could explain the market conditions at the time:[788]

- The prevailing medium-term MRP was above the long-term MRP, but would return to the long-term MRP over time, or

780 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.

781 ICRC, *Final decision, Investigation into prices for electricity distribution services in the ACT*, March 2004, p. 70.

782 IPART, *Revised access arrangement for Country Energy gas network, Final decision*, November 2005, p. 69.

783 ESCOSA, *Proposed revisions to the access arrangement for the South Australian as distribution system, Final decision*, June 2006, p. 80.

784 QCA, *Final decision, Revised access arrangement for gas distribution networks: Allgas Energy*, May 2006, p. 62.

785 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania, Final report and proposed maximum prices*, September 2007, p. 152.

786 ESC, *Gas access arrangement review 2008–2012, Final decision, Public version*, March 2008, p. 489.

787 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

788 AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, p. 238.

- 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.

The AER considered that there was insufficient evidence at that time to establish which scenario was the correct interpretation. The inability to distinguish between these two scenarios should be understood in the context of the CAPM framework that had informed decisions on the MRP.

- The forward looking expected MRP remained unobservable, and there remained disparate expert views.[789] There was little data on market conditions after the onset of the GFC simply because such a short-time span had elapsed.[790] This made it particularly difficult to determine if a structural break had occurred, since the appropriate test is to compare data from before and after the break point but the latter category was largely empty. Further, evidence which was explicitly forward looking (such as survey based estimates) was sparse.

- Long-term (10 year) market expectations needed to be distinguished from short-term effects of the GFC. It is difficult to separate transient market sentiment from long-term expectations other than in hindsight. In several cases (such as implied volatility analysis) the short-term conditions could be observed but there was considerable doubt about how these would relate to a longer horizon.

- The domestic impact of the GFC needed to be distinguished from the international impact. Although domestic and international conditions are linked, it was not yet clear to what extent the Australian economy would be influenced by international experience.

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.[791] The AER noted that this increase was appropriate under either scenario, even though it could not identify which was the correct interpretation.

The AER has evaluated, on the evidence currently before it, whether either scenario is correct.

No structural break has occurred

The AER considers that the GFC did not generate a structural break in the MRP, even though this might have been a plausible interpretation of the available evidence in May 2009. Although opinion varies, the GFC began to affect Australian capital markets in late 2007 or 2008.[792] At the time of the WACC review, the AER therefore had (at most) eighteen months of data regarding conditions after the onset of the GFC. There is now almost four years of evidence available. The AER considers that the GFC did not generate a structural break because:

- Survey measures since the GFC accord with those from before the GFC[793]

[789] 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.

[790] The AER acknowledges that there is ongoing debate about the precise starting date for the GFC (particularly with regard to Australian capital markets), but considers that a range of commencement dates across late 2007 or 2008 are plausible.

[791] AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, p. 228.

[792] As noted above, the start date for the GFC is contentious. The AER does not presume to precisely date the GFC.

[793] See Fernandez (2009), Fernandez and Del Campo (2010), Fernandez et al (2011), Asher (2011).

- Market commentary from the RBA and other economic commentators does not indicate that the GFC resulted in a structural break[794]

- Implied volatility returned to the long run average after the GFC.[795]

These matters are discussed in detail below. The GFC was a significant event and its magnitude should not be understated. However, the GFC now seems best interpreted as not being fundamentally different from earlier historical dislocations in financial markets. This is particularly true for Australian capital markets, where the impact of the GFC 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.[796] 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.

The 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 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:

- Historical excess returns (updated to the end of 2010)

- Survey measures from after the GFC

- Dividend growth models from after the GFC

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 (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, the present market conditions are comparable to the market conditions that generally existed across the fluctuating business cycles through the last fifteen years. The MRP for a forward looking 10 year horizon (encompassing business cycles, as such a time horizon necessarily entails) will be the same now as pre-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 9.5.

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794 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.

795 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.

796 Burns and Mitchell, *Measuring business cycles*, National Bureau of Economic Research, 1946.

Table 9.5 Regulatory decisions from 2010 onwards with an MRP of 6 per cent

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
ESC	August 2011	Rail	6.0
ACCC	September 2011	Airports	6.0

Source: ACCC,[797] AER,[798] ERA,[799] ESC,[800] QCA.[801]

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,[802] including in the AER's gas network decisions in March and June 2010.[803] 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.[804] This includes determinations by different Australian regulators and for various regulated sectors.

797 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.

798 AER, *Final Decision, APT Allgas Access arrangement proposal for the Qld gas network, 1 July 2011–30 June 2016*, 17 June 2011, p. 41.

799 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.

800 ESC, *Metro proposed access arrangement, Final decision, August 2011*, p. 85.

801 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.

802 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.

803 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.

804 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.

Importantly, those that had increased their MRP have subsequently had published decisions returning to the 6 per cent MRP.[805]

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 improvements in financial markets, there is now a 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 with setting the MRP at its long-term estimate of 6 per cent.

The AER considers that the available evidence is that 6 per cent is appropriate as a forward looking estimate of the 10 year MRP.

Historical excess return estimates

The latest long-term historical estimates of excess returns, adjusted to incorporate a value for the imputation credit utilisation rate (theta) of 0.35, produce a range of 3.6–6.4 per cent based on different sampling periods and averaging methods as set out in Table 9.6.[806] The starting points for each sampling period were chosen because of changes in the underlying data sources (1883, 1937, 1958 and 1980) and the introduction of the imputation tax system (1988).[807]

Table 9.6 Historical excess return estimates—assuming an imputation credit utilisation rate of 0.35 (per cent)

Sampling period	Arithmetic mean	Geometric mean
1883–2010	6.2	4.8
1937–2010	5.9	3.9
1958–2010	6.4	3.8
1980–2010	6.2	3.6
1988–2010	5.6	3.7

Source: Handley.[808]

The AER has considered estimates of historical excess returns that have been explicitly 'grossed-up' for an assumed value of theta of 0.35.[809] That is, the historical excess return estimates considered by the AER were first estimated using data on dividends and capital gains from accumulation indices,

805 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.

806 The geometric mean estimates ranged from 3.6–4.8 per cent over different sampling periods (1883–2010, 1937–2010, 1958–2010, 1980–2010 and 1988–2010), while the arithmetic mean estimates ranged from 5.6–6.4 per cent.

807 Brailsford, Handley and Maheswaran, *Re-examination of the historical equity risk premium in Australia, Accounting and Finance*, vol. 48, 2008, pp. 85–86.

808 Handley, *Memorandum, Additional Estimates of the Historical Equity Risk Premium for the Period 1883 to 2010*, 25 May 2011, p. 2.

809 This value is consistent with the theta estimate used to determine the cost of corporate income tax for this draft decision.

and observations of yields on 10 year CGS. These estimates were then adjusted for an assumed theta value.[810]

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 range:[811]

- 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 the 1883 data source the least reliable and more reliable data sources 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.

On balance, the AER considers that the three longest time series (from 1883, 1937 and 1958) should all be given primary consideration, but the shorter time series (from 1980 and 1987) are also relevant.

In arriving at an estimate of a 10-year MRP using historical annual MRP data, it is important to consider both the arithmetic and geometric means.

The AER has previously noted the widely held view that the use of arithmetic means is appropriate when arriving at a forward looking estimate. However, it is also imperative to understand the nature of the value being estimated. As noted previously, the CAPM is a single period model, with its components aligning to that period. Consistent with the Tribunal's decision, the risk-free rate component of the CAPM is set at 10 years. Consequently, the MRP must be a 10-year estimate, even though it is expressed in annual terms.[812]

Therefore, in estimating the MRP, one must look at the return on the market for 10 years over the return on the risk-free asset for the same 10 years. This is similar to the AER's determination of the DRP, where the debt premium is determined for the entire 10 year period, rather than the arithmetic average of premia from 10 one-year periods.

Historical data, on the other hand, is usually presented in terms of annual returns and annual MRPs. However, a 10 year MRP can be approximated from annual MRPs by determining a geometric average of ten annual MRPs within that 10 year period. This geometric average approximates the 10 yearly MRP in annual terms.[813]

In historical studies noted above, the geometric averages estimate a cumulative return over the relevant sample period. This period is significantly longer than the 10 year time horizon assumed for

810 Handley, *An Estimate of the Historical Equity Risk Premium for the Period 1883 to 2010*, 25 January 2011, pp. 3–4.

811 See also AER, *Final decision, Review of weighted average cost of capital parameters,* 1 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.

812 Indeed, the MRP is estimated as a return on the market portfolio over the return on the 10-year risk-free asset.

813 For example, a 10 per cent per annum 10 year MRP equals a total return of 159.7% over 10 years.

the forward looking MRP,[814] and is likely to understate the historical excess return over a 10 year horizon. On the other hand, arithmetic means of historical excess returns are likely to overstate the historical 10 year excess return to some degree. This is because they do not take account of the cumulative effect of returns over a 10 year horizon.

The AER considers that the best estimate of historical excess returns over a 10 year period is likely to be somewhere between the geometric mean and the arithmetic mean of annual excess returns (between 3.6–6.4 per cent). Consequently, the AER considers that the latest historical excess return estimates, derived from more up to date data since the SRI, supports a forward looking long-term MRP of 6 per cent. Given that this estimate is at the top of the quoted range, the AER considers that, if anything, it has erred on the side of caution when making its assessment for regulated businesses.

Survey based estimates

In the SRI, the AER noted that survey evidence of the MRP prior to the onset of the GFC supported a forward looking estimate of 6 per cent.[815] The latest survey based estimates of the MRP indicate that the forward looking MRP expected to prevail in the future has not changed as a result of the GFC. In fact, the survey evidence did not indicate a step change in the MRP employed by market practitioners even at the height of the GFC. In chronological order, these surveys include the following:

- KPMG (2005) found that the MRP adopted in independent expert valuation reports ranged from 6–8 per cent. KPMG's report showed that 76 per cent of survey respondents adopted an MRP of 6 per cent.[816]

- Capital Research (2006) found that the average MRP adopted across a number of brokers was 5.09 per cent.[817]

- Truong, Partington and Peat (2008) found that 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.[818]

- Fernandez (2009) found that the MRP used by Australian academics in 2008 ranged from 2–7.5 per cent with an average of 5.9 per cent.[819]

- Fernandez and Del Campo (2010) 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.[820]

- A further survey by Fernandez et al (2011) reported that average MRP used by 40 Australian respondents ranged from 5–14 per cent, with an average of 5.8 per cent.[821]

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814 The AER considers that an assumption of a 10 year time horizon for the forward looking MRP is appropriate to maintain consistency with the term of the risk free rate proxy used in the CAPM.

815 AER, *Final decision, Review of weighted average cost of capital parameters*, 1 May 2009, pp. 221–225.

816 KPMG, *Cost of capital – market practice in relation to imputation credits*, August 2005, p. 15.

817 Capital Research, *Telstra's WACC for network ULLS and the ULLS and SSS businesses – Review of reports by Prof. Bowman*, March 2006, p. 17.

818 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.

819 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.

820 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.

821 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.

- Asher (2011) reported that 33 out of a total of 58 Australian analysts responded to the survey expects 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.[822]

The latest survey evidence indicates that the MRP applied by market practitioners does not appear to have changed as a result of the GFC. Further, in its recent South Australian gas access arrangement review, the AER noted that the range of MRP estimates used in broker reports is between 5 to 6.5 per cent, with an average of approximately 5.9 per cent.[823] In addition to this, recent research completed by Shane Oliver, Head of Investment Strategy and Chief Economist at AMP Capital Investors, suggested that the likely equity risk premium for a 5 to 10 year period is 5.9 per cent based on historical data.[824] However, Oliver noted that this realised equity risk premium is probably exaggerated by a low starting point for the price to earnings ratio, making it easier for shares to provide decent returns. Oliver stated that AMP Capital Investors' estimate of the prospective required equity risk premium for shares is around 3.5 per cent.[825]

The AER is of the view that survey based estimates of the MRP are relevant for consideration. They provide some indication that expectations of the forward looking long-term MRP have not been affected by the GFC. They also show that a structural break of the type considered at the time of the WACC review has not occurred. Moreover, this evidence supports the view that a forward looking MRP of 6 per cent is the best estimate in the current circumstances.

Current market conditions and economic outlook

Since the date of the SRI, there has been a material change in market conditions.

First, the AER notes comments from respected market commentators that the GFC had little impact on Australia relative to international experience. The Deputy Governor of the Reserve Bank explained why the GFC did not have a major effect on the Australian economy in this way:

> While there was some sub-prime lending activity in Australia, it was on a small scale, and mainly by non-bank lenders. As such, arrears rates on housing loans have remained at low levels, and Australian banks have remained profitable. Australia, therefore, did not have a home-grown financial crisis in 2008/09, and its financial institutions also had little direct exposure to the US housing market. As a consequence, just as had been the case in 2001, Australia experienced only a mild economic slowdown in 2008/09.[826]

This RBA statement then goes on to describe the role of China in protecting the Australian economy from the GFC. This sentiment is also supported by the World Economic Outlook released in September 2011. In this report the IMF stated that the economic outlook for Australia is favourable as it is supported by strong terms of trade and positive trade spillovers from Asia. Growth is forecast to pick up from 1.8 per cent in 2011 to 3.3 per cent in 2012, and remain steady in the medium term at 3.3 per cent to 2016.[827] The consensus view of respected market commentators is that the Australian economy has emerged from the GFC relatively unscathed. Economic activity is returning to the long run average.

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822 Actuary Australia 2011 Issue 161, Asher, *Equity Risk Premium Survey – results and comments*, July 2011, pp. 13–14.

823 AER, *Final decision, Envestra Ltd Access arrangement proposal for the SA gas network*, June 2011, p. 200.

824 This value also incorporates the imputation credit value.

825 AMP Capital Investors, *Are shares good value and what about bank deposits?, Oliver's insights*, 16 September 2010.

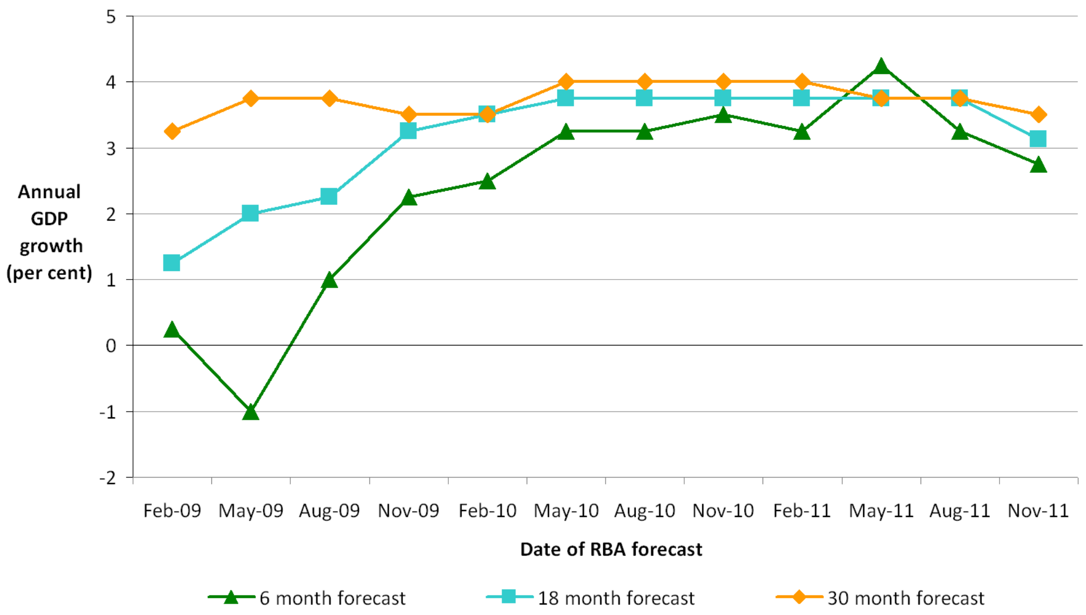
826 Rick Battellino, Deputy Governor, *Reserve Bank of Australia, Will Australia catch a US cold?, Address to the Euromoney Forum*, 21 September 2011, available online at <http://www.rba.gov.au/speeches/2011/sp-dg-210911.html>, accessed 1 November 2011.

827 IMF, *World Economic Outlook (WEO)*, pp. 86–87 and Table A.2, September 2011, available at http://www.imf.org/external/pubs/ft/weo/2011/02/index.htm

The AER does not directly equate overall economic activity with the MRP. Nonetheless, the general economic conditions are a relevant consideration, particularly with regard to the assessment of whether or not a structural break occurred at the time of the GFC. There is theoretical support for the consideration of economic activity in the estimation of the MRP,[828] and in practice economic conditions are routinely cited when market analysts explain their return expectations.[829]

The limited impact of the GFC on long-term expectations can be illustrated with reference to RBA forecasts for economic growth. Since February 2009,[830] the RBA Statement of Monetary Policy has included short-term forecasts for Australian gross domestic product (GDP) growth, extending out to 2.5 years from the date of each statement.[831] Figure 9.1 depicts the annual GDP growth rate for different forecast horizons, relative to the date of each RBA statement.

Figure 9.1 RBA forecasts of changes in Australian gross domestic product



Source: RBA Statements of Monetary Policy from February 2009 to November 2011, AER analysis.
Notes: As statements are published quarterly but projection end dates only change semi-annually, there is rounding of up to two months in the forecast dates.

Figure 9.1 shows that even at the height of the GFC, the RBA considered that the GFC would have little impact on the Australian economy beyond the short-term. In May 2009, the 6 month forecast was for a 1 per cent decline in GDP.[832] However, at the same date the 30 month forecast was for GDP growth of 3.25 per cent.[833] In fact, across the entire period shown in Figure 9.1, the forecast for GDP growth at a 2 year horizon remains within the 3 to 4 per cent band, equal to the long-term historical

828 For example, see 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, the 2011 edition*, February 2011, working paper.

829 For example, see AMP Capital Investors, *Are shares good value and what about bank deposits?, Oliver's insights*, 16 September 2010; and the various broker reports referenced in section 9.4.8.

830 The AER has examined earlier Statements of Monetary Policy but could not find equivalent RBA forecasts.

831 The statements are published quarterly but projection end dates only change semi-annually. Hence, the projections extend between 28 and 31 months.

832 More specifically, this is an annual growth rate for the year ending in six months time—that is, the year starting six months before May 2009 and ending six months after May 2009. There is a time lag before GDP data is available, so even though half this year has past, it is still labelled a forecast.

833 More specifically, this is the annual growth rate forecast for the year starting in 18 months time and finishing in 30 months time.

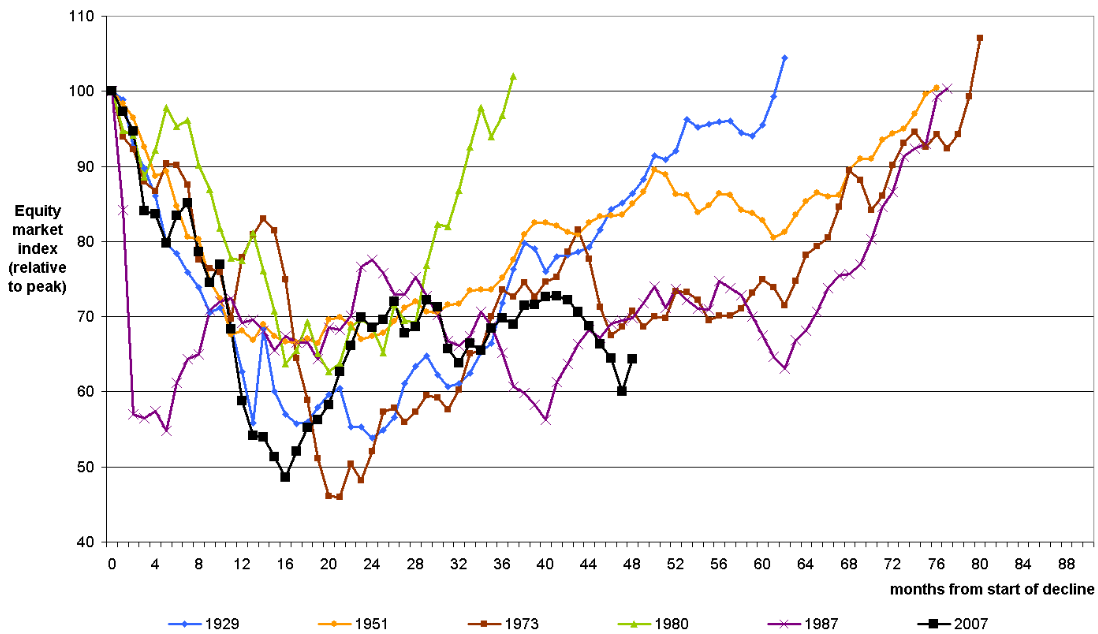
average growth rate. This is true even though the GDP projection at the 6 month horizon varies substantially, above and below the historical average. That is, the RBA did not consider that the impact of the GFC would reduce GDP growth rate expectations at a 2 year horizon, let alone for a 10 year horizon.

These RBA statements support the conclusion that:

- no structural break has occurred in the equity markets
- any adverse effects on the relevant horizon (10 years starting in 2012) have subsided.

Figure 9.2 shows the current status of the Australian equity market relative to the pre-GFC peak (October 2007) and compared to other prior market downturns. As at the end of October 2011, the equity market index had recovered to approximately 65 per cent of the pre-GFC peak. Although this suggests that the market had not yet fully recovered from the GFC, it supports the view that the GFC did not generate a structural break. Considering both the length and depth of each downturn, similar events occurred in 1987 and 1973, and comparable events occurred in 1980, 1951 and 1929. The GFC is similar to other prior downturns in the market, as discussed above—they are part of cyclical trends in financial markets.

Figure 9.2 Time to recovery of the Australian equity market after major market downturns



Source: Wren Research, ASX All Ordinaries Index monthly average data (1929-2000); Bloomberg, ASX All Ordinaries Index month end data (2000-2011).

Considering the range of evidence available,[834] the AER is of the view that current conditions in economic and financial markets:[835]

[834] That is, not just the equity index presented in figure 9.1, but also the market commentary on economic and financial markets and implied volatility analysis (presented below).

[835] To clarify, these assessments relate to current conditions and (less directly) to short term expectations. Such an assessment has limited relevance to long term investor expectations and the 10 year MRP. However, the current conditions still provide support for the rejection of a structural break.

- have improved since the height of the GFC in early 2009
- have not returned to the heights experienced just before the onset of the GFC (in late 2006 and early 2007)
- still reflect some uncertainty about future economic conditions.

It is important to note the AER does not consider that the market conditions now are identical to the market conditions just before the GFC, but that this is a normal aspect of economic and financial markets. The present market conditions are comparable to the market conditions that generally existed across the fluctuating business cycles through the last fifteen years, given the cyclical nature of the financial market.

The RBA makes a balanced assessment:

> At this juncture, the US and Australian economies find themselves in very different cyclical positions. The United States is still struggling to recover from the deep recession caused by the sub-prime crisis, while Australia, having grown for 20 years, is operating with relatively little spare capacity and is investing heavily to meet rapidly growing demand for resources from China, and elsewhere in Asia.
>
> A topical question at present is whether the recent turmoil in global markets will eventually overwhelm the positive effects on the Australian economy from China.
>
> That could occur either because the financial uncertainty undermines household and business confidence, and therefore consumer and investment spending, or because the turmoil also weakens the Chinese economy, leading to reduced demand for resources.
>
> It is simply too early to be able to answer this question.[836]

The AER acknowledges the uncertainty in the markets. However, it considers that the level of uncertainty is consistent with a 6 per cent MRP. The level of uncertainty is below that existing during the GFC, when the AER increased the MRP to 6.5 per cent. In relation to the potential impact of the European sovereign debt issue on markets outside of the European region, the RBA stated:

> Compared with the pre-crisis [GFC] period, the major banking systems should be better positioned to cope with a period of renewed market stress. Most large banks in the major advanced countries have strengthened their capital and funding positions over recent years. While banks in Europe are carrying significant aggregate exposures to debt of the sovereigns whose creditworthiness has declined, there is less uncertainty about problem exposures than there was during the 2008 crisis. This is partly because sovereign bonds are less complex than the structured securities that sparked the crisis [GFC], and partly because recent supervisory stress test results provided detailed data to markets about those exposures. These differences should help to limit any contagion effects compared with those seen during 2008–09.[837]

That is, the RBA considered that even if the European sovereign debt issue escalates, the effect on non-European banking systems will be less than that of the GFC. In addition to the comments from the RBA, the AER observes that:

- there are no significant monetary and fiscal policy changes being implemented by the RBA and the government respectively in response to the current circumstances in the market. In contrast, such responses were put in place during the GFC
- the latest economic outlook from the RBA, OECD and IMF for Australia as noted above remains robust despite the recent development in the financial market.

836 Rick Battellino, Deputy Governor, *Reserve Bank of Australia, Will Australia catch a US cold?, Address to the Euromoney Forum*, 21 September 2011, available online at <http://www.rba.gov.au/speeches/2011/sp-dg-210911.html>, accessed 1 November 2011.

837 RBA, *Financial Stability Review, Overview*, September 2011, p. 1.

At its November 2011 meeting, the RBA lowered the overnight money market interest rate (the cash rate) by 25 basis points to 4.50 per cent. The RBA described this as a return to a neutral monetary policy stance:

> Over the past year, the Board has maintained a mildly restrictive stance of monetary policy, in view of its concerns about inflation. With overall growth moderate, inflation now likely to be close to target and confidence subdued outside the resources sector, the Board concluded that a more neutral stance of monetary policy would now be consistent with achieving sustainable growth and 2–3 per cent inflation over time.[838]

This can be compared with changes in the cash rate around the onset of the GFC. In the six months commencing in September 2008, the RBA lowered the cash rate by 400 basis points to 3.25 per cent, with another reduction of 25 basis points to 3.00 per cent in April 2009.

On balance, the AER considers that the current circumstances in the market represent a materially different scenario compared to that which occurred at the time when the SRI decision was made. Therefore, for this draft decision, the AER considers that there is persuasive evidence to justify a departure from the approach it took in the SRI.

There is overall a more robust outlook for long-term Australian economic and financial markets than was the case at the height of the GFC. Therefore, the conditions that underlined the AER's reasons for increasing the MRP to 6.5 per cent in the SRI appear to no longer be present.

Dividend growth model analysis

Using DGM analysis[839] with adjustments to incorporate market wide assumptions, the AER estimates the range of MRP is approximately 4.5–5.6 per cent over a notional 10 year horizon. The estimates are based on the following assumptions, which the AER considers to be reasonable:

- a theta value of 0.35, consistent with the value applied in estimating the cost of corporate income tax for this draft decision[840]
- an assumed dividend growth rate of 6 per cent, consistent with long-term GDP growth estimates from the RBA of approximately 3.5 per cent[841] and an assumed inflation rate of approximately 2.5 per cent, consistent with long-term inflation forecasts[842]
- a dividend yield of approximately 4–5 per cent, consistent with average dividend yields on the ASX 200 index[843]

The above DGM analysis suggests that a forward looking 10 year MRP of 6 per cent is not unreasonable.

838 RBA, Statement by Glenn Stevens, Governor: Monetary policy decision, 2 November 2011, available online at http://www.rba.gov.au/media-releases/2011/mr-11-24.html, retrieved 4 November 2011.

839 The DGM analysis was developed by CEG, on behalf of Envestra, and submitted the model to the AER as part of the South Australian gas access arrangement review for 2011–16.

840 See section 9.4.5.

841 RBA, *Statement on monetary policy*, May 2011, p. 63.

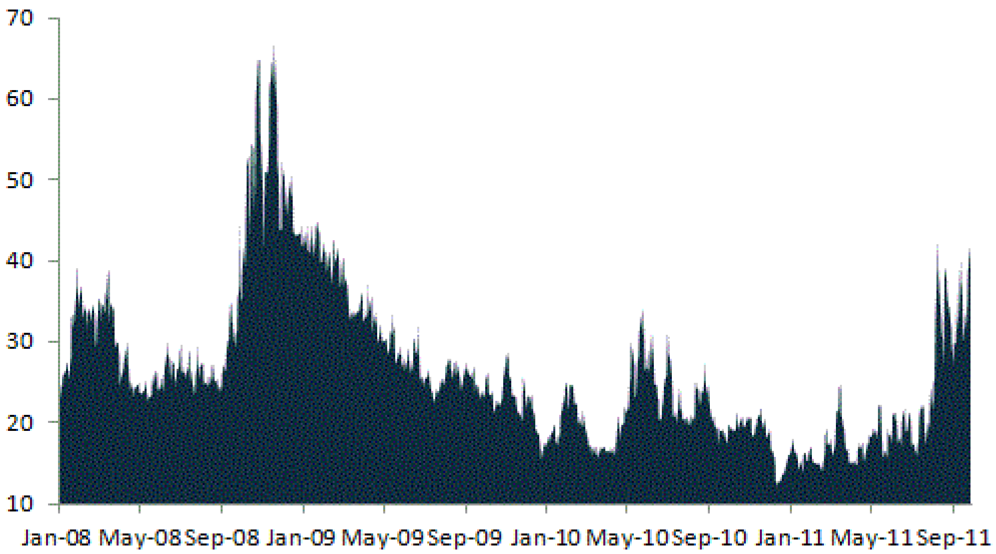
842 The 2.5 per cent inflation forecast represents the mid-point of the RBA inflation target band of between 2–3 per cent, See RBA, *About Monetary Policy,* available at http://www.rba.gov.au/monetary-policy/about.html, retrieved 5 October 2011.

843 Average dividend yields estimated from the MSCI Australia index for 2005–2011 as reported in RBA statistical tables, Table F.7 – share market, available at http://www.rba.gov.au/statistics/tables/pdf/f07.pdf, retrieved 13 May 2011. This is also reflected in Capital Research's DGM analysis, which illustrates that most analysts' forecasts of dividend yields since 1999 have been around 4–5 per cent; see CR, *Forward estimates of market risk premium*, April 2011, p. 15. SFG has suggested that the current dividend yield of approximately 4 per cent is higher than much of the past decade; see SFG, *Issues affecting the estimation of MRP*, 21 March 2011, p. 11.

Implied volatility analysis

Under this method, the current level of volatility in the stock market can be estimated using the Black-Scholes option-pricing formula. However, implied volatility varies significantly and provides only a very short-term view of market volatility at any point in time. This can be seen in Figure 9.3.

Figure 9.3 Implied volatility on S&P/ASX200 as reported by the ASX



Source: ASX.[844]

Based on the following research, the AER has a number of concerns with the use of implied volatility to inform the forward looking estimate of the MRP over a 10 year horizon:

- The research by Doran et al found that short run volatility had a surprisingly small impact on the medium-term MRP. Specifically, they found that short-term volatility only has a 10 per cent weight in determining the medium term volatility and suggested 'that investors focus more on long-term volatility and are relatively insensitive to short-term volatility swings.' Doran et al also found that their implied risk approach produced a negative implied equity risk premium from S&P 500 index option prices during periods of 'irrational exuberance'.[845]

- Santa-Clara and Yan studied the ex ante risk premiums implied from S&P 500 index option prices. Their research showed that option implied volatility is much higher than realised market risk. Santa-Clara and Yan stated:[846]

> …the average premium that compensates the investor for the risks implicit in option prices, 11.8 per cent, is about 40 per cent higher than the premium required compensating the same investor for the realised volatility in stock market returns, 6.8 per cent.

[844] ASX, http://www.asx.com.au/products/indices/types/sp_asx200_vix_index.htm, retrieved 12 September 2011.

[845] Doran, Ronn and Goldberg, *A simple model for time-varying expected returns on the S&P 500 index*, working paper, University of Texas, June 2005, p. 19.

[846] Santa-Clara and Yan, *Crashes, volatility, and the equity premium lessons from S&P options*, *Review of Economics and Statistics, 92(2)*, May 2010, p. 450.

Chernov studied the role of risk premia in volatility forecasting and explained why at-the-money option implied volatility is a biased and inefficient forecast of future realised volatility.[847]

Therefore, the AER considers that option implied volatility is too variable to be used as a basis for estimating the forward looking 10 year MRP. In its recent South Australian gas access arrangement decision, the AER also reviewed the implied volatility and 'glide-path' approach for estimating the MRP.[848] The 'glide path' approach incorporates a highly variable one year estimate of the MRP based on implied volatility and then combines it with a long-term historical MRP estimate over a five year horizon. Consistent with that decision, the AER considers the use of the implied volatility and the 'glide-path' approach does not provide a reliable method of estimating the forward looking 10 year MRP. Realised excess market returns fluctuate significantly between a positive and a negative MRP. It is quite possible that in any one year realised excess market returns will be below their long-term estimate, but this was not taken into account in the 'glide-path' analysis.

Further, the AER is not aware of a reliable way of directly estimating the MRP over a one year period (let alone for a 10 year time horizon) using implied volatility from option prices. For the reasons discussed above and consistent with the SRI, the AER has placed little weight on the implied volatility analysis to inform the appropriate MRP for this draft decision.

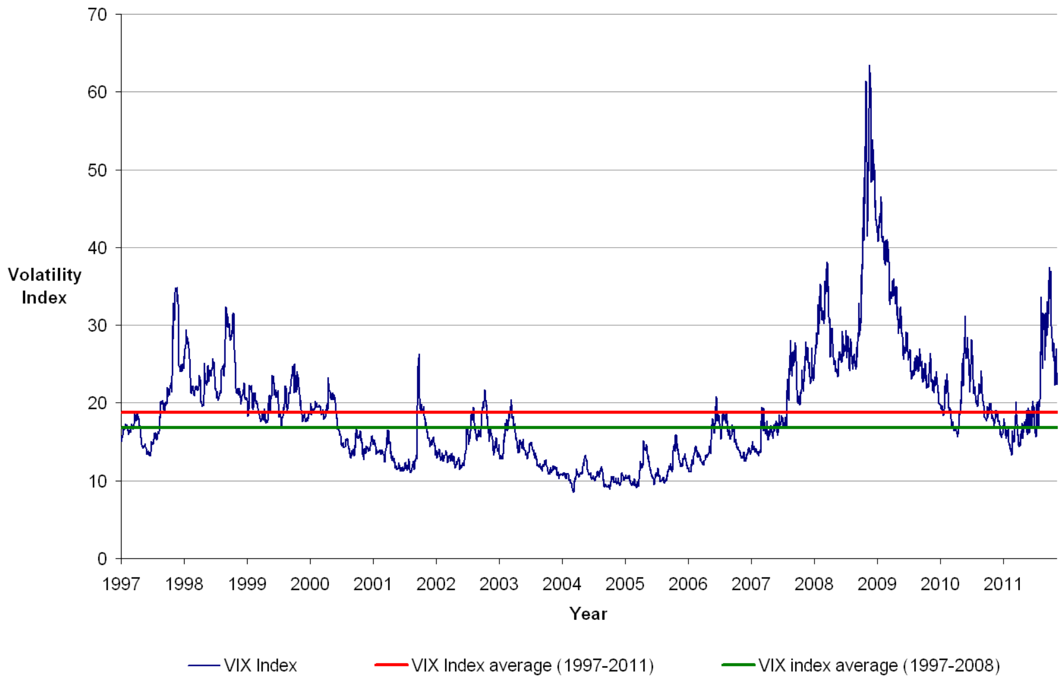
However, the AER notes that the implied volatility studies support its conclusion that:

- there has been no structural break in the market that would result in a higher MRP
- any temporary worsening of market conditions subsides over the short-term.
- The assessment is also informed by a broader context for implied volatility levels, as shown in Figure 9.4.

[847] Chernov, *On the role of risk premia in volatility forecasting, Journal of Business and Economic Statistics*, October 2007, vol. 25, no. 4, pp. 411–426.

[848] AER, *Draft decision, Envestra Ltd Access arrangement proposal for the SA gas network*, June 2011, pp. 280–283; and AER, *Final decision, Envestra Ltd Access arrangement proposal for the SA gas network*, June 2011, pp. 195–197.

Figure 9.4 Implied volatility from prices of 3 month options on the ASX 200 index



Source: Bloomberg, AER analysis.

As evident from Figure 9.4, implied volatility has subsided from the height of the GFC. Implied volatility returned to the long-term average briefly in early 2010, and then again around late 2010 and early 2011. This supports the position that there was no structural break as a result of the GFC, but that this was a temporary elevation. Further, the increase in implied volatilities resulting from the GFC subsided in less than two years—well within the 10 year estimation period. This also supports the position that such short-term measure has little relevance to a long-term (10 year) MRP estimate.

Figure 9.4 also provides appropriate context for the recent (from August 2011) increase in implied volatility above the long-term average. This increase in implied volatility is comparable to the increase in 1998, and remained below the height of the GFC (late 2008). For the reasons discussed above, the AER considers that this level of implied volatility has limited relevance for the long run MRP estimate.

9.4.5 Gamma

Under the Australian imputation tax system, domestic investors receive a credit for tax paid at the company level (an 'imputation credit' or gamma) that offsets part or all of their personal income tax liabilities. For eligible shareholders, imputation credits represent a benefit from the investment in addition to any cash dividend or capital gains received.

For this draft determination, the AER adopts a gamma value of 0.25 for the purposes of estimating Aurora's corporate income tax allowance. The AER considers that there is persuasive evidence justifying a departure from the gamma value specified in the SRI.

Aurora proposed a gamma value of 0.25 in its regulatory proposal.[849] This value is based on the findings by the Tribunal in its review of the AER's 2010 distribution determinations for Energex, Ergon

[849] Aurora, *Regulatory proposal addendum*, June 2011, pp. 13–14.

Energy and ETSA Utilities.[850] Aurora stated that the Tribunal's decision provides persuasive evidence justifying a departure from the value of gamma set in the SRI.

The AER accepts Aurora's proposal to adopt the value of 0.25 for gamma. There is no new evidence before the AER to cause it to vary from the findings of the Tribunal. On this basis, the AER agrees that the Tribunal's decision contains persuasive evidence to justify a departure from the value of gamma set in the SRI. Consistent with the Tribunal's decision, the payout ratio estimate of 70 per cent multiplied by the estimated value for a dollar of distributed imputation credits (theta) of 0.35 provides a gamma estimate of approximately 0.25.

9.4.6 Debt risk premium

The DRP is the margin above the nominal risk free rate that a debt holder would require in order for it to invest in a benchmark efficient firm. When combined with the nominal risk free rate, the DRP represents the cost of debt and is an input for calculating the WACC.

The cost of debt varies depending on the firm's default risk. The risk of default is generally taken into account by a firm's credit rating and reflects both the operational and financial risks of the debt issuance.[851] Typically, a lower credit rating is associated with a higher yield to maturity demanded by investors. The cost of debt will also vary depending on the term of the debt. Higher yields are often associated with longer terms of debt.

The AER does not accept Aurora's proposed DRP. In particular, the AER considers it is not appropriate to rely on the extrapolated 7 year Bloomberg BBB rated FVC to estimate the DRP. The AER has calculated the DRP based on the average of observed bond yields from the market. This approach results in the allowed cost of debt to reflect the current cost of borrowing.[852]

For this draft determination, the 20 business days moving average for observed bond yields for the period ending 14 October 2011, results in an indicative benchmark DRP of 3.14 per cent (effective annual compounding rate). The AER will update the DRP, based on the agreed averaging period, at the time of its final determination.[853]

Aurora proposed to apply the benchmark term of 10 years and a credit rating of BBB+ set in the SRI to estimate the DRP.[854] Submissions received as part of this distribution determination process did not comment on whether there was persuasive evidence to depart from the SRI in respect of the benchmark term and credit rating. The AER is also unaware of any persuasive evidence to cause it to depart from the SRI. Given there is no persuasive evidence before the AER to justify a departure from the approach specified in the SRI, the AER adopts the benchmark assumptions of a 10 year term and credit rating of BBB+ for the purposes of estimating the DRP.

Based on these benchmark assumptions, Aurora proposed a DRP of 4.54 per cent. Aurora proposed the approach to estimate the DRP using the Bloomberg BBB rated 7 year FVC extrapolated to a 10 year term to maturity.[855] The AER does not accept Aurora's proposed approach to estimate the DRP.

[850] Australian Competition Tribunal, *Application by Energex Limited (Gamma) (No. 5)[2011] ACompT 9*, 12 May 2011, paragraph 42.

[851] Other factors can affect bond yields, such as bond size, market sentiment, industry prospect and comparable bond issuances.

[852] Based on the benchmark assumption of Australian corporate bond with a term of 10 years and credit rating of BBB+.

[853] For internal consistency within the WACC formulation specified in clause 6.5.2(b), the same averaging period used to determine the nominal risk free rate will be used to determine the DRP (see section 9.4.7).

[854] Aurora Energy, *Cost of capital, 2012–2017 electricity distribution revenues*, April 2011, p. 6.

[855] Based on the indicative averaging period of 20 business days ending on 25 March 2011. Aurora, *Regulatory proposal addendum*, June 2011, p. 14.

As part of assessing Aurora's proposal, the AER has taken into account the EUAA's submission. The EUAA stated that the AER should carefully scrutinise Aurora's proposed approach to estimate the DRP and considered the AER's previous approach had produced excessive DRP estimates.[856]

The AER considers its sample based approach is consistent with the requirement under the NER that the DRP be based on the observed annualised Australian benchmark corporate bond rate.[857] This is because observed yield data is the best available source of data on the prevailing market perceptions of investors. While some bonds may have specific characteristics, or may be perceived by investors as different to the AER's benchmark assumptions,[858] a sample based average containing sufficient market data should mitigate these differences to some extent. The sample based approach, with appropriately selected parameters,[859] would therefore provide an appropriate estimate of the benchmark DRP that is consistent with the NER requirements.

The AER considers its sample based approach is consistent with the requirements under the NER and NEL, for the following reasons:

- The AER's sample based approach closely reflects the observed Australian benchmark corporate bond rate,[860] as the input data is derived from observed yields on Australian corporate bonds.
- The sample parameters of the AER's approach are chosen to ensure a sufficient number of bonds that is, on average, a close match to the benchmark 10 year BBB+ standard fixed rate bond.[861]

For these reasons, the sample based DRP estimate should provide Aurora with a reasonable opportunity to recover at least its efficient costs, and effective incentives to promote economic efficiency with respect to the provision of network services.[862]

The AER considers its sample based approach is also consistent with guidance from the Tribunal. In the reasons for its decision on the DRP review for ActewAGL, the Tribunal stated that:

> In a robust bond market, it would likely be possible for the AER to calculate the yield based on particular representative bonds issued in Australia in reasonably close proximity to the time of the AER's determination.
>
> In the absence of a deep market for corporate bonds, the AER will likely have to rely on published fair value curves to estimate benchmark debt financing costs.[863]

The AER considers this reasoning supports a view that:

- where market data is available, it is possible to estimate the DRP using this data
- where market data is not available, FVCs are a viable second-best alternative.

856 EUAA, *Submission to the Australian Energy Regulator on Aurora Energy's regulatory proposal on distribution prices for 2012–2017*, August 2011, p. 17.

857 NER, clause 6.5.2(e).

858 The 10 year benchmark reflects consistency with the term of the risk free rate, while the BBB+ credit rating reflects what the AER determined during the WACC review following consideration of comparable energy businesses. AER, *Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009, p. 7.

859 Such parameters include the ranges of terms and credit ratings allowed in the sample, and the required adjustment for inclusion of non-standard bonds in the sample. These factors are discussed in the AER's approach to assessing the DRP, and should ensure that the sample consists only of bonds that are informative and relevant to the benchmark DRP.

860 NER, clause 6.5.2(e).

861 As defined in the SRI, NER clause 6.5.2(e).

862 NEL, part 1, section 7A)2)–(3).

863 Australian Competition Tribunal, *Application by ActewAGL Distribution*, September 2010, paragraphs 74–75.

Applying the approach outlined above, the AER considers the sample size in the current circumstances comprising 9 bonds is sufficiently robust, particularly when compared with the deficiencies of Bloomberg's 7 year BBB rated FVC.

Conversely, the AER considers that Aurora's proposed DRP is excessive and does not satisfy the requirements of the NER and NEL.[864] In particular, the AER considers Aurora has, in estimating the DRP, had insufficient regard to:

- achieving 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[865]
- the regulatory and commercial risks involved in providing the network service, and the economic costs and risks of the potential for under and over investment.[866]

The AER's approach to estimating the benchmark DRP has evolved and has been refined in response to changing circumstances of data availability and quality. In previous regulatory determinations, the AER used FVCs to estimate the DRP.[867] The AER's use of the FVC to estimate the DRP was principally a consequence of there being limited observable pricing data for relevant long-term corporate bond issuances. In making its December 2010 distribution determination for the Victorian electricity networks, the AER moved from exclusive reliance on the use of FVCs to a weighted average of the Bloomberg BBB rated (extrapolated) FVC and the observed APA Group bond yield to estimate the benchmark DRP.[868] Independent market evidence and commentary suggested the Bloomberg BBB rated FVC had not reflected improvements in Australian debt market conditions since the GFC. The AER considered the APA Group bond was a close comparator to the benchmark corporate bond, and that its observed yield should therefore be used to estimate the DRP.

In making its recent June/July 2011 gas access arrangement decisions,[869] the AER identified five recently available observations of long dated bonds that were close comparators to the benchmark corporate bond.[870] The observed yields on these bonds were consistent with those observed for the APA Group bond, having accounted for differences in credit rating and term. They provided further support for relying on the APA Group bond instead of only the Bloomberg FVC. Taking account of the evidence, the AER considered that more weight could be placed on the APA Group bond yield for the purposes of estimating the benchmark DRP.[871]

For the reasons discussed below, the AER does not consider it appropriate to continue relying on the Bloomberg BBB rated FVC to set the DRP. In light of the increased volume of observed market data currently available, and ongoing market evidence and commentary that suggest the Bloomberg BBB rated FVC does not reflect prevailing Australian bond market conditions, the AER considers the sample based average of relevant observed bonds would result in an appropriate estimate of the DRP.

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864 NER, clauses 6.5.2 and 6.5.4.

865 NEL, part 1, section 7.

866 NEL, part 1, section 7A(5)–(6).

867 See for example AER, *Final decision, Queensland distribution determination 2010–11 to 2014–15*, May 2010, p. 252.

868 See AER, *Final decision, Victorian electricity distribution network service providers, Distribution determination 2011 to 2015*, October 2010, pp. 514–515.

869 See for example AER, *Final decision, Access arrangement proposal for the Amadeus Gas Pipeline*, July 2011, pp. 181–182.

870 SP AusNet and Stockland issued A– rated, 10-year bonds, and Brisbane Airport issued two BBB rated 8-year bonds, and observed yields for two BBB rated Sydney Airport floating rate notes (maturing in 2021 and 2022) became available.

871 AER, *Final decision, N.T. Gas, Access arrangement proposal for the Amadeus Gas Pipeline*, July 2011, pp. 167–178.

Analysis of sample based approach

The AER's sample of bonds, as observed during the indicative averaging period, is set out in Table 9.7. The sample has an average remaining term of approximately 10 years, and an average credit rating between BBB and BBB+. To the extent that lower credit ratings result in higher yields, the sample is likely to produce a conservative estimate of the DRP.

Table 9.7 Bond sample used to estimate the DRP

Bond issuance	Term to maturity (years)[a]	S&P credit rating	DRP (per cent)[b]
APA Group	8.8	BBB	3.03
Brisbane Airport	7.7	BBB	2.64
Sydney Airport	10.1	BBB	3.77
Sydney Airport	11.0	BBB	3.86
Dalrymple Bay Coal Terminal	9.7	BBB+	4.26
Dalrymple Bay Coal Terminal	11.2	BBB+	3.69
Coca Cola Amatil	10.0	A–	1.42
SPI Electricity and Gas	9.5	A–	2.63
Stockland Trust	9.1	A–	2.97
Average	**9.7**		**3.14**

Source: Bloomberg, UBS, AER analysis.
Notes:
(a) Term to maturity at the end of the averaging period.
(b) Based on 20 business day averaging period ending 14 October 2011.

Based on the review of available data, the AER concludes that a DRP of 3.14 per cent satisfies the requirements of the NER.[872] The AER considers its DRP estimate will contribute to a rate of return that promotes efficient investment in Aurora's network, and reflects the regulatory and commercial risks of providing its network services. Table 9.8 sets out the debt refinancing outlooks for various NSPs, compiled from market analyst reports.

[872] NER, clauses 6.5.2 and 6.5.4.

Table 9.8 Market analyst outlooks

Company	Market analyst	Comments on debt outlook
APA Group (BBB)	Macquarie Equities Research	APA is expected to refinance $900 million bank debt at approximately 240 bps spreads
Spark Infrastructure Group (A–)	Macquarie Equities Research	Debt spreads relatively constant for A– rated stocks, with spreads at ~150bps compared to 160bps last year. SKI however demonstrated at both CHEDHA and ETSA they could raise debt at better spreads and, we believe, ahead of their budgets
DUET Group (BBB–)	Bank of America Merrill Lynch	The DUET Group (BBB–) has refinanced $3 billion of debt at approximately ~300 bps since April 2011. Recent refinancing by other BBB– assets has been conducted at ~330 bps

Source: Macquarie Equities Research,[873] Bank of America Merrill Lynch.[874]

While this commentary is limited to specific providers of regulated network services, the AER notes the following:

- The three groups discussed account for 15 gas and electricity NSPs subject to full regulation.[875] The estimates can therefore inform the debt market outlook for at least a wide range of regulated utilities.
- Of these three groups, two have credit ratings within the AER's sample range to estimate the cost of debt (A– to BBB–). To the extent that credit ratings influence required spreads, the expected spreads for BBB+ rated debt should lie between those for A– (~150bps) and BBB– (~330bps) rated debt. As a BBB+ rating is closer to an A– rating (1 band removed) than a BBB– rating (2 bands removed), the AER considers it is reasonable to assume the expected spreads on a BBB+ should be closer to 150bps than to 330bps.
- The AER's estimated DRP (314bps) is within the top of the range considered in the market commentary.

Also, in discussing the AER's historical approach to estimating the DRP and the DRP outlook for Australian regulated utilities, market analyst Credit Suisse stated:

> It is clear why the AER is having some concerns with the current methodology, with recent regulatory decisions gaining a debt risk premium of over 400bp… In the most recent decision, the AER stated that, without its modification to the accepted methodology, the DRP would have hit 469bp. This is extraordinary when compared with BBB-band companies borrowing at rates more in the order of 300bp.[876]

- This suggests a DRP of approximately 300 basis points is appropriate for the benchmark NSP. The AER's DRP estimate of 314 basis points is consistent with this commentary. Credit Suisse has also stated that DRP estimates derived using the proposed methodology are 'extraordinary'.

873 Macquarie Equities Research, *APA Group—Predictable with a dividend twist*, August 2011, p. 2; Macquarie Equities Research, *Spark Infrastructure Group—An A– credit, A+ yield*, September 2011, p. 2.

874 Bank of America Merrill Lynch, *DUET Group—Gearing fixed, 10% yield attractive*, August 2011, p. 4.

875 Specifically: APA Group–Amadeus Gas pipeline (gas transmission), APT Allgas (gas distribution), Central Ranges pipeline (gas transmission), Central Ranges network (gas distribution), Direct & Murraylink Interconnectors (electricity transmission), GasNet (gas distribution) Moomba to Sydney pipeline (gas transmission), Roma to Brisbane pipeline (gas transmission); Spark Infrastructure Group–ETSA Utilities (electricity distribution), Citipower (electricity distribution) and Powercor (electricity distribution); DUET Group–Dampier to Bunbury Pipeline (gas transmission), United Energy (electricity distribution), Multinet (gas distribution).

876 Credit Suisse, *Regulated utilities, sector review—Debt risk premium at risk in future WACCs*, November 2011, p. 3.

The AER considers this supports a movement away from reliance on the Bloomberg BBB rated FVC, as approaches relying on the FVC have produced these extraordinary results.

The Bloomberg BBB rated FVC

The AER considers the Bloomberg BBB rated FVC is a second-best source of pricing information for estimating the benchmark DRP.[877] FVCs may be useful—and have been used—to estimate the DRP where insufficient relevant market data is available. The Bloomberg FVC is derived from estimates made by a market data provider, which are then reconciled with observed yield data drawn mostly from short dated bonds.[878] The proprietary techniques used to produce the yield estimates cannot be assessed by third parties. This limits the ability of interested parties to gauge the efficiency of the underlying estimates, or to what extent they reflect the available market observed data. The AER understands the FVC:

- is not intended to be a predictive source of pricing information.879 The AER considers it should be interpreted as a supplementary source of data where prices cannot be obtained for relevant bond comparators
- excludes floating rate bonds from the sample used to generate the FVC, which prevents representation of the full range of available information880
- is calculated by minimising the deviation between a predicted yield and the observed yield information in a constituent sample of bonds. Where there are few or no long dated bonds in the sample, the AER considers the scope for the FVC estimate to differ from a 'true' price at the benchmark term is likely to increase.

In its recent regulatory decisions for the Queensland, South Australian and Northern Territory gas service providers, and the Victorian electricity service providers, the AER estimated the DRP based on the spreads of the observed yields of the APA Group bond and the Bloomberg 7 year BBB rated FVC, extrapolated to 10 years.[881] In making these decisions, the AER considered the following:

- The Bloomberg BBB rated (extrapolated) FVC is not transparent, and the resulting spreads had behaved contrary to what would be expected under prevailing market conditions. Specifically, recent evidence published by the RBA in its bulletins suggested a narrowing of debt spreads since the GFC, while the extrapolated FVC produced estimates that remained above levels observed during the GFC. The RBA's view was corroborated by reports from the IMF, the OECD, and Moody's Investors Service—all indicating an improvement in Australian debt market conditions.[882]
- The (then) recent issuance of several long dated bonds further suggested the extrapolated Bloomberg BBB rated FVC was not a reliable estimator of long dated corporate bond yields. In

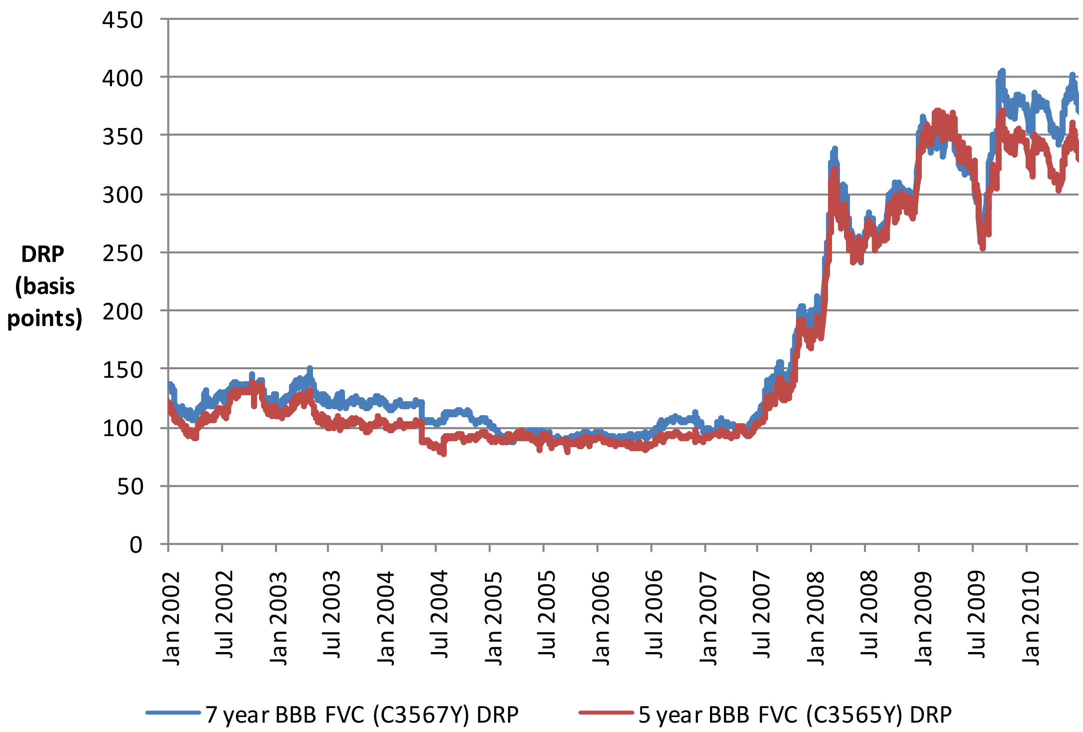
877 Australian Competition Tribunal, *Application by ActewAGL Distribution*, September 2010, paragraphs 74–75.
878 That is, with five or less years remaining term to maturity.
879 Bloomberg, *Letter to the AER,* October 2011.
880 Bloomberg, *Letter to the AER,* October 2011.
881 Using the spread between the 7 and 10 year Bloomberg AAA rated FVCs, which is no longer available (publication ceased on 22 June 2010). The AER applied different proportions to the data sources to estimate the DRP in the Queensland/South Australian/Northern Territory gas and Victorian electricity decisions.
882 AER, *Final decision, N.T. Gas, Access arrangement proposal for the Amadeus Gas Pipeline*, July 2011, pp. 167–178.

contrast, the observed yields for bond issuances were consistent with those for the APA Group bond.[883]

- The bonds used to derive the Bloomberg BBB rated FVC consisted largely of bonds with less than 5 years term-to-maturity, which may have explained the disparities between the observed yields for long dated bonds and the Bloomberg FVC estimates.[884]
- Both Bloomberg and CBASpectrum had ceased publication of their 10 year FVCs, which might indicate a lack of confidence in the reliability of the FVC estimates for long-term debt.[885]

The AER maintains its view about the problems of relying on the Bloomberg BBB rated FVC to estimate the benchmark DRP. Further analysis since the time of those decisions shows that the long dated FVC estimates have remained at historical highs, despite consistent independent commentary indicating an improvement of Australian debt market conditions. Figure 9.5 shows that the Bloomberg BBB rated 5 and 7 year FVC spreads increased markedly from 2007–2009, and remain at (5 year FVC) or above (7 year FVC) the spreads observed during the GFC.

Figure 9.5 Implied DRP—Bloomberg 5 and 7 year BBB rated FVCs



Source: Bloomberg, RBA, AER Analysis.

In contrast, the RBA stated in its August 2011 Statement on Monetary Policy that:

> Spreads between corporate bond yields and CGS have increased a little over the past few months but remain well below the levels of the past few years.[886]

883 AER, *Final decision, N.T Gas, Access arrangement proposal for the Amadeus Gas Pipeline*, July 2011, pp. 176–178.

884 *AER, Final decision, Victorian electricity distribution network service providers, Distribution determination 2011–2015, October 2010, p. 509.*

885 AER, *Final decision, N.T Gas, Access arrangement proposal for the Amadeus Gas Pipeline*, July 2011, p. 167.

886 RBA, *Statement on Monetary Policy*, August 2011, p. 60.

Market analyst JP Morgan, discussing recent Australian regulated utility debt refinancing, stated that:

> The encouraging reality for the regulated utilities is that, for the moment at least, **global appetite for BBB rated Australian utility debt remains buoyant**. Refinancing of existing debt facilities, alongside the funding of future expansion projects, has driven significant debt issuance sector-wide. While margins remain higher than pre-GFC levels, **funding costs have diminished materially since 2008-09**.[887] (emphasis added)

Similarly, market analyst Bank of America Merrill Lynch recently stated, in discussing the expected cost of debt allowance for Multinet Gas Network (a regulated gas utility) by reference to recent regulatory decisions:

> We note the current WACC under MGN's current regulatory period is ~8.81%. Recent regulatory decisions for UED and ENV's gas distribution networks in SA and QLD suggests that a more favourable outcome could be expected. **But we note that debt markets have progressively improved**. As such, the debt premiums received by UED and ENV will likely represent the blue-sky scenario. We think that a debt risk premium of ~280bps is more likely.[888] (emphasis added)

Figure 9.6 shows the 5 year iTraxx credit default swap index (CDSI) plotted against the Bloomberg 5 year BBB rated FVCs.[889] The CDSI reflects the prevailing Australian market perceptions of market default risk, based on the prices of credit default swaps (CDSs) for highly liquid Australian corporate entities.[890] The liquidity of the underlying instruments makes the iTraxx CDSI a robust indicator of market perceptions on default risk.[891] In general, the DRP, for a standard fixed rate bond, exclusively reflects the risk that the investor will not be paid out in full for its investment. This in turn is based on the likelihood of default and the probability of recovery in the event of default. The Bloomberg FVCs therefore should move broadly in line with the CDSI, which also increases with heightened perceptions of default risk. At any point in time, the iTraxx yield should not necessarily be equal to the FVC prediction, because they are based on distinct financial instruments with different characteristics. Nonetheless, the overall shape of the curves should be similar.

887 JP Morgan, *The Wire, NSW power selloff…Round 2; APA refinance*, November 2011, p. 7.

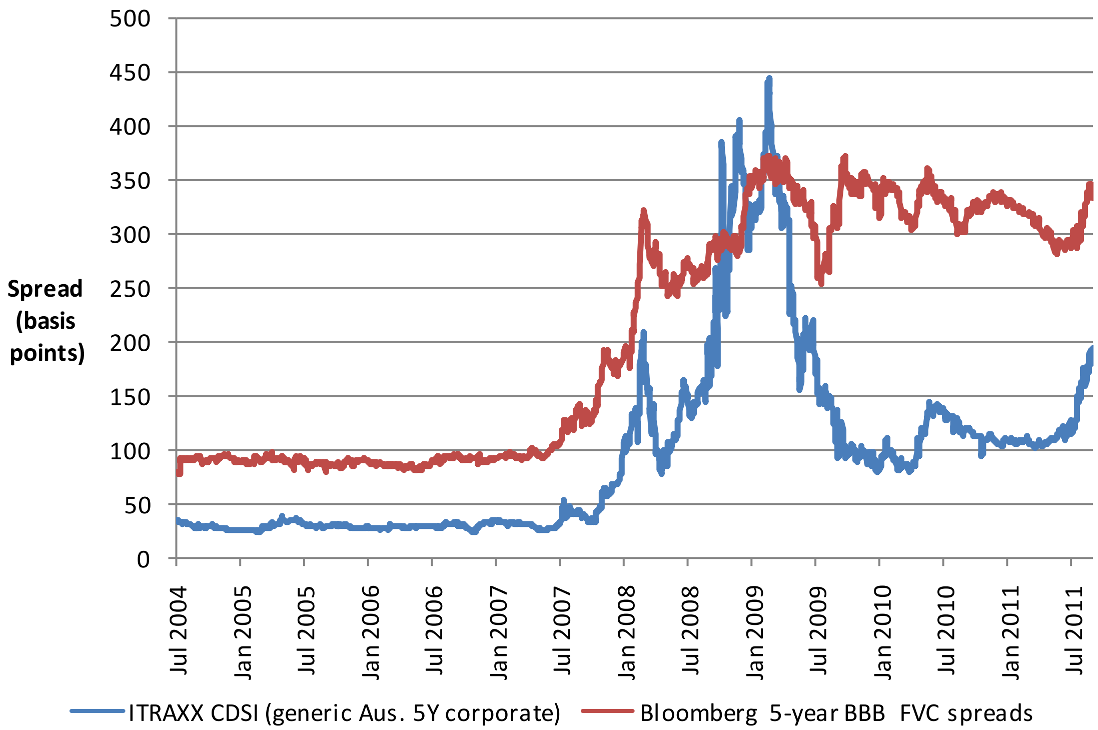
888 Merrill Lynch, *DUET Group—Earnings review*, August 2011, p. 6.

889 The 5 year ITRAXX CDSI is the most liquid and most widely used index of its kind. The AER has therefore compared this series against the 5 year BBB rated FVC, to ensure that market perceptions of default risk are compared over the same term.

890 Credit default swaps (CDSs) are agreements between two parties (A and B) where party B purchases a CDS from party A relating to a specific debt issuer, and party A agrees in return to pay a specified value back to party B if the specified issuer defaults. The iTraxx CDSI is based on an equally weighted average of CDS prices for the 25 most liquid investment-grade Australian corporate entities.

891 Market analyst JP Morgan uses the iTraxx index as a 'gauge for the measurement of credit risk facing local borrowers'. See: JP Morgan, *The Wire, NSW power selloff…Round 2; APA refinance*, November 2011, p. 8.

Figure 9.6 Perceptions of default risk—iTraxx CDSI compared to the Bloomberg 5 year BBB rated FVC



Source: Bloomberg, RBA, AER analysis.

Before July 2008, the iTraxx CDSI and Bloomberg FVCs tracked closely. Between January 2009 and January 2010, the iTraxx CDSI decreased sharply from its peak during the GFC. This suggests that the perceived risk of default in the market had decreased markedly. In contrast, the Bloomberg BBB rated FVC has remained at levels at or near those observed during the GFC. The divergence between the CDSI and the FVC, suggests that reductions in the perceived risk of default for Australian corporates have not been observed in the Bloomberg BBB rated FVC. The Bloomberg BBB rated FVC therefore does not appear to reflect prevailing market conditions, and appears likely to overstate the benchmark DRP.

In circumstances where insufficient market data is available, the FVCs may be used to estimate the benchmark DRP. However, where sufficient market data is available, the AER considers that observable market data should be used as the primary source of pricing information. As the Bloomberg BBB rated FVC does not currently reflect the available market evidence for long dated bonds, or the stated views of other independent market commentators, the AER considers the Bloomberg BBB rated FVC does not reflect the prevailing cost of debt for the benchmark Australian corporate bond.

Extrapolation of the Bloomberg BBB rated FVC

Bloomberg does not currently publish any BBB or AAA FVCs at longer than 7 years term to maturity. It ceased publishing the 10 year BBB FVC in October 2007, and ceased publishing the 7 and 10 year AAA FVCs in June 2010. Consequently, Aurora's proposed methodology uses spreads between the Bloomberg 7 year AAA rated FVC and the 10 year AAA rated FVC to extrapolate the 7 year BBB rated FVC.[892] This approach has been accepted by the AER in previous decisions, but these were made in closer proximity to the last published date of the AAA FVC spreads.[893] When the AER determines Aurora's DRP for the final decision, the 7–10 year AAA rated FVC spread will be almost 2 years old. Continued extrapolation of the Bloomberg 7 year BBB rated FVC using this data relies on the assumption that the spreads between FVCs of different credit ratings and terms have not varied since June 2010. Aurora has not provided any assessment to support the reliability of this assumption in its regulatory proposal.

Figure 9.7 demonstrates that, the spreads between terms of the Bloomberg AAA and BBB rated FVCs have regularly and substantially changed since Bloomberg ceased publication of the 7 and 10 year AAA FVCs.[894] This is inconsistent with Aurora's approach, which assumes these spreads are sufficiently stable that it would be appropriate to use the last recorded 7–10 year AAA rated FVC spread at the time of this final decision. Each series in Figure 9.7 shows the difference in spread for the corresponding FVC with different terms.[895] In order to conclude that spreads between terms are relatively consistent, these series should be constant (or flat). In contrast, they vary by up to 50 basis points. A variation of 50 basis points in the extrapolation of the FVC could result in a 0.5 per cent difference to the DRP estimate, or approximately 0.3 per cent to the overall WACC. The AER considers it is not appropriate to assume that spreads between FVCs have been stable since the 7 and 10 year AAA FVCs were last published.

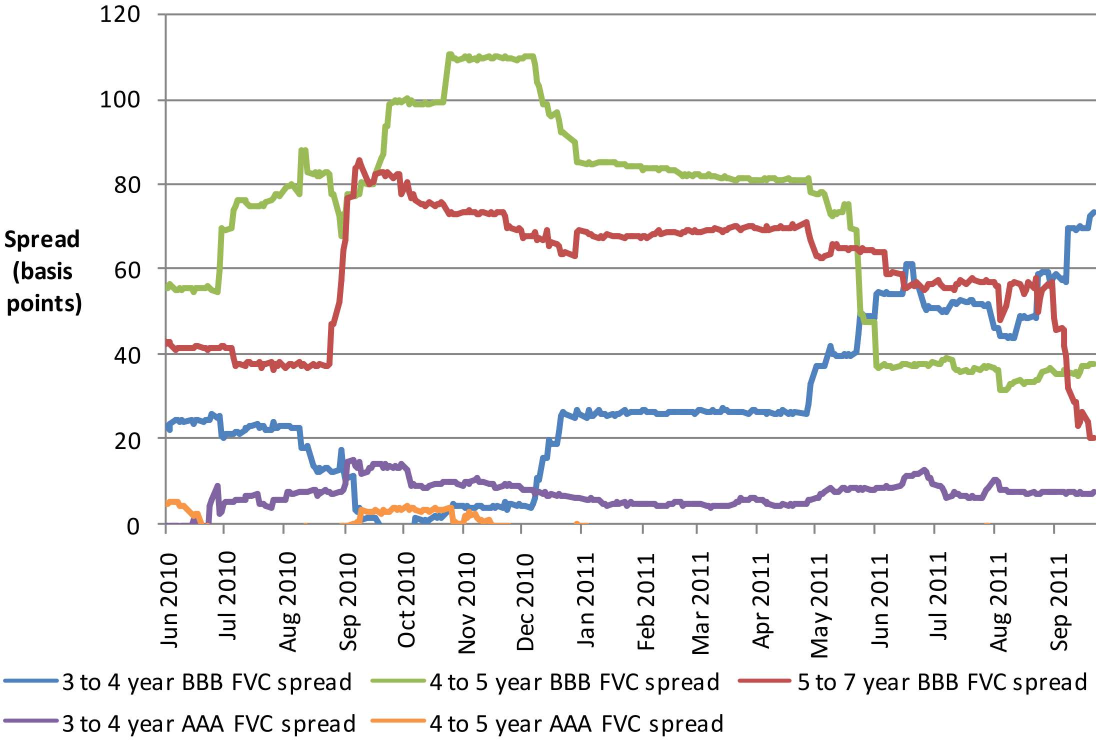
892 Aurora Energy, *Cost of capital, 2012–2017 electricity distribution revenues*, April 2011, pp. 8–9.

893 The Bloomberg 10 year AAA FVC was last published on 22 June 2010.

894 The BBB rated FVCs were used for this demonstration as they are both directly relevant to the benchmark cost of debt, and because there are no contemporaneous AAA rated FVCs at longer than 5 years with which to make such a comparison.

895 For example, the '3 to 4 year BBB FVC spread' is calculated as the implied 4 year DRP (being the 4 year FVC yield minus the 4 year risk free rate) minus the implied 3 year FVC DRP (being the 3 year FVC yield minus the 3 year risk free rate). Where the spread falls below zero, this suggests that the implied DRP for the shorter of the two terms is higher than the implied DRP for the longer term—that is, a negative sloping DRP. This may indicate that either the FVC yield at the shorter term exceeds that at the longer term, or it may indicate the risk free rate between terms increases by a greater margin than the FVC yields increase.

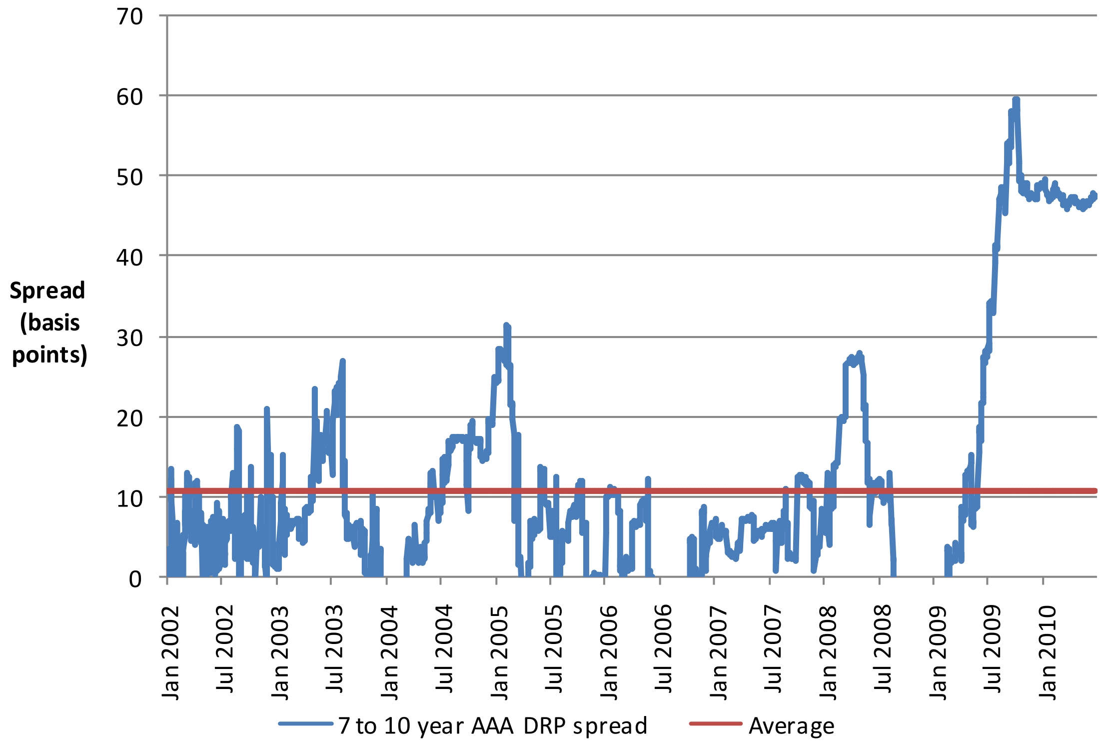
Figure 9.7 Bloomberg AAA and BBB rated FVC spreads since June 2010



Source: Bloomberg, RBA, AER Analysis.

Bloomberg has not published the 7 or 10 year AAA rated FVCs since June 2010. Accordingly, there is no scope to check the recent stability of spreads between FVCs with longer terms. Figure 9.8 demonstrates, using the same method applied to derive Figure 9.7, that the spreads between the 7 and 10 year AAA rated FVCs have not been constant over time. Further, during the period in which Aurora's extrapolation is based (June 2010), the 7–10 year AAA rated FVC spread was nearly 50 basis points above its 10 year average. Based on the above analysis, the AER does not consider that Aurora's extrapolation methodology reflects current circumstances in the Australian bond market. It is therefore not appropriate for the purposes of estimating the DRP in the current circumstances of data availability.

Figure 9.8 Historical DRP spreads between the 7 and 10 year AAA FVCs



Source: Bloomberg, RBA, AER Analysis.

Sensitivity analysis

The AER, in developing its sample based approach, set parameters to define which bonds would be included in the sample. These decisions were made based on theoretical considerations, data reliability and past Tribunal guidance. The AER then performed the following sensitivity analysis on these parameters. Based these tests, the AER considers its sample based approach will closely reflect the benchmark Australian 10 year, BBB+ rated corporate bond.

Inclusion of BBB, BBB+ and A– rated bonds

Based on the averaging period employed for this draft decision, only two relevant bonds were available with BBB+ ratings. The AER considers this is too small a sample to form a robust estimate of the DRP. It is therefore appropriate also to include BBB and A– rated bonds in the sample.

The 7–13 year term range

The AER's approach uses a 7–13 year term range (symmetrical around the benchmark term of 10 years) to select bonds for the sample.[896] Table 9.9 sets out the sample sizes and DRP estimates, using the AER's approach and various term ranges. On this basis, the AER considers the following:

- The 7–13 year sample produces a sample with an average credit rating between BBB and BBB+, and an average term of approximately 9.7 years.

896 Specifically, the 7–13 year term results in bonds in the sample with an average term to maturity of approximately 10 years. It also results in an equal number of issuances with credit ratings higher (A–) or lower (BBB) than the benchmark BBB+ rating. This should, holding other factors constant, balance the effect of bond specific factors, such as systematically higher or lower yields due to credit ratings. It should therefore result in a representative average.

- The narrower 9–11 year sample reduced the sample size by 50 per cent, and resulted in an average credit rating between BBB+ and A– and an average term of 9.9 years.
- The wider 5–15 year sample increased the sample size, and produced a slightly higher DRP. [897] The AER considers the higher average DRP, despite a shorter average remaining term and credit rating between A and A–, suggests that factors other than credit rating and term influence yields.

Overall, the AER considers the 7–13 year sample produces a sufficiently robust sample size, an average term to maturity that closely matches the benchmark, and a conservative credit rating distribution.

Table 9.9 Sensitivity test—term range

Term range scenarios	DRP	Sample size	Average term to maturity	Credit rating distribution
9 – 11 years	3.15	6	9.9	BBB: 2 BBB+: 1 A–: 3
7 – 13 years	3.14	9	9.7	BBB: 4 BBB+: 2 A–: 3
5 – 15 years	3.21	13	9.2	BBB: 4 BBB+: 4 A–: 5

Source: Bloomberg, UBS, AER analysis.

Floating rate bonds

The AER's approach includes floating rate bonds in its sample. Table 9.10 sets out the sample sizes and DRP estimates, with floating rate bonds included and excluded. The AER considers:

- Inclusion of floating rate bonds increases the sample size, and provides an average credit rating of between BBB and BBB+ and an average term of approximately 9.7 years.
- Exclusion of the floating rate bonds reduces the sample size, and provides a credit rating of between BBB+ and A– and an average term of approximately 9 years.

Overall, the AER considers that the inclusion of the floating rate bonds provides a more robust sample that closely reflects the benchmark term and credit rating.

897 Although 21 bonds with remaining terms of 5–7 years were excluded from this potential sample due to non-standard features. Specifically, these bonds were either callable or subordinated or both.

Table 9.10 Sensitivity test—floating rate bonds

Callable bond scenarios	DRP	Sample size	Average term to maturity	Credit rating distribution
Including floating rate bonds	3.14	9	9.7	BBB: 4 BBB+: 2 A–: 3
Excluding floating rate bonds	2.59	5	9.0	BBB: 2 BBB+: 0 A–: 3

Source: Bloomberg, UBS, AER analysis.

Aurora's 'reasonableness checks'

At page 20 of its cost of capital attachment (AE066),[898] Aurora included a chart to graphically support the reasonableness of the proposed DRP, which was estimated using the extrapolated Bloomberg BBB rated FVC. The AER considers, in contrast with Aurora's proposal, that the chart shows the extrapolated Bloomberg BBB rated FVC is consistently higher than the observed market data. Specifically:

- of the 13 yield observations with greater than 5 years term to maturity, 10 observations are below the Bloomberg BBB rated FVC, many by at least 50 basis points
- of the BBB or BBB+ rated bonds with greater than 5 years term to maturity, 5 of the 8 data observations lie below the Bloomberg BBB rated FVC. The 5 higher (A–) rated bonds all lie below the Bloomberg BBB rated FVC
- of the 3 BBB or BBB+ yield observations above the Bloomberg BBB rated FVC, all are from one issuer—specifically DBCT (BBB+). The AER has previously excluded DBCT bonds from reasonableness checks, on the basis that their yields were driven primarily by factors other than their credit ratings.[899] More recently, the yields on the DBCT bond maturing in 2021 have dropped below the Bloomberg BBB rated FVC.

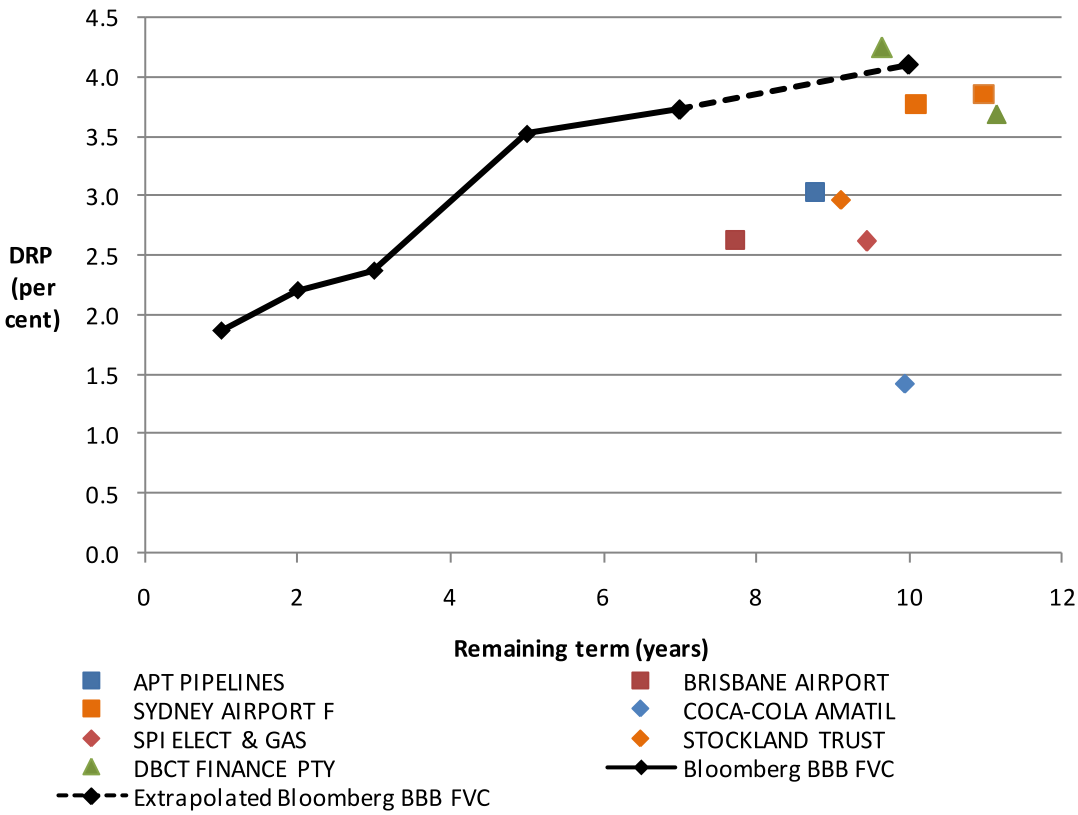
For the draft decision averaging period, Figure 9.9 shows a comparison of the bonds in the AER's sample, selected on the basis of appropriateness for comparison with the benchmark, and the Bloomberg BBB rated FVC. This chart shows that:

- Of the 9 bonds in the sample, 8 are below the FVC including BBB, BBB+ and A– rated bonds of varying terms—some longer than the Bloomberg BBB rated FVC.
- Of the one bond above the FVC, the issuer (DBCT) has issued another bond that lies below the Bloomberg BBB rated FVC, despite having a remaining term of greater than 11 years.

This suggests that the Bloomberg BBB rated FVC overstates the required DRP for the observed benchmark Australian corporate bond.

898 Aurora Energy, *Cost of capital, 2012–2017 electricity distribution revenues*, April 2011, p. 20.
899 AER, *Draft decision, N.T Gas, Access arrangement proposal for the Amadeus Gas Pipeline*,, April 2011, p. 207.

Figure 9.9 Bloomberg (extrapolated) BBB rated FVC compared to the relevant bond sample A– to BBB rated fixed and floating rate bonds



Source: Bloomberg, UBS, AER analysis.

The APA Group Bond

Aurora proposed that:

- the APA Group bond was not reflective of the benchmark 10 year BBB+ corporate bond, due to specific bond characteristics that made it unusually desirable to investors
- the AER had inappropriately placed significant weight on a single bond.[900]

The AER considers that the APA Group bond's characteristics are a close match to the benchmark corporate bond.[901] Its BBB rating, holding other factors equal, implies a higher expected yield than a BBB+ rated bond with the same term to maturity. The AER does not consider the observed yields on the APA Group bond are unusually low with respect to its credit rating or other benchmark characteristics.

Figure 9.9 shows that the observed spreads on the APA bond are consistent with those observed for other comparable bonds. In its decision for the Northern Territory gas access arrangement, the AER considered the consistency of the APA Group Bond with the Brisbane Airport, Sydney Airport,

[900] Aurora Energy, *Cost of capital, 2012–2017 electricity distribution revenues*, April 2011, pp. 14–15.

[901] It has a BBB credit rating and 8.8 years remaining term to maturity. The AER understands that Bloomberg has included the APA Group bond as an input into the calculation of the 7 year BBB rated FVC on at least one business day. Due to the proprietary nature in which the FVC is calculated by Bloomberg, it is not clear how and to what extent the APA Group bond influenced the 7 year BBB rated FVC during its inclusion.

Stockland and SP AusNet bonds. Broadly, the observed yields on these comparator bonds were consistent with the APA Group bond yield. The Bloomberg (extrapolated) BBB rated FVC, in contrast, appeared not to be representative of prevailing Australian bond market conditions for purposes of estimating the DRP based on the AER's notional benchmark service provider. The extrapolated Bloomberg BBB rated FVC produced yields which were consistently above the observed market data by unexpectedly large magnitudes, even having accounted for differences in term and credit rating.[902] Figure 9.9 also shows that the Bloomberg (extrapolated) BBB rated FVC remains above the relevant observed market data.

Aurora's more general concerns about the weight placed on an individual bond are not directly applicable to the AER's updated approach, as the AER has increased the sample of relevant observed bond data used to determine the DRP.[903] Previously, the AER has averaged the implied DRPs from the APA Group bond and the Bloomberg BBB rated FVC to estimate the benchmark DRP.[904] Under the AER's updated approach, the bond sample that the AER uses to estimate the DRP includes all observed long dated bonds, including the APA Group bond.[905]

9.4.7 Nominal risk free rate

The risk free rate measures the return an investor would expect from an asset with zero volatility and zero default risk. The yield on long-term CGS is often used as a proxy for the risk free rate because the risk of government default on interest and debt repayments is considered to be low.

In the CAPM framework, all information used for deriving the rate of return should be as current as possible in order to achieve an unbiased forward looking rate. It may be theoretically correct to use the on the day rate as it represents the latest available information. However, this can expose the DNSP and customers to daily volatility. For this reason, an averaging method is used to minimise volatility in observed bond yields.

The AER accepted Aurora's proposed averaging period of 20 business days to calculate the nominal risk free rate.

For this draft determination, the moving average of 20 business days for CGS yields with a 10 year maturity for the period ending 14 October 2011, results in an indicative risk free rate of 4.28 per cent (effective annual compounding rate).[906] The AER will update the risk free rate, based on the agreed averaging period, at the time of its final determination.[907]

Aurora proposed an averaging period of 20 business days to calculate the risk free rate and requested the dates be kept confidential.[908]

In a letter dated 23 June 2011, the AER advised Aurora that it accepted the proposed averaging period and agreed to the request that the period be kept confidential until expiry of that period in accordance with clause 6.5.2(c)(2)(iii) of the NER.[909] The AER also noted Aurora's request for the opportunity to amend the agreed averaging period, should a period of extreme volatility in the financial

902 AER, *Final decision, N.T. Gas, Access arrangement proposal for the Amadeus Gas Pipeline*, July 2011, pp. 176–178.
903 The AER's bond sample includes 9 bonds of 7–13 years term to maturity.
904 AER, *Final decision*, *N.T. Gas, Access arrangement proposal for the Amadeus Gas Pipeline*, July 2011, p. 182.
905 For bonds with non-standard features or floating rate bonds, these are included in the sample where the fixed rate equivalent yields can be reliably obtained by adjusting for those features.
906 CGS yields sourced from the Reserve Bank of Australia: http://www.rba.gov.au/statistics/tables/xls/f16.xls
907 The same averaging period will be used to calculate the DRP.
908 Aurora, *Regulatory proposal addendum*, June 2011, p. 12.
909 AER, *Notice of commencement of consultation on regulatory proposal, timeline for review, proposed risk free rate averaging period, and confidentiality*, 23 June 2011, p. 2.

markets occur with significant changes to prices for interest, currency and credit rates. In response the AER stated that this matter had been considered by the Federal Court of Australia. In the judgment handed down on 8 June 2011, the Court discussed this issue and clause 6.5.2(c)(2), where it held that:[910]

> 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 proposed averaging period, the AER considers that Aurora is unable to amend the period.

9.4.8 Overall rate of return

This section presents the overall rate of return resulting from the individual parameters determined by the AER, as detailed above. The AER discusses whether the overall rate of return determined for this draft determination reflects the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by Aurora.[911]

The techniques available to the AER to assess the overall rate of return can produce a broad range of plausible rates of return. In view of this, the AER primarily relies upon detailed analysis of the input parameters in accordance with established finance practice to determine the rate of return. However, this overall rate of return analysis is an important 'reasonableness check' and the AER has had regard to it.

For this draft determination, the AER has determined an indicative overall rate of return using a nominal vanilla WACC of 8.08 per cent. This is based on a cost of equity of 9.08 per cent, a cost of debt of 7.42 per cent and a gearing level of 60 per cent. The AER considers that the overall rate of return accords with the broad range of estimates inferred from market sources. The overall rate of return provides Aurora with a reasonable opportunity to recover at least its efficient costs.[912]

The AER considered the implications of the parameters values in the SRI for the resulting overall rate of return at the time of the WACC review.[913] This included evaluation of the return to debt and equity holders, market data on overall rates of return, the interactions between individual parameters and the implementation of the CAPM.[914] The AER concluded that the parameters set out in the SRI contributed to an overall rate of return that met the relevant legislative requirements.[915]

For this draft determination, those parameters specified in the SRI as methods (not values) can now be estimated using the indicative averaging period for this draft determination.

The AER examined broker reports, regulated asset sales and trading multiples, and these analyses support the conclusion that the overall rate of return set by the AER reflects the return required by the relevant investors in the market.[916] When assessed together, the three information sources suggest that, if anything, the regulated cost of capital may be considered high relative to observed market

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910 Federal Court of Australia, *ActewAGL Distribution v The Australian Energy Regulator [2011] FCA 639*, paragraph 85.

911 NER, clause 6.5.2(b).

912 NEL, clause 7A(2).

913 AER, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital parameters*, 1 May 2009, pp. 9–49.

914 AER, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital parameters*, 1 May 2009, pp. 9–49, 61–66, 97–101, 333–341.

915 AER, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital parameters*, 1 May 2009, pp. ii–vi, 47–49.

916 Relevant investors are those investing in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by Aurora.

rates of return. However, the AER appropriately interprets this analysis with caution, in view of the imprecision inherent in the techniques.

Broker reports

Equity analysts release broker reports on those listed companies operating regulated energy networks in Australia. These reports include a range of information and analysis on the current position of these companies, as well as forecasts or predictions of future performance. However, 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.[917] 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.[918] However, the broker reports do reliably report discount rates, which are equivalent to the broker's estimate of the WACC for the company.

The AER has analysed recent equity broker reports, coinciding with the most recent round of earnings announcements for these companies.[919] 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

The companies evaluated by the broker reports are:

- APA Group
- DUET Group
- Envestra Limited
- Spark Infrastructure Group
- SP AusNet

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. In general, the regulated activities of the firms—operation of monopoly transmission and distribution networks—are less risky than the unregulated activities they undertake in competitive markets.[920] As they are less risky, return required on regulated activities is

917 AER, *Final decision, Envestra Limited Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016,* June 2011, pp. 153–154 (appendix A).

918 AER, *Final decision, Envestra Limited Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016,* June 2011, pp. 155–158 (appendix A); and AER, *Draft decision, Envestra Limited Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016,* February 2011, pp. 257–262 (appendix C)..

919 Analysis of broker reports from an earlier period is contained in AER, *Final decision, Envestra Limited Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016,* June 2011, pp. 39–40, 154–155 (appendix A).

920 More specifically, the regulated activities have less exposure to systematic risk than the unregulated activities. Under the CAPM, diversifiable risk (for both regulated and unregulated activities) requires no compensation. See AER, *Final decision, Envestra Limited Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016,* June 2011, p. 154 (appendix A).

less than the return required by the firm as a whole. This means that the overall rate of return implied by broker reports will overstate the rate of return for the benchmark firm, Therefore the WACC for a regulated bench mark firm should be toward the lower end of the observed range, noting the large range of broker WACCs.

The assessment of the five regulated companies' broker reports reveals an aggregate range of nominal vanilla WACCs of 7.52% to 10.64%. As expected, the benchmark firm nominal vanilla WACC of 8.08% falls within the lower half of that range.

Asset sales

When a regulated asset is sold, comparison of the market value (the sale price) with the book value (the regulated asset price) provides an insight into the WACC required by the new owners.[921] If the market value exceeds book value, this implies that the regulatory rate of return is above that required by investors, and the converse when the book value exceeds market value. However, a range of other factors may contribute to a difference between the market and book values. Therefore, caution should be exercised before inferring that the difference indicates a disparity in WACCs—particularly where the difference is small.[922] Further, such asset sales in the market are relatively infrequent.

There has been one such sale in the period since the GFC, when Envestra purchased Country Energy's NSW gas network in October 2010. The regulated assets were sold at a price 25 per cent above the regulated asset value.[923] This is a substantial difference. Similarly, sales of regulated assets across the preceding decade all occurred at substantial premiums above the regulated asset base, with market values exceeding book values by between 20 and 119 per cent.[924] The AER considers that observed premiums of this magnitude are unlikely to be entirely explained by non-WACC factors. This suggests that the regulated cost of capital has been equal to or above the actual cost of capital faced by the businesses.

Trading multiples

Comparison of the asset value implied by share prices against the regulatory asset base—often expressed as a 'trading multiple', reflecting the excess of the market value over the book value—also provides insight into the market required rate of return. As with regulated asset sales, a trading multiple above one implies that the market discount rate is below the regulated WACC. Caution needs to be exercised because factors other than a WACC disparity may cause a difference between market value and book value. Further, the assessment relies on the assumption that share prices reflect the fundamental valuation of the company.[925]

Analysis conducted by Grant Samuel in the period after the GFC shows that trading multiples for listed businesses operating regulated networks have exceeded the value of the regulatory asset base

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921 Kevin Davis, *Cost of equity issues: A report for the AER*, January 2011, p. 17; and AER, *Final decision, Envestra Limited Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016,* June 2011, pp. 159–160 (appendix A).

922 For example, the presence of (non-regulated) growth opportunities, adoption of a financial structure that differs from the benchmark or synergies arising from economies of scale across networks. AER, *Draft decision, Envestra Limited Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016,* February 2011, p. 254 (appendix C).

923 AER, *Final decision, Envestra Limited Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016,* June 2011, p. 160 (appendix A).

924 AER, *Final decision, Envestra Limited Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016,* June 2011, p. 41. The source document is Grant Samuel and Associates Pty Limited, *Financial Services Guide and Independent Expert Report in relation to the Recapitalisation and Restructure of Babcock & Brown Infrastructure*, 9 October 2009, p. 78.

925 While this is not overly contentious as a general proposition, there will be periods (for instance, in times of significant market sentiment) where prices might be misaligned.

by between 15 and 81 per cent.[926] The AER considers that premiums of this magnitude are unlikely to be entirely explained by non-WACC factors. This suggests that the regulated cost of capital has been equal to or above the actual cost of capital faced by the businesses.

Other techniques

In recent decisions, the AER has also evaluated other techniques for assessing the overall rate of return.[927] In general, the AER considers that these techniques are of limited usefulness because of inherent conceptual problems.[928]

9.4.9 Expected inflation rate

The expected inflation rate is not an explicit parameter within the calculation of the WACC. However, it is used in the PTRM to forecast nominal allowed revenues and to index the RAB. It is an implicit component of the nominal risk free rate, with implications for the return on both equity and debt. The inflation forecast must be consistent with the 10 year investment horizon of the risk free rate.

For this draft determination, the AER adopts an inflation forecast of 2.62 per cent per annum because it represents the best estimate for a 10 year period.

Aurora stated that it has adopted the AER's approach to estimate the expected inflation rate and proposed an inflation forecast of 2.58 per cent.[929] The AER's approach to determine the best estimate of inflation is to adopt an average inflation forecast over a 10 year period.[930] As a result of the measurement period being 10 years, the AER uses the RBA short-term inflation forecasts extending out to two years and the mid-point of its target inflation band of 2.5 per cent for the remaining eight years. An implied 10 year forecast is derived by averaging these individual forecasts as shown in table 9.11.

Although Aurora has applied this approach in its regulatory proposal, the AER notes that Aurora has used the 10-year period from 2011–12 to 2020–21. The AER considers that the 10 year period should be from 2012–13 to 2021–22, where 2012–13 coincides with the start of the regulatory control period.[931]

Based on the AER's approach of using a 10 year period from 2012–13 to 2021–22, an implied 10 year forecast of the annual expected inflation rate is derived by averaging the individual forecasts as shown in Table 9.11.

926 More specifically, this analysis was at 30 June 2009 and 30 June 2010. AER, *Final decision, Envestra Limited Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016,* June 2011, p. 42,. The source document is Grant Samuel and Associates Pty Limited, *Financial Services Guide and Independent Expert Report in relation to the Recapitalisation and Restructure of Babcock & Brown Infrastructure*, 9 October 2009, p. 77.

927 Specifically, analysis based on dividend yields, relative returns to debt and equity, credit rating metrics and the Miller-Modigliani theorem. AER, *Final decision, Envestra Limited Access arrangement proposal for the SA gas network, 1 July 2011 – 30 June 2016,* June 2011, pp. 42–43, 153–163 (appendix A).

928 This includes techniques that produce a very wide range of results such that no meaningful conclusion can be drawn from them.

929 Aurora, *Regulatory proposal addendum*, June 2011, p. 14.

930 Consistent with the 10-year term of the bond rates used in the calculation of the WACC.

931 Actual inflation data for 2011–12 would be available for use in the RAB roll forward at the time of the final decision.

Table 9.11 AER inflation forecast (per cent)

	2012 – 2013	2013 – 2014	2014 – 2015	2015 – 2016	2016 – 2017	2017 – 2018	2018 – 2019	2019 – 2020	2020 – 2021	2021 – 2022	Geometric average
Forecast inflation	3.75	2.50[a]	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.62

Source: RBA.[932]

(a) The RBA has not yet released a forecast for the financial year ending June 2014. This forecast is expected to be available and will be adopted by the AER (including any updated forecasts) at the time of the final decision. The mid-point of the RBA's target inflation band has been adopted for the purposes of this draft decision.

The AER considers that the estimate of expected inflation should be updated to incorporate the latest available RBA forecasts closer to the time of the final decision. Inflation forecasts can change in line with market sensitive data and regulatory practice in Australia has been to update these forecasts at the time of making a decision. The AER will update its inflation forecast based on the latest RBA forecasts for 2012–13 and 2013–14 as close as is practical to the date of the final determination.

9.5 Revisions

The AER requires the following revision to Aurora's proposal in relation to its WACC:

Revision 9.1: The AER has determined a WACC of 8.08 per cent for Aurora as set out in Table 9.1.

932 RBA, *Statement on monetary policy*, August 2011, p. 73.

10 Corporate income tax

The AER is required to make a decision in relation to the estimated cost of corporate income tax to the DNSP.[933] This attachment sets out the AER's assessment of Aurora's proposed corporate income tax liabilities for the forthcoming regulatory control period. 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.

10.1 Draft determination

The AER accepts Aurora's proposed methodology used to establish the opening tax asset base for the transition from pre-tax to post-tax framework. In turn, the AER accepts the standard tax asset lives and remaining tax asset lives used to quantify and establish the opening tax asset base. However, the AER does not accept Aurora's proposed estimated cost of corporate income tax allowance of $110.5 million ($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 $88.6 million ($nominal), as shown in Table 10.1. Based on the approach to modelling the cash flows in the PTRM, the AER has derived an effective tax rate of 30.8 per cent for this draft determination.

Table 10.1 AER's draft decision on corporate income tax allowance for Aurora ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Tax payable	22.6	24.9	23.8	23.4	23.4	118.1
Less value of imputation credits	5.6	6.2	5.9	5.9	5.8	29.5
Net corporate income tax allowance	16.9	18.7	17.8	17.6	17.5	88.6

Source: AER analysis.

10.2 Aurora's proposal

Table 10.2 presents Aurora's proposed corporate income tax allowance for the forthcoming regulatory control period. In estimating its allowance, Aurora adopted:

- a proposed opening tax asset base of $1015.3 million at 1 July 2012[934]
- a gamma value of 0.25 based on a theta value of 0.35 and a distribution ratio of 0.70[935]

933 NER, clause 6.12.1(7).
934 Aurora, *Regulatory proposal addendum*, June 2011, p. 16.
935 Aurora, *Regulatory proposal addendum*, June 2011, p. 14.

Table 10.2 Aurora's proposed corporate income tax allowance ($million, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Tax payable	27.76	30.08	29.61	29.82	30.08	147.36
Less value of imputation credits	6.94	7.52	7.40	7.46	7.52	36.84
Net corporate income tax allowance	20.82	22.56	22.21	22.37	22.36	110.52

Source: Aurora.[936]

10.3 Assessment approach

Under clause 6.5.3 of the NER, the AER must make an estimate of the taxable income that would be earned by an efficient benchmark company operating Aurora's business. This involves comparing a DNSP's estimate with the taxable income that would be earned by a benchmark efficient DNSP as determined through the PTRM. As a result, the AER must establish such an estimate. The statutory income tax rate is then applied to that income to arrive at a notional amount of tax payable. The AER then applies a discount to that notional amount of tax payable to account for the assumed use of imputation credits. This amount is then included as a separate building block in determining the DNSP's required revenue.

During the current regulatory period Aurora was regulated using a pre-tax framework. However, the AER's building blocks assessment occurs under a post-tax framework utilising a nominal post-tax WACC.[937] Under a post-tax framework, the allowance for tax is based on cash flow analysis rather than having the allowance for tax included implicitly in the cost of capital (as OTTER previously did).

To estimate the corporate income tax allowance, the AER requires a tax asset base to be able to determine tax depreciation. The tax depreciation is offset against the business's forecast income to forecast taxable income. Given that OTTER operated under a pre-tax framework, Aurora has not previously had to provide a tax asset base to the regulator. Accordingly, the tax asset base for regulatory purposes will be established with this decision.

The AER is also required to decide on the gamma value for the assumed use of tax imputation credits.[938] The AER's position has been to adopt the gamma value specified under the statement of regulatory intent, unless persuasive evidence justifies a different value.[939]

10.4 Reasons for draft determination

10.4.1 Tax asset base

The AER does not accept Aurora's proposed opening tax asset base of $1,015.3 million as at 1 July 2012. This is because of the capex adjustments the AER has made for capitalised provisions, discussed in attachment 7. These adjustments reduce the opening tax asset base to $1,007.6 million as at 1 July 2012.

The AER accepts Aurora’s methodology for establishing its opening tax asset base. The AER also accepts Aurora's proposed tax asset lives for each asset class used to calculate the tax asset base.

936 Aurora, *Regulatory proposal addendum*, June 2011, p. 17.
937 Clause 6.5.2(b) NER.
938 Clause 6.5.3 NER.
939 AER, *Statement of intent on the revised WACC parameters (distribution)*, 2009, p. 7.

The tax asset lives have been calculated in accordance with the post-tax revenue model under straight line depreciation. These are shown in Table 10.3:

Table 10.3 Tax asset lives by asset classes (year)

Asset class	Standard tax asset life	Remaining tax asset life
Overhead subtransmission lines (urban)	44.5	40.17
Underground subtransmission lines (urban)	50.0	48.32
Urban zone substations	32.8	28.75
Rural zone substations	32.8	30.98
SCADA	32.8	29.28
Distribution switching stations (ground)	36.3	28.99
Overhead high voltage lines urban	34.9	29.16
Overhead high voltage lines rural	33.4	24.66
Voltage regulators on distribution feeders	45.5	43.60
Underground high voltage lines	31.4	18.97
Underground high voltage lines SWER	31.4	30.37
Distribution substations HV (pole)	37.6	32.97
Distribution substations HV (ground)	33.2	25.42
Distribution substations LV (pole)	36.6	31.86
Distribution substations LV (ground)	34.1	28.74
Overhead low voltage lines underbuilt urban	37.4	31.29
Overhead low voltage lines underbuilt rural	38.7	34.54
Overhead low voltage lines urban	35.3	28.58
Overhead low voltage lines rural	36.7	30.86
Underground low voltage lines	42.5	39.47
Underground low voltage common trench	43.1	40.92
HVST service connections	36.4	0.00
HV service connections	36.4	31.44
HV metering CA service connections	36.4	34.96
HV/LV service connections	36.4	31.52
Business LV service connections	36.4	31.16

Domestic LV service connections	36.4	31.90
Domestic LV metering CA service connections	36.4	34.66
Emergency network spares	1.0	0.00
Motor vehicles	9.2	4.40
Minor assets	5.2	2.92
Non-system property	34.5	22.78
Spare parts	1.0	0.00
NEM assets	3.0	1.60
Land	n/a	n/a
Easements	n/a	n/a

Source: Aurora, PTRM, June 2011.

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. The AER's approach is to take an asset's value when the asset first became subject to tax, and roll this value forward to the date when a post-tax approach is to apply. The AER will account for relevant tax depreciation rules and actual capital expenditure (capex) and disposals.[940]

Aurora provided the AER with its proposed method for the establishment of the opening tax asset base for the transition to a regulatory framework. The AER engaged McGrathNicol to assess Aurora's method, having regard to whether the proposed method is consistent with the AER's approach and whether Aurora calculated the tax asset base in accordance with the proposed method. The AER also asked McGrathNicol to assess the validity of Aurora's approach to rolling forward the tax asset base for 1 July 2007 to 20 June 2012, and to examine the reasonableness of Aurora's assumptions when reconciling financial reports and Australian Taxation Office (ATO) lodgements with the opening tax asset base at 1 July 2012.

The AER reviewed McGrathNicol's advice and is satisfied with the assessment of Aurora's opening tax asset base. The AER notes that Aurora provided McGrathNicol with additional models and further responses in support of its method. Based on its review, McGrathNicol considers that Aurora's method for calculating its opening tax asset base is reasonable. McGrathNicol has provided a detailed report to the AER of its assessment and the tasks undertaken in providing its advice.[941]

Having regard to the advice provided by McGrathNicol, the AER considers that the remaining tax asset lives and standard tax asset lives in Aurora's PTRM as at 1 July 2012 are consistent with the tax provisions of the NER. The AER also accepts the method used by Aurora to determine its tax asset base as at 1 July 2012. However, due to the capex adjustments the AER made for capitalised provisions (discussed in attachment 7) the tax asset base has been reduced to reflect these adjustments.

[940] For further explanation on establishing the opening tax asset base and transitioning businesses from pre-tax to post-tax regulation, See AER, *Issues Paper: Transition of energy businesses from pre-tax to post-tax regulation*, June 2007.

[941] McGrathNicol, *Assessment of Aurora Energy's proposed methodology and calculation of its tax asset base for the 2012–2017 regulatory control period - Final*, August 2011.

10.4.2 Utilisation of imputation credits (gamma)

The AER accepts Aurora's proposal to adopt the value of 0.25 for gamma. As part of the post-tax nominal 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. Further details on the AER's consideration of gamma are set out in the cost of capital attachment 9.

10.4.3 Tax standard life for equity raising costs

The AER rejects Aurora's proposed tax standard life for equity raising costs.

Aurora has proposed a tax standard life of 33.2 years for its equity raising costs asset class in the PTRM. The AER notes that an ATO determination requires equity raising costs to have a tax standard life of 5 years.[942] The AER will therefore apply a tax standard life of 5 years for equity raising costs in the PTRM for tax purposes.

10.5 Revisions

The AER requires the following revisions to Aurora's proposal in relation to its forecast corporate income tax allowance.

Revision 10.1: The AER has determined Aurora's forecast regulatory depreciation allowance to be $88.6 million ($nominal) over the forthcoming regulatory period as set out in Table 10.1.

[942] ATO, *Guide to depreciating assets 2001-02: Business related costs - section 40-880 deductions, ATO reference; NO NAT7170.*

11 Efficiency benefit sharing scheme

The NER requires the AER to specify in this draft determination how it will apply the efficiency benefit sharing scheme (EBSS) to Aurora.[943] 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 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. The AER considers that the electricity distribution EBSS should apply to Aurora in the forthcoming regulatory control period.

11.1 Draft determination

The AER will apply the electricity distribution EBSS to Aurora in accordance with the AER's framework and approach paper published on 29 November 2010.[944] 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.

The AER will 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. Consistent with section 2.3.2 of the EBSS, the AER will make these adjustments using the same relationship between growth and expenditure that the AER uses in establishing forecast total opex.[945] Attachment 6 discusses the AER's method of escalating forecast opex for forecast network growth.

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 draft determination:

- superannuation costs for defined benefits schemes
- Demand Management Incentive Allowance (DMIA) expenditure
- expenditure for non-network alternatives
- 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.

[943] NER, clauses 6.3.2(a)(3) and 6.12.1(9).
[944] AER, *Framework and approach paper*, November 2010.
[945] AER, *Electricity distribution network service providers: Efficiency Benefit Sharing Scheme*, 26 June 2008, p. 6 (AER, *Electricity DNSPs: EBSS*, 26 June 2008).

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:[946]

- debt raising costs
- Guaranteed Service Level (GSL) payments.

The calculation of carryover amounts under the EBSS should include all other opex costs relating to standard control services in accordance with section 2.3.2 of the EBSS. It should also include events that qualify as pass through events but do not satisfy the materiality threshold.

Table 11.1 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 6 further discusses the determination of Aurora's total forecast opex for the forthcoming regulatory control period.

Table 11.1 AER draft 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	60.4	60.8	61.5	62.1	62.4
Adjustment for excluded cost categories	–7.1	–7.2	–7.3	–7.5	–7.6
Forecast opex for EBSS purposes	53.3	53.6	54.2	54.6	54.8

Source: AER analysis.
Note: Both the total forecast opex and the adjustment for excluded cost categories exclude debt raising costs and the demand management incentives scheme allowance.

11.2 Aurora's proposal

Aurora proposed the AER exclude the cost of recognised pass through events and operating costs on non-network alternatives from the opex amounts used to calculate carryover amounts in accordance with section 2.3.2 of the EBSS.[947] Aurora also proposed to exclude:

- superannuation costs relating to defined benefit and retirement schemes
- demand management incentive scheme amounts (DMIA)
- debt raising costs
- self insurance costs
- GSL payments.[948]

Further, Aurora considered the following cost categories to be uncontrollable and proposed the AER exclude them from the opex amounts used to calculate carryover amounts:

- the Electrical Safety Inspection Levy

946 NER, clause 6.5.8(c)(2).
947 Aurora, *Regulatory proposal*, May 2011, p. 193.
948 Aurora, *Regulatory proposal*, May 2011, p. 193.

- the National Energy Market Levy
- trunk mobile radio charges
- NEM and retail contestability costs.[949]

Aurora proposed the opex amounts in Table 11.2, which exclude the proposed uncontrollable cost categories, should be the forecast opex used to calculate EBSS carryover amounts.

Table 11.2 Aurora's proposed forecast opex for EBSS purposes ($million, 2009–10)

	2012–13	2013–14	2014–15	2015–16	2016–17
Total forecast opex	70.638	68.644	68.100	67.299	65.449
Adjustment for excluded cost categories	–10.507	–10.745	–10.619	–10.513	–10.427
Forecast opex for EBSS purposes	60.131	57.899	57.481	56.786	55.022

Source: Aurora.[950]

11.3 Assessment approach

The AER was required to set out its likely approach to applying the EBSS in its framework and approach paper for Aurora.[951] It stated that the electricity distribution EBSS would apply to Aurora for the forthcoming regulatory control period.[952] The NER also requires the AER to specify in its determination how the EBSS will be applied to Aurora, having regard to clause 6.5.8(c) of the NER.[953] The AER has given particular consideration to:

1. the need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce opex[954]
2. the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses.[955]

The AER has had particular regard to these matters, in addition to the other matters required by clause 6.5.8(c) of the NER, in determining how the EBSS will apply to Aurora. This approach is consistent with that adopted for the Victorian distribution determination.[956]

11.4 Reasons for draft determination

The AER is satisfied that most of the cost categories proposed by Aurora for exclusion from the EBSS are reasonable. Aurora did not discuss in its regulatory proposal how forecast opex should be adjusted for the cost consequences of any differences between forecast and actual demand growth over the regulatory control period.

949 Aurora, *Regulatory proposal*, May 2011, p. 193.
950 Aurora, *Regulatory proposal*, May 2011, p. 195.
951 NER, clause 6.8.1(b)(3).
952 AER, *Framework and approach paper*, November 2010, p. 127.
953 NER, clauses 6.3.2(a)(3) and 6.12.1(9).
954 NER, clause 6.5.8(c)(2).
955 NER, clause 6.5.8(c)(3).
956 AER, *Victorian electricity distribution network service providers Distribution determination 2011–2015: Final decision*, October 2010, pp. 640–58.

11.4.1 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.[957] This approach reduces the possibility that Aurora will be rewarded (or penalised) for cost decreases (increases) due to network growth factors beyond its control.

The AER included a scale escalation allowance for network growth in its substitute total forecast opex allowance for Aurora (attachment 6). This network growth escalation is calculated from forecast customer connections, line length, number of distribution transformers and zone substation capacity over the forthcoming regulatory control period. The network growth escalation amount will be updated using actual figures to calculate carryover amounts.

11.4.2 Excluded cost categories

The EBSS allows DNSPs to propose the AER exclude uncontrollable cost categories from the scheme's operation. A DNSP is thus not rewarded (or penalised) for cost decreases (increases) that are uncontrollable. DNSPs must propose cost categories for exclusion in their regulatory proposal before the regulatory control period during which the EBSS will be applied. [958]

Two key factors are relevant to whether an opex category should be excluded from the EBSS.

The first is the control the DNSP has over the expenditure. The AER does not consider it appropriate for a DNSP to receive benefits or penalties through the EBSS for opex variances in cost categories that are uncontrollable.[959] By including opex categories that are uncontrollable, a DNSP may not be rewarded for efficiency gains or penalised for efficiency losses.[960] The AER considers superannuation costs for defined benefits schemes are uncontrollable because the fund is affected by changes in market interest rates beyond Aurora's control. Therefore, the AER considers they should be excluded from the EBSS for calculating carryover amounts.

Second, the EBSS assumes actual opex is used to set future opex allowances. But, for example, if opex forecasts for a given cost category are calculated from an external benchmark, the EBSS will not provide a continuous incentive to reduce opex. Consequently, in implementing the EBSS, the AER should exclude these costs to provide the DNSP with a continuous incentive to reduce opex.[961] Actual opex in the base year is not used to set opex forecasts for the cost categories below. As a result, the AER has excluded them from the EBSS for calculating carryover amounts:

- Electrical Safety Inspection Levy payments
- National Energy Market Levy payments
- NEM and retail contestability operating costs
- debt raising costs
- GSL payments.

957 AER, *Electricity DNSPs: EBSS*, 26 June 2008, p. 6.
958 AER, *Electricity DNSPs: EBSS*, 26 June 2008, p. 6.
959 AER, *Electricity DNSPs: EBSS*, 26 June 2008, pp. 6–7.
960 NER, clause 6.5.8(c)(3).
961 The AER must have regard to the need to provide a continuous incentive to reduce opex: NER, clause 6.5.8(c)(2).

In addition, Aurora proposed to exclude trunk mobile radio costs from the EBSS. Aurora stated that arrangements for the provision of this service had yet to be finalised and the costs were uncertain and beyond the control of Aurora.[962] However, the AER considers that, absent a legal obligation on Aurora to participate in the trunk mobile radio, the decision to continue to participate and incur costs rests with Aurora.[963] In this way trunk mobile radio costs are controllable and the AER considers they should be included in the EBSS.

Aurora also proposed that self insurance costs be excluded from the EBSS. However, Aurora also stated it did not propose to self insure during the forthcoming regulatory control period.[964] Consequently there are no self insurance costs in Aurora's forecast opex to exclude from the EBSS.

The EBSS also requires that the AER must measure actual opex over the regulatory control period using the same cost categories and methodology as those the AER uses to calculate the forecast opex for that regulatory control period.[965] To determine Aurora's forecast opex the AER has removed the movement in provisions from Aurora's base year expenditure (attachment 6). Therefore the AER will exclude any movements in provisions from Aurora's actual opex during the forthcoming regulatory control period consistent with section 2.3.2 of the EBSS.

11.5 Revisions

Revision 11.1: The AER will include trunk mobile radio charges from the EBSS for the forthcoming regulatory control period.

962 Aurora, *Regulatory proposal*, May 2011, p. 194.
963 Aurora, *Response to information request AER/019 of 29 July 2011*, received 8 August 2011, p. 3.
964 Aurora, *RIN Response, Part A, General*, p. 24.
965 AER, *Electricity DNSPs: EBSS*, 26 June 2008, p. 7.

12 Application of the STPIS to Aurora

The AER's Service Target Performance Incentive Scheme (STPIS) provides a financial incentive for DNSPs to maintain and improve their performance.[966] This incentive counters the financial incentive under revenue regulation to pursue cost reductions at the expense of service performance. The AER, in making its distribution determination must specify how the STPIS is to apply to Aurora.[967]

12.1 Draft determination

The STPIS lists all the matters that the AER will determine when applying the scheme. The STIPS will apply to Aurora in accordance with the details set out below.

12.1.1 Parameters and components[968]

The AER will apply the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability of supply parameters. These parameters will be calculated using embedded transformer capacity in each area of Aurora's network. Individual SAIDI and SAIFI targets will be set for segments of Aurora's network. The network will be segmented by the *Tasmanian Electricity Code* (TEC) supply reliability areas.

The AER will also apply the telephone answering parameter. However, the STPIS GSL scheme will not apply to Aurora. This is because Aurora must comply with the existing TEC GSL scheme.

12.1.2 Revenue at risk[969]

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). The revenue adjustment from the application of the STPIS[970] 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 period, and then a cap of ±0.5 per cent for the last two.

12.1.3 Incentive rates[971]

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

	Critical infrastructure	High density commercial	Urban	High density rural	Low density rural
SAIFI	0.5227	0.6263	4.6999	1.5193	1.2563
SAIDI	0.0063	0.0089	0.0547	0.0137	0.0100

Source: AER analysis.

[966] AER, *Service target performance incentive scheme*, November 2009, (AER, *STPIS*, November 2009), clause 1.4(a).
[967] National Electricity Rules (NER) clause 6.3.2(a)(3).
[968] AER, *STPIS*, November 2009, clause 2.1(d)(1).
[969] AER, *STPIS*, November 2009, clause 2.1(d)(2).
[970] As defined by NER clause 6.4.3(a)(6).
[971] AER, *STPIS*, November 2009, clause 2.1(d)(3).

12.1.4 Performance targets[972]

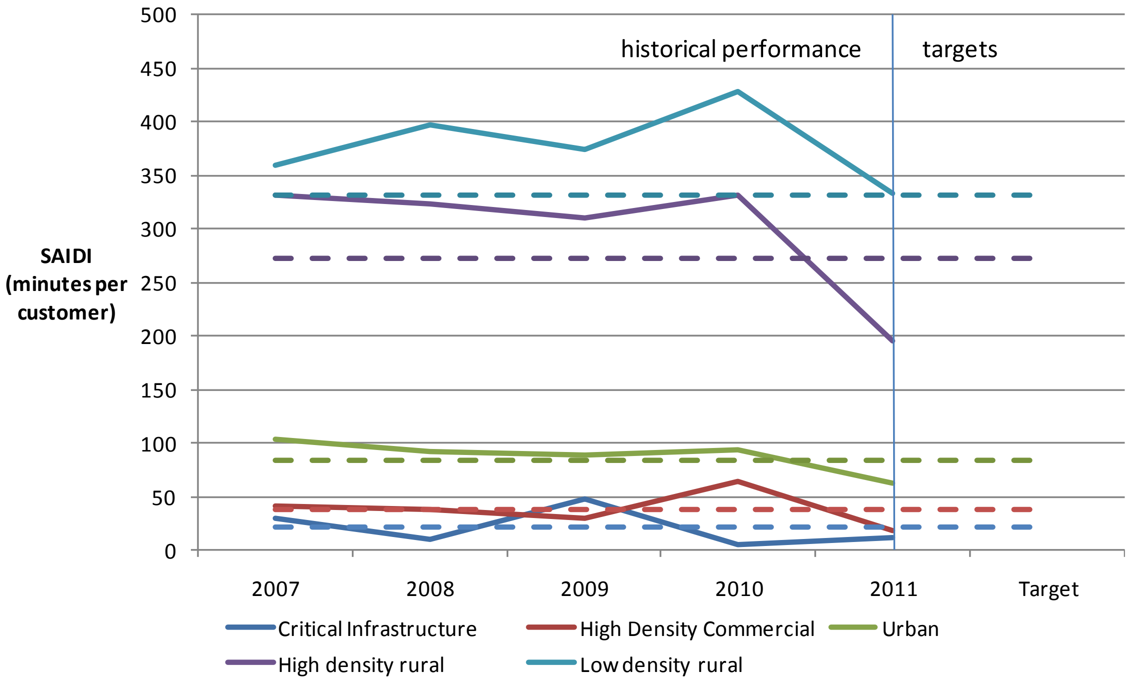
The performance targets for Aurora's STPIS parameters are presented in Table 12.2.

Table 12.2 AER's determination of Aurora's SAIDI and SAIFI targets

	Critical infrastructure	High density commercial	Urban	High density rural	Low density rural
AER determination					
SAIFI	0.21	0.48	1.00	2.64	3.03
SAIDI	19.86	38.29	83.30	267.16	351.05
Aurora's proposal					
SAIFI	0.28	0.53	1.06	2.88	3.21
SAIDI	50	42	93	297	399

Source: AER analysis.

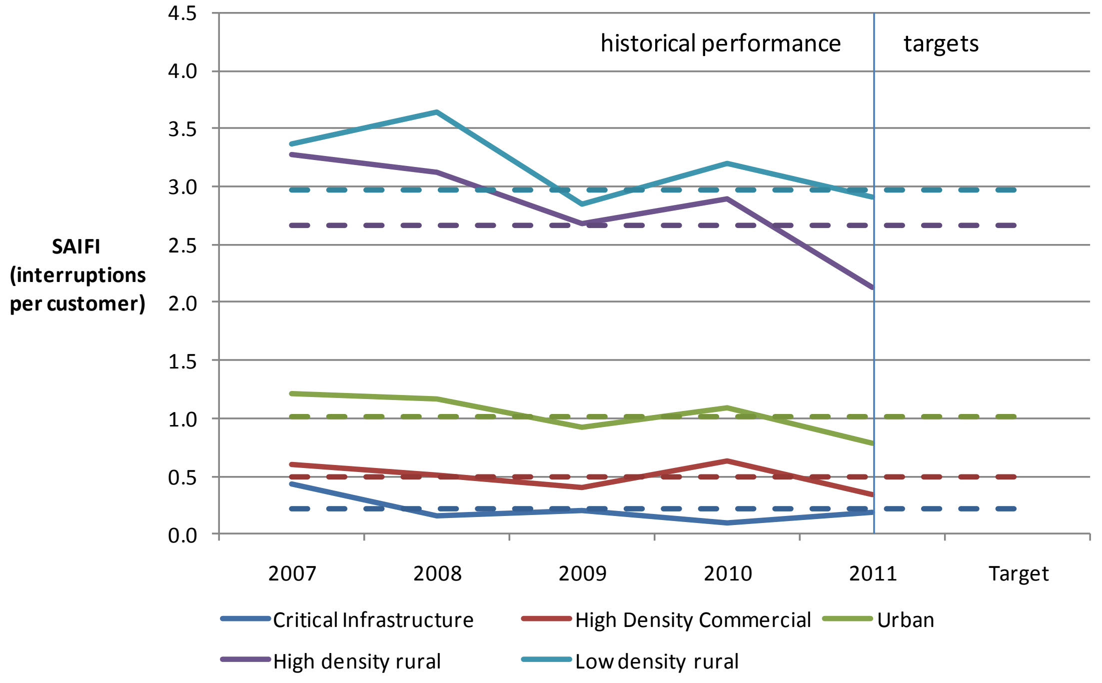
Figure 12.1 Aurora's Historical SAIDI performance and AER targets[973]



Source: AER analysis.

[972] AER, *STPIS*, November 2009, clause 2.1(d)(4).
[973] Aurora's historical SAIDI performance has been adjusted to remove MED days and excluded events.

Figure 12.2 Aurora's historical SAIFI performance and AER targets[974]



Source: AER analysis.

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.

Telephone answering

For the first three years of the forthcoming regulatory control period Aurora's telephone answering performance target will be based upon an average of call centre performance for the Victorian rural DNSPs – SP AusNet and Powercor. This target is 73.6 per cent. For the final two years of the forthcoming regulatory control period 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.[975]

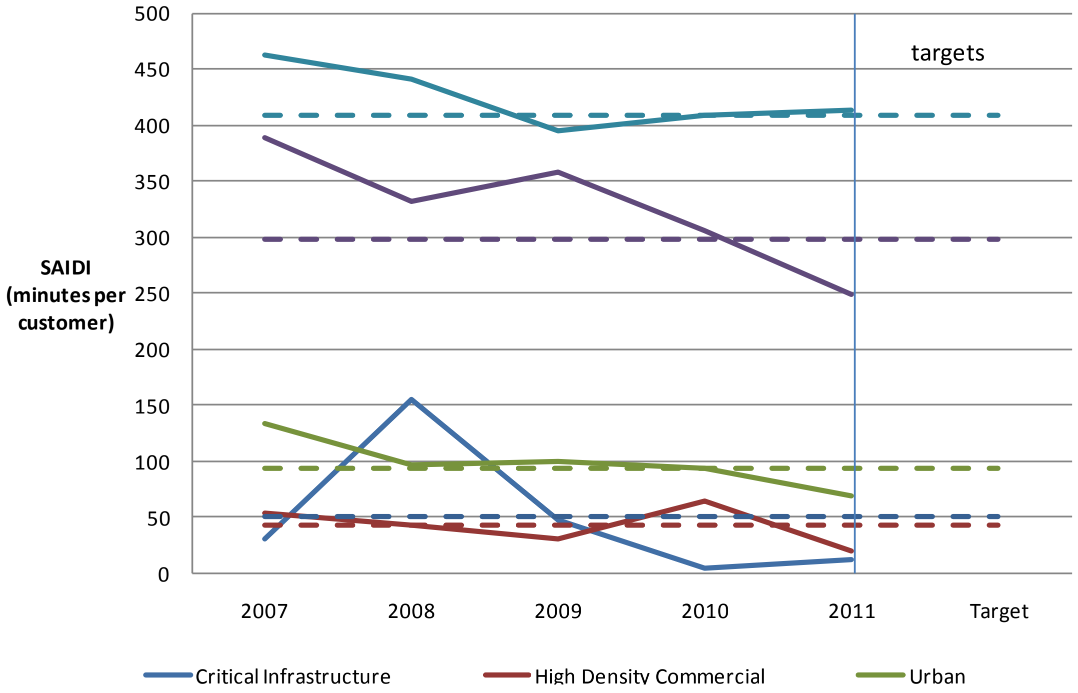
12.2 Aurora's proposal

Aurora broadly accepted the application of the STPIS proposed by the AER in its framework and approach paper.[976] This included the proposal to incentivise SAIDI and SAIFI performance. Aurora proposed that a 2.5 per cent cap be applied to revenue at risk as opposed to a five per cent cap.[977] Aurora provided STPIS targets in line with its proposed application of the STPIS.[978] These include

[974] Aurora's historical SAIDI performance has been adjusted to remove MED days and excluded events.
[975] AER, *STPIS*, November 2009, clause 5.3.1 - performance targets.
[976] Aurora, *Regulatory proposal*, May 2011, pp. 198–203.
[977] Aurora, *Regulatory proposal*, May 2011, pp. 198–203.
[978] Aurora, *Regulatory proposal*, May 2011, p. 203.

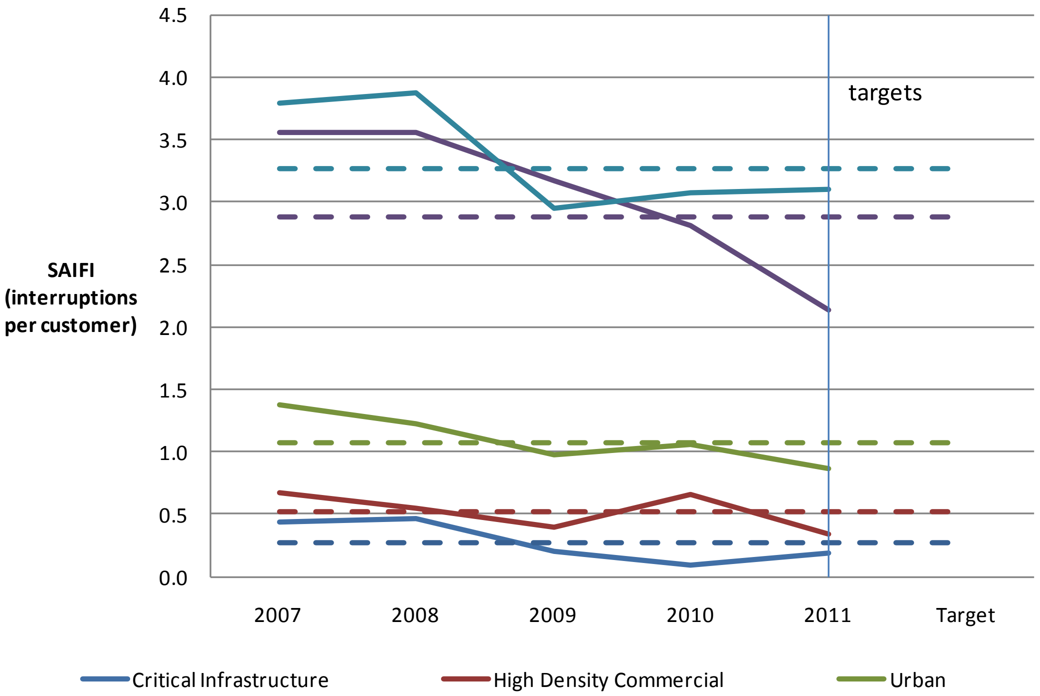
SAIDI and SAIFI targets weighted by connected kVA as a proxy for customer numbers.[979] The targets for SAIDI and SAIFI are presented in the figures below.

Figure 12.3 Aurora's historical SAIDI performance and its proposed targets



Source: Aurora, *NW-#30181358-v2A-STPIS_Category_Target_Modelling_by_kVA*, May 2010

Figure 12.4 Aurora's historical SAIFI performance and its proposed targets



Source: Aurora, *NW-#30181358-v2A-STPIS_Category_Target_Modelling_by_kVA*, May 2010

979 Connected kVA reflects the embedded transformer capacity in the different areas of Aurora's network.

In its framework and approach paper, the AER proposed to apply the telephone answering parameter of the STPIS.[980] In its regulatory proposal, Aurora stated that it did not have data available to apply the telephone answering parameter.[981] Aurora proposed to report on telephone answering in the first three years of the forthcoming regulatory period. Following this Aurora proposed to calculate a target for the final two years of the forthcoming period in accordance with the STPIS.[982]

Aurora did not propose to apply an incentive target for MAIFI.[983]

12.3 Assessment approach

The STPIS sets out the determination that the AER must make when applying the STPIS. There are two parts to this. The AER must:

1. determine all performance targets, incentive rates, revenue at risk and other parameters required to apply the scheme[984]

2. consider any proposals to vary the scheme made by the DNSP to which the scheme is to apply.

The AER outlined its likely approach to the application of the STPIS in its framework and approach paper for Aurora. The AER also outlined the justification for its likely position in the framework and approach paper.

The AER has adopted the position in the framework and approach paper, unless new information has become available or new arguments have been forwarded which warrant a reconsideration of this position. In each instance the AER has considered the relative merits of the alternative against the objectives of the STPIS. Section 12.4 outlines this reasoning.

12.4 Reasons for draft determination

The implications of the AER's determination on the STPIS parameters can potentially alter Aurora's STPIS penalties or reward up to the cap on rewards or penalties. This is discussed in the next section.

12.4.1 Cap on reward or penalties

Aurora proposed that the AER should cap the revenue at risk under the STPIS at 2.5 per cent of annual revenue. Aurora considers that the larger target would provide an incentive to gold plate its distribution network.[985]

The cap on rewards or penalties can have a significant effect on the financial effects of the scheme to Aurora and consumers. A 2.5 per cent cap as proposed by Aurora would limit the penalties or rewards of the scheme to $6.5 million. A five per cent cap would result in a penalty or reward cap of $13 million.

The AER determines that the revenue at risk should remain ±5 per cent of annual revenue.

[980] AER, *Framework and approach*, Nov 2010, p.120.
[981] Aurora, *Regulatory proposal*, May 2011, p. 201.
[982] Aurora, *Regulatory proposal*, May 2011, p. 201.
[983] Aurora, *Regulatory proposal*, May 2011, pp. 198–203.
[984] AER, *STPIS*, November 2009, clause 2.1(d).
[985] Aurora, *Regulatory proposal*, May 2011, p. 202.

The first objective of the scheme is to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty to Aurora.[986] The STPIS sets incentive rates for reliability parameters based on the Value of Customer Reliability (VCR). The VCR measures the benefit to consumers of energy delivered at any given point in time. Aurora accepted the AER's proposed VCR. Penalties or rewards under the STPIS reflect the benefit to consumers as the reward is equal to the VCR gained by consumers. Consequently, investment undertaken to gain revenue through the STPIS is efficient because the cost of the investment should be equal to or less than the benefit that network users gain from that investment.

Service improvements that result in STPIS rewards do not constitute "gold plating." The reward for service improvement is reflective of the benefits gained by consumers for the improved performance. The STPIS provides Aurora with an incentive to invest in network performance improvements where the cost of the investment is equal to or less than be benefit gained by consumers. As such, the investment must be efficient as the cost of that investment is less than or equal to the benefit of that investment.

The STPIS also provides an incentive for Aurora to undertake the reliability maintenance capex it has been granted. By reducing the penalty or reward, the penalty for not undertaking the investment is diminished. The AER considers that a cap of ±5 per cent provides a more adequate cap on the penalty or reward. This cap still mitigates the risk of the scheme to Aurora, but provides a stronger incentive for Aurora to maintain and improve performance.

12.4.2 Adjustments for reliability improvement expenditure

Performance targets should reflect the performance Aurora is expected to achieve in the forthcoming regulatory control period, including the expected impact of Aurora's capital and operating programs on its reliability performance.[987] One of the STPIS objectives is to ensure that benefits to consumers are likely to warrant any penalty or reward under the scheme.[988] Targets that do not take this into account would unduly reward Aurora for spending its forecast allowance. Hence, these targets would not give effect to the objectives of the scheme.

The AER's forecasts of capital and operating expenditure do not include expenditure to improve reliability.[989]

In this section the AER outlines its reasoning for adjusting Aurora's STPIS targets for reliability improvement expenditure in the current regulatory period.

The AER has accepted adjustments to performance targets proposed by Aurora. However the AER has made further adjustments to the performance targets so that performance targets in each community area reflect, at a minimum, the mandated TEC reliability standards. The AER's adjustment could potentially reduce Aurora's revenues by $0.9 million.

The STPIS provides that performance targets for a regulatory control period must be based on average performance over the previous five regulatory years, modified for:

- exclusions

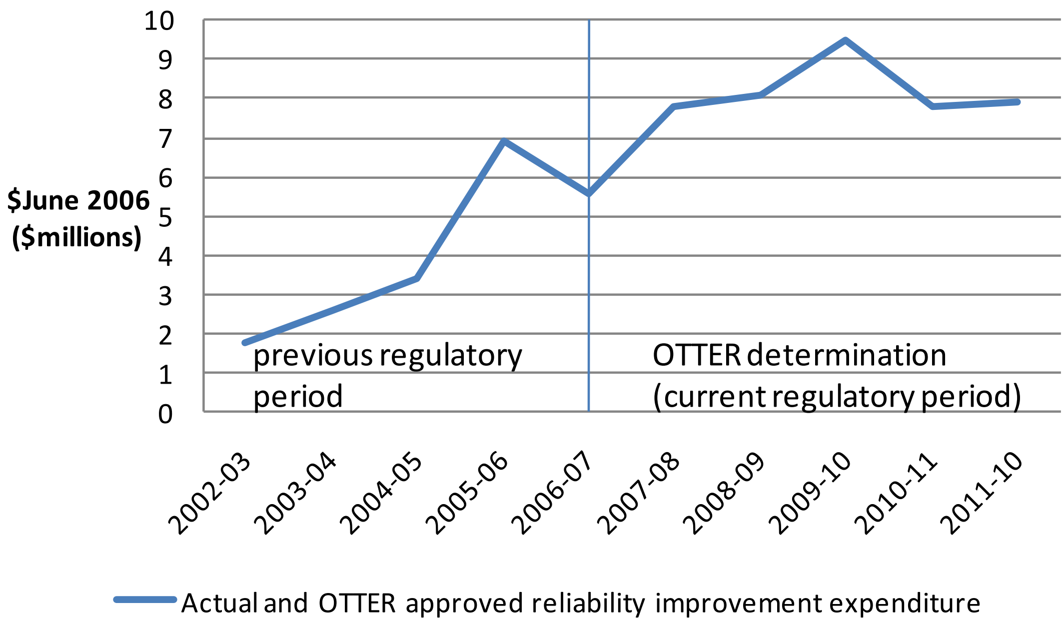
986 AER, *STPIS*, November 2009, clause 1.5(b)(1).
987 AER, *STPIS*, November 2009, clause 3.2.1(1A).
988 STPIS objective 1.5(b)(1).
989 See attachments 5 (capex) and 6 (opex).

- planned or completed reliability improvements
- any other factors that will materially effect network performance.[990]

In February 2007 a joint working group developed a set of reliability standards to which Aurora was to adhere under the TEC.[991] These formed the basis of the supply reliability standards in clause 8.6.11 of the TEC. Aurora requested funding for a program of capital works to improve reliability. This was to adhere to the minimum service standards in the TEC by the start of the forthcoming regulatory control period.[992]

Aurora proposed a 60 per cent increase in service improvement capital expenditure to meet the TEC reliability standards in January 2007.[993] The Office of The Tasmanian Economic Regulator (OTTER) approved all of Aurora's proposed capital expenditure to improve reliability.[994] Figure 12.5 shows the forecast and actual expenditure for the current and previous regulatory periods.

Figure 12.5 Aurora's actual and forecast Reliability Improvement Capital Expenditures 2002-03 to 2011-12 ($million, June 2006)[995]



STPIS targets are based upon average performance over the previous five years. Average performance is considered to be an appropriate basis for STPIS targets as STPIS performance is affected by the weather and other factors external to Aurora. Targets based upon average historical performance account for annual variations in performance brought about these factors.

As the STPIS targets are based upon average performance, adjustments may be necessary to make these targets reflect expected performance. This is because if reliability has been improving, targets

990 AER, *STPIS*, November 2009, clause 3.2.1(a), pp. 9–10.

991 Office of the Tasmanian Energy Regulator, Aurora Energy, Office of Energy Planning and Conservation, *Joint Working Group Final Report – Distribution Network Reliability Standards – Volume I – Summary of Recommendations and Overview*, February 2007.

992 Aurora, *Aurora's submission to the investigation of prices for electricity distribution services in mainland Tasmania 2007, January 2007*, p. 84.

993 OTTER, *2007 Electricity Pricing Investigation – Draft Report*, July 2007, p. 94.

994 OTTER, *2007 electricity pricing investigation – Final Report, September 2007*, p. 109.

995 OTTER, *2007 electricity pricing investigation – Final Report, September 2007*, p. 104.

based upon average historical performance will not adequately reflect future performance. Future performance will be affected by the improvement projects that are being undertaken in the current regulatory period.

Aurora has proposed adjustments to the STPIS targets for Targeted Reliability Improvement Projects (TRIPs).[996] These are for reliability improvement programs that Aurora has undertaken in the current period.[997] The AER has accepted these adjustments as they represent the effect of projects that Aurora was funded to deliver in the previous period.

However, the AER considers further adjustments are required because these adjustments do not fully account for the performance improvements that Aurora proposed to undertake. Aurora has adjusted its performance targets so that the targets reflect the historical trend in reliability improvement.[998] This method does not reflect the projects allowed by OTTER to deliver new reliability standards. Though the historical trend goes some way to ensuring that the STPIS targets reflect new reliability standards, in a few of instances the targets are higher than would be expected if Aurora complied with the reliability standards. This is because Aurora's historical average performance is below the TEC reliability standards in some instances. Where the historical performance has been below the TEC reliability standards, the AER has made an adjustment so the targets reflect performance at the level of the performance standards, and not below them. For this reason the performance targets are consistent with the TEC standards and the capital allowance in Aurora's previous regulatory determination.

In his submission on Aurora's regulatory proposal David Asten notes that the network business boundary between Transend and Aurora is inappropriate. He considers this boundary adversely affects supply reliability.[999] The AER considers that Aurora's STPIS targets should not be adjusted for the operational boundary and delineation of assets between Aurora and Transend as this is outside the AER’s jurisdiction.

12.4.3 Weighting for SAIDI and SAIFI

The SAIDI and SAIFI parameters in the STPIS reflect the average number and average duration of interruptions per customer. Aurora has proposed to weight its SAIDI and SAIFI numbers by kVA capacity (embedded transformer capacity) as an approximation for the number of customers.[1000] In the framework and approach paper the AER stated that it would weigh SAIDI and SAIFI calculations by customer numbers unless Aurora's historical data proved to be unreliable.[1001]

The customer number data used by Aurora to calculate customer minutes off supply and the number of customers affected by outages is unreliable. The AER has therefore determined that performance targets should be based upon embedded transformer capacity. Going forward the AER will require Aurora to collect reliable SAIDI and SAIFI data weighted by customer numbers to ensure that future STPIS performance targets can be calculated using distribution customers.

The STPIS provides that performance targets should be based on an average of performance for the previous five years. However the STPIS also states that where five regulatory years of data is not

[996] These adjustments are contained in Aurora’s STPIS model.
[997] Aurora, *NW-#30181358-v3-STPIS_Category_Target_Modelling_by_kVA*, 29 September 2011.
[998] Aurora, *Regulatory proposal*, May 2011, p. 203.
[999] David Asten, *Tasmanian electricity networks to suit the customer*, August 2011, p. 2.
[1000] Aurora, *Regulatory proposal*, May 2011, p. 199.
[1001] AER, *Framework and approach*, Nov 2010, p. 120.

available, the AER may base targets on an alternative methodology so long as that methodology gives effect to the objectives of the scheme.[1002]

The STPIS intends that SAIDI and SAIFI are calculated using distribution customers. This requires reliable data on the number of customers affected by individual network interruptions and the number of customer minutes off supply for these interruptions. Prior to 1 January 2008, Aurora has used kVA capacity in network areas to estimate the effect of interruptions on customers. The use of kVA to approximate the effect of outages on customers is not optimal as kVA capacity is an endogenous part of Aurora's network. This would mean that Aurora's SAIDI and SAIFI performance would be partially dependent on when Aurora alters the kVA capacity of its network.

However, the AER considers that for the forthcoming regulatory control period, kVA capacity is appropriate as a transitional measure because Aurora does not have reliable historical customer data to calculate SAIDI and SAIFI. The STPIS requires a full five years of reliable customer data for performance targets based upon the effects of outages on customers.[1003] The customer number data used to calculate GSL payments is based upon a project that Aurora is undertaking to link customers' assets. This project was 80 per cent complete three years ago and is considered to be 95 per cent complete currently.[1004] Prior to this date Aurora estimated STPIS weighted by customer numbers based upon the kVA capacity assuming that customers have a certain standard demand.[1005]

To test whether targets based upon customer numbers are accurate the AER has compared the results of three different methods of forecasting STPIS performance using customer numbers. The AER forecast SAIDI based upon three years worth of data, five years using Aurora's historical engineering estimates, and five years using its own back-cast projection based on Aurora's kVA data. The AER found that these forecasts differed materially. Based on this the AER has concluded that performance targets based upon customer numbers may not accurately reflect the performance that Aurora is expected to deliver. This is because the choice of forecasting methodology will materially affect the targets.

Hover, Aurora can calculate targets based on kVA capacity from five years of reliable data. Under the STPIS, targets must be based upon average performance over five years if data is available.[1006] The AER considers that weighting SAIDI and SAIFI by kVA capacity is consistent with the objectives of the scheme. One objective of the scheme is the need to ensure that benefits to consumers of the scheme are sufficient to warrant any penalty or reward to Aurora.[1007] Where targets are based upon unreliable data, the penalties or rewards to Aurora may not be warranted. In implementing the scheme the AER must take into account the past performance of the network.[1008] In this instance the AER has the option to use a kVA weighting for SAIDI and SAIFI, which is a more accurate representation of the past performance of Aurora's network than a customer numbers weighting.

1002 AER, *STPIS*, November 2009, clause 3.2.1 (c).

1003 AER, *STPIS*, November 2009, clause 1.5(b)(1) provides that the AER must take into account the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs.

1004 Aurora, *Service target performance incentive scheme – submission to AER preliminary positions*, October 2010.

1005 Aurora, *Service target performance incentive sheme, submission to AER preliminary positions*, October 2010, p. 22.

1006 AER, *STPIS*, November 2009, clause 3.2.1(a).

1007 AER, *STPIS*, November 2009, clause 1.5(b)(1).

1008 AER, *STPIS*, November 2009, clause 1.5(b)(3).

12.4.4 Exclusions

Certain events are excluded from the calculation of the S-factor revenue adjustment. These exclusions include events that are beyond the control of Aurora, or major events that have the potential to significantly affect STPIS performance.

Aurora accepted the AER's position in the framework and approach paper on exclusions.[1009] No evidence or arguments have come to light that warrant a re-consideration of the AER's framework and approach paper position. Consequently, the AER's draft determination is to apply the exclusions specified in the framework and approach paper. The AER has incorporated its calculation of exclusions into the modelling of STPIS targets in accordance with the STPIS.

The AER considered in the framework and approach that sustained outages caused when Aurora's auto-reclosers are set to lock out on high fire days would be excluded under the scheme. The AER indicated in its framework and approach that it would consider the definition of high fire days in its distribution determination.[1010] Aurora proposed the following definition in its regulatory proposal.[1011]

> A day of total fire ban as advised by the Tasmanian Fire Service in accordance with section 70 of the Fire Service Act 1979.

The AER accepts Aurora's proposed definition of high fire risk days.

Target forecasts

In accordance with the STPIS, forecasts of targets must be exclusive of exclusions.[1012] The AER considers a number of events are included in Aurora's proposed targets that are excluded events. These include:

- Outages caused by customer installation faults
- Planned outage for system works
- Total fire ban days
- Transmission faults
- Transmission scheduled works

The AER has removed these events from the STPIS target calculations.

12.4.5 Telephone answering

The telephone answering parameter measures the proportion of calls forwarded to an operator that are answered in 30 seconds.

In the framework and approach paper the AER proposed to apply the telephone answering parameter.[1013] With the submission of its regulatory proposal Aurora stated that it did not collect the

1009 Aurora, *Regulatory proposal*, May 2011, pp. 200–201.
1010 AER, *Framework and approach paper*, Nov 2010, p. 101.
1011 Aurora, *Regulatory proposal*, May 2011, p. 201.
1012 AER, *STPIS*, November 2009, clause 3.2.1(a)(1).
1013 AER, *Framework and approach paper,* p.120.

historical data required to implement this parameter. Aurora proposed to collect data for the first three years of the period, and set performance targets for the last two based on this data.[1014]

The AER has set targets for telephone answering based upon a benchmark of rural Victorian DNSPs for the first three years of the forthcoming regulatory control period. The targets for the last two years will then be set based upon average performance in the previous three years, as proposed by Aurora. This target is 73.58 per cent of calls answered in 30 seconds.[1015]

The cap on the penalty or reward for telephone answering will be ±0.025 per cent of annual revenue for the first three years of the forthcoming regulatory control period and ±0.05 of annual revenue for the last two.

The STPIS specifies that where five years of data is not available, the AER may approve a target based upon an alternative methodology or benchmark where this meets the objectives of the scheme.[1016]

Basing targets on three years of actual performance in a regulatory period does not meet the objectives of the scheme. If targets are based upon performance in the first three years Aurora will not have an incentive to perform well in the first three years. If Aurora under performs in the first three years it would reward itself with easy targets for the final two.

To mitigate this, the AER has developed a benchmark target based upon the performance of the Victorian Rural DNSPs Powercor and SP Ausnet. An average of performance for rural Victorian DNSPs is an appropriate benchmark because Aurora's network is similar in geography and composition to that of the rural Victorian DNSPs. The AER's call centre performance targets are in the AER's distribution determination for the Victorian DNSPs.[1017]

There is some risk that the telephone answering performance for the Victorian DNSPs may not reflect Aurora's expected performance. If so, the objective of ensuring that the benefit to consumers likely to result from the scheme may not warrant the reward or penalty to Aurora. The risk of inaccurate targets would be mitigated by reducing the penalty or reward cap on the parameter. In order to account for this risk the AER has set the incentive rate for the telephone answering parameter at ±0.025 per cent of total revenue for the first three years.

12.4.6 MAIFI

MAIFI measures the number of momentary outages[1018] experienced by customers on average.

In the framework and Approach paper the AER did not propose to apply the MAIFI parameter. This was on the basis that Aurora does not possess a historical data series for MAIFI which can be used to set an appropriate incentive target.

In the current period Aurora has been installing auto reclosers[1019] and other technology that improves SAIDI and SAIFI performance, but increases the number of MAIFI events. Though preferential to SAIDI and SAIFI events, MAIFI events still adversely affect customers.

1014 Aurora, *Regulatory proposal*, May 2011, p. 201.

1015 In accordance with the full definition of call answering performance located in the STPIS, p. 23.

1016 AER, *STPIS*, November 2009, clause 5.3.1(d).

1017 AER, *Final decision, Victorian electricity distribution network service providers Distribution determination 2011–2015* October 2010, p. 730.

1018 Defined as outages of less than one minute.

The AER will require Aurora to report MAIFI data to the AER, which can be publically reported. Aurora has acknowledged that it is implementing the capability to collect and report information on MAIFI.[1020]

Public reporting of MAIFI will provide some incentive for Aurora to manage its MAIFI performance. In future the AER could use MAIFI performance data collected from Aurora to set financial incentives to improve MAIFI performance.

12.5 Revisions

The AER has made the following revisions to Aurora's proposed application of the STPIS.

Revision 12.1: The AER has modified Aurora's SAIDI and SAIFI targets to account for previous reliability improvement expenditure. The AER has also removed excluded events from the calculation of the targets.

Revision 12.3: The AER has calculated targets for the telephone answering parameter for the first three years of the forthcoming period based upon the performance of the rural Victorian DNSPs.

1019 Aurora, *Response to information request AER/015 of 22 July 2011*, received 29 July 2011, p. 5.
1020 Aurora, *Response to information request AER/015 of 22 July 2011*, received 29 July 2011, p. 5.

13 Demand management incentive scheme

The AER published its proposed demand management incentive scheme (DMIS) to apply to Aurora on 25 June 2010.[1021] The AER published the final version of the DMIS to apply to Aurora on 15 October 2010. The DMIS is designed to provide incentives for Aurora to implement efficient non-network alternatives, or to manage the expected demand for standard control services in some other way.[1022]

The AER's DMIS for Aurora comprises an annual demand management incentive allowance (DMIA). The DMIA is provided as an annual, ex-ante allowance in the form of a fixed amount of additional revenue at the commencement of each regulatory year of the regulatory period.[1023] Aurora can only access the DMIA to fund expenditure on initiatives approved by the AER.[1024]

The DMIA is capped at an amount based on the AER's understanding of typical demand management project costs, and scaled to the relative size of each DNSP's average annual revenue allowance in the previous regulatory period.[1025] The AER proposed an annual DMIA for Aurora of $1.9 million ($ 2009–10) over the regulatory period.[1026]

Clause 6.3.2(a)(3) of the National Electricity Rules (NER) provides that the AER must specify how the applicable DMIS is to apply to a DNSP when making a building block determination for a DNSP. The DMIS comprehensively sets out how the AER applies the DMIS.

The AER must also make a determination on Aurora's annual revenue requirement under the building block approach, including revenue increments or decrements arising from the application of a DMIS.[1027]

13.1 Draft determination

The AER has determined to apply the current DMIS to Aurora without amendment. The AER also considers that Aurora's DMIS is not the appropriate mechanism to fund DMIS reporting costs.

13.2 Aurora's proposal

Aurora did not propose any alterations to the AER's current DMIS.[1028] Other stakeholders did not comment on the application of the AER's DMIS.

13.3 AER approach

In its framework and approach paper for Auroa, the AER stated that its likely approach[1029] is to apply the DMIS to Aurora for the 1 July 2012 to 30 June 2017 regulatory period. The AER must have regard

1021 The distribution consultation procedures set out in the NER require the AER to publish a proposed DMIS and explanatory statement, inviting submissions and giving stakeholders and interested parties at least 30 business days to respond in accordance with clause 6.16 of the NER.

1022 AER, *Aurora DMIS*, p. 2.

1023 AER, *Demand management incentive scheme, Aurora Energy, Regulatory control period commencing 1 July 2012*, 15 October 2010, p. 3 (AER, *Aurora DMIS*, October 2010).

1024 AER, *Aurora DMIS*, October 2010, pp. 4-5.

1025 AER, *Aurora DMIS*, October 2010, p. 4.

1026 AER, *Framework and approach paper*, November 2010, p. 136.

1027 Clause 6.4.3(a)(5) of the NER.

1028 Aurora, *Regulatory proposal*, May 2011, pp. 205–207.

1029 AER, *Framework and approach paper*, November 2010, p. 136.

to the factors set out in clause 6.6.3(b) of the NER in developing and implementing a DMIS. These are:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any penalty or reward under the scheme
- the effect of a particular control mechanism on a DNSP's incentives to adopt or implement efficient non-network alternatives
- the extent the DNSP is able to offer efficient pricing structures
- the possible interaction between a DMIS and other incentive schemes
- the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.

The AER had regard to these factors in developing its DMIS to apply to Aurora.[1030]

13.4 Reasons for determination

Aurora did not propose any alterations to the AER's proposed DMIS.[1031] Also, stakeholders made no comment on the application of the AER's DMIS. Therefore, the AER has determined to apply the current DMIS to Aurora without amendment.

Aurora set out its proposed demand management projects for the forthcoming regulatory period, including those it proposed to fund through the DMIS.[1032] The AER's proposed DMIS provides for ex post review of claims for funding under the scheme.[1033] The AER therefore does not need to make a decision at this time on whether Aurora's proposed projects are consistent with, or are likely to be consistent with, the criteria for funding under the DMIS.

Aurora proposed a number of demand management costs as part of its opex and capex allowances. The AER's DMIS states that costs recovered under the DMIS must not be included in the forecast capital or operating expenditure approved in the distribution determination, or under any other incentive scheme in that determination. Therefore, Aurora will not be able to obtain funding under the DMIS for demand management activities already funded through its standard control capex or opex allowances.

Aurora's proposed DMIS-funded activities include reporting to the AER on the demand management activities Aurora undertakes.[1034] Aurora will incur these reporting costs as it submits DMIS funding claims to the AER. However, the AER will determine whether or not to provide funding under the DMIS. The AER will make this determination at the end of the regulatory period based on the information reported by Aurora. Therefore, reporting may be required even if no projects meet the AER's criteria for DMIA funding. For this reason, the AER considers that Aurora's standard control opex allowance is a more appropriate mechanism to fund reporting costs than the DMIS. The AER considers that Aurora's forecast opex allowance is sufficient to cover all of Aurora's regulatory reporting costs. The AER's discussion of Aurora's opex allowance is in attachment 6.

1030 AER, *Final decision, demand management incentive scheme, Aurora Energy 2012-13—2016-17, October 2010*, p. 9.
1031 Aurora, *Regulatory proposal*, May 2011, pp. 205–207.
1032 Aurora, *Regulatory proposal*, May 2011, pp. 206–207.
1033 AER, *Aurora DMIS*, p. 5.
1034 Aurora, *Regulatory proposal*, May 2011, pp. 206–207.

14 Pass through events

This chapter sets out the AER's consideration of additional pass through events for Aurora during the forthcoming regulatory control period.

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.[1035]

The National Electricity Rules (NER) allow pass throughs only if they result from a previously defined pass through event.[1036] It prescribes the following four events:

(a) a regulatory change event

(b) a service standard event

(c) a tax change event

(d) a terrorism event. [1037]

The AER must make a constituent decision on the additional pass through events (nominated events) to apply in the forthcoming regulatory control period.[1038]

14.1 Draft determination

The AER nominates three events proposed by Aurora as additional pass through events. It considers that the other six proposed by Aurora are covered under other mechanisms, as summarised in Table 14.1.

1035 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.

1036 NER, clause 6.6.1.

1037 NER, chapter 10 (glossary) – definition of 'pass through event'. Each of the four events is defined in the glossary.

1038 NER, clause 6.12.1(14).

Table 14.1 AER decisions on proposed pass through events

Aurora's proposed events	AER decision
Natural disaster Insurer credit risk Liability above insurance cap	Accepted as nominated pass through events
Bushfires Storms	Not nominated— The AER considers this type of event is covered by natural disaster event or other cost recovery mechanisms.
Industry restructure	Not nominated—The AER considers this type of event is covered by service standard or regulatory change event.
Declared retailer of last resort	Not nominated—The AER considers this type of event is covered by regulatory change event, the new retailer insolvency event, or other cost recovery mechanism.q
Carbon tax	Not nominated—The AER considers this type of event is covered by tax change, service standard or regulatory change event.
Feed-in tariff	Not nominated—The AER considers this type of event is covered by the NER's provisions for recovery of jurisdictional scheme amounts.

14.2 Aurora's proposal

Aurora proposed the nine additional pass through events listed in Table 14.1. Aurora provided a specific explanation and definition of each event in its regulatory proposal.[1039]

14.3 Assessment approach

The AER must make a constituent decision on the additional pass through events (nominated events) to apply for the regulatory control period.[1040]

The NER does not specify criteria for assessing additional pass through events, and allows the AER a broad discretion in its decisions.[1041] However, in developing appropriate criteria the AER has considered broader principles in the national electricity framework, particularly:

- the National Electricity Objective (NEO), which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of electricity consumers with respect to

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

(b) the reliability, safety and security of the national electricity system.[1042]

1039 Aurora, *Regulatory Proposal*, May 2011, chapter 27; and Aurora, Response to the AER's Regulatory Information Notice, p. 22–27.

1040 NER, clause 6.12.1(14).

1041 The extent of this discretion is discussed in: AER, *Draft decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, June 2010, p. 700. (AER, *Victorian draft decision*, 2010)

1042 National Electricity Law (NEL), section 7.

- the revenue and pricing principles (RPP), which set out that a provider should be provided with a reasonable opportunity to recover efficient costs and should be provided with incentives to undertake efficient investment and supply.[1043]

The AER's criteria for assessing additional pass through events have evolved in recent decisions. The AER applied the following criteria in the most recent decision for DNSPs in Victoria:

- the event is not already provided for:
  - in the defined event definitions in the NER (and does not conflict or undermine the events defined in the NER)
  - through the opex allowance (for example, the insurance or self insurance components)
  - through the weighted average cost of capital (WACC), because events which affect the market generally and not just the provider are systematic risk and already compensated through the WACC, or
  - through any other mechanism or allowance. [1044]
- the event is foreseeable, in that the nature or type of event can be clearly identified.
- the event is uncontrollable, in that a prudent service provider could not have reasonably prevented the event from occurring or substantially mitigated the cost impact of the event.
- the event cannot be self insured because a self insurance premium cannot be calculated or the potential loss to the relevant DNSP is catastrophic.
- the party in the best position to manage the risk is bearing the risk.
- the passing through of the costs would not undermine the incentive arrangements within the regulatory regime.

In addition, the AER specifies a materiality threshold for each pass through event.

An objective of the incentive framework is to ensure that risks are appropriately managed. If a DNSP fails to manage risks appropriately and incurs additional costs, it would be expected to bear those costs. However, the NER recognises a DNSP can be exposed to risks beyond its control—specifically, risks which are not considered elsewhere in the NER and which may have a material impact on a DNSP's costs. The pass through provisions of the NER, in conjunction with the above criteria, provide DNSPs with a mechanism to recover such costs, thereby meeting primary requirements of the RPPs.[1045] At the same time, the pass through provisions and criteria above promote efficiency and protect consumers' interests by restricting pass throughs to uncontrollable events, leaving the incentive for DNSPs to minimise costs within their control.[1046] The regulatory regime encourages DNSPs to insure or self-insure against risks which are reasonably quantifiable and can be in part controlled or mitigated by DNSPs.

1043 NEL, section 7A.
1044 AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015,* October 2010, p. 745. (AER, *Victorian distribution determination*, 2010).
1045 NEL, s. 7A(2) and (6).
1046 NEL, s. 7A(3).

Materiality threshold

The NER allows the AER considerable discretion in how it treats pass throughs, including in the setting of materiality thresholds.[1047] The AER sets a materiality threshold in order to reduce the administrative burden of excessive applications for pass through events, while still including events which materially affect the business. The AER has developed its approach to materiality over successive determinations, having regard to the following factors:

- the NEO and RPP
- the applicability to DNSPs of statements of the Australian Energy Market Commission (AEMC) about incentive regulation for TNSPs[1048]
- the use of the concept of materiality in the NER and in various other regulatory regimes.

The AER's approach to materiality on the basis of the above factors was explained in the most recent determination for Victoria.[1049] The application to Aurora's proposal is discussed below in section 14.4.2.

14.4 Reasons for draft determination

In this section the AER first considers a submission that addressed the general principles of pass throughs. The AER then outlines its view on each of the nine events proposed by Aurora, grouped into two categories:

- those nominated by the AER as pass through events
- those not nominated but considered to be covered by other cost recovery provisions.

The materiality threshold to apply to the nominated events is then discussed.

The Energy Users Association of Australia (EUAA) opposed pass throughs in principle, stating that they allow low risk Government owned network monopolies to avert risk to a greater degree than competitive firms. The EUAA also noted that pass through events are inherently asymmetrical in favouring cost increases over decreases.[1050]

However, the AER considers that its approach achieves an appropriate balance between ensuring that DNSPs have the opportunity to recover efficient costs, and maintaining the incentive for efficient supply of and investment in electricity distribution services. The AER seeks to maintain incentives through its criteria limiting additional events, explained in the previous section, and materiality thresholds. Another mechanism to exclude unnecessary costs is through the NER criteria for assessing the amount of costs passed through when an event occurs during the regulatory period. These criteria require the AER to take account of matters such as the efficiency of the DNSP's actions, and whether the costs have already been factored into the revenue requirements.[1051]

1047 NER, clause 6.12.3(a) - Extent of AER's discretion in making distribution determinations.
1048 AEMC *Rule Determination 18-2006, Economic Regulation of Transmission Services*.
1049 AER, *Victorian distribution determination*, 2010, section 16.6.1.4.
1050 EUAA, *Submission to the Australian Energy Regulator on Aurora Energy's Regulatory Proposal on Distribution Prices for 2012-2017,* August 2011, p. 18. (EUAA, *Submission*, August 2011)
1051 NER clause 6.6.1(j).

The EUAA also submitted that the proposed storms, feed-in tariff, carbon tax and retailer of last resort events were either questionable or should be rejected.[1052] The AER's conclusions below are in broad agreement with the EUAA's submission on these events.

The AER accepts the following three proposed events as pass through events for Aurora's next regulatory control period:

- Natural disaster event
- Insurer credit risk event
- Liability above insurance cap event

The AER considers that Aurora proposed natural disaster event[1053] satisfies the criteria in section 14.3.[1054] Aurora has not proposed an allowance for self insurance, but some costs of natural disasters may be recoverable elsewhere through insurance or the liability above insurance cap event proposed by Aurora. The AER recognises that some potential overlap is inevitable, but will consider any specific cost claim under the most appropriate event and ensure it is not double-counted.

Insurer credit risk events are increases in Aurora's insurance costs resulting from insolvency of its nominated insurer. The AER accepts that the insurer credit risk event meets the criteria required to qualify as a pass through event.[1055] A DNSP could affect such an event, by selecting a cheap but unstable insurance company, for example. However, the criteria for approving actual pass through costs take account of whether the DNSP could have done anything to mitigate the costs.

Liability above insurance cap event

Aurora can optimise its risk management by designing its network and externally insuring to a certain level of risk. Under this approach, it will leave uninsured some losses which are below the deductible threshold or above the insurance cap. The above-cap losses tend to be low probability, potentially high cost risks. The AER accepts that the above-cap losses meet the criteria for pass through events.[1056] The AER thus accepts 'liability above insurance cap' as a pass through event.

14.4.1 Events covered elsewhere

The AER considers the remaining proposed events are more appropriately covered under other pass through events or cost recovery arrangements, as discussed below.

Bushfires event

Aurora proposed a bushfires event as separate from the natural disaster event because some fires, such as those caused by arson, may not be considered natural disasters.[1057]

1052 EUAA, *Submission*, August 2011, pp. 18–20.

1053 Aurora, *Regulatory Proposal*, May 2011, p. 210.

1054 The AER nominated a similar natural disaster event for Victorian DNSPs: AER, *Victorian distribution determination*, 2010, summary LII and p. 746.

1055 The AER accepted an insurer credit risk event in its Victorian final decision: AER, *Victorian distribution determination*, 2010, s. 16.6.3.

1056 The AER nominated a similar 'insurance event' in its 2010 Victorian determination in place of a proposed legal liability above insurance cap. The AER's change was designed to guard against over-compensation in cases where the DNSP did not take up the insurance policy allowed for. Aurora's definition accommodates this concern: AER, *Victorian distribution determination*, 2010 s.16.6.10.

1057 Aurora, *Information clarification: Aurora reponse to questions raised by the AER of 15 June 2011*, 23 June 2011, p. 10.

The AER has not nominated a separate bushfire event in other determinations as fires are covered by a range of other mechanisms. Small fires can be covered by opex or capex allowances including insurance and self insurance, or the costs absorbed within the materiality threshold. The AER considers that major bushfires could qualify under Aurora's definition of natural disaster event, regardless of whether they were initiated by humans. Very large fires could also involve costs above the insurance cap and thus qualify for the liability above insurance cap event. The AER therefore will not nominate an additional event for bushfires.

Storms event

Aurora also proposed a storms event. The AER considers a specific new event for storms is not necessary, for similar reasons as for bushfires. Smaller more frequent storms can be covered by components of opex or capex, or minor costs absorbed within the materiality threshold. The AER considers major storms could qualify under either the natural disaster event (as 'other natural disaster') or liability above insurance cap.

Industry restructure event

The Tasmanian Government is reviewing the electricity industry, which could result in restructure of Aurora's businesses, with associated extra costs for Aurora.

If such a restructure occurs, the AER considers that it should be covered by one of the prescribed pass through events — either a regulatory change event or service standard event. A separation of business areas, for example, would alter the scope of Aurora's services, and may qualify as a service standard event.[1058] The AER thus considers a distinct industry restructure event is not necessary.

Declared retailer of last resort event

When an electricity retailer fails, a DNSP could incur costs when customers of the failed retailer are transferred to the declared retailer of last resort (RoLR). The AER has nominated this as a pass through event in its Victorian, South Australian and ACT determinations.[1059] Subsequently, however, a new National Energy Customer Framework (NECF) is being implemented through the National Energy Retail Law (South Australia) Act 2011 (Retail Law). Under the Retail Law, upon application by a RoLR, the AER must make a RoLR cost recovery scheme determination.[1060] This scheme is designed for the RoLR to recover its applicable RoLR scheme costs. As part of the RoLR cost recovery scheme determination, the AER must make a distributor payment determination that one or more distributors are to make payments towards the cost of the scheme.[1061] A distributor payment determination allows the RoLR to recover its RoLR scheme costs through payments by the distributor.

Distributors are required to make payments to a RoLR in accordance with their liability under a distributor payment determination. The Retail Law provides for such a determination to be both a regulatory change event and a positive change event for the purposes of the NER. Further, the distributor's payments are taken to be positive pass through amounts approved under the NER.[1062]

[1058] The exact definition is in NER, chapter 10 (glossary).
[1059] AER, *Victorian distribution determination*, 2010, p. 797.
[1060] *National Energy Retail Law (South Australia) Act 2011*, s. 166. The target date for commencement of the NECF is 1 July 2012.
[1061] *National Energy Retail Law (South Australia) Act 2011*, s. 167.
[1062] *National Energy Retail Law (South Australia) Act 2011*, s. 167(2) and (4)(a).

Moreover, as part of the NECF the National Electricity (Retail Support) Amendment Rules 2010 introduces a new pass through event, a 'retailer insolvency event', which provides for the recovery of costs associated with unpaid network distribution charges by a insolvent retailer.[1063]

Any other costs that a distributor incurs in relation to a RoLR event, such as preparing for or responding to the event, are unlikely to be covered by the above provisions. However, the AER considers that such costs should be recoverable under existing mechanisms such as revenue allowances and cost pass through provisions (subject to materiality). The issuing of a RoLR notice by the AER after a RoLR event is likely to constitute either a service standard or regulatory change event.[1064] Thus, the AER considers it unnecessary to nominate an additional event for the residual costs not covered by the mechanisms discussed above.

Aurora proposed a zero materiality threshold for the RoLR event, noting the NECF reforms provided no threshold for this event.[1065] As the National Energy Retail Law automatically deems distributor payments to be a cost pass through amount, the materiality threshold does not apply to these payments.

Once the National Electricity (Retail Support) Amendment Rules 2010 commence, positive change events will be defined in the NER to include a retailer insolvency event that increases the costs of providing direct control services.[1066] Whereas other positive change events have to *materially* increase the costs, the normal materiality threshold will not apply for the retailer insolvency event.

Carbon tax event

Aurora proposed a new pass through event for any new carbon pricing mechanism which materially affected its costs. Subsequently the Australian Government's Clean Energy Legislative Package has been passed by Parliament. Under this legislation, a fixed carbon price will commence on 1 July 2012, and transition on 1 July 2015 to a flexible price set by the market under an emissions trading scheme (ETS).[1067]

The AER considers this carbon pricing mechanism can be covered by one of the prescribed pass through events—regulatory change event, service standard event or tax change event. A separate pass through event for this type of event is therefore not necessary.

Feed-in tariff event

A requirement to pay customers for power they feed into the grid from micro-generators can increase net costs for the distributor. Aurora offers, on a voluntary basis, a feed-in tariff through its net metering buyback scheme. The Tasmanian Government has a declared policy of mandating a feed-in tariff based on a net metering scheme. The tariff is to be paid at a fair and reasonable rate, consistent with

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1063 *National Electricity (Retail Support) Amendment Rules 2010*, r. 3(2), r. 4. These Rules were approved by the Ministerial Council on Energy in 2010 and will be made by the South Australian Minister shortly before the application by the first participating jurisdiction of the Schedule to the *National Energy Retail Law (South Australia) Act 2010*. These Rules will commence on the same date and at the same time as the application of that Schedule in that jurisdiction.

1064 *National Energy Retail Law (South Australia) Act 2011*, s. 136(1).

1065 Aurora, *Regulatory Proposal*, May 2011, p. 211. The NECF was in draft form at the time of Aurora's proposal.

1066 National Electricity (Retail Support) Amendment Rules 2010, 5.2 - amendment to NER, chapter 10, definition of positive pass through event..

1067 Commonwealth Government, ***Securing a clean energy future, The Australian Government's Climate Change Plan***, 2011, p. xiii, 21; The Clean Energy legislation package includes the Clean Energy Act which sets up the carbon pricing mechanism. The legislation was passed by the Senate on 8 November 2011 and will be enacted after it has received Royal Assent.

the agreed national principles for feed-in tariff schemes.[1068] However, the Tasmanian Government has not legislated to implement this policy.

Any cost increase above efficient levels due to Aurora's voluntary arrangement is not subject to cost recovery through the AER's price setting approach. However, the NER provides a mechanism for DNSPs to recover, through their annual pricing proposals, payments made under approved jurisdictional schemes.[1069] If a feed-in tariff is established under Tasmanian law and is determined by the AER to be a jurisdictional scheme, Aurora could recover costs of the feed-in tariffs under the new NER mechanism. Accordingly, the AER does not consider a feed-in tariff should be nominated as a new pass through event.

14.4.2 Materiality threshold

Aurora proposed two different approaches to the materiality threshold for different pass through events:[1070]

- a threshold of 1 per cent of forecast revenue—to apply to natural disaster, bushfires, storms, industry restructure and liability over insurance cap events
- no threshold—to apply to retailer of last resort, carbon tax, insurer credit risk and feed-in tariff events.

The AER accepts Aurora's proposal for a 1 per cent threshold on the natural disaster and liability above insurance cap events. Insurer credit risk is the only other event nominated by the AER. Aurora stated that the increased costs from such an event would be beyond its control, and proposed no materiality threshold.

The AER nominated a similar insurer credit risk event in its determination for Victorian DNSPs, with the same 1 percent materiality threshold as the other nominated events.[1071] The AER is following the same approach to materiality for Aurora's pass through events as applied in the Victorian determination. The AER's full reasoning is set out in that Victorian determination but the broad arguments are as follows.

The NEO effectively provides that the objective of the NEL is to 'promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity'. The AER considers that a one per cent materiality threshold reflects the efficiency requirements in the NEO.

One of the key functions of the pass through regime is to allow DNSPs a reasonable opportunity to pass on costs associated with unexpected events to network users. This provides some degree of protection in the event that a high magnitude, uncontrollable event occurs, such that the financial viability of the DNSP is not undermined, and that the security and reliability of the network are not threatened.[1072]

1068 Hon David Llewellyn MP, Minister for Energy (Tasmania), *Statement On Energy*, 3 December 2009.
1069 NER, clause 6.18.2(b) (6A) and 6.18.7A (Recovery of jurisdictional scheme amounts)
1070 Aurora, *Regulatory Proposal*, May 2011, chapter 27, pp. 209–212.
1071 AER, *Victorian distribution determination*, 2010,,s.16.6.1, pp. 759–775.
1072 See NEL section 7(b). In the context of transmission, the AEMC summarised the intended approach as follows: 'The objective of the cost pass-through is to provide a degree of protection for the TNSP from the impact of unexpected changes in costs outside its control' (.AEMC *Rule Determination 18-2006, Economic Regulation of Transmission Services*, p. 104).

The AER does not consider that providing 100 per cent recovery for all costs incurred by the service provider is consistent with promoting the long terms interests of consumers with respect to price (as required under s. 7(a) of the NEL). To permit the annual pass through of all costs incurred would create a price volatility which is undesirable for customers (where non-recovery of those costs does not present a situation where the security or reliability of the network is undermined).

The AER also considers that such a cost of service regime may impact on the efficiency incentives of the DNSP. While noting that pass through events are excluded from the EBSS, the AER considers that allowing for a 'cost of service' regulatory regime removes the incentive for DNSPs to mitigate, where possible, costs from unexpected events. Therefore, full recovery or compensation for events under a zero materiality threshold would be inconsistent with the RPP. In particular, s.7A (3) of the NEL compels the AER to provide incentives for DNSPs to act efficiently.

Although uncontrollability is a feature of pass through events, there are frequently ways in which DNSPs may affect or mitigate the related costs if provided with the incentive. For example, the DNSP's choice of insurer may affect their insurer credit risk. The incentive regime is in any case intended to allow for DNSPs to absorb some unanticipated losses while capturing a proportion of the benefits of unanticipated cost savings.

A major purpose of a materiality threshold is to ensure that the administrative costs of considering pass throughs do not exceed the benefit of the mechanism. However, the AER has rejected the use of a threshold of administrative costs of assessing a pass through application.[1073] Such a threshold would not generally meet the requirement in clause 6.6.1 of the NER that a positive change event and negative change event must 'materially' increase or decrease the costs of providing direct control services. The NER does not define 'materially' in this context but states that 'the word has its ordinary meaning' which in one dictionary is 'serious, important; of consequence'.[1074] The AER considers that administrative costs would generally not be material in that sense, but a 1 per cent threshold would still enable serious or important events to qualify.[1075]

In other regulatory environments, a 1 per cent threshold has been defined as being 'material'. This has been accepted, for example, by the Queensland Competition Authority (QCA), and the Independent Price and Regulatory Tribunal of NSW (IPART).[1076]

The AER notes that there is some guidance in the NEL and NER as to what policy makers have considered is 'material'. While the AER accepts that the NER treats TNSPs and DNSPs differently in respect of the materiality threshold for NER defined events, a 1 per cent materiality threshold does exist in the NER in the context of transmission. As this threshold appears in Chapter 6A of the NER, it is a threshold that is clearly consistent with the NEO and the RPP. The RPP do not differentiate between DNSPs and TNSPs as denoted by the use of the term 'regulated network provider'.

A percentage or dollar threshold is also consistent with the policy intention outlined in the development of Chapter 6 of the NER. The Ministerial Council on Energy—Steering Committee of Officials (SCO) noted there is no justification in terms of differences in the underlying characteristics

1073 AER, *Victorian distribution determination*, 2010, p. 767.

1074 Shorter Oxford Dictionary (5th edn, 2002). The Macquarie Dictionary (5th edn, 2009) defines material as 'of substantial import or much consequence'.

1075 AER, *Victorian draft decision*, 2010, s. 16.5.4.

1076 IPART, *NSW Electricity Distribution Pricing, 2004/05 to 2008/09, Final Report*, June 2004, p. 129. and QCA, *Final Determination, Regulation of Electricity Distribution*, April 2005, p. 50.

of electricity distribution networks for the rules to differ from those for electricity transmission networks.[1077]

That SCO also noted that the flexibility in the NER would allow the AER to evolve its approach over distribution determinations, with a view to eventual codification. In developing Chapter 6, SCO envisaged similar pass through arrangements for DNSPs as were currently in place for TNSPs. In support of the view that transmission and distribution are not fundamentally different, SCO further noted that:

> However, there has not been a consistent approach by jurisdictional regulators to defining pass-through events for distribution. In transmission there has been consistency, which allows for codification.[1078]

These observations from SCO lend further support to a uniform threshold expressed in percentage terms for additional pass through events.

The AER therefore maintains its view that the same materiality threshold should apply to all nominated events including the insurer credit risk event— namely, 1 per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

14.5 Revisions

Revision 1.1 The AER does not accept Aurora's proposal to nominate: bushfires, storms, declared retailer of last resort, carbon tax, industry restructure and feed in tariff events as nominated pass through events.

Revision 1.2 The AER does not accept Aurora's proposal of no threshold for the insurer credit risk event, and intends to apply a materiality threshold of 1 per cent of forecast revenue to all nominated events.

[1077] SCO, *Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution, Explanatory Material*, April 2007 p. 13. (SCO, *Explanatory material*, 2007)

[1078] SCO, *Explanatory material*, 2007 p. 53.

15 Alternative control services

In general terms, alternative control services are services that are regulated separately to Aurora's standard electricity distribution services. These are services for which there is little, if any potential for the development of competition, and Aurora possesses significant market power. However, these services warrant separate regulation to standard control services as the costs of these services can be directly attributed to a specific set of customers.[1079] The AER classified the following services as alternative control services:[1080]

- metering services—providing, installing and maintaining standard meters (types 5, 6 and 7) 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

Alternative control services comprise approximately nine per cent of Aurora's regulated revenue for the forthcoming regulatory control period.[1081]

OTTER previously regulated metering services under an annuity approach to calculating the capital allowance. OTTER did not regulate all fee based services under a price cap mechanism. However, OTTER monitored prices of all fee based services. OTTER did not previously regulate public lighting and quoted services.

The AER is required by clause 6.12.1(12) of the NER to make a decision on the control mechanism for alternative control services in the distribution determination for Aurora. This includes a decision on the form of control to apply and the basis of the control mechanism.

15.1 Draft determination

15.1.1 Control mechanism

The NER requires the control mechanism to be as set out in the Framework and approach paper for Aurora.[1082] In the Framework and approach paper for Aurora, the AER indicated that it would apply price cap regulation in the forthcoming regulatory control period to:

- all standard metering services
- repair, replacement and maintenance of public lighting, and provision of new public lighting assets

1079 AER, *Framework and approach paper*, November 2010, pp. 38–39.
1080 The AER’s decision on the classification of services is in attachment 1
1081 Metering services comprise approximately 5%, public lighting services comprise approximately 1% and fee based services comprise approximately 3% of Aurora's total regulated revenue for the forthcoming regulatory control period. The AER calculated Aurora's expected revenues from alternative control services using the models Aurora provided in its regulatory proposal.
1082 NER clause 6.12.3(c).

- all fee based services
- unit costs of inputs of quoted services[1083]

The AER's draft determination is to apply a price cap as the form of control to all alternative control services. The AER has determined price caps for individual alternative control services for each year of the forthcoming regulatory control period. These prices have been calculated based upon the AER's forecast of inflation. These prices will be adjusted annually to account for the difference between forecast and actual inflation

Compliance with the control mechanism

The AER considers that Aurora must demonstrate compliance with the control mechanism through an annual pricing proposal.[1084] Aurora will be required to submit to the AER for approval an initial pricing proposal for alternative control services for the first year (2012–13) and an annual pricing proposal for each subsequent year of the forthcoming regulatory control period. The annual pricing proposal must be submitted to the AER in accordance with clause 6.18.2 of the NER.

Aurora's pricing proposal should demonstrate its compliance with the AER's determination on the form of control for alternative control services for the forthcoming regulatory year. Aurora must also publish the annually approved prices for alternative control services on its website.[1085]

15.1.2 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 control for calculating the annual capital allowance for metering. This differs from Aurora's proposal to apply a replacement cost annuity approach for these services. The price caps for metering services determined by the AER are shown in Table 15.1 below.

Table 15.1 Metering prices determined by AER (cents per register per day, nominal)

Year	2012-13	2013-14	2014-15	2015-16	2016-17
Business LV - Single Phase	7.600	7.769	7.945	8.075	8.268
Business LV - Multi Phase	12.720	13.006	13.286	13.671	14.024
Business LV – CT Meters	16.284	16.703	17.107	17.727	18.238
Domestic LV - Single Phase	7.819	8.031	8.248	8.431	8.674
Domestic LV - Multi Phase	12.631	12.859	13.082	13.404	13.695
Domestic LV – CT Meters	15.463	15.722	15.971	16.401	17.181
Other Meters (PAYG)	13.014	13.234	13.454	13.795	14.102

Source: AER analysis.
Note: Prices are in nominal terms and all prices referred to in this chapter are exclusive of GST. Remote read meters omitted.

1083 AER, *Framework and approach paper*, November 2010, p. 17.
1084 Clause 6.12.1(13) of the NER requires the AER to set out a decision on how compliance with the control mechanism is to be demonstrated in its distribution determination.
1085 NER, clause 6.18.9.

The prices determined by the AER are 29 per cent lower than Aurora's proposed prices on average in real terms over the forthcoming regulatory control period. The AER prices result from the following adjustments made to Aurora's method and inputs into the model:

- the adoption of a RAB approach (and the resultant removal of fully depreciated meters from the initial asset base)
- reduction in costs of meters
- increase in regulatory life of mechanical meters from 20 to 30 years
- reduction in proposed rate of installation of new and replacement meters
- applying post-tax WACC with Aurora's accelerated tax depreciation rate
- reduction in WACC as for standard control services

The AER's analysis and reasons for this draft determination are in appendix C.

15.1.3 Public lighting services

The AER accepts Aurora's proposed public lighting annuity model as the basis of control for public lighting services. However, the AER rejects Aurora's proposed price caps for public lighting services as it does not agree with the following inputs into Aurora's public lighting annuity model:

- The AER considers that the opex forecasts in Aurora's regulatory proposal contain a number of errors and the AER replaces these with the forecasts in appendix D
- The AER rejects Aurora's proposed replacement cost for brackets and replaces these with the replacement costs in appendix D

The AER's analysis and reasons for this draft determination are in appendix D.

The AER's draft determination on price caps for 80W mercury vapour and 250W sodium vapour lights for 2012–13 is shown in Table 15.2. These two light types make up approximately 70 per cent of Aurora's public lighting services. Prices for each individual lighting type are in appendix D.

Table 15.2 AER draft determination for price caps for 80W mercury vapour and 250W sodium vapour lights for 2012–13 (cents per day, nominal)

	Aurora's proposed price cap for 2012–13	AER draft determination price cap for 2012–13	% difference between AER draft determination and Aurora's proposal
80W mercury vapour (private contract)	23.03	18.65	-19%
80W mercury vapour (Aurora owned)	36.49	28.71	-21%
250W sodium vapour (private contract)	24.80	20.29	-18%
250W sodium vapour (Aurora owned)	42.87	34.93	-18%

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

15.1.4 Fee based and quoted services

The AER accepts Aurora's proposed fee based services cost build-up model as the basis of control for fee based services. The AER rejects Aurora's proposed price caps for fee based services as it does not agree with the following inputs into Aurora's fee based services model:

- the AER rejects the proposed materials costs for the following fee based services and replaces it with $0:
  - site visit – credit action or site issues
  - renewable energy connection – after hours
  - temporary supply underground – single phase – temporary position
  - temporary builders connection – after hours
- the AER rejects the proposed time assumptions for the following services:
  - truck tee-up
  - all wasted visits
- the AER rejects Aurora's proposed fee for all late cancellation services and replaces it with $0
- The AER rejects Aurora's allocation of PAYG services to fee based alternative control services. The AER has removed the costs and prices relating to PAYG services from Aurora's fee based services model.

The AER's detailed analysis and reasons for this draft determination are in appendix E. The AER's draft determination on price caps for the six most common fee based services for 2012–13 is shown in Table 15.3. The AER's draft determination on price caps for fee based services is in appendix E.

Table 15.3 AER draft determination on price caps for the six most common fee based services for 2012–13 ($nominal)

	Aurora's proposed price	AER draft determination	% difference between Aurora's proposal and AER draft determination
Site visit – no appointment	55.60	49.47	-11%
Site visit – credit action or site issue	349.28	49.47	-86%
Tariff alteration – single phase	164.25	167.45	2%
Tariff alteration – three phase	223.97	228. 33	2%
Renewable energy connection	164.25	167.45	2%
Truck tee-up (initial 30 mins)	n/a	125.03	n/a
Truck tee-up (additional 15 mins)	n/a	51.38	n/a
Truck tee-up (2 hour service)*	782.95	433.31	-45%

Source: AER analysis.

Note: *This two hour service fee is for comparative purposes as Aurora's proposed price is for a two hour truck visit. The AER's draft determination on prices for "truck tee-up" is on the basis of the time based fee structure.

The AER accepts Aurora's proposed price caps for charge out rates for quoted services. The AER also accepts Aurora's proposed method for calculating prices/quotes for quoted services. The AER's reasons for accepting Aurora's proposal are in appendix E. Price caps for hourly labour charge-out rates for quoted services are shown in Table 15.4.

Table 15.4 AER draft determination for price caps for labour charge-out rates for quoted services ($nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17
Apprentice	79.11	75.93	73.32	71.14	73.63
Cable Joiner	60.84	60.67	60.82	60.63	60.45
CC Commercial Metering	68.23	68.02	67.87	67.77	67.72
CC Service Crew	61.43	61.25	61.13	61.05	61.01
Designer	76.43	76.30	76.24	76.24	76.30
Distribution Electrical Technician	61.20	61.03	60.87	60.75	60.67
Distribution Linesman	55.93	55.77	55.66	55.59	55.56
Distribution Linesman LL	61.00	60.83	60.70	60.61	60.56
Distribution Operator	66.05	65.56	65.66	66.13	65.76
Electrical Inspectors	65.13	65.03	65.13	64.81	65.04
Field Service Co-ordinator	85.33	85.01	85.12	84.36	84.11
Labourer OH	51.41	51.27	51.28	51.35	51.39
Meter Reader	46.84	46.80	46.76	46.78	46.85
Pole Tester	51.08	51.00	50.97	50.99	51.05
Project Manager	76.58	76.36	77.27	77.17	76.87

Source: AER analysis.

15.2 Aurora's proposal

15.2.1 Metering services

Aurora's proposed prices for metering were generated by an annuity model which adds the following components:

- an annuity based on the replacement cost of meters (purchase and installation)[1086]
- an annuity based on capital overhead costs, such as vehicles

1086 An annuity is the annual capital allowance that would recover the initial cost of an asset over its expected life.

- operating expenditure (predominantly meter reading costs)
- an allocation of overhead operating costs (corporate and shared services, network division management etc)

Aurora calculated an annual revenue allowance for each meter type from the above components, and from that derived prices per register per day. A separate register is required for each electricity tariff used by a customer.

Table 15.5 Metering prices proposed by Aurora (cents per register per day, $2011–12)

	2012–13	2013–14	2014–15	2015–16	2016–17
Business LV - Single Phase	10.4	10.6	10.6	10.1	10.0
Business LV - Multi Phase	15.8	17.0	18.0	18.3	19.0
Business LV - CT Meters	21.3	22.7	23.8	24.1	24.6
Domestic LV - Single Phase	10.6	10.8	10.9	10.5	10.5
Domestic LV - Multi Phase	15.5	15.7	15.7	15.2	15.1
Domestic LV - CT Meters	19.6	19.9	19.9	19.4	19.2
Other Meters	17.3	17.5	17.6	17.1	16.9

Source: Aurora.[1087]

These are indicative prices only, as actual prices for the forthcoming regulatory control period will be determined following the submission and approval of Aurora's annual pricing proposals to the AER.[1088] Further, the annual price cap will be adjusted year-on-year for inflation.

15.2.2 Public lighting services

The services Aurora proposed as public lighting services are:

- provision, maintenance and replacement of public lighting assets owned by Aurora
- maintenance of public lighting assets owned by customers (i.e. contract lighting)
- provision, maintenance and replacement of Aurora-owned public lighting poles

Aurora proposed to apply a price cap to individual public lighting services in line with the AER's Framework and approach paper for Aurora.[1089] Aurora calculated the charges in its regulatory proposal based on its current annuity approach. Aurora's public lighting annuity model calculates an annuity for:

- the replacement cost for each lamp (including replacement and installation costs of brackets, fittings and luminaires)
- forecast opex (predominately globe replacement costs)

[1087] Aurora, *Regulatory proposal*, May 2011, Chapter 33 (as updated in Metering Annuity Model, 25 July 2011).
[1088] This is in accordance with clause 6.18.2 of the NER.
[1089] AER, *Framework and approach paper*, November 2010, p. 17.

- capex (where the assets are owned by Aurora)
- allocation of overhead costs
- Aurora's proposed prices for 80W mercury vapour and 250W sodium vapour lights for the forthcoming regulatory are shown in Table 15.6.

Table 15.6 Aurora's proposed prices for 2012–13 and current prices for 2011–12 ($2011–12)

Prices of most common light types	Aurora prices for 2011–12	Aurora proposed prices for 2012–13
80W Mercury Vapour - Aeroscreen (contract)	37.81	22.44
80W Mercury Vapour (Aurora owned)	29.79	35.56
250W High pressure sodium vapour (contract)	98.83	24.17
250W High pressure sodium vapour (Aurora owned)	38.77	41.77

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

15.2.3 Fee based and quoted services

Fee based services

Aurora defined fee based services as those services it provides for the benefit of a single customer and at the request of a third party (typically received from a retailer on behalf of a customer). These services are largely homogenous in nature and therefore a fixed fee can be set in advance with reasonable certainty.

Aurora proposed to apply a price cap to individual services. Aurora's proposed price caps are determined through a build up of costs in Aurora's fee based services model based on:

- labour costs
- materials costs
- contractor costs (where applicable)
- other costs (overhead costs and direct shared costs)

Aurora calculated prices for 2013–14 to 2016–17 by escalating the costs for 2012–13 using real cost escalators and CPI.

Aurora noted that the prices for fee based services were indicative only and are for the purposes of providing a high level overview of price impacts for the forthcoming regulatory control period. Aurora proposed that actual prices for fee based services will be determined in its annual pricing proposals in accordance with clause 6.18.2 of the NER.[1090]

[1090] Aurora Energy, *Regulatory proposal addendum*, June 2011, p. 51.

Quoted services

Aurora defined quoted services as services where the nature and scope of the service is specific to individual customers' needs and varies from customer to customer. Requests for these services are typically received directly from the customer or from a retailer on behalf of the customer.[1091]

Aurora proposed to apply a price cap form of control to all quoted services with price caps applying to individual costs of inputs. Prices for the services will be calculated on an individual basis using a formula based approach:

Price = Labour + Materials + Contractor + Other Costs + Overheads[1092]

Aurora's proposed price caps for the hourly charge-out rates of workers for 2012–13 are shown in Table 15.4. Aurora proposed to charge for materials at cost.

15.3 Assessment approach

The AER is required by clause 6.12.1(12) of the NER to make a decision on the control mechanism for alternative control services in the distribution determination for Aurora. This includes a decision on the form of control to apply and the basis of the control mechanism. The rules provide that the control mechanism must be as set out in the AER's framework and approach paper.[1093]

Clause 6.2.6(b) of the NER provides that the control mechanism for alternative control services must have a basis as stated in the distribution determination. Clause 6.2.6(c) allows the AER flexibility as to the basis of control to apply to alternative control services.

The AER must have regard to the five factors in clause 6.2.5(d) of the NER when determining the basis of control for alternative control services. These factors are:

1. the potential for the development of competition in the relevant market and how the control mechanism might influence that potential

2. the possible effects of the control mechanism on administrative costs of the AER, the Distribution Network Service Provider and users or potential users

3. the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination

4. the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)

5. any other relevant factor.

The AER considers that another relevant factor is the extent to which the basis of control for alternative control services gives effect to and is consistent with the national electricity objective[1094] (NEO) and revenue and pricing principles (RPP) in the National Electricity Law.[1095]

[1091] Aurora Energy, *Regulatory proposal addendum*, June 2011, p. 51.
[1092] Aurora Energy, *Regulatory proposal addendum*, June 2011, p. 51.
[1093] NER clause 6.12.3(c) provides that: the control mechanisms must be as set out in the relevant framework and approach paper.

[1094] NEL, s7
[1095] NEL, s7A.

The RPP require the AER to provide a network service provider with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control services.[1096] The AER considers that prices should be cost reflective in order to ensure that the DNSP is able to recover the costs it incurs in providing alternative control services.

The AER has previously interpreted 'efficient costs' to mean the expected costs based on outcomes in a workably competitive market.[1097] The AER therefore considers it is consistent with the RRP to set price caps for alternative control services based on the expected costs in a workably competitive market.

By setting prices at the level of efficient costs, the AER is promoting efficient investment in, and use of electricity services consistent with the NEO. Consumption where prices are set at the level of a workably competitive market would be efficient, as the marginal benefit of consumption at that level of service would reflect the cost of providing the service. This is consistent with the NEO.

The AER considers that the basis of control most likely to result in cost reflective pricing given Aurora's circumstances and the information available to the AER are:

- RAB roll forward approach for metering services
- annuity approach for public lighting services
- cost build up for fee based and quoted services

The AER's reasons for determining these bases of control for alternative control services are set out in appendixes C, D and E.

The AER has utilised a number of assessment methods to determine whether Aurora's proposed cost inputs into the relevant basis of control are reasonable and efficient. These include:

- benchmarking analysis to assess whether Aurora's proposed input costs, total costs and prices are comparable to the actual costs of other DNSPs
- historical cost and trend analysis to determine base year costs
- assessments of drivers of proposed step changes
- expert engineering advice from consultants

This assessment approach is consistent with the AER's approach in recent distribution determinations.[1098]

In determining the price caps for public lighting, metering and fee based services, and price caps for unit costs of inputs for quoted services, the AER had regard to prices and input costs for similar services in other jurisdictions and a range of industry benchmarks across the NEM. The AER considers that where similar services are provided across the NEM, prices should reflect some level of convergence. Therefore the AER considers that benchmarking Aurora's input costs and prices

[1096] NEL, s7A(1)
[1097] AER, Victorian electricity distribution network service providers Distribution determination 2011–2015, October 2010, p. 397.
[1098] See: AER, Victorian electricity distribution network service providers Distribution determination 2011–2015, October 2010, pp. 840–854; 914–917.

against a reasonable range of input costs, prices and industry benchmarks will provide an indication of whether Aurora's proposed costs are efficient.

The AER considers historical cost and trend analysis a useful tool to indicate whether forecast costs are reasonable. The AER has used Aurora's historic expenditure to to indicate whether forecast costs reflect the expenditure of a DNSP in its circumstances.

The AER has used historical analysis in combination with benchmarking and other analytical tools to determine if Aurora's proposed costs have a reasonable basis. The AER then assessed any step changes away from this efficient cost base. These step changes were assessed on the basis of circumstances requiring a change in costs and the drivers of those cost changes.

Clause 6.12.1(13) of the NER requires the AER to make a decision on how compliance with the control mechanism is to be demonstrated. The AER considers that Aurora should demonstrate compliance with the control mechanism through an annual pricing proposal. The AER's reasons for this decision are set out in appendixes C, D and E.

16 Negotiated services

The AER's distribution determination imposes controls over the prices and revenues that DNSPs can recover from the provision of direct control services. Services classified as negotiated distribution services do not have their terms and conditions determined by the AER. These services are subject to negotiation between parties, or alternatively arbitration and dispute resolution by the AER. These processes are facilitated through two instruments:

- a negotiating framework
- a negotiating distribution service criteria (NDSC).

A negotiating framework sets out procedures to be followed when negotiating terms and conditions of access for a negotiated distribution service.[1099]

A NDSC sets out the criteria that a Distribution Network Service Provider (DNSP) will apply in negotiating terms and conditions of access, including the prices and access charges for negotiated transmission services.[1100] It also sets out the criteria that the AER will apply in resolving disputes about terms and conditions of access for negotiated services.[1101]

The AER is required to make a constituent decision on the negotiating framework and the NDSC that are to apply to Aurora in the forthcoming regulatory period.[1102] This chapter sets out the AER's considerations and conclusions on Aurora's proposed negotiating framework and the NDSC.

16.1 Draft determination

The AER refuses to approve the negotiating framework as proposed by Aurora for the forthcoming regulatory period. The proposed negotiating framework uses inconsistent concepts when referring to specified time limits.[1103] This issue is further discussed in section 16.4.1.

The AER determines the proposed NDSC published on 26 June as the NDSC that is to apply to Aurora in the forthcoming regulatory period in accordance with clause 6.7.4 of the National Electricity Rules (NER). The proposed NDSC gives effect to the negotiated distribution services principles set out in clause 6.7.1 of the NER.

16.2 Aurora's proposal

16.2.1 Negotiating framework

The negotiating framework proposed by Aurora for the forthcoming regulatory period is set out in Appendix A. The proposed negotiating framework identifies the new public lighting technology distribution service as the only negotiated distribution service for the forthcoming regulatory period.

1099 NER, clause 6.7.5(a)
1100 NER, clause 6.7.4(a)(1)
1101 NER, clause 6.7.4(a)(2)
1102 NER, clause 6.12.1(15)-(16)
1103 The minimum requirements for a negotiated framework are set out in clause 6.7.5(c) of the NER.

16.2.2 Negotiated distribution services criteria

The AER published its proposed NDSC on 26 June 2011 as required under clause 6.9.3 of the NER.[1104] In specifying the proposed NDSC, the AER adopted the negotiated distribution service principles set out in clause 6.7.1 of the NER as criteria.

Appendix A sets out the AER's proposed NDSC that is to apply to Aurora in the forthcoming regulatory period.

16.3 AER approach

16.3.1 Negotiating framework

A negotiating framework that complies with the NER requirements must specify each of the requirements set out in clause 6.7.5(c) and comply and be consistent with the applicable requirements of the distribution determination, including the NDSC.

The AER examined whether Aurora's proposed negotiating framework met these requirements. The specific requirements set out in clause 6.7.5(c) are summarised below.

16.3.2 Negotiated distribution services criteria

The AER considers a NDSC that adopts the negotiated distribution service principles as criteria would satisfy the NER requirements. Therefore, the assessment of the proposed NDSC involves the examination of whether it reflects the negotiated distribution service principles set out in clause 6.7.1 of the NER.

16.4 Reasons for draft determination

16.4.1 Negotiating framework

The AER refuses to approve Aurora's proposed negotiating framework.

The proposed negotiating framework is reasonably compliant with the requirements of the NER. However, there is a minor aspect that needs correction for the AER to approve the proposed negotiating framework.

The AER refuses to approve the proposed negotiating framework as it inconsistently identifies specified time limits. Aurora refers to two different concepts in specifying time limits for progressing negotiations: 'business days' and 'days'. The term 'business day' is separately defined in the proposed negotiating framework but the term 'day' is not defined, which may give rise to uncertainty.[1105] The AER considers the term 'day' would be interpreted differently to a 'business day' which may also cause confusion in the practical application of the framework.

The AER considers clause 6.7.5(c)(5) does not require a DNSP to use a particular concept when specifying time limits–'day' or 'business day'. However, to ensure consistency and certainty in the application of clause 6.7.5(c)(5) of the NER, the AER considers Aurora should amend the proposed negotiating framework to use 'business days' instead of 'days' when referring to specified time limits. The replacement of 'days' with 'business days' also ensures all sections of Aurora's proposed

[1104] AER, *Call for submissions: Proposed negotiated distribution service criteria for Aurora*, June 2011.
[1105] Aurora, *Negotiating Framework, 2012-17 Regulatory control period*, May 2011, clause 9.1, p. 5. (negotiating framework)

negotiating framework that make reference to a specified time limit are consistent (clauses 6.3, 7.2, 7.4, 7.5 and 10 of Aurora's proposed negotiating framework).[1106]

In requiring Aurora to specify time limits in 'business days', the AER notes:

- specifying time limits by reference to 'business days' will ensure that time limits do not expire on non-business days
- using one defined term to specify time periods is likely to cause less confusion for those negotiating than using two different terms, one of which is not defined
- in the proposed negotiating framework, Aurora referred to 'business day' ten times compared with two times for 'day'
- in the recent distribution determination for Victorian DNSPs, 'business day' was consistently referred to when specifying time limits in the negotiating framework.[1107]

For the above reasons, the AER refuses to approve Aurora's proposed negotiating framework under clause 6.12.3(a) of the NER.

The AER's assessment of Aurora's proposed negotiating framework is set out in Table 16.1. The AER did not receive submissions on the proposed negotiating framework.

Table 16.1 AER's assessment of the negotiating framework proposed by Aurora

NER requirement	AER assessment
Requirement to negotiate in good faith–clause 6.7.5(c)(1) of the NER	Clause 5 of Aurora's proposed negotiating framework satisfies this requirement
Requirement for Aurora to provide all such commercial information reasonably required to allow effective negotiation, including certain cost information –clause 6.7.5(c)(2) of the NER	Clause 6 of Aurora's proposed negotiating framework satisfies this requirement
Requirement for Aurora to identify and inform the negotiated service applicant of reasonable costs of providing the negotiated service and demonstrate that charges reflect costs; and to have appropriate arrangements for assessment and review of the charges and the basis on which they were made –clause 6.7.5(c)(3) of the NER	Clause 6.5 of Aurora's proposed negotiating framework satisfies this requirement
Requirement for the applicant to provide all such commercial information reasonably required to enable effective negotiation–clause 6.7.5(c)(4) of the NER	Clause 7 of Aurora's proposed negotiating framework satisfies this requirement
Requirement for negotiation to be commenced and finalised within specified periods and for each party to make reasonable endeavours to adhere to the specified time limits–clause 6.7.5(c)(5) of the NER	Clauses 9 and 10 of Aurora's proposed negotiating framework seek to address this requirement. However, Aurora uses different concepts in referring to time period for progressing negotiation which may lead to confusion and uncertainty. The AER's consideration in regard to this issue is further discussed above.

1106 Clause 15 of Aurora's proposed negotiating framework defining terms and concepts only provides a definition for 'business day', p. 9.
1107 AER, *Draft decision: Victorian Electricity network service providers: Distribution determination*, 2011-2015, *Appendix C, 2010*, p. 4.

Requirement to specify a process for dispute to be dealt with in accordance with the relevant provisions for dispute resolution[1108]–clause 6.7.5(c)(6) of the NER	Clause 11 of Aurora's proposed negotiating framework satisfies this requirement
Requirement to specify arrangements for the payment of Aurora's reasonable direct expenses incurred in processing the application to provide the negotiated distribution service–clause 6.7.5(c)(7) of the NER	Clause 12 of Aurora's proposed negotiating framework satisfies this requirement
Requirement for Aurora to determine the potential impact of the negotiated distribution service on other network users–clause 6.7.5(c)(8) of the NER	Clause 13.1 of Aurora's proposed negotiating framework satisfies this requirement
Requirement for Aurora to notify and consult with any affected network user and ensure the negotiated distribution service does not result in non-compliance with obligations in relation to other network users under the NER–clause 6.7.5(c)(9) of the NER	Clause 13.2 of Aurora's proposed negotiating framework satisfies this requirement
Requirement for Aurora to publish the results of negotiations on its website–clause 6.7.5(c)(10) of the NER	Clause 14.1 of Aurora's proposed negotiating framework satisfies this requirement

16.4.2 Negotiated distribution services criteria

The AER determines that the proposed NDSC published on 26 June 2011 is the NDSC that is to apply to Aurora in the forthcoming regulatory period.

The AER's proposed NDSC directly reflects the negotiated distribution service principles set out in clause 6.7.1 of the NER. This is because, in specifying the proposed NDSC, the AER adopted the negotiated distribution service principles as criteria.

The AER did not receive submissions on the proposed NDSC.

16.5 Revisions

The AER refuses to approve the negotiating framework proposed by Aurora. The AER requires Aurora to amend the proposed negotiating framework, for it to be approved in accordance with the NER. The AER would accept the following changes to the proposed negotiated framework if Aurora submits a revised negotiating framework to the AER for approval.

Revision 16.1 Clause 9.1 of the proposed negotiating framework, table 1.1, line 3, column 3 should be changed to read 'No more than 20 business days after written request'

Revision 16.2 Clause 9.1 of the proposed negotiating framework, table 1.1, line 4, column 3 should be changed to read 'No more than 30 business days after written request'

1108 The relevant provisions for dispute resolution are set out in part L of chapter 6 of the NER.

Appendixes

A 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.

A.1 Negotiating framework

Aurora Energy Pty Ltd
Negotiating Framework
2012-17 Regulatory control period

1

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 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*	No more than 30 days after written request.

	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.	
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 appointed under the *Public Holidays Act 1993*.

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.

Public Holidays Act 1993 means the law pursuant to *Public Holidays Act 1993*.

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*.

A.2 Negotiated Distribution Service Criteria

A.2.1 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.

A.2.2 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.

A.2.3 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).

B Operating expenditure benchmarking

The AER must have regard to the benchmark operating expenditure of an efficient DNSP when assessing a DNSP's forecast opex.[1109]

Benchmarking has played a role in previous price determinations, both by the AER and by other regulators, such as the United Kingdom's Office of the Gas and Electricity Markets (Ofgem).[1110]

The AER used benchmarking in its electricity distribution determination for the Victorian DNSPs.[1111] It was an informative tool that enabled conclusions to be drawn about the performance of the Victorian DNSPs against efficient regulatory benchmarks, and against the performance of their peers.

In contrast, Ofgem uses its benchmarking to directly inform its regulatory allowances. The key distinction from the AER's current practice is Ofgem went through an extensive process with industry to develop comprehensive sets of data to support and enable the benchmarking it undertakes.

The availability and quality of data limits the benchmarking techniques that can be applied by the AER.[1112]

While benchmarking may provide an indication of the relative performance of a DNSP with its efficient peers, the AER must be satisfied that total forecast opex reasonably reflects the costs that a prudent operator in the circumstances of the relevant DNSP would require to meet the opex objectives.[1113] There are many reasons why benchmarking alone may not reflect the costs of a prudent operator in the circumstances of the relevant DNSP. The AER has previously discussed the limitations of benchmarking.[1114] Limitations to the benchmarking analysis that have been identified by the AER include:

- different licence requirements in the NEM jurisdictions
- differences between purchase and leasing policies
- variations in the network characteristics of DNSPs including the age, size and maturity of their networks and the markets they serve
- different capitalisation, cost allocation and other accounting policies
- different regulated service classifications.
- Despite these limitations, expenditure benchmarking at an aggregate level, combined with analysis aimed at identifying and accounting for these differences, can provide and indication of the relative efficiency of DNSPs.

1109 NER clause 6.5.6(e)(4)

1110 See: AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011-2015*, October 2010, Appendix H and Ofgem, *Electricity distribution price control review methodology and initial results paper*, 8 May 2009, pp. 38–46.

1111 AER, Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015, October 2010, Appendix I

1112 This was noted by the AEMC in its review of TFP, see AEMC, *Review into the use of total factor productivity for the determination of prices and revenues: Preliminary findings paper*, December 2009, pp. 47–64.

1113 NER clause 6.5.6(c)(2)

1114 AER, *Draft decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, Appendix I, pp. 78–79.

B.1 Accounting for differences between DNSPs

Adjustments can be made to aggregate expenditure data to account for differences between DNSPs. Two key factors the AER can adjust, when considering the benchmark efficiency of opex, are density and size.

Typically more opex is required for less dense networks, due to equipment type and asset ratios.[1115] For example, in rural areas there are a greater number of smaller transformers, which are more dispersed, than there are in urban areas.[1116] Further, less dense networks typically have a higher proportion of line assets (poles and conductors) compared to capacity assets (substations and transformers). Line assets typically require greater maintenance, since poles and conductors must be inspected and surrounding vegetation must be trimmed.[1117] Size is also important because larger DNSPs will benefit from economies of scale.

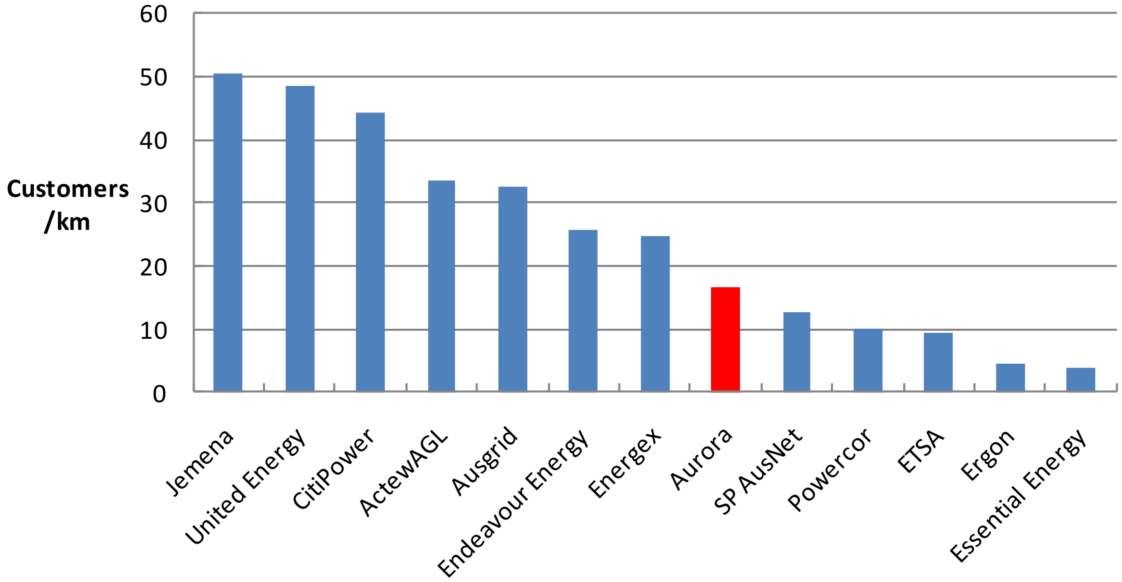
Of the two key factors mentioned above, density is most important,[1118] but there are different density measures to choose from:

- Customer density is favoured by Nuttall Consulting due to unexplained inconsistencies between Aurora's peak demand and energy distributed figures.[1119] Customer density measures the number of customers per km of line.[1120]
- Load density is favoured by Benchmark Economics. It considers load density has greater explanatory power.[1121] Load density measures the average peak energy demand per km of line. Nuttall Consulting has noted some inconsistencies between Aurora's consumption and peak demand but has been unable to identify the cause. Nuttall Consulting is therefore hesitant to use either of these density measures as a normalising factor.[1122]

The AER considers customer density is the appropriate measure, given that there are unexplained inconsistencies in Aurora's load data. However, the AER considers the use of load density would not alter the outcome of this analysis.

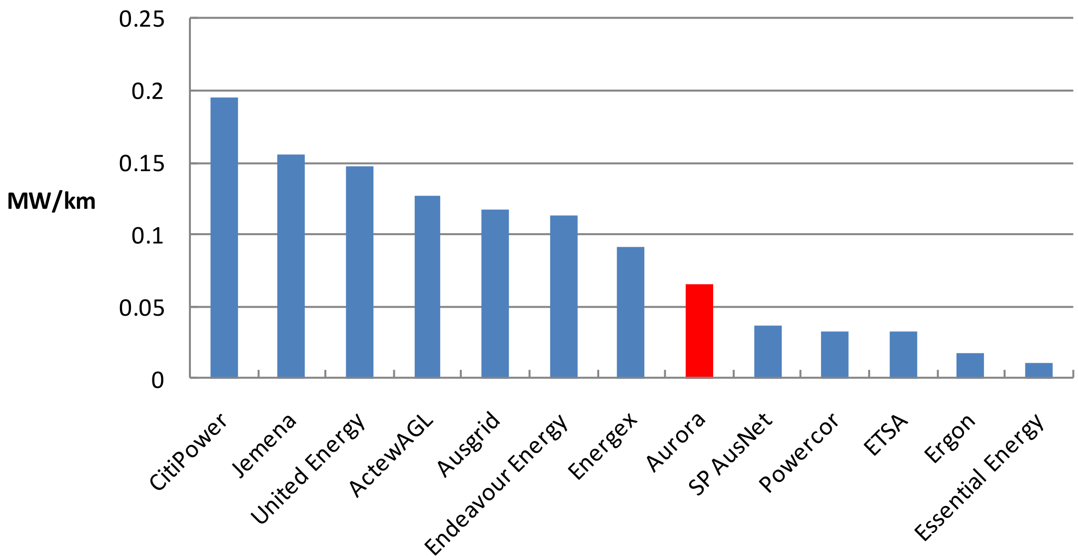
1115 Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, p. 36.
1116 Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, pp. 37–39.
1117 Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, pp. 39–41.
1118 Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, p. 36.
1119 Nuttall Consulting, *Aurora Electricity Distribution Revenue Review*, October 2011, (Nuttall, *Aurora Revenue Review*), p. 12.
1120 For the charts below, the number of customers is equal to the number of connections.
1121 Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, pp. 1–6.
1122 Nuttall, *Aurora Revenue Review*, October 2011, p. 13.

Figure B.1 Customer density of DNSPs in the NEM



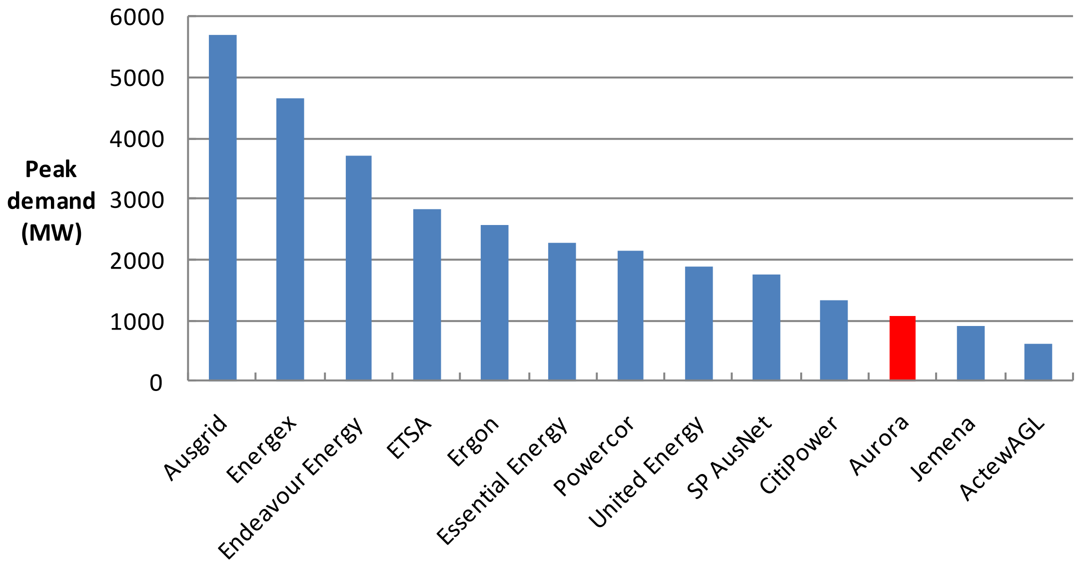
Source: AER analysis.

Figure B.2 Load density of DNSPs in the NEM



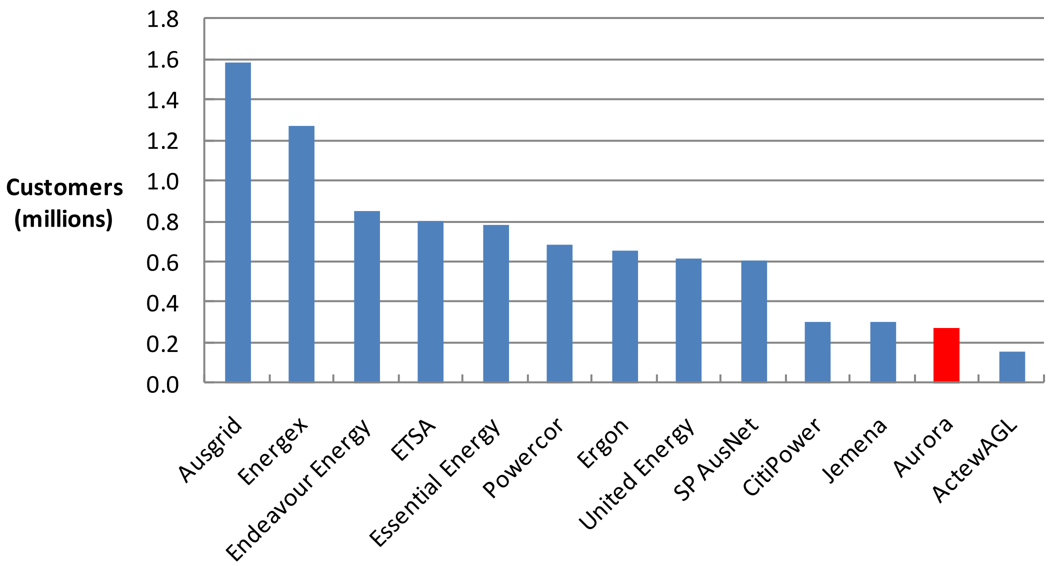
Source: AER analysis.

Figure B.3 Size of DNSPs in the NEM, peak demand



Source: AER analysis.

Figure B.4 Size of DNSPs in the NEM, customer numbers



Source: AER analysis.

Based on the factors depicted by the data in Figure B.1 to Figure B.4 relating to customer density, load density, peak demand and customer numbers for DNSPs in the NEM, the AER considers the following DNSPs to be the most comparable to Aurora in the NEM:

- ETSA
- Powercor
- SP AusNet

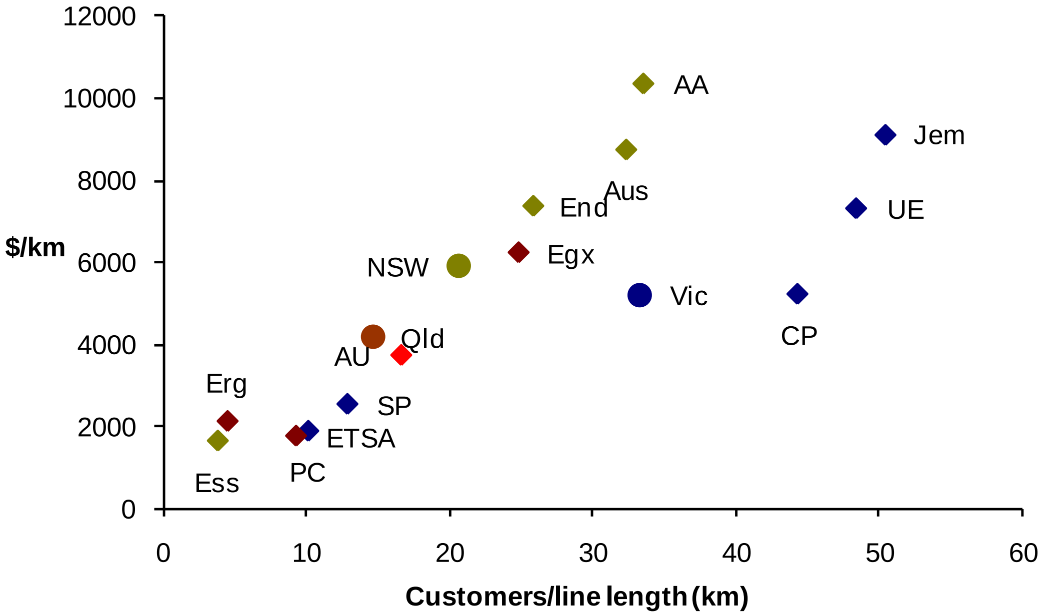
- Energex
- Endeavour Energy

The AER considers Aurora's operating environment is most like that of SP AusNet's and Powercor's because they have a similar density and size.[1123]

B.2 Benchmarking

The AER undertook a ratio analysis to compare the level of recent historical opex for Aurora against other DNSPs in the NEM (see Figure B.5 to Figure B.9). The AER used customer density to normalise the results. The analysis below suggests Aurora is at an average level when compared to other DNSPs.

Figure B.5 Opex/line length[1124]

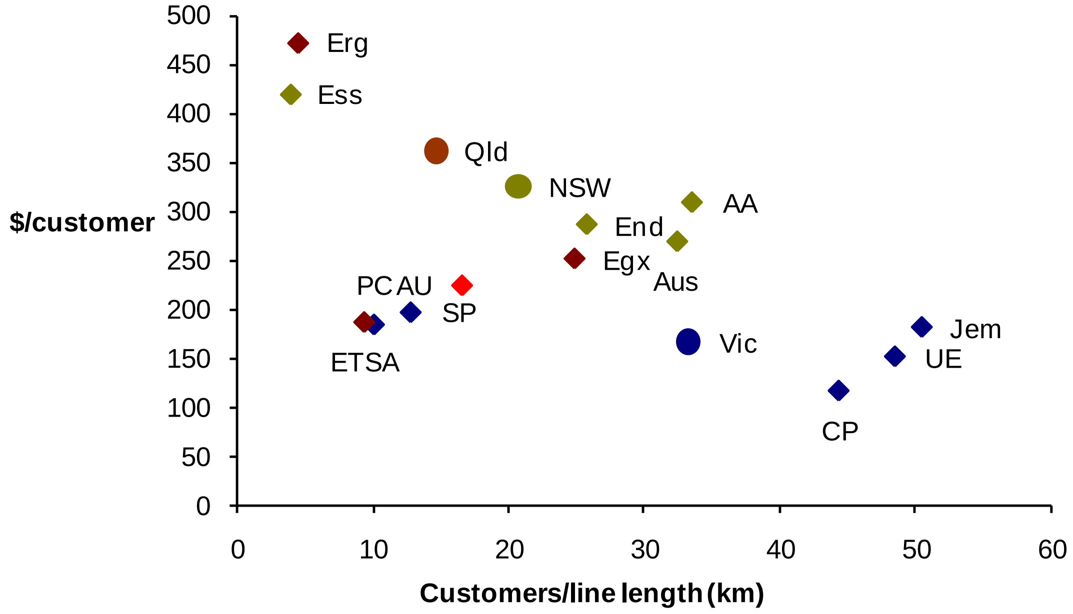


Source: AER analysis.

1123 This claim is supported by Nuttall consulting, see: Nuttall, *Aurora Revenue Review*, October 2011, p. 6.

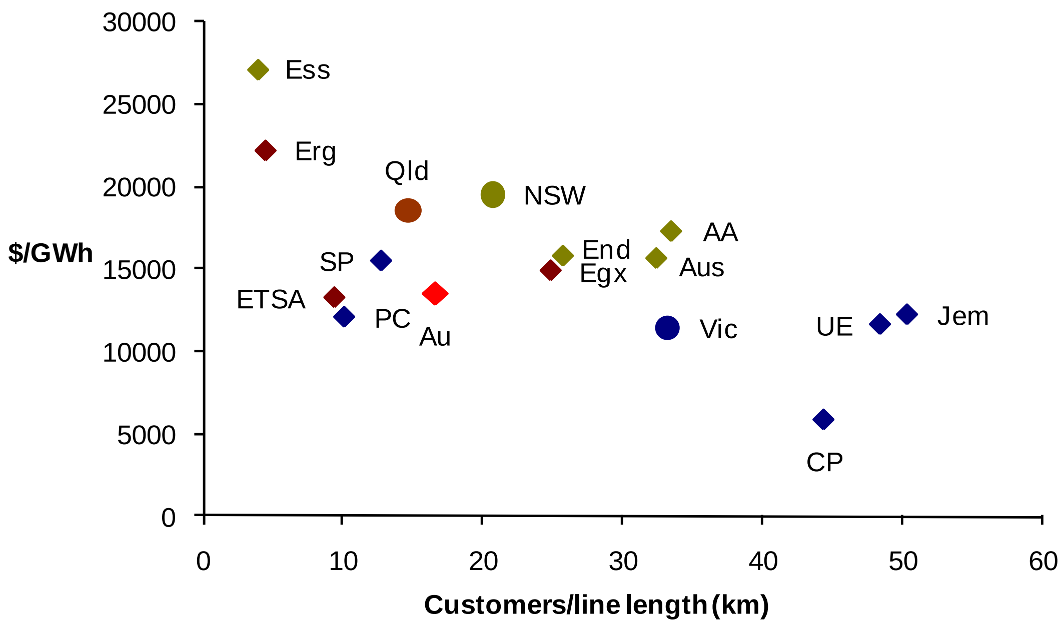
1124 The shortened versions of the business names in the figures are: AA – ActewAGL, AU – Aurora, Aus – Ausgrid, CP – CitiPower, End - Endeavour Energy, Egx – Energex, Erg – Ergon Energy, Ess – Essential Energy, ETSA – ETSA Utilities, Jem – Jemena, PC - Powercor, SP – SP AusNet, UE – United Energy.

Figure B.6 Opex/customer



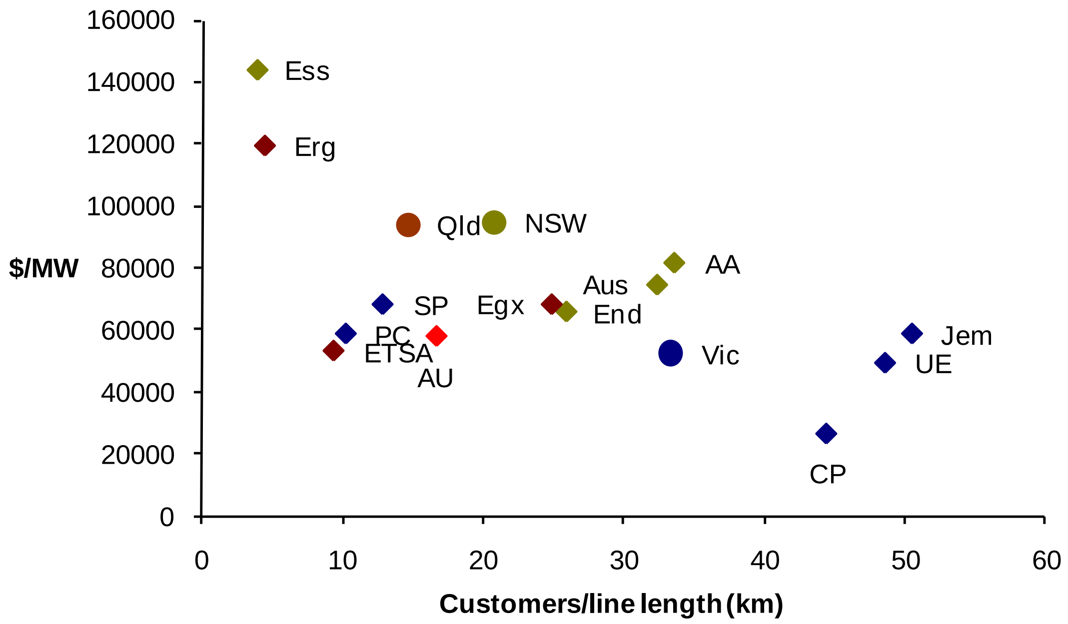
Source: AER analysis.

Figure B.7 Opex/electricity distributed



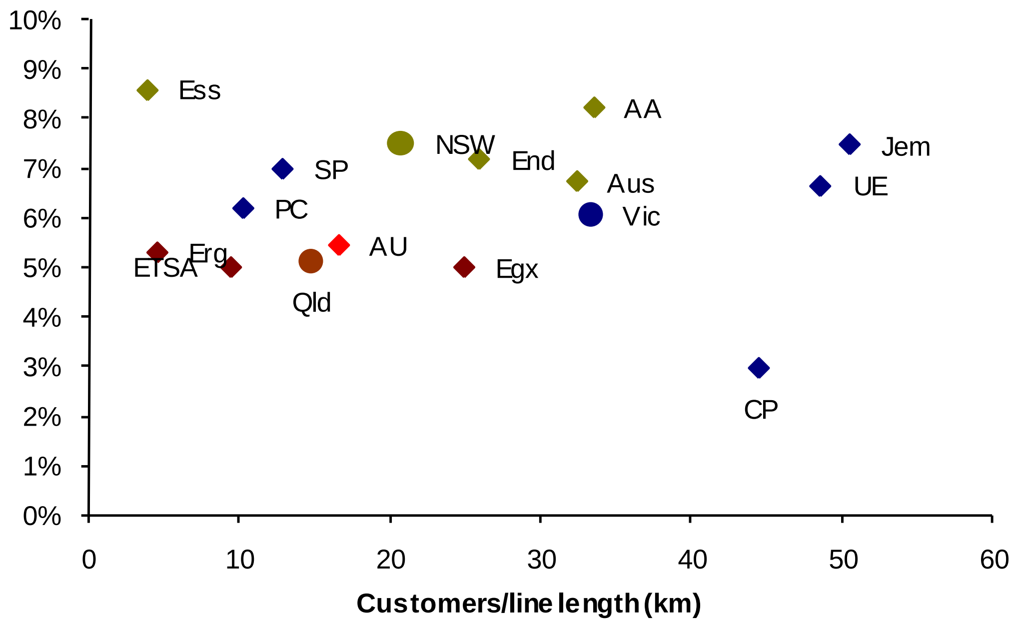
Source: AER analysis.

Figure B.8 Opex/peak demand



Source: AER analysis.

Figure B.9 Opex/RAB[1125]



Source: AER analysis.

[1125] RAB can be used as a broad measure of network size. However, the robustness of this measure is influenced by a number of factors including different points at which NSPs may be in their investment cycle. That is, an older network of similar size to another will likely have a smaller RAB since more of it will have been depreciated. For this reason, the AER has put less weight on this measure in interpreting the results.

Conclusions from benchmarking analysis

Based on the benchmarking analysis performed by the AER, it can be concluded that Aurora performed better than the NSW DNSPs on every measure. It also performed better than Ergon but similar to Energex, which performed slightly better on four of the five measures. The AER considers the benchmarking analysis suggests that on the whole Aurora has not performed as well as ETSA and the Victorian DNSPs, but has outperformed Ergon and the NSW DNSPs.

The benchmarking analysis results for Aurora, are evaluated against its comparable peers, ETSA, SP AusNet and Powercor, in Table B.1. In comparison to ETSA, Aurora's costs were higher in all categories. In comparison to SP AusNet and Powercor, Aurora's costs were lower in some categories but higher in others.

Table B.1 Summary of opex benchmarking — Aurora's performance compared to benchmark peers (per cent of Aurora)

	ETSA	SP Ausnet	Powercor
Opex / line length	+114	+47	+99
Opex / customer	+20	+14	+22
Opex / electricity distributed	+2	–13	+12
Opex / peak demand	+9	–15	–1
Opex / RAB	+8	–22	–12

Source: AER analysis.

This analysis suggests Aurora's opex tends to be above or similar to its benchmark peers—SP AusNet, ETSA and Powercor.

Submissions provided to the AER regarding benchmarking opex

The Energy Users Association of Australia (EUAA) provided a submission with some high level trend analysis benchmarking Aurora's historical and forecast opex per customer compared to the other jurisdictions.[1126] The EUAA benchmarking contends that Aurora's historical actual opex is higher than actual opex incurred by privately owned DNSPs, particularly in relation to the Victorian DNSPs. The AER's benchmarking is consistent with these findings.

In support of its regulatory proposal Aurora provided two benchmarking reports. Parsons Brincknerhoff (PB) undertook a high level trend analysis of Aurora's historical and forecast opex.[1127] PB's report is primarily focused on Aurora's forecast using its historical actual values. PB concluded Aurora's forecast opex was lower than:

- would be expected based on the historical trend
- the average expenditure over the most recent 5 year period.

[1126] EUAA, *Submission to the Australian Energy Regulator on Aurora Energy's regulatory proposal on distribution prices for 2012-17*, August 2011, pp. 15–16.

[1127] Parsons Brinckerhoff*, Capex and opex benchmarking study: Aurora Energy*, March 2011.

PB also undertook ratio analysis benchmarking Aurora against other DNSPs. It concluded that Aurora's forecast opex is generally aligned with or below industry expectations when normalised using a range of comparators.[1128] PB's concluded Aurora's:

- emergency management expenditure per kilometre of line was above average but within the range of other businesses
- vegetation management costs per kilometre of line were below average and outside the range of other businesses
- asset inspection costs were in line with industry expectations.

PB considered costs within plus or minus 20 per cent of industry average unit costs to be within a reasonable range.[1129]

Benchmark Economics noted there are various approaches and methods to benchmarking, each with its own advantages and disadvantages.[1130] Despite this, Benchmark Economics considered benchmarking should be given more significant consideration by the AER. It considers benchmarking is one of two opex factors (along with actual and expected opex during the previous regulatory period) that provide a transparent and objective metric against which costs can be compared.[1131]

Benchmark Economics undertook regression analysis, benchmarking both Aurora's actual and forecast expenditures. Benchmark Economics proposed an 'envelope of prudent and efficient' opex for each period. Benchmark Economics concluded for Aurora's current regulatory period, actual opex is within its envelope of prudent and efficient opex.[1132] It also concluded Aurora's forecast opex is below this envelope and more opex may be required over the forthcoming regulatory period if older assets are not replaced.[1133]

The benchmarking undertaken by Benchmark Economics is similar to that completed by the AER, but it differs is some respects including:

- load density is preferred over customer density as a normalising factor[1134]
- a single year's expenditure is used rather than a five year average[1135]
- efficient costs are considered to be the line of best fit through the entire sample set[1136]

Both PB and Benchmark Economics support an increase in Aurora's forecast opex. As appropriately stated by Benchmark Economics, the different benchmark approaches have their strengths and weaknesses. Indeed, Benchmark Economics uses regression analysis based on one data point (2009), while PB uses allowances in forming a view on Aurora's forecast opex.

The AER's analysis has been based upon an average of historical costs as opposed to a single year, as used by Benchmark Economics, or allowances, as used by PB. An average of historical costs accounts for annual fluctuations in non-recurrent costs and reflects the underlying costs of providing

[1128] Parsons Brinckerhoff, *Capex and opex benchmarking study: Aurora Energy*, March 2011, p. iv.
[1129] Parsons Brinckerhoff, *Capex and opex benchmarking study: Aurora Energy*, March 2011, p. 4.
[1130] Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, p. 17.
[1131] Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, p. 15.
[1132] Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, pp. 77–78.
[1133] Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, p. 85.
[1134] Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, p. 1.
[1135] Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, pp. 27–28.
[1136] Benchmark Economics, *A comparative analysis: Aurora Energy's network cost structure*, May 2011, p. 13.

distribution services. The AER notes PB and Benchmark Economics both consider Aurora's current opex is in the average range when compared to the other DNSPs in the NEM. However, unlike PB and Benchmark Economics, the AER does not consider average performance provides an indication of the efficiency of Aurora's historical or forecast opex. For these reasons the AER does not accept the conclusions of Aurora's submissions on its benchmark efficiency.

C Alternative control – metering services

This appendix sets out the AER's detailed analysis and reasoning supporting its decision on Aurora's metering services in attachment 15.

The AER's assessment of Aurora's proposed price caps for metering services focused on:

- the basis of control to apply to metering services
- the inputs into cost build up under the building block model.

The AER considered whether the inputs into the building block model reflected reasonable and efficient costs using the method outlined in section 15.3 of attachment 15. The AER's decisions on each of the inputs were incorporated into the building block model to calculate the AER's decision on price caps for metering services.

C.1 AER draft determination

C.1.1 Basis of control

An element of the basis of control is the approach to determining the annual capital allowance (return on and of capital) for each alternative control service. The AER has determined that a limited building block model, based on the Regulated Asset Base (RAB) roll forward approach should be used to calculate the annual capital allowance for metering. This differs from Aurora's proposal to apply an annuity approach for these services.

The AER set out its proposed approach to determining the basis of control for metering services in the Framework and approach paper for Aurora:[1137]

> The AER's starting position is the current application of the annuity approach as the basis of control for standard metering services. Through the distribution determination process the AER will further investigate and confirm whether a more appropriate basis of control (for example whether the use of a regulatory asset base for standard metering services) is required in the forthcoming regulatory control period.[1138]

The AER has considered both Aurora's proposed annuity approach and a RAB roll forward approach. The AER considers the RAB roll-forward approach better satisfies the NER requirements. Table C.1 outlines the AER's consideration of the five factors in clause 6.2.5(d) of the NER.

1137 AER, *Framework and approach paper*, November 2010, pp. 73–75.
1138 AER, *Framework and approach paper*, November 2010, p. 75.

Table C.1 NER factors and the basis of control for metering services

NER factors	AER consideration
The potential for the development of competition	There is little if any potential for the development of competition in metering services.[1139] The choice of a RAB roll forward approach or annuity approach will have little effect on the potential for competition.
Administrative costs	The application of a RAB roll forward approach may impose some additional administrative cost on Aurora as it has not previously used this approach. However, the AER has constructed a RAB and building block model for this assessment, using data supplied by Aurora.[1140] This model will be made available to Aurora. Some further costs could be incurred in restructuring information systems to input future data directly into the RAB model. However, the AER considers that these potential additional costs would be largely transitional in nature and not material.
Previous regulatory arrangements	The previous regulatory arrangement for metering services in Tasmania is the annuity approach. Previously, OTTER considered that it was impractical to determine the age and value of the meter stock so it initially used the annuity approach to determine Aurora's metering prices in 1999.[1141] OTTER replicated the annuity approach in the following two distribution determinations. However, as noted in relation to administrative costs, the AER now considers that Aurora has sufficient information to construct a RAB.
Desirability for a consistent regulatory approach	The most common approach across the NEM is the RAB roll forward approach. For metering services this was applied in the ACT and SA determinations where metering services were classified as being alternative control services. In NSW and Qld, metering services are standard control services for which the RAB roll forward is mandated.
Any other relevant factor	The AER considers that the NEO and RPP are relevant. The RAB roll forward is mandated for standard control services and thus can be said to deliver on the NEO and RRP. The annuity approach may or may not deliver the NEO and RRP depending on the accuracy of forecasts.

On balance, the AER considers that the RAB roll forward approach better satisfies the five factors. The administrative costs are likely to be immaterial as Aurora currently collects the information required to establish a RAB. There is limited potential for the development of competition for metering services. The application of a RAB roll forward is supported by the desirability for a consistent regulatory approach, and delivery of the NEO and RRP. It is not supported by the historical regulatory practice in Tasmania. However, the AER considers that two factors are of particular importance in this instance:

- the achievement of the NEO and RRP and
- the desirability of consistency between regulatory arrangements.

1139 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. Reference: AER, Final decision: Framework and approach paper – Aurora Energy, November 2010, p. 25.

1140 Aurora currently records and has supplied the AER with the key information required to establish a RAB, including an age profile of its metering assets, in its RIN response, the metering annuity model and responses to AER information requests:. Aurora, *Response to information request AER/006 of 7 July 2011*, received 15 July 2011, Aurora, *Response to information request AER/013 of 22 July 2011*, received 28 July 2011, Aurora, Response to information request AER/020 of 1 August 2011, received 15 August 2011, Aurora, *Response to information request AER/021 of 1 August 2011*, received 5 August 2011 and Aurora, *Response to information request Aurora/005 of 12 August*, received 12 August.

1141 Office of the Tasmanian Electricity Regulator*, Investigation into Electricity Pricing – Draft Report*, Sept 1999, p. 137.

The achievement of the NEO and RPP

The NEO and RPP will be promoted if Aurora is able to recover its efficient costs, including an allowance for efficient capital costs incurred.

Under the RAB roll forward approach, the choice of asset lives will affect the time period across which the capital costs are returned to the firm. However, the RAB approach ensures that Aurora recovers just the net present value on its capital investments regardless of the regulatory life chosen—.once assets are fully depreciated Aurora would no longer earn a return on those assets.

Under the annuity approach proposed by Aurora, the choice of asset lives will affect the ability of Aurora to recover the net present value of its capital investments. Aurora's model calculates an annual capital charge on the basis of the assumed life of the meters, but then applies that charge for every year the meter is actually in service, without regard to its assumed life. For assets that outlive their estimated asset lives, Aurora will over recover its capital costs, while for assets that do not reach their estimated asset lives, Aurora will under recover its capital costs. Therefore, there is less certainty of cost recovery for Aurora under this approach.

The AER considers that there is a risk of under or over recovery of capital costs under the annuity approach as it is difficult to forecast asset lives with a reasonable degree of precision. In contrast, the RAB roll forward approach represents a more transparent and certain approach for cost recovery. Therefore, the AER considers that the RAB roll forward approach is more likely to achieve the NEO and RRP in most circumstances.

Desirability of consistency between regulatory arrangements

A RAB roll forward approach has generally been applied to regulate alternative control services with significant asset bases and capital expenditure. The exception to this is public lighting services installed in New South Wales after 1 July 2009 (prior to this date a RAB was applied). However, for all other alternative control services that require significant investment, the AER has decided to apply the RAB roll forward approach.

In deciding to apply a RAB roll forward approach for metering services, the AER considered the availability and accuracy of data on existing assets and the likely incremental administrative costs that may arise from the application of the RAB roll forward approach. While Aurora has previously applied an annuity approach, the AER has found that Aurora currently collects sufficient data to establish a RAB roll forward approach. Further, Aurora can use the building block model already constructed by the AER. The AER considers that by the time of the next price reset, Aurora should be readily able to structure its data systems to more efficiently feed into the building block model. The AER thus considers that the additional administrative costs for Aurora of applying a RAB roll forward approach are likely to be immaterial. Therefore, the AER considers that the RAB roll forward approach better satisfies the NER requirements.

C.1.2 Inputs into the RAB roll forward building block model

The AER's assessment results in total revenue over the forthcoming regulatory control period of $74 million, as shown in Table C.2. This is 30 per cent less than the revenue proposed by Aurora.

Table C.2 AER's Building block summary ($million, nominal)

Year	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17	Total
Building block components (nominal)							
Return on capital		3.39	3.68	3.89	4.07	4.31	19.33
Return of capital		2.89	3.56	4.07	4.04	4.49	19.05
O&M		6.82	6.89	7.16	7.37	7.46	35.68
Benchmark Tax liability		0.01	0.01	0.08	0.13	0.17	0.41
Total Revenue – AER	15.24	13.10	14.14	15.19	15.61	16.44	74.48
Total Revenue - Aurora proposal	15.11	18.79	20.22	21.71	22.37	23.32	106.41

Source: AER analysis.

Each of the inputs for the building block cost build up for metering services is considered below.

C.1.3 Capital charges - return on and return of capital

The annual capital charge in the building block is equivalent to the annuity component under Aurora's proposed approach. It is the sum of two components:

- depreciation (return of capital) — on annual straight line basis, equals Regulatory Asset Base (RAB) divided by remaining life, for each asset class
- return on capital— WACC multiplied by average RAB for the year.

The inputs to the capital charge are considered below— first for the initial RAB, and then capex to roll forward the RAB in subsequent years.

RAB – initial written down value

The AER's estimate of the initial written-down RAB for meter stocks is $35 million ($2009-10).[1142] This RAB is based on depreciated replacement cost and includes about 62 per cent of the meters currently in service. The other 38 per cent of the meter population have been fully depreciated, based on their standard asset lives as applied by Aurora. Therefore these assets are not eligible to be included in the initial RAB to earn a further return. This is explained further in the section on asset lives.

The AER derived the initial RAB by taking each batch of meters, by type and age class, and calculating their written down value from their initial value less accumulated depreciation.[1143] To do this the AER relied on Aurora's age profile data showing the number of meters of each type purchased in each year.[1144]

The input data used to determine the initial RAB are discussed below.

1142 In Aurora's model the capital replacement cost of the whole meter stock is $85 million and the accounting written-down value of the stock is $47 million ($2010 June). (Aurora, *Metering annuity model*, revised version, 15 August 2011)

1143 The calculations are simplified by grouping the meters into just two classes - mechanical and electronic -which have different lives. Different types of meter such as single-phase and multi-phase are combined into a composite unit based on their average cost. Further, meters are removed from the RAB after their age exceeds their regulatory life.

1144 The distribution of asset ages for Aurora's meters (all combined) is shown in Aurora Energy, *Management Plan 2011 - Metering Assets*, Figure 1, p. 7.

Number of meters

The AER accepts the number of meter registers shown in Aurora's model— 453,000 for 2012-13, as a basis for the initial RAB. Aurora's forecast for the total number of meter registers at the start of 2012-13 is based on its most recent meter count in 2010, escalated for customer growth.

It is important to distinguish between number of meters and number of registers, as both appear in Aurora's proposal. The measure of volume used in Aurora's annuity model is the number of registers. Prices are effectively calculated per register rather than per meter. A register is a dial that records electricity consumption. Most households in Tasmania have two or three tariffs, and each tariff requires its own register.[1145] Where mechanical meters are used, a household needs a separate meter for each tariff, each with a single register. In recent years, however, Aurora has been installing electronic meters. Each electronic meter is a single physical unit containing multiple registers. Aurora's model assumes there are two registers for each domestic electronic meter. Most businesses have multi-phase or CT meters with one register per meter.

Meter cost

For the purpose of calculating the initial RAB, the AER has used:

- for mechanical meters —replacement costs as accepted by OTTER in 2007, escalated for inflation
- for electronic meters — replacement costs based on
- i) purchase price from a market quote obtained by Aurora in 2010
- ii) installation costs based on costs accepted by OTTER, escalated for inflation.

These values are outlined in Table C.3.

Table C.3 Meter costs per register – purchase plus on-costs and installation – low voltage single phase ($2009–10)

Type of meter	Aurora proposed cost	AER cost
Mechanical meters	174	156
Electronic meters	174	CIC

Source: Aurora annuity model; AER analysis.

The AER accepts that current replacement costs may be an appropriate proxy for the reasonable and efficient costs for meters, in particular where these are based on competitive market prices. Nuttall Consulting found that Aurora's proposed cost for meter purchase is above recent costs for DNSPs in Victoria, but that additional features and the economies of scale in the Victorian purchases may account for the difference.[1146] Aurora provided a (confidential) supplier's quote for electronic meters in 2010. Nuttall recommended that the meter purchase cost be set at the level shown in this quote, plus an allowance proposed by Aurora for escalation and on-costs.

1145 For example, tariff 31-light and power, tariff 42 - hot water and space heating, tariff 61 - off-peak..

1146 Nuttall Consulting, *Aurora electricity distribution review: report to AER, Confidential final report*, 5 October 2011 - Appendix C: Alternative Control Services, pp. 178–179.

In the absence of other market data for Tasmania, the AER accepts Nuttall's recommendation for electronic meters, which results in a total cost (including installation) that is less than the cost input to Aurora's model. Aurora stated that it is planning a tender for a new supply of electronic meters in late 2011. This process may provide a more suitable benchmark for replacement costs. The AER will consider revising its cost estimates when data from that tender process is available.

Mechanical meters are no longer an industry standard for new meters and Nuttall found no evidence of current market prices to justify Aurora's proposed cost. On that basis it recommended that the values accepted by OTTER in 2007 for mechanical meters be used. Given the lack of relevant current data, the AER accepts this recommendation.

Aurora's costing included on-costs associated with acquisition of meters, such as warehousing, distribution and delivery, testing and programming. Nuttall found the on-costs advised by Aurora, as a percentage of purchase cost, to be excessive compared with Victorian DNSPs. Nuttall recommended that an allowance of 10 per cent of purchase cost is reasonable in Aurora's circumstances. The AER accepts this recommendation.

Aurora proposed installation costs of $104 for a single-phase meter.[1147] Nuttall found that the proposed cost was significantly higher than the cost previously accepted by OTTER. It could see no justification for an increase in costs and recommended that the current allowance of $73 be maintained, with appropriate escalation.[1148] The AER accepts this recommendation.

Asset lives for initial RAB

The AER is applying the depreciation rates previously used by OTTER to calculate the depreciated value for each age class and thus calculate the total RAB at the start of the forthcoming regulatory control period. The initial RAB thus measures the written-down value of the meters after deducting depreciation allowances that have already been recovered in prices.

Table C.4 Regulatory asset lives for meters

Type of meter	OTTER 2003–2007	OTTER 2007–2012	Aurora proposal 2012–17
Mechanical	25	20	20
Electronic	20	15	15

Source: OTTER,[1149] Aurora.[1150]

Capex

The average annual capex determined by the AER over the forthcoming regulatory control period is $5.7 million, including meters (all electronic) and capital overheads. This reflects downward adjustments to Aurora's forecast number of new meters and cost per meter.

1147 For electronic meters, Aurora's model allocated half of this cost to each register.
1148 Nuttall Consulting, *Aurora electricity distribution review: report to AER, Confidential final report*, 5 October 2011 - Appendix C: Alternative Control Services, p. 182.
1149 OTTER, *metering annuity model for 2003 determination (confidential)*; OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices,* September 2007
1150 Aurora, *Regulatory proposal*, May 2011.

Table C.5 AER draft determination Capex ($million, 2009–10)

	2011–12	2012–13	2013–14	2014–15	2015–16
New and replacement meter installations	4.16	3.84	4.00	4.38	4.35
Non-network shared assets	1.71	1.54	1.39	1.47	1.46
Total capex expenditure	5.87	5.38	5.39	5.85	5.82

In rolling forward the RAB, the AER has reviewed Aurora's data to estimate the reasonable capex for the forthcoming regulatory control period. In particular, the AER has assessed the following factor inputs:

1. Number of new meters, and
2. Cost per meter
3. Capital overhead costs.

These are considered individually below.

Number of meters

Two types of capex for new meter are considered:

1. new installations - which generate a net increase in the number of meters each year
2. replacement of old meters with new ones - which is not reflected in a change in the total number, but is an important part of capex.

Aurora's proposal and the AER's decision on these numbers are shown in Table C.6.

Table C.6 Number of new meters, 2012–13 to 2016–17

Reason	Average number of new meters per year	
	Aurora's proposal	AER
New installations (registers)	**9,986**	**5,788**
Replacements (meters)		
Non-compliance (faulty meters or family of meters)	5,150	5,150
ERT (Easy-to-Read Technology) meters	1,460	1,460
Access & Key Management	7,200	0
Reading Issues (Pay As You Go meters)	7,840	0
Total replacements	**21,650**	**6,610**

Source: Aurora,[1151] AER analysis.

New customers

Aurora forecast an increase in the number of meter registers averaging almost 10,000 per year for the forthcoming regulatory control period.[1152] The AER considers that an average increase of 5,788 per year is appropriate. The reduction results from adjustments for new installations and Pay As You Go (PAYG) meters.

The change in the number of meters each year depends mainly on growth in installations for new customers. The net average annual increase forecast by Aurora comprised the following components:

Residential: 6,590

Business: 1,396

PAYG: 2,000

Aurora's assumption for new residential installations is above the forecasts of growth in customer numbers used by the AER for the broader demand forecasts. Making allowance for new residential customers each needing two registers, the AER considers the average allowance for new residential should be 5,273 per year.

Aurora's forecast increase for business is well above the estimate for the demand forecasts. For consistency with the forecasts it accepts for the broader demand analysis, the AER will reduce the forecast increase for business to 515 per year.

The forecast increase includes replacement of unregulated Pay-as-you-go meters with standard electronic meters at an average rate of 2,000 per year. These replacements effectively count as new installations since the old meters were not included in the regulated asset base. The old units are

1151 Aurora, *Metering annuity model* (new installations)*; Aurora Energy, Management Plan 2011 - Metering Assets*, p. 11 (replacements).

1152 Aurora, *Metering annuity model*, revised version 15 August 2011.

integrated PAYG meters currently owned by Aurora Retail.[1153] Aurora Energy as DNSP is planning to take over ownership of the PAYG meters although no date has been specified for such a transfer.[1154] Aurora is planning to replace the integrated PAYG meters by standard electronic meters with a Payguard unit attached. The new meters owned by Aurora as DNSP would then become regulated, excluding the Payguard unit owned by Aurora Retail.[1155]

Aurora's reasons for replacing the PAYG meters fall into two broad classes: access and reading problems and failing testing programs.

In its report Nuttall Consulting considered that Aurora had not adequately justified the replacement program with a business case in relation to access and reading problems or evidence of failing testing requirements. It recommended that the proposed replacement volumes not be allowed.[1156] Further, the realisation of benefits from easier reading of the PAYG meters depends on having remote reading facilities, but Aurora has not provided for such expenditure in its proposal.[1157]

The AER accepts Nuttall's advice that Aurora has not sufficiently justified its proposed replacements for PAYG meters, and reduces the allowance to zero.

Rate of replacement

The AER has reduced the proposed replacement numbers for meters in the forthcoming regulatory control period from Aurora's proposed 21,650 to 6,610 new meters. Table C.6 shows the main components of Aurora's proposed replacement program (based on its management plan for metering assets) together with the numbers for the AER's capex allowance.[1158]

Aurora’s management plan entails replacing meters only when necessary for faults or to replace families of non-compliant or suspect meters. Aurora also wishes to replace the ERT meters on the grounds that the meters and reading units are approaching the end of their useful life. Aurora stated that it is becoming increasingly difficult to source spare parts for ET equipment, and supplier support is due to expire in 2012.

Nuttall Consulting's report recommends that the replacements volumes for non-compliant and ERT meters appear reasonable and should be allowed. The AER accepts the proposed allowance for replacing non-compliant meters and ERT meters.

The Access and key management category involves improving access and reading at difficult sites by providing an electronic meter with remote communications functionality. However, Aurora has not proposed any expenditure associated with the required facilities for remote reading, nor has it proposed specific reductions in opex to reflect the stated benefits.[1159]

1153 These are integrated PAYG meters in that the unit encompasses the entire PAYG product, including the recording of energy consumption and the card reading facility and credit management.

1154 Aurora, *Management Plan 2011 - Metering Assets*, p. 11–13.

1155 The standard meter records the energy consumption, and a separate Payguard unit (provided by Aurora Retail) accommodates the card reading facility and credit management.

1156 Nuttall Consulting, Aurora electricity distribution review: report to AER, Confidential final report, 5 October 2011 - Appendix C; Alternative Control Services, p.185-6.

1157 Aurora allowed for potential savings of 75 per cent of the meter reading cost for remote read meters, but included only one such meter in its model for indicative purposes. (Aurora, *Response to information request AER/006 of 7 July*, received 15 July 2011 -metering question 6.1)

1158 Aurora Energy, *Management Plan 2011 - Metering Assets*, p. 11.

1159 Aurora confirmed that there are no further savings factored into forecast costs for standard electronic meters, other than those referred to for remote read meters (Aurora, *Response to AER information request AER/020 of 1 August*, received 15 August 2011, question 8).

Nuttall Consulting's report stated that if Aurora is able to develop a business case for the replacement of these meters that has a positive net present value, it will be able to implement this program and benefit from the overall cost reductions in the forthcoming regulatory control period.[1160] The AER considers that the replacements should not be allowed in the annual capital allowance, without the associated costs for communications facilities and savings in forecast operating costs. The AER agrees that it is not necessary to allow for replacement at the proposed level in the forthcoming regulatory control period, and accepts Nuttall's advice on the replacement program for the access and key management category. Aurora is able to replace meters that are still serviceable if it believes the savings would be greater than the costs.

The Reading Issues group concerns PAYG meters which have been treated above as new capex. Therefore, this category will be excluded here from replacements.

Meter cost - new installations

Aurora proposed the same value (at current replacement cost) for all meters regardless of age. Its proposed cost for new meters is the same for new customers as for replacements. The AER considers that new meter installations should ideally be brought into the RAB at their expected actual cost each year, provided it is an efficient market-based price. Thus for capex on electronic meters, the AER will use the most up-to-date forward-looking competitive quotes. Aurora is planning a tender for a new supply of electronic meters around November 2011 which may provide usable data for the costs of new capex.

In the absence of data from a new tender, the AER will use the same purchase and installation costs as for the initial RAB.

Capital overheads

Aurora proposed capital overhead costs for shared services capital assets in separate annuity components.[1161] The AER has reviewed the allocation of shared costs from Aurora's CAM and accepts the values allocated to metering. The AER accepts the written-down values and depreciation rates on these shared assets, and has calculated a capital charge for the assets in its building block calculations, averaging approximately $1.5 million per year over the period.

Aurora also allocates a share of direct capital overheads from its corporate and network service divisions to metering services. Aurora's CAM has allocated a share of about $1.1 million per year to metering, almost all to installation costs for capex on meter replacements. The AER has reviewed Aurora's overhead allocation as discussed in attachment 6 and concluded that they were at a reasonable level. The AER has included these direct capital overheads as an allowance in metering capex, additional to the installation cost which is based on OTTER's allowance in 2007.

The capital overhead costs are included in the combined capital charges shown as building block components in Table C.2.

[1160] Nuttall Consulting, *Aurora electricity distribution review: report to AER, Confidential final report*, 5 October 2011 - Appendix C: Alternative Control Services, p. 186.

[1161] This covers corporate and shared services and network division management capital overhead costs, including motor vehicles, minor assets, non-system property and NEM assets.

Asset lives - forward-looking

The AER accepts the regulatory life of 15 years for electronic meters proposed by Aurora. The AER considers that the asset life for mechanical meters should be 30 years.

Data provided by Aurora shows that over half of its mechanical meters are over 20 years old, and the average age is 21.5 years. Nuttall Consulting concluded that a useful operating life for existing mechanical meters is between 30 and 40 years. The lower end of this range matches Aurora's accounting life for this asset. The AER considers a 30 year life for mechanical assets should be used in the building block model from 2012-13 onward.

The regulatory life proposed by Aurora for electronic meters is 15 years, although their accounting life is 20 years. For Tasmania, there is relatively little evidence at this point in time to assess whether the 15 year asset life proposed for electronic meters by Aurora is a robust estimate. Aurora began installing electronic meters about 15 years ago, although not in substantial numbers until 2001. Nuttall Consulting recommends a 15 year life which is common in other in jurisdictions. On the basis of these factors, the AER thus accepts the 15 years proposed for electronic meters.

The AER notes that the mechanical meter asset life used for calculating the initial RAB differs from the asset life the AER is proposing for the forward-looking calculation of capital charges. This difference in approach is appropriate as the key issue in setting the initial RAB is to ensure that Aurora is able to recover the remaining value of assets not already returned to it through regulated charges. The AER considers that the asset lives applied by the regulator in previous determinations are appropriate for this calculation. However, this should not constrain the AER in its consideration of the appropriate asset lives for the future RAB roll-forward.

WACC

Aurora's annuity model uses a pre-tax WACC. Since the AER is adopting a building block approach for metering, it considers it appropriate to use a post-tax WACC and estimate company income tax as a separate block in the cost build-up. It will use the same approach and WACC for metering as for standard control services.

The AER has historically adopted a nominal ‘vanilla’ WACC which uses a nominal post tax return on equity and nominal pre-tax cost of debt.[1162] In a vanilla WACC, tax liabilities are explicitly included in the cash flows and a separate tax cost block is included in the building block model. The cash flows are adjusted to account for the utilisation of imputation credits. The advantage of this model is that it allows for modelling of taxes based on the estimated cash flows of the businesses. This is likely to be a more accurate representation of the tax obligations of a regulated business over the regulatory period.

The nominal vanilla WACC applied is 8.08 per cent. The tax allowance is considered below.

[1162] The vanilla WACC is a post tax WACC that is appropriate for net cash flows whereby expected tax benefits are incorporated into expected after tax cash flows such that post tax cash flows will reflect the tax deductibility of interest.

Tax

The AER's model includes a benchmark company tax payment as a building block component. The AER is applying the same approach and tax rate for metering as for standard control, with the appropriate depreciation rates for Aurora's metering equipment.

As a government-owned enterprise, the National Tax Equivalence Regime applies to Aurora. Under the NTER, the depreciation rate applied to Aurora's metering equipment is 37.5 per cent per year on a diminishing value basis.[1163] This is highly accelerated compared with depreciation based on actual lives, but is typical tax treatment for low-value assets.

The result of the accelerated tax depreciation is higher depreciation for tax purposes in the early years of the assets' lives, with a faster reduction in the written down value. The net effect for Aurora is that tax depreciation averages $5.3 million per year over the regulatory period, compared with $3.8 million of regulatory depreciation. The resultant benchmark tax liability averages $0.1 million over the period.

Opex

Aurora's proposed opex allowance in the model, including overheads, is shown in Table C.7. The AER accepts the proposed opex allowances.

Table C.7 Aurora's proposed opex ($million, 2009–10)

	2012–13	2013–14	2014–15	2015–16	2016–17
Opex Base Costs	3.77	3.68	3.68	3.62	3.53
Opex Overheads Costs	2.50	2.50	2.58	2.65	2.66
Total current expenditure	6.27	6.18	6.26	6.27	6.19

Source: Aurora's metering annuity model, with escalation for real prices of labour and materials.

Total opex proposed by Aurora is at a similar level to the historical expenditure in the current regulatory period which averaged $6.2 million. The slight reduction in base opex over the next 5-year period in part reflects an efficiency factor applied by Aurora.[1164] The AER accepts the proposed allowance for base opex as reasonable.

The operating overheads for metering reflect Aurora's allocation of shared costs across the whole company. Aurora's CAM allocates shared costs to each service classification in proportion to its cost drivers, as explained in attachment 6.[1165] The AER has reviewed Aurora's proposed overhead costs as a whole and its decision is outlined in attachment 6. As a consequence of that review, the AER has accepted the amount of opex overheads flowing to metering services from Aurora's cost allocation model.

1163 Aurora, *Response to AER information request AER/020 of 1 August*, received 15 August 2011, question 10. Under this method the depreciation in any year is 37.5 per cent of the written-down value from the previous year.

1164 The AER notes that the efficiency factor– reducing labour costs by 3 per cent a year – is general across Aurora's expenditures, and is not specific to particular programs such as remote reading of meters.

1165 Aurora Energy, Cost Allocation Method – Version 6.3, May 2011, p. 17.

Prices

The AER has derived the reasonable and efficient annual required revenues, as outlined above, and converted them to price caps for each meter class in cents per register per day as outlined in Table C.9.[1166]

The AER's modelling of allowable revenues generated prices such that the average price for 2012-13 would be 15 per cent lower than the price set by OTTER for 2011-12. The prices would then increase over the following four years.[1167] The AER considers that there is merit in having relative price stability over the regulatory period, where it is efficient and possible. The AER will therefore smooth the annual prices so that the discounted value of forecast revenue remains the same but the year-to-year change in prices is less variable, as shown in attachment 15. The smoothing generates a smaller one-off reduction in the price for 2012-13; then prices increase at approximately the inflation rate, and revenue is close to forecast costs in the final year.

Table C.8 Average metering prices (cents per register per day, nominal)[1168]

Year	2012–13	2013–14	2014–15	2015–16	2016–17	2012–13
Aurora	9.280	11.358	11.998	12.531	12.560	12.912
AER prices unsmoothed	9.286	7.873	8.397	8.910	9.015	9.398
AER prices smoothed	9.286	8.265	8.481	8.701	8.899	9.149
Year-on-year change in smoothed price		-11.00%	2.62%	2.59%	2.28%	2.81%

Source: OTTER 2007 (2011-12), AER analysis.
Notes: Nominal prices include forecast inflation rate. Actual prices approved by the AER through annual pricing process will reflect lagged actual CPI. All prices referred to in this chapter are exclusive of GST.

C.2 Revisions

Revision C.1: The AER does not accept Aurora's proposed annuity approach as the form of control for metering, and has instead adopted a limited building block with RAB.

Revision C.2: The AER does not accept Aurora’s proposed prices for metering services The AER's draft decision on prices for Aurora metering services is set out in Table C.9.

1166 The annual revenue requirements were calculated separately for mechanical and electronic meters, and then apportioned between different meter classes in proportion to the costs per meter.

1167 The decrease in prices at 2012–13 is largely the result of the one-off change to a written-down RAB approach. The subsequent increases are largely due to the capex provisions exceeding the retirement of old assets.

1168 This price indicator represents no particular tariff class but is a weighted average of all classes.

C.3 Metering Prices

Table C.9 AER draft decision on metering prices (cents per register per day, nominal)

Year	2012–13	2013–14	2014–15	2015–16	2016–17
Business LV - Single Phase	7.600	7.769	7.945	8.075	8.268
Business LV - Multi Phase	12.720	13.006	13.286	13.671	14.024
Business LV - CT Meters	16.284	16.703	17.107	17.727	18.238
Domestic LV - Single Phase	7.819	8.031	8.248	8.431	8.674
Domestic LV - Multi Phase	12.631	12.859	13.082	13.404	13.695
Domestic LV - CT Meters	15.463	15.722	15.971	16.401	17.181
Other Meters (PAYG)	13.014	13.234	13.454	13.795	14.102
Business LV - Single Phase - Remote Read	6.880	7.130	7.333	7.470	7.693
Business LV - Multi Phase - Remote Read	12.219	12.519	12.767	13.111	13.446
Business LV - CT Meters - Remote Read	16.510	16.859	17.147	17.655	18.075
Domestic LV - Single Phase - Remote Read	6.880	7.130	7.333	7.470	7.693
Domestic LV - Multi Phase - Remote Read	12.219	12.519	12.767	13.111	13.446
Domestic LV - CT Meters - Remote Read	16.510	16.859	17.147	17.655	18.075

Source: AER analysis.

D Alternative control – public lighting services

This appendix sets out the AER's detailed analysis and reasoning supporting its decision on Aurora's public lighting services in attachment 15.

The AER's assessment of Aurora's proposed price caps for public lighting services focused on:

- the basis of control to apply to public lighting services
- the inputs into Aurora's public lighting annuity model (opex forecasts, replacement and installation costs for lamps, luminaires and brackets, asset lives and number of lights)
- the allocation of overhead costs.

The AER considered whether the inputs into Aurora's annuity model and opex and capex forecasts reflected reasonable and efficient costs using the method outlined in appendix D. The AER's decisions on each of the inputs were incorporated into Aurora's public lighting annuity model to calculate the AER's decision on price caps for individual public lights.

D.1 Reasons for draft determination

D.1.1 Basis of control

The AER will apply the annuity approach as the basis of control for public lighting services. A key factor in this decision is the fact that there is limited historical information on public lighting assets that can be used to accurately estimate a RAB.

Table D.1 outlines the AER's consideration of all the relevant NER factors for determining the basis of control for public lighting. On balance, the AER considers that the annuity approach better satisfies the five factors in clause 6.2.5(d) of the NER for public lighting services. In theory, the RAB roll forward approach may lead to more cost reflective prices than an annuity approach. This in turn may better promote the development of competition and the RPP and NEO. However, in this instance, the annuity approach is likely to better achieve these objectives as data is not available to accurately value Aurora's public lighting RAB.

Table D.1 NER factors and the basis of control for public lighting services

NER factor	AER consideration
The potential for the 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.[1169] 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. The RAB roll forward approach is the best approach to develop cost reflective prices as it represents a more transparent and certain approach for cost recovery. However, the AER would have to approximate the installation date of Aurora's public lighting assets for a RAB. Aurora itself has not collected and maintained the required asset installation data.[1170] As a result, the AER would need to make a number of potentially inaccurate assumptions to develop a RAB. In future, the AER considers that a RAB would be more cost reflective. As such the AER will require Aurora collect data for the development of a RAB.
Administrative costs	The AER considers that the application of the annuity approach will not apply an additional administrative burden. Aurora currently applies the annuity approach. Requiring Aurora to collect data for a RAB would result in an additional administrative burden. However (as for metering services) this will only mean that Aurora must separate its capex by asset class. The AER considers that these additional costs would be immaterial as Aurora already collects this information at a high level.
Previous regulatory arrangement	This is the first time that Aurora's public lighting services are to be regulated. Therefore there are no previous regulatory arrangements relevant to pricing public lighting services in Tasmania.
Desirability for a consistent regulatory approach	The most common approach to calculate the annual capital allowance for alternative control services is the RAB roll forward approach. However, the annuity approach has been applied to public lighting assets installed after 1 July 2009 in NSW.
Any other relevant factor	The AER considers that the NEO and RRP are relevant factors. These favour cost efficient service provision. In this instance, because of the lack of historical data, it cannot be said whether the RAB roll forward or the replacement cost annuity would be more efficient.

D.1.2 Inputs into the annuity model

The AER assessed each input into Aurora's proposed public lighting annuity model. The AER's conclusions on each of these inputs have led to the AER's draft determination on Aurora's proposed price caps for individual public lights.

The AER examined Aurora's total opex forecasts, asset lives, number of lights and overhead costs for all light types in Aurora's regulatory proposal. The AER focused on Aurora's proposed replacement and installation costs for the two major light types in Tasmania (80W mercury vapour and 250W vapour). These two types account for 70 per cent of the total lighting population in Tasmania.

1169 AER, *Final decision: Framework and approach paper – Aurora Energy*, November 2010, p. 38.

1170 Aurora's RIN response does not contain installation data on Aurora's public lighting assets prior to 2004. This installation data can only be broken down by asset category from 2008–09.

Opex forecasts

Aurora's proposed public lighting opex are costs incurred for the operation and maintenance of the Tasmanian public lighting system. The majority of opex costs are for inspection and repair of public lighting assets and the bulk lamp replacement program.

Aurora's opex forecasts are a direct input into its public lighting annuity model. Aurora also uses its opex forecasts for public lighting to allocate overhead costs to services as per the method outlined in its CAM.

The AER's decision on Aurora's public lighting opex for the next regulatory period is set out in Table D.2.

Table D.2 AER draft decision on public lighting opex for forthcoming regulatory control period ($million, 2009–10)

	2012–13	2013–14	2014–15	2015–16	2016–17
AER decision – opex	1.59	1.56	1.53	1.42	1.38
Aurora proposed opex	2.36	2.30	2.27	2.78	2.67
% difference	-33%	-32%	-33%	-49%	-49%

Source: AER analysis

The AER rejects Aurora's proposed public lighting opex for the following reasons:

- Aurora has not provided sufficient evidence to support the large increase in total opex for the next regulatory period
- Aurora has not provided 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'. The AER classified new public lighting technology services as a negotiated distribution service[1171] and Aurora accepted this classification.[1172]

Aurora's total forecast opex for public lighting for the next regulatory period is 45 per cent higher than the total opex for public lighting for the current regulatory period. Aurora's proposal also included step change increases in 2012–13 and 2015–16. Aurora only provided general high-level explanations for these proposed cost changes in its proposal, attachments to the proposal and responses to information requests from the AER.[1173] Aurora's explanation for the step change increase in 2015–16 was also inconsistent with its own forecasts. Aurora stated that the increase was due to the start of the third cycle of the bulk lamp replacement program. However, this program will not start until 2016–17.

1171 AER, *Framework and approach paper*, November 2010, p. 39.
1172 Aurora, *Regulatory proposal addendum*, June 2011, p. 39.
1173 Aurora Energy, Management Plan 2011—Public Lighting, 9 May 2011; Aurora, *Response to information request AER/006 of 7 July 2011*, received 15 July 2011; Aurora, *Response to information request AER/013 of 22 July 2011*, received 29 July 2011; Aurora, *Response to information request AER/027 of 17 August 2011*, received 25 August 2011.

The AER requested that Aurora provide further information on the drivers of the cost increases and clarification of the inconsistencies between its forecasts and explanations.[1174] In response, Aurora stated:

> AER's questions have highlighted a number of anomalies within the Public Lighting Management Plan which do not align with the forecast expenditure. The potential correction of these anomalies may potentially involve recalculation of costs and overheads associated with the provision of Standard Control Services. Aurora has yet to undertake a full investigation of this anomaly and is reluctant to undertake further modelling of Standard Control Services at this late stage of the AER's investigation of Aurora's Regulatory Proposal.[1175]

This response indicates that there are errors in Aurora's proposed public lighting cost forecasts, which may have implications for the allocation of costs and overheads across standard control and alternative control services. The AER requests that Aurora corrects these anomalies in its revised Regulatory Proposal.

The AER has removed the costs for 'Trials/evaluation of new road lighting technologies - Major and Minor' from Aurora's forecast opex as these costs are incorrectly allocated to alternative control services. The AER has also rejected Aurora's proposed step change increases in opex in 2012–13 and 2015–16. These increases are driven by costs in the work category 'Replace Road lighting - Major and Minor, bulk lamp replacement (4 year replace cycle)' (RLBLR). The costs for the other opex work categories did not have significant cost increases proposed from the current period. The AER has therefore accepted the cost forecasts for all public lighting opex work categories except RLBLR and 'Trials/evaluation of new road lighting technologies - Major and Minor'.

The AER has replaced Aurora's forecast for 2012–13 for RLBLR with the average yearly opex for RLBLR for the period 2008–09 to 2011–12 escalated by CPI. The AER has escalated this forecast to the remaining years of the next regulatory period using real labour escalators and incorporated the 3% efficiency factor Aurora proposed.[1176] The AER has relied on historical data in the absence of other comparative data to establish whether Aurora's proposed opex is reasonable. The AER used the average yearly opex for RLBLR from the current regulatory period rather than extrapolating historical trend. This was because historical opex for public lighting in the current period (including historical numbers for RLBLR costs) is quite lumpy. The lumpiness is due to Aurora reducing the volumes of lights being replaced in 2010–11 and 2011–12 to reduce opex costs.[1177] Further, the current bulk lamp replacement program was introduced in 2008, therefore Aurora's costs prior to 2008 would not reflect Aurora's current bulk lamp replacement program. The AER considers that the average opex for RLBLR from 2008–09 to 2011–12 is a reasonable estimate for the opex for RLBLR for 2012–13, as it:

- reflects Aurora's actual historical expenditure for its bulk lamp replacement program
- reflects average yearly replacement volumes for Aurora's current bulk replacement program

[1174] Aurora, *Response to information request AER/027 of 17 August 2011*, received 25 August 2011, Questions 9–12.
[1175] Aurora, *Response to information request AER/027 of 17 August 2011*, received 25 August 2011, p. 8.
[1176] Aurora applied an annual three percent efficiency factor to the labour rates within its proposal which reflect the operational efficiencies Aurora is targeting to achieve within the next regulatory period. Source: Aurora, *Regulatory proposal*, May 2011, p. 2. This three percent efficiency factor was incorporated into Aurora's opex forecasts for public lighting.
[1177] Aurora Energy, *Management Plan 2011—Public Lighting*, 9 May 2011, p. 16.

Replacement costs

Replacement costs are one of the key inputs into the public lighting annuity model and have a significant impact on the prices for public lighting.

For the public lighting annuity model, the relevant replacement costs relate to:

- lamp (light globe)
- luminaire (globe housing, diffuser and electrical supply)
- bracket.

Replacement costs in Aurora's annuity model also include installation costs.

The AER accepts Aurora's proposed replacement and installation costs for lamps and luminaires. The AER rejects Aurora's proposed replacement cost for brackets. The replacement costs for 250W sodium vapour and 80W mercury vapour lights are shown in Table D.3.

Table D.3 AER draft decision on Aurora's replacement costs for 80W mercury vapour and 250W sodium vapour lights ($2009–10)

Light Type	Lamp	Luminaire	Bracket
80W mercury vapour	1.93	68.49	184.84
250W sodium vapour	27.15	166.45	184.84

Source: AER analysis.

The AER engaged Nuttall Consulting to provide advice regarding the reasonableness of Aurora's proposed costs associated with 80W mercury vapour and 250W high pressure sodium vapour lights.

Nuttall reviewed Aurora's proposed lamp and luminaire material costs and considers them reasonable:

> Nuttall Consulting has reviewed the proposed lamp costs against those of other DNSPs and the proposed lamp material costs appear reasonable. The luminaire material costs proposed by Aurora Energy appear reasonable as these costs also include the photo-electric cell that activates the lamp based on the level of ambient light, and the ballast that converts the power supply to the appropriate voltage and current type.[1178]

The AER accepts Nuttall's advice on Aurora's proposed lamp and luminaire replacement costs.

Nuttall also reviewed Aurora's proposed bracket costs. Nuttall agreed with Aurora's method for calculating average bracket costs. However, it was not satisfied with Aurora's proposed volumes of bracket types.

Aurora indicated that it does not collect information on bracket types and that the volumes submitted are based on managerial estimates.[1179] These estimates favour longer bracket types. Nuttall considers that the prudency of Aurora's bracket type selection is not justified. In particular:

[1178] Nuttall Consulting, *Report – Principle Technical Advisor: Aurora Electricity Distribution Revenue Review*, 5 October 2011, p. 197.

[1179] Aurora, *Response to information request AER/027 of 17 August 2011*, received 25 August 2011, p. 9.

> Aurora Energy has provided detailed drawings and diagrams of the various bracket types used for public lighting. These brackets range from a “reach” or length of 250mm to 2,000mm for minor roads lighting. This range of brackets is consistent with the range typically seen in other NEM DNSPs. Shorter reach brackets are typically used in residential and low traffic areas where the lighting standards require a lower level of lighting than for major roads.
>
> The bracket allocation and costs information provided by Aurora Energy does not list the shorter types of public lighting brackets, although these brackets are very commonly used for minor road lighting in many Australian states.
>
> …
>
> Nuttall Consulting has been unable to identify any reason that the standard public lighting design for minor roads in Tasmania would not include a sizeable proportion of short reach brackets. Of particular note is that fact that Aurora Energy has standard designs for these brackets, but does not report any of these as having been installed.[1180]

The AER notes that the volumes of bracket types provided by Aurora are estimates and that Aurora does not collect information on bracket types. The AER considers that these managerial estimates favour the longer, more expensive bracket types, which appears to be inconsistent with industry practice.

The AER has calculated the ratio of bracket types for major and minor lights based on Aurora's purchase history from 2010 and 2011.[1181] The AER used this bracket type ratio to estimate volumes of bracket types for each light type and calculate the average bracket cost. The AER's draft decision on average bracket costs is in Table D.4.

Table D.4 AER draft decision on average bracket costs ($2009–10)

	Aurora proposal	AER draft decision	% difference between AER draft decision and Aurora proposal
Average bracket cost	$201.41	$184.84	-8%

Source: AER analysis.

Nuttall also reviewed Aurora's proposed installation costs for 80W mercury vapour and 250W high pressure sodium vapour lights. Nuttall considered Aurora's installation costs are reasonable for the replacement of a single item based on Aurora's labour rates and the time typically required to undertake a luminaire or bracket replacement.[1182]

The AER accepts Nuttall's conclusions on Aurora's proposed installation costs. The AER accepts Aurora's proposed installation costs.

Estimated asset lives

The AER accepts Aurora's proposed Aurora's proposed asset lives. Aurora's proposed asset lives are broadly consistent with Australian industry practice.

The AER engaged Nuttall Consulting to assess the reasonableness of Aurora's proposed asset lives. Nuttall benchmarked Aurora's proposed asset lives against asset lives used by other DNSPs to

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1180 Nuttall Consulting, *Report – Principle Technical Advisor: Aurora Electricity Distribution Revenue Review*, 5 October 2011, p. 198–199,

1181 Aurora provided purchase history and invoices from April 2010 to August 2011 in Light Bracket Invoices.pdf, attached to Aurora, *Response to information request AER/027 of 17 August 2011*, received 25 August 2011. These invoices include brackets ranging from a length of 250mm to 3000mm.

1182 Nuttall Consulting, *Report – Principle Technical Advisor: Aurora Electricity Distribution Revenue Review*, 5 October 2011, p. 200.

ascertain whether Aurora's proposed asset lives are reasonable and reflect industry practice (i.e. are these asset lives reflective of what an efficient business would estimate). Nuttall Consulting reviewed Aurora's proposed public lighting asset ages against those of similar jurisdictions. This comparison is shown in Table D.5. Nuttall Consulting concluded that Aurora's proposed asset lives are reasonable and consistent with industry practice.[1183] The AER accepts Nuttall Consulting's advice.

Table D.5 Nuttall Consulting comparison of public lighting asset lives

Asset	Aurora proposed asset life	AER accepted asset life in NSW	Victoria depreciated life
Luminaire	20 years	20 years	n/a
Bracket	40 years	20 years	35 years
Pole	50 years	35 years	35 years

Source: Nuttall Consulting.[1184]

Number of lights

Total number of lights is a driver of total costs (both opex and capex) and a key input into Aurora's public lighting annuity model.

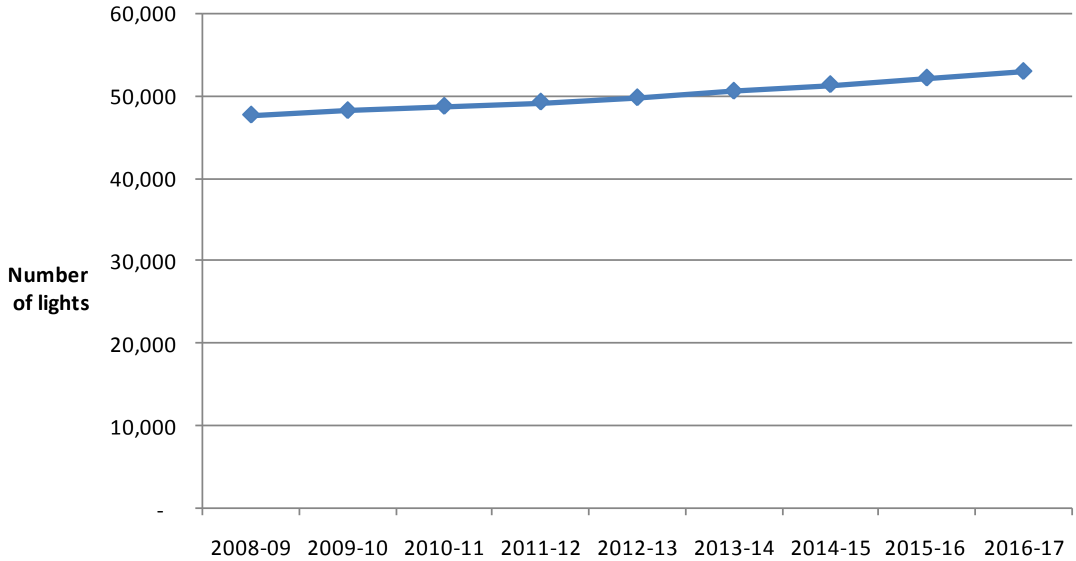
The AER considers that Aurora's proposed volumes of public lights for the next regulatory period are consistent with historical trend. The key driver of growth of public lighting is population growth. Aurora's forecast growth rate for public lights is consistent with the customer growth rate. Therefore, the AER accepts Aurora's proposed public lighting volumes.

The AER assessed Aurora's forecast number of lights based on historical numbers and growth rates. A comparison of historical trend with forecast trend indicates that the total number of lights grew at around one per cent per year from 2008–09 to 2011–12. The forecast growth in the number of lights over the next regulatory period ranges from 1.05 per cent to 1.59 per cent per year which is not a material change from the historical trend. This growth in the number of lights is shown in Figure D.1.

1183 Nuttall Consulting, Report – Principle Technical Advisor: Aurora Electricity Distribution Revenue Review, 5 October 2011, p. 201.

1184 Nuttall Consulting, Report – Principle Technical Advisor: Aurora Electricity Distribution Revenue Review, 5 October 2011, pp. 200–201.

Figure D.1 Aurora number of public lights - current and forecast



Source: AER analysis, data from public lighting annuity model v 2.

D.1.3 Overheads

Aurora's method for allocating overhead costs to its distribution services is outlined in its CAM. The allocation of Network Division shared costs is on the basis of total direct costs (including opex and capex) for each service classification. That is, the allocation of Network Division overheads to public lighting services is determined by Aurora's forecast opex and capex for public lighting services. Allocated overheads for public lighting are then input into Aurora's public lighting annuity model and allocated to individual services on the basis of direct labour hours.[1185]

The AER has reviewed Aurora's proposed overhead costs as a whole and its decision is outlined in attachment 6. The AER's analysis of overhead costs in this appendix focuses on the method in the public lighting annuity model of allocating the overheads for public lighting to individual services.

Capex forecasts

Aurora's proposed capex forecasts for public lighting are not a direct input into Aurora's public lighting annuity model. However, as capex forecasts are used to determine the amount of overheads allocated to public lighting services, the AER has assessed Aurora's proposed capex. Aurora's capex forecasts are based on its replacement programs of luminaires and poles and installation of new lights. The unit costs in these work programs correspond to the replacement and installation costs that are inputs into the annuity model.

The AER considers Aurora's forecast capex for public lighting is reasonable as it is consistent with historical capex in years with standard replacement and installation rates.

Aurora's proposed capex for public lighting for the next regulatory period includes a step change decrease to 2012–13 and decreasing capex over the period. Total public lighting capex for the forthcoming regulatory control period is 21 per cent lower than for the current period. This is shown in

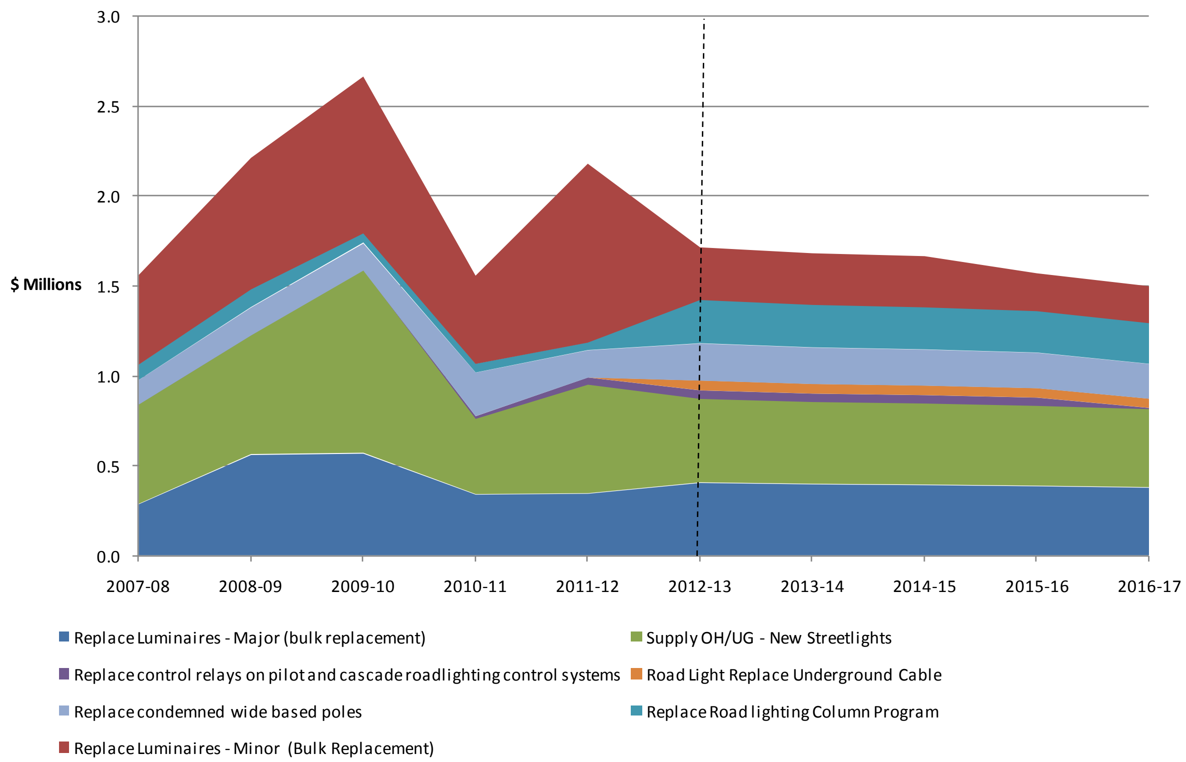
1185 Aurora Energy, *Cost Allocation Method – Version 6.3*, May 2011, p. 17.

Figure D.2. The step change decrease is in the 'Replace Luminaires – Minor (Bulk Replacement)' (RLMIN) capex categories. Aurora has attributed this decrease to two factors:

1. a reduction in the luminaire replacement rate for minor lights from 8–10 per cent per year to 5 per cent
2. costs for the removal of switch wires in residential areas being funded by NBN Co due to an agreement between Aurora and NBN Co. NBN Co requires the removal of the switch wire in order to increase the height available on Aurora's poles to run the optical fibre cables in areas where the NBN roll-out is occurring. This is a temporary cost reduction that will continue for the next seven years during the NBN roll-out.[1186]

   - The costs for the other capex categories are proposed to remain fairly steady from the current period.

Figure D.2 Aurora's historical and forecast public lighting capex ($million, 2009–10)



Source: AER analysis, data from public lighting annuity model v2.

The spike in historical capex is attributable to the Tasmanian government's investment in new major road infrastructure which increased the capex costs in 2008–09 and 2009–10. The Tasmanian government has not proposed any new major projects that will require the installation of new lights in the next regulatory period. Therefore, capex for the forthcoming regulatory control period is forecast to return to the levels experienced in 2007–08 and 2010–11.

1186 Aurora, *Response to information request AER/006 of 7 July 2011*, received 15 July 2011, p. 19.

Overhead costs

Aurora's CAM requires it to allocate overheads to individual public lighting services on the basis of direct labour hours.[1187]

The AER's analysis of Aurora's public lighting annuity model indicates that Aurora has applied the method specified in its CAM to allocate overhead costs to individual public lighting services. The AER therefore accepts Aurora's method for allocating overhead costs to individual public lighting services. The quantum of overhead costs allocated to public lighting services is outlined in attachment.6.

D.1.4 Other issues

The other relevant inputs into Aurora's public lighting annuity model are:

- WACC
- escalation rates

These are issues that are common to Aurora's whole regulatory proposal. The AER has considered Aurora's proposed WACC in attachment 9 and Aurora's proposed real cost escalation in attachment 4. The AER has adopted this position for alternative control services.

D.2 Revisions

Revision D.1: The AER rejects Aurora's proposed opex forecasts for public lighting services and replaces it with the opex in Table D.2. The AER requests Aurora submit revised opex forecasts for public lighting with the anomalies in its forecasts are corrected in its revised Regulatory Proposal.

Revision D.2: The AER rejects Aurora's proposed bracket replacement costs and replaces it with the replacement costs in Table D.3.

Revision D.3: The AER accepts Aurora's public lighting annuity model to calculate price caps for public lighting services. The AER rejects Aurora's proposed price caps. The AER's draft determination price caps for public lighting services are shown in section D.3.

[1187] Aurora Energy, *Cost Allocation Methodology – version 6.3*, p. 17.

D.3 Prices

The AER's draft decision on prices for Aurora owned lights are set out in Table D.6.

Table D.6 AER draft decision on prices for Aurora owned public lights (cents per day, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17
50W Mercury Vapour	28.713	29.429	29.699	27.916	27.723
80W Mercury Vapour (Aeroscreen)	28.713	29.429	29.699	27.916	27.723
80W Mercury Vapour (Art decorative)	47.225	48.624	49.479	48.126	48.398
125W Mercury Vapour	33.653	34.398	34.737	32.973	32.793
250W Mercury Vapour	34.100	34.860	35.215	33.459	33.291
400W Mercury Vapour	38.427	39.349	39.838	38.185	38.125
70W Sodium Vapour	30.891	31.685	32.026	30.292	30.155
100W Sodium Vapour	31.062	31.806	32.121	30.349	30.170
150W Sodium Vapour	34.809	35.595	35.971	34.233	34.083
250W Sodium Vapour	34.930	35.722	36.102	34.367	34.219
400W Sodium Vapour	35.128	35.927	36.313	34.583	34.440
150W Metal Halide	34.809	35.595	35.971	34.233	34.083
250W Metal Halide	34.930	35.722	36.102	34.367	34.219
2x20W Fluorescent	32.649	33.509	33.904	32.212	32.118
2x40W Fluorescent	32.303	33.092	33.446	31.703	31.555
42W Compact Fluorescent	30.832	31.625	31.963	30.229	30.090
60W Incandescent	28.094	28.786	29.038	27.240	27.032

Source: AER analysis.

The AER's draft decision on prices for contract lights is set out in Table D.7.

Table D.7 AER draft decision on prices for private contract public lights (cents per day, nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17
50W Mercury Vapour	18.662	19.138	19.169	17.217	16.848
80W Mercury Vapour Aeroscreen	18.651	19.126	19.156	17.204	16.835
125W Mercury Vapour	19.609	20.061	20.091	18.119	17.727
250W Mercury Vapour	19.681	20.137	20.168	18.197	17.808
400W Mercury Vapour	19.736	20.193	20.226	18.257	17.870
70W Sodium Vapour	18.848	19.330	19.367	17.419	17.055
150W Sodium Vapour	20.319	20.797	20.850	18.893	18.521
250W Sodium Vapour	20.286	20.764	20.814	18.857	18.484
400W Sodium Vapour	20.360	20.841	20.893	18.938	18.566
150W Metal Halide	20.319	20.797	20.850	18.893	18.521
250W Metal Halide	20.286	20.764	20.814	18.857	18.484
400W Metal Halide	20.286	20.764	20.814	18.857	18.484
1x20W Fluorescent	18.716	19.194	19.226	17.275	16.908
2x20W Fluorescent	18.834	19.316	19.352	17.405	17.040
1x40W Fluorescent	18.724	19.202	19.234	17.284	16.916
2x40W Fluorescent	19.794	20.254	20.289	18.321	17.934
3x40W Fluorescent	19.920	20.385	20.423	18.458	18.074
4x40W Fluorescent	20.748	21.243	21.308	19.362	19.000
60W Incandescent	18.648	19.124	19.154	17.202	16.832
100W Incandescent	19.593	20.046	20.075	18.101	17.710
Pole Surcharge	19.443	19.953	20.476	20.954	21.563

Source: AER analysis.

E Alternative control – Fee based and quoted services

This appendix sets out the AER's detailed analysis and reasoning supporting its decision on Aurora's fee based and quoted services in attachment 15.

The AER focussed its assessment of Aurora's proposed price caps for fee based services and hourly charge out labour rates for quoted services focused on:

- the inputs into Aurora's fee based services model (labour rates and materials costs)
- Aurora's proposed charge-out rates for labour for quoted services
- Aurora's allocation of overhead costs
- Aurora's proposed prices of fee based services.

The AER has considered whether the inputs into Aurora's fee based services model and charge-out rates for quoted services reflect efficient costs using the method outlined in attachment 15. The AER incorporated its decisions on each of these components of Aurora's proposal into Aurora's model for fee based services to adjust the price caps for individual fee based services.

E.1 Reasons for draft determination

E.1.1 Basis of control mechanism

The AER will apply Aurora's proposed cost build up method as the basis of the control mechanism for fee based and quoted services. Table E.1 summarises the AER's consideration of the factors in clause 6.2.5(d) of the NER for fee based and quoted services.

Table E.1 NER factors and the basis of control mechanism for fee based and quoted services

NER Factor	AER consideration
The potential for the development of competition	There is little if any potential for the development of competition for fee based and quoted services[1188] therefore the choice of a cost build up approach will not have any material impact on the potential for competition
Administrative costs	The application of a cost build-up approach to all fee based services may impose an additional burden on Aurora. This change in administrative costs is expected to be largely transitional in nature. These additional costs are likely to result from incorporating additional services into Aurora's fee based services model.[1189] This is because the AER proposes to apply price caps to all fee based services and labour rates for quoted services. OTTER previously regulated only some fee based services under a price cap. The AER therefore considers that the additional costs are immaterial. Further, the AER considers this is justified as the change in the basis of control will create consistency in the price setting method and greater cost reflectivity for the prices of these services.
Previous regulatory arrangements	Under the current regulatory arrangements, fee based services are two separate sets of services. The reference set of services are currently regulated under a price cap and the other category are not. The AER considers that all fee based services should be regulated by the same control mechanism Quoted services are unregulated under the current regulatory arrangements. Therefore there are no previous regulatory arrangements relevant to pricing quoted services
Desirability for a consistent regulatory approach	The most common approach to setting prices for fee based and quoted services is to apply a cost build up approach.
Any other relevant factor	The AER considers that the NEO and RPP are relevant. The AER considers that prices for fee based and quoted services should be cost reflective and based on a cost build up in order to ensure that the DNSP is able to recover the efficient costs of providing these services. The AER considers that a cost build up approach based on the costs that would be expected to be incurred by an operator in a workably competitive market is consistent with the RRP.[1190] By setting prices at the level of efficient costs, the AER is promoting efficient investment in, and efficient operation of the use of electricity services in line with the NEO. Consumption where prices are set at the level of a workably competitive market would be efficient, as the marginal benefit of consumption at that level of service would reflect the cost of providing the service.

In this assessment, the AER considers that two factors are of particular importance:

- the achievement of the NEO and RPP
- the desirability of consistency between regulatory arrangements.

[1188] In the framework and approach paper, the AER considered that there is a regulatory barrier to any party other than Aurora providing fee based and quoted services. AER, *Framework and approach paper*, November 2010, pp. 11, 13, 42 and 55.

[1189] Aurora currently records cost information for all fee based and quoted services. Aurora provided this information in its RIN.

[1190] The AER has previously interpreted 'efficient costs' to mean the expected costs based on outcomes in a workably competitive market.. AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, 2010, p. 397.

The AER considers that the regulation of fee based and quoted services should move to a more transparent and cost reflective fee system. Fee based and quoted services are generally provided for the benefit of a single customer rather than uniformly supplied to all network customers. Therefore the cost of providing each service should be directly passed on to the customer requesting the service.[1191] The AER considers that this can be best achieved by applying cost reflective pricing. Further, cost reflective pricing allows a DNSP to recover the efficient costs of providing fee based and quoted service, which is consistent with the RRP and NEO.

The AER considers that the basis of control mechanism for fee based and quoted services most likely to result in cost reflective pricing, given Aurora's circumstances and the information available to the AER, is a cost build up.

The AER considers that Aurora's proposed method for calculating prices for fee based and quoted services will result in prices that are cost reflective because it is based on a cost build-up approach. The AER therefore accepts Aurora's proposed cost build-up method.

E.1.2 Inputs into the fee based and quoted services cost build-up

The AER has assessed each input into the fee based services and quoted services cost build-up. The AER has rerun Aurora's fee based services model with the AER’s revised inputs. The AER has relied on the results of this process to make its draft determination on price caps for fee based services.

Labour rates

Many of Aurora's fee based services are largely labour based with very little materials costs.[1192] Therefore, a key driver of the cost (and therefore price) of these services is labour rates. Aurora's proposal for fee based services identified the relevant class of labour as an input into the fee based services model as 'CC Commercial Metering'.[1193]

Labour costs are also a key component of charges for quoted services. Aurora identified a number of classes of labour relevant to the provision of quoted services as part of its response to the regulatory information notice (RIN) and in the fee based services model.[1194]

The AER has assessed each of Aurora's proposed labour rates in terms of actual historical labour rates,[1195] and industry benchmarks[1196] to determine whether the proposed costs are reasonable. The AER’s analysis indicates that Aurora's proposed labour rates are in line with historical trends. The AER's benchmarking analysis shows that Aurora's proposed wage rates for 2012–13 are:

1191 AER, *Framework and approach paper*, November 2010, pp. 80, 82–83.

1192 Aurora, Fee based services model.

1193 Aurora, Fee based services model.

1194 NW-#30188740 RIN_Alternative_Control_Services_Data_(16-17-18); Aurora fee based services model

1195 The AER compared the indicative hourly labour rates of each class of labour proposed for the forthcoming regulatory control period to the actual hourly rates for the previous and current regulatory control periods. This shows that Aurora's proposed labour rates generally follow the consistent historical trend of approximately 2 per cent increase per year. This is lower than CPI growth and a slightly lower rate of increase than prior to 2009–10 where labour rates increased by approximately 5 per cent per year.

1196 The AER has benchmarked a selection of Aurora's proposed labour rates (inclusive of non-productive time) against the charge-out rates for fee based and quoted services of other DNSPs, industry benchmarks, and a wage rate build up (The wage rate build up was prepared by Impaq Consulting for the Victorian Distribution Determination 2011–15. The report is available on the AER's website.)

- within the wage build-up based on the Electrical Power Industry Award[1197]
- within the NECA benchmark range[1198]
- within the range recommended by Impaq for the Victorian DNSPs in the Victorian distribution determination[1199]
- generally lower than comparable wage rates of other DNSPs in Victoria, South Australia and NSW, which have been approved by the AER[1200]

The AER therefore considers Aurora's proposed labour rates reasonable. The AER accepts Aurora's proposed charge out rates as the price caps for quoted services and hourly wage rate for CC Commercial Metering in Table E.7 as an input into the fee based services model.

Material costs

A number of fee based services include materials costs as part of the costs of providing the services. Aurora proposed to charge for materials at cost for fee based and quoted services.

The AER accepts Aurora's proposed method of charging for materials at cost.

Aurora proposed materials costs for a number of fee based services in the fee based services model. Aurora identified what materials these costs were for in response to an information request from the AER.[1201] This response showed a number of inconsistencies in the way Aurora has allocated materials costs to individual services. A number of very similar services in terms of the tasks and materials required to provide the service have different materials costs allocated in the fee based services model. In particular:

- "site visit - credit action or site issues" was the only site visit service to have materials costs allocated
- "renewable energy connection" has no materials costs allocated, whereas "renewable energy connection - after hours" has $160.08 materials cost allocated[1202]
- "temporary supply underground – single phase – temporary position" and "temporary builders connection – after hours" have an inconsistent allocation of materials costs compared with the other services in the temporary builders connection group[1203]

1197 Impaq Consulting, *Victorian Electricity Distribution Determination 2011 – Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010, section 6.2, pp. 34–39; Impaq Consulting, *Victorian Electricity Distribution Determination 2011 – Addendum to Review of Distributors Proposed Rates in ACS Charges*, 31 August 2010, pp. 6–10.

1198 The National Electrical and Communications Association (NECA) undertakes an annual charge-out rate survey. For the 2009 study, the most common hourly charge-out rate for an electrical tradesperson was between $60 and $80 (including the cost of a vehicle). Source: Impaq Consulting, *Victorian Electricity Distribution Determination 2011 – Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010, p 42.

1199 Impaq Consulting, *Victorian Electricity Distribution Determination 2011 – Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010, p. 24; Impaq Consulting, *Victorian Electricity Distribution Determination 2011 – Addendum to Review of Distributors Proposed Rates in ACS Charges*, 31 August 2010, p. 10.

1200 CitiPower, *2011 Pricing Proposal*, 3 December 2010, p. 101; Powercor, *2011 Pricing Proposal*, 7 December 2010, p. 107; SP AusNet, *Electricity Distribution Annual Tariff Report 2011*, 1 January 2011, p. 104; United Energy, *UED Pricing proposal 2011*, 22 November 2010, p. 92; AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, 2010, p 783; Impaq Consulting, *Victorian Electricity Distribution Determination 2011 – Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010, p 45–50.

1201 Aurora, *Response to information request AER/027 of 17 August 2011*, received 25 August 2011, pp. 5–7.

1202 Aurora, Fee based services model, first year calcs tab (provided as an attachment to Aurora, *Response to information request AER/027 of 17 August 2011*, received 25 August 2011)

1203 Aurora, *Response to information request AER/027 of 17 August 2011*, received 25 August 2011, pp. 5–7.

Aurora did not explain the apparent inconsistent allocation of materials costs to individual services. The AER has rejected the proposed materials costs for the four services listed above on the basis that these services are very similar (or identical to) other services provided by Aurora, where Aurora has not proposed materials costs for the service. The AER has therefore allocated $0 for material costs for these four services. The AER accepts the other proposed materials costs for fee based services.

Opex and capex forecasts

The AER has focused on forecast changes from historical opex and capex to assess whether Aurora's proposed opex and capex for fee based services is reasonable and reflects the costs of an operator in a workably competitive market.[1204] The AER has made a number of changes to the cost inputs for fee based services (discussed above in the section on materials cost and below in the section on proposed price caps), therefore it has replaced Aurora's proposed opex and capex with its own forecasts. Further, Aurora's proposal for fee based services included costs for PAYG services. The AER considers that these services fall within the category of PAYG metering services that the AER classified as unregulated services in the framework and approach paper.[1205] Aurora accepted the AER's classification of services in its regulatory proposal.[1206] Therefore, the AER has removed the costs relating to PAYG services from Aurora's proposed opex and capex forecasts for fee based services. The AER's forecast opex is built-up from the AER's amended costs in Aurora's fee based services model.

The AER's draft decision on fee based services opex is set out in Table E.1.

Table E.1 AER draft decision on Aurora's opex forecasts for fee based services ($million, 2009–10)

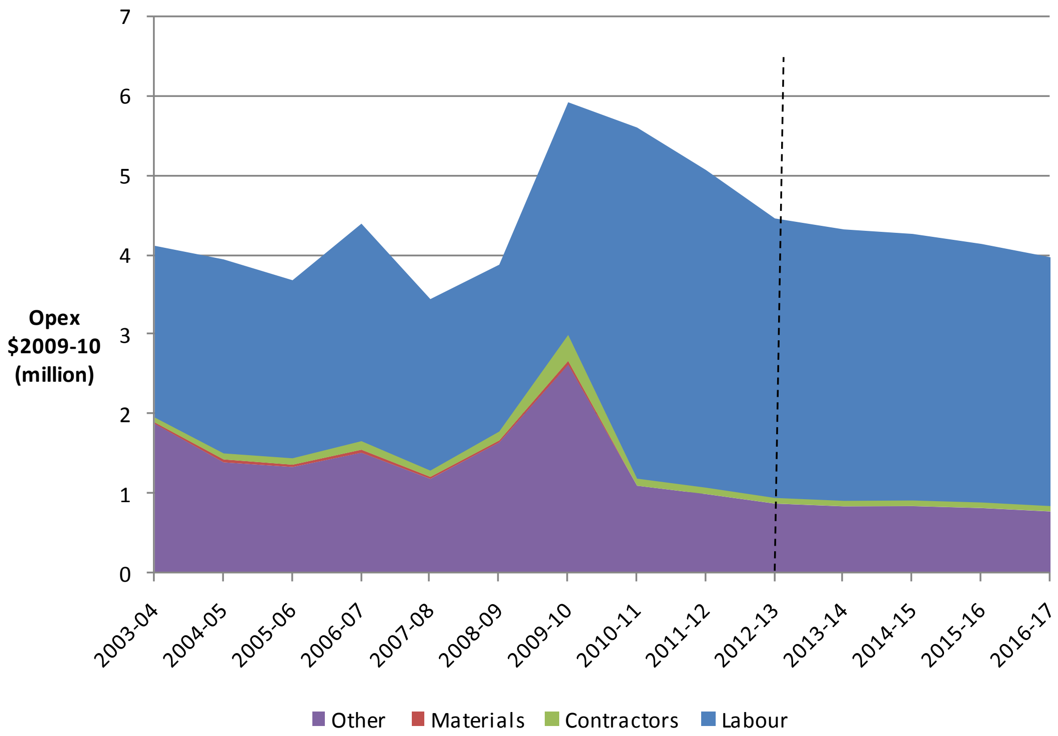
	2012–13	2013–14	2014–15	2015–16	2016–17
AER draft decision opex	2.7	3.1	3.0	3.0	2.9
Aurora proposed opex	4.6	4.5	4.4	4.3	4.1
% difference	-42%	-31%	-31%	-30$	-28%

Source: AER analysis.

Aurora's proposed opex for fee based services is forecast to decrease from 2011–12 to 2012–13. This is a continuation of the historical trend from 2009–10. Opex for fee based services is forecast to remain fairly constant over the forthcoming regulatory control period. This is shown in Figure E.1.

1204 AER, Victorian electricity distribution network service providers Distribution determination 2011–2015, October 2010, p. 397.
1205 AER, *Framework and approach paper*, November 2010, p. 59.
1206 Aurora, *Regulatory proposal addendum*, June 2011, p. 39.

Figure E.1 Aurora's proposed opex for fee based services ($million, 2009–10)



Source: AER analysis.

The AER considers that Aurora's forecast opex for fee based services is reasonable as there are no significant movements away from opex incurred in the last 3 years. This is consistent with the number of fee based services Aurora has provided and is forecast to provide. However, as the AER has adjusted a number of the inputs into the fee based services model,[1207] the opex forecasts proposed by Aurora do not reflect the input costs approved by the AER. Therefore the AER undertook a build-up of opex costs in the fee based services model incorporating the AER's draft decision on material costs and time assumptions.

Aurora's proposed capex forecasts for fee based services are not a direct input into Aurora's fee based services model. However, capex forecasts are used to determine the amount of overheads allocated to fee based services. Therefore the AER has assessed Aurora's proposed capex. The AER's draft decision on Aurora's capex forecasts for fee based services is set out in Table E.2.

Table E.2 AER draft decision on Aurora's capex forecasts for fee based services ($million, 2009–10)

	2012–13	2013–14	2014–15	2015–16	2016–17
AER draft decision capex	0.28	0.07	0.07	0.29	0.29
Aurora proposed capex	0.51	0.31	0.31	0.52	0.52
% difference	-46%	-76%	-76%	-44%	-44%

Source: AER analysis.

1207 The AER made adjustments to Aurora's proposed materials costs and time assumptions for a number of services and removed PAYG costs from the fee based services model

Aurora's proposed capex for fee based services is made up of shared costs and PAYG costs. As discussed above, PAYG costs should not be allocated to fee based services costs. Therefore, the AER has removed these costs from Aurora's proposed capex.

Aurora has not incurred capex for fee based services in the previous or current regulatory period. Forecast capex consists of shared IT costs and network services minor assets, which are direct shared costs. As forecast capex for fee based services is relatively minor and entirely compromised of direct shared costs the AER accepts Aurora's proposed capex except for the PAYG costs.

E.1.3 Overheads

Aurora's method for allocation of overhead costs to its distribution services is outlined in its CAM. The allocation of Network Division shared costs is on the basis of total direct costs for each service classification. Therefore, the forecast capex and opex for fee based services determines the allocation of Network Division shared costs to fee based services. Allocated overheads for fee based are then input into Aurora's fee based services model and allocated to individual services on the basis of direct labour hours.[1208]

The AER has reviewed Aurora's proposed overhead costs as a whole and its position is outlined in attachment 6. The AER's analysis of overhead costs in this appendix focuses on the method in the fee based services models of allocating the overheads allocated to fee based services to individual services. The AER's analysis of Aurora's fee based services model indicates that Aurora has applied the method specified in its CAM to allocate overhead costs to individual fee based services. The AER therefore accepts Aurora's method for allocating overhead costs to fee based services.

The AER's decisions on inputs into the fee based services model have been input into Aurora's fee based services model to determine the AER's decision on price caps for individual fee based services. The AER's draft decision on price caps for fee based services is in section E.1.4.

E.1.4 Proposed price caps - fee based services

In addition to its assessments of the inputs into the cost build-up, the AER has also undertaken an assessment of Aurora's price-caps. The AER has focused its assessment of Aurora's proposed price caps for fee based services on:

- services provided most commonly
- services where Aurora's proposed prices are significantly higher than current prices
- similar services where Aurora's proposed prices differ

The AER considered advice provided by Nuttall Consulting on the reasonableness of Aurora's proposed prices for the six most commonly provided fee based services. The AER also considered advice provided by Impaq Consulting for the Victorian distribution determination[1209] as part of its analysis to determine whether Aurora's proposed prices reflect the reasonable costs of providing fee based services.

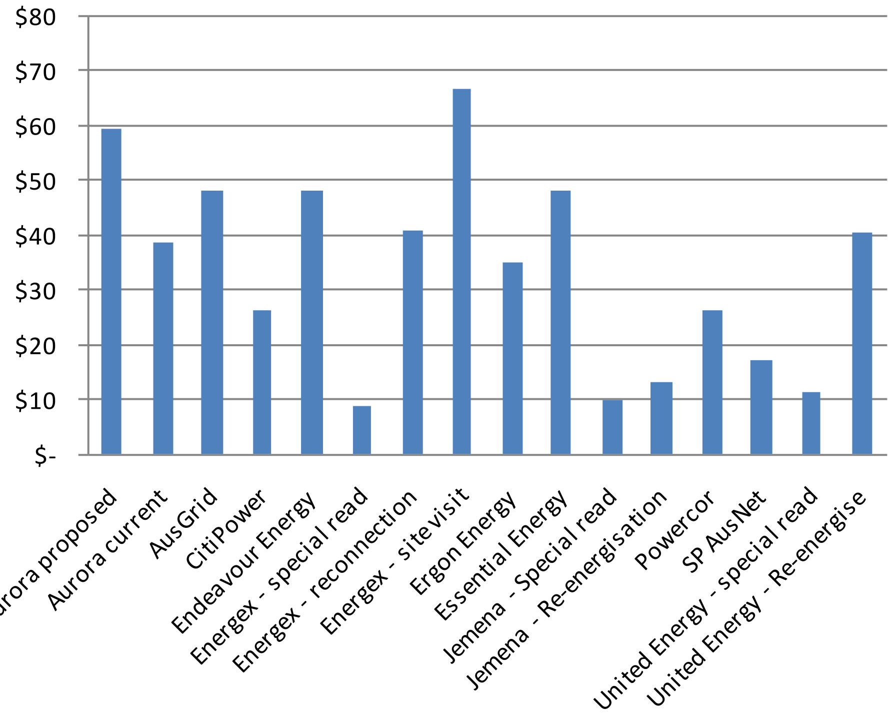
[1208] Aurora, *Cost Allocation Method – Version 6.3*, May 2011, p. 17.
[1209] Impaq Consulting, *Victorian Electricity Distribution Determination 2011 – Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010; Impaq Consulting, *Victorian Electricity Distribution Determination 2011 – Addendum to Review of Distributors Proposed Rates in ACS Charges*, 31 August 2010.

E.1.5 Benchmarking analysis

The AER engaged Nuttall Consulting to assist with its assessment of Aurora's proposed prices for fee based services. Nuttall Consulting undertook benchmarking analysis of Aurora's six most commonly provided services against prices of other DNSPs in the NEM with similar customer density.[1210] The results of this analysis are shown in Figure E.2 to Figure E.6. Nuttall Consulting concluded that Aurora's proposed price for:

- "Site visit – no appointment" is higher than the fees charged by almost all DNSPs (Figure E.2)
- "Site visit – credit action or site issue" is higher than the fees charged by other DNSPs and the standard site visit (see Figure E.3)
- "Tariff alteration" (single phase and three phase) is within the range of fees charged by other NEM DNSPs (see Figure E.4)
- "Renewable energy connection" is within the range of fees charged by other NEM DNSPs (see Figure E.5)
- "Truck tee-up" is greater than the fees charged by most other DNSPs (see Figure E.6)

Figure E.2 Nuttall Consulting benchmarking: Site visit–no appointment prices (including GST)

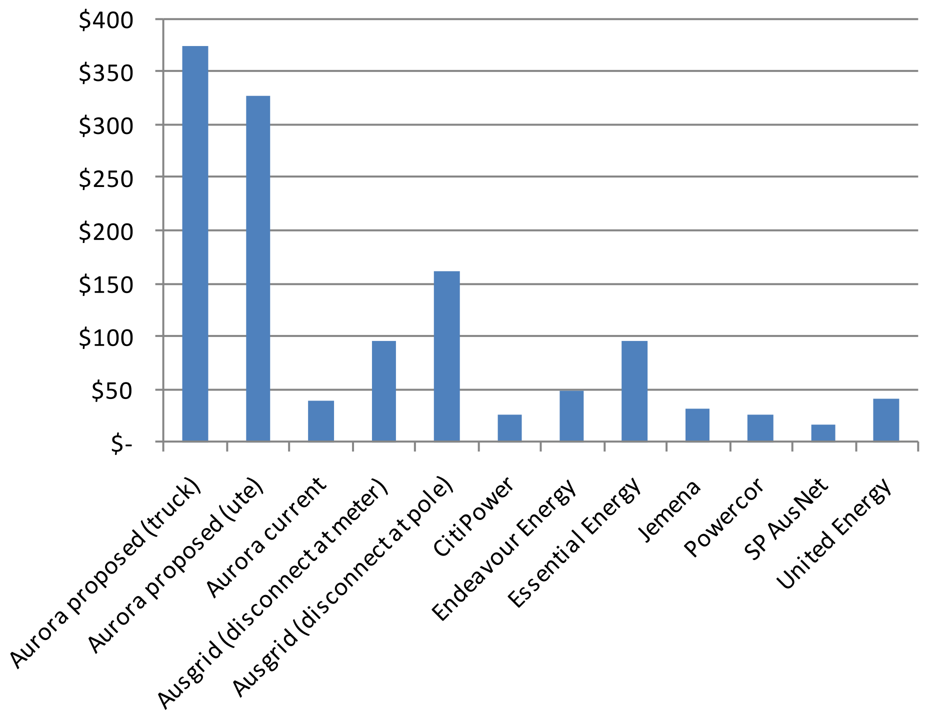


Source: AER analysis, Nuttall Consulting.[1211]

[1210] Nuttall Consulting, *Report – Principle Technical Advisor: Aurora Electricity Distribution Revenue Review*, 5 October 2011, section C.2 (Nuttall Consulting, *Aurora Revenue Review*, October 2011).

[1211] Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 190.

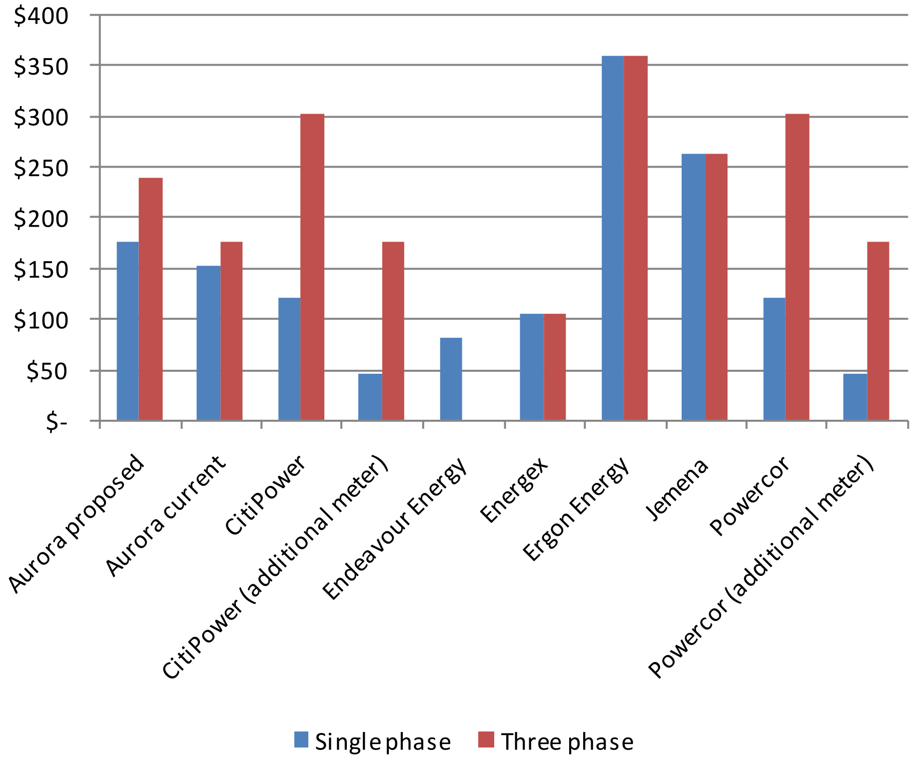
Figure E.3 Nuttall Consulting benchmarking: Site visit–credit action or site issue prices (including GST)



Source: AER analysis, Nuttall Consulting.[1212]

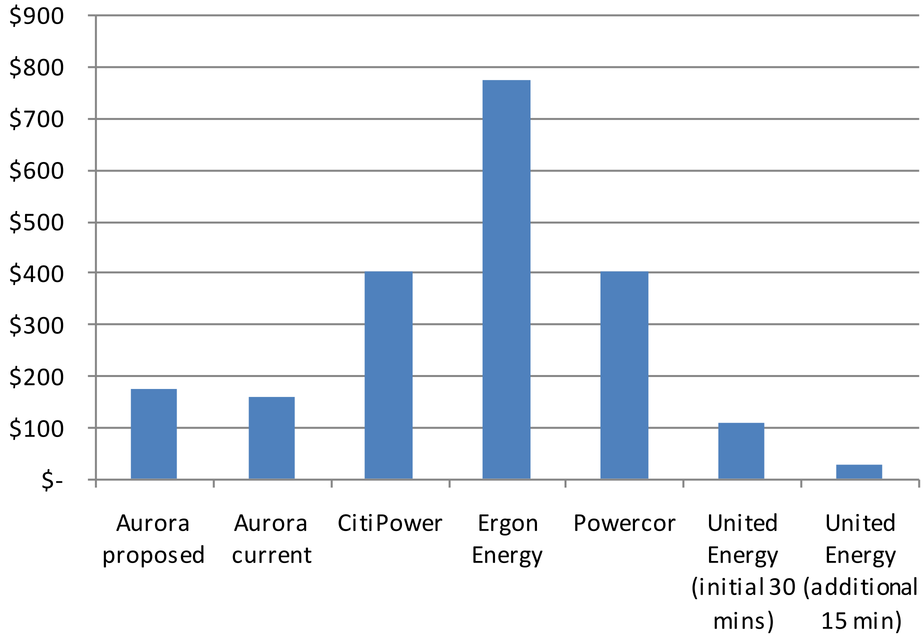
[1212] Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 191.

Figure E.4 Nuttall Consulting benchmarking: Tariff alteration prices (including GST)



Source: AER analysis, Nuttall Consulting.[1213]

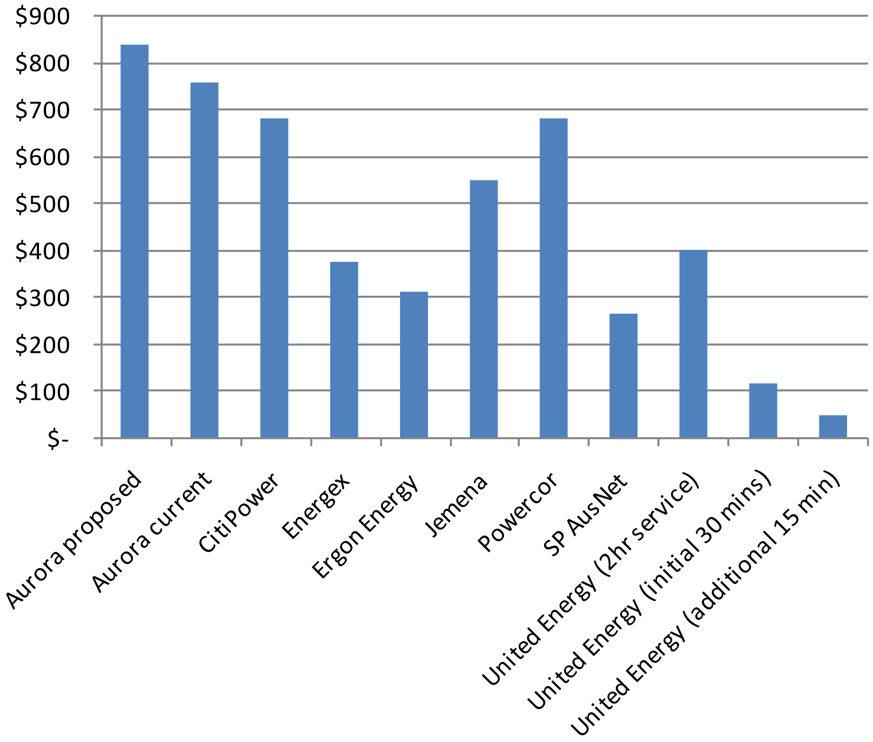
Figure E.5 Nuttall Consulting benchmarking: Renewable energy connection prices (including GST)



Source: AER analysis, Nuttall Consulting.[1214]

[1213] Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 192–193.

Figure E.6 Nuttall Consulting benchmarking analysis: Truck tee-up prices (including GST)



Source: AER analysis, Nuttall Consulting.[1215]

Site visit – no appointment

Nuttall Consulting considered that Aurora's proposed price was considerably higher than almost all other DNSPs for a site visit. Nuttall Consulting considered that Aurora provided insufficient evidence to explain why its fee is higher than other DNSPs and increasing from current prices. Nuttall Consulting recommended that the current price be maintained with an allowance for the allocation of overheads in accordance with Aurora's cost allocation methodology.[1216]

The AER accepts Nuttall Consulting's advice and rejects Aurora's proposed price cap for "site visit – no appointment". The AER's draft decision on the price cap for this service is in Table E.4.

Site visit – credit action or site issue

This is a new category of service for Aurora and has been separated from "site visit – no appointment". Nuttall Consulting considers that Aurora did not provide evidence to establish the case for a fee that is significantly different from the fee for "site visit – no appointment", or why the proposed fee is significantly greater than other DNSPs. Nuttall Consulting recommended that the same fee should be adopted for "site visit – no appointment" and "site visit – credit action or site issue".[1217]

1214 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 194.
1215 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 195.
1216 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 190–191.
1217 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p 192.

The AER agrees with Nuttall Consulting's view that Aurora has not provided evidence to support the significantly different price for "site visit – credit action or site issue". Therefore, the AER rejects Aurora's proposed price for "site visit – credit action or site issue". The AER's draft decision on the price for "site visit – credit action or site issue" is in Table E.4.

Truck Tee-up

The AER considers that Aurora's proposed fee for "truck tee-up" is not reflective of the efficient costs of providing the service because:

- Aurora's proposed price is significantly higher than the benchmark prices for a two hour service
- the times for the service are likely to vary materially for individual customers

Aurora's proposed fee for "truck tee-up" is approx $724.74 ($2009–10) excluding GST. Nuttall Consulting's benchmarking analysis indicated that this fee is greater than the fees charged by most other DNSPs (see Figure E.6).

Nuttall considers that a fee in the order of $400 for a two hour service is reasonable, based on the fees from other DNSPs. This is greater than the fees charged by SP AusNet and Ergon Energy who have a similar customer density to Aurora. However, considering the fees of all other DNSPs, Nuttall Consulting considers that the United Energy truck tee-up fees are representative of efficient costs.[1218] For a two hour service, United Energy's fees would be $400.33 which is within the range of fees of most other DNSPs and below Aurora's proposed charge.

Aurora's proposed price for "truck tee-up" is designed to provide an incentive for registered electrical contractors to reduce the reliance on Aurora crews for onsite works and to minimise the time that Aurora crews need to spend at each site. Nuttall Consulting notes that this is an issue that is common across the industry. Nuttall Consulting recommended a fee with a low initial charge and then additional time-based increments on the basis that this fee structure would provide a much greater incentive for contractors to have a site adequately prepared for the Aurora crews. This type of time based fee structure is common for electrical and plumbing trades. It is also utilised by United Energy in Victoria.[1219]

The AER also considered Impaq's recommended field staff times for the comparable services provided by the Victorian DNSPs.[1220] Impaq recommended a time of between one and two hours on site for these services.[1221]

The AER considers that Impaq's recommended range of time on site allows for a significant variation in times that are considered reasonable for providing the same service. Further, Aurora stated that the times on site and tasks performed for a "truck tee-up" is dependent on the service order type associated with each appointment.[1222] The AER therefore considers that it is likely that the task times for "truck tee-up" will vary significantly for individual customers. Given this factor, the AER considers that adopting a time-based fee structure for "truck tee-up" will result in cost reflective pricing. The AER

1218 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p 196.
1219 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p 196.
1220 The comparable services were CitiPower, Powercor and Jemena: New connection - single phase where the business is responsible for customer metering.
1221 Impaq Consulting, Victorian Electricity Distribution Determination 2011 – Review of Distributors Proposed Rates in ACS Charges, 25 May 2010, p. 53.
1222 Aurora, *Response to information request AER/021 of 1 August 2011*, received 5 August 2011, p. 10.

considers that cost reflective prices are consistent with and give effect to the NEO and RPP for the reasons stated in attachment 15.

Nuttall Consulting recommended adopting United Energy's fee structure for Aurora:

- $115.51 for the first 30 minutes
- $47.47 for each additional 15 minutes[1223]

The AER considers that the prices recommended by Nuttall Consulting are reflective of the efficient cost of providing this service. Therefore, the AER rejects Aurora's proposed price for "truck tee-up". The AER's decision on price caps for "truck tee–up" is in Table E.4.

Table E.4 AER draft decision on price caps for site visit – no appointment, site visit – credit action or site issue and truck tee–up for 2012–13 (nominal)

	Aurora proposed price	AER draft decision	% difference between Aurora proposal and AER draft decision
Site visit – no appointment	55.60	49.47	-11%
Site visit – credit action or site issue	349.28	49.47	-86%
Truck Tee–up (initial 30 mins)	n/a	125.03	n/a
Truck Tee–up (additional 15 mins)	n/a	51.38	n/a
Truck Tee–up (2 hour service)*	782.95	433.31	-45%

Source: AER analysis.
Note: * This two hour service fee is for comparative purposes as Aurora's proposed price is for a 2 hour truck visit. The AER's draft decision on prices for truck tee-up is on the basis of the time based fee structure.

Nuttall Consulting considered that Aurora's proposed prices for "tariff alteration single phase", "tariff alteration three phase" and "renewable energy connection" were reasonable.[1224] The AER agrees with Nuttall Consulting's conclusions and considers that Aurora's proposed prices for these three services are reasonable and efficient.

E.1.6 Historical price analysis

The AER's analysis of pricing trends for Aurora's fee based services indicated that prices for fee based services are both increasing and decreasing from current prices. This is the result of an adjustment to the basis of control mechanism for fee based services for the forthcoming regulatory control period. The current basis of control mechanism for fee based services allows Aurora to set and rebalance individual charges as long as they meet the notional maximum revenue for the reference set of fee based services. This allows for cross-subsidisation among the reference set of fee based services.[1225] Moving to a cost build-up basis of control is resulting in a rebalancing of individual charges leading to these varied price outcomes.

The AER notes that prices for services provided outside of standard business hours will increase significantly under Aurora's proposed pricing structure. This is because the prices now incorporate the

1223 Nuttall Consulting, *Aurora Revenue Review*, October 2011, p. 196.
1224 Nuttall Consulting, *Aurora Revenue Review*, October 2011, pp. 193–194.
1225 AER, *Framework and approach paper*, November 2010, p. 80.

minimum payment to workers required to work after hours.[1226] Whilst the price changes for these services are significant, only two per cent of the services Aurora provided in 2010–11 were provided outside of standard business hours. Therefore, the overall impact of these changes is small.

The other large price increases result from the allocation of overhead costs to fee based services which is the result of Aurora's new CAM.

Aurora proposed prices for ten late cancellation services and nine wasted visit services. The AER considers that these services are identical, regardless of what type of service they initially related to (i.e. Aurora should incur the same cost for the late cancellation of a site visit as for the late cancellation of a meter test). The descriptions of each fee based services provided by Aurora in response to an information request from the AER indicated that the tasks involved for late cancellations and wasted visits are identical regardless of what type of service the initial request related to.[1227]

Aurora's proposed prices for the late cancellation services and nine wasted visit services were not identical. The AER therefore considered the cost build-up for these services in detail. The AER also considered advice provided by Impaq Consulting for the Victorian distribution determination[1228] which included recommendations as to the reasonable amount of time required for individual services.

Wasted visits

Aurora's cost build-up for wasted services included time on site of 18 minutes. Impaq recommended that 10 minutes on site was appropriate.[1229] The AER accepted this recommendation in the Victorian distribution determination.[1230] The AER considers that on average, 10 minutes on site is sufficient to determine whether the requested service can be completed. The AER therefore adopted this time assumption for its build-up of Aurora's costs for wasted services. The AER calculated prices for each of Aurora's proposed wasted services. This has resulted in two different prices based on whether the initial service requested required one or two field staff. The AER's draft decision for price caps for wasted visits is in Table E.5.

[1226] Aurora's enterprise agreement requires field staff to be paid a minimum of 4 hours work for after hours fault work. Aurora Energy, *Regulatory proposal addendum*, June 2011, p. 48.

[1227] Aurora, *Fee_based_services_descriptions_for_2012-17_PD.doc*, provided as an attachment to Aurora, *Response to information request AER/027 of 17 August 2011*, received 25 August 2011.

[1228] Impaq Consulting, *Victorian Electricity Distribution Determination 2011 – Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010; Impaq Consulting, *Victorian Electricity Distribution Determination 2011 – Addendum to Review of Distributors Proposed Rates in ACS Charge*s, 31 August 2010.

[1229] Impaq Consulting, *Victorian Electricity Distribution Determination 2011 – Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010, p. 52.

[1230] AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, November 2010, p. 920.

Table E.5 AER draft decision on price caps for wasted visit services for 2012–13 ($nominal)

	Aurora proposed	AER draft decision	% difference between Aurora's proposal and AER draft decision
Meter alteration Wasted visit	113.48	91.33	-20%
Meter test – wasted visit	113.48	91.33	-20%
New connection – wasted visit	113.48	91.33	-20%
Supply abolishment – wasted visit	186.52	150.68	-19%
Renewable energy connection – wasted visit	88.35	150.68	71%
Temporary supply – wasted visit	186.52	150.68	-19%
Temporary supply (show & carnival connection) – wasted visit	186.52	150.68	-19%
Tee-up – wasted visit	186.52	150.68	-19%
Miscellaneous service – wasted visit	186.52	150.68	-19%

Source: AER analysis.

Late cancellations

Aurora defined late cancellation services as services where the request to cancel the service is received within one business day of the scheduled date. Aurora also indicated that the full charge for a site visit would apply for these services.[1231]

The AER considers that this fee is a penalty fee and does not reflect the cost to Aurora of a late cancellation. The AER considers that the cost incurred by Aurora for this service is for back office work to cancel the service. The AER considers that a late cancellation would not likely result in wasted time for field staff. The majority of late cancellations are for site visits.[1232] These services have no specific appointment time, only a scheduled day for the service. Therefore, where a late cancellation occurs, the field staff would skip the customer who cancelled the service and continue to the next customer for that day. This is unlikely to result in any lost or unproductive time for field staff. The AER therefore considers that Aurora does not incur a cost for field staff for a late cancellation.

The AER notes that the DNSPs in Victoria, New South Wales, Queensland and South Australia do not have charges for late cancellations of fee based services. The AER considers that this indicates that the costs incurred by a DNSP for late cancellations of services are insignificant. Therefore, the AER rejects Aurora's proposed time allocation for field staff for this service. The AER considers that there should be 0 minutes allocated to field staff for this service.

The AER considers that the costs for back office work for all fee based services is being recovered through the network services overhead costs allocated to fee based services. These overheads are

1231 Aurora, *Fee_based_services_descriptions_for_2012-17_PD.doc*, p. 2, provided as an attachment to Aurora, *Response to information request AER/027 of 17 August 2011*, received 25 August 2011.

1232 Less than 1% of Aurora's fee based services are late cancellations. Of these, the majority are for the late cancellation of a site visit. Source: Aurora, Fee based services model; AER analysis.

apportioned across all fee based services on the basis of labour hours. The AER notes that it would be more cost reflective to apportion back office costs to each service on the basis of actual cost incurred. However, Aurora has not provided sufficient information to do so.

The AER notes that having a time for field staff of 0 minutes results in no back office time being allocated to this service. However, the AER considers that this cost will still be recovered through the allocation of overheads costs to all fee based services.

The AER does not consider it appropriate for Aurora to earn a penalty rate for this service in excess of the cost it incurs. The AER therefore rejects Aurora's proposed fee for these services. The AER replaces Aurora's proposed fee for late cancellation services with $0.

E.2 Revisions

Revision E.1: The AER accepts Aurora's proposed approach to charge for materials at cost for fee based and quoted services. The AER rejects Aurora's proposed materials costs for the following fee based services and replaces it with $0:

- Site visit –credit action or site issues
- Renewable Energy Connection – after hours
- Temporary supply underground – single phase– temporary position
- Temporary Builders Connection – after hours.

Revision E.2: The AER rejects Aurora's proposed opex and capex forecasts for fee based services. The AER's draft decision on opex and capex forecasts for fee based services is shown in Table E.1 and Table E.2.

Revision E.3: The AER accepts the approach Aurora has taken to setting the price caps for fee based services. The AER rejects Aurora's proposed price caps. The AER's draft decision price caps for fee based services are shown in section E.3.

E.3 Prices

The AER's draft decision on prices for Aurora's fee based services is set out in Table E.6.

Table E.6 AER draft decision on fee based services prices ($nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17
De-energisation, re-energisation and special reads					
Site visit – no appointment	49.47	51.34	52.30	50.65	51.17
Site visit – non scheduled visit	114.85	116.09	117.06	112.10	112.54
Site visit – same day premium service	296.70	299.91	302.41	289.59	290.73
Site visit – after hours	765.68	773.96	780.41	747.33	750.27
Site visit – credit action or site issues	49.47	51.34	52.30	50.65	51.17
Site visit - rectification of illegal connection	228.33	241.86	243.88	233.54	234.46
Site visit - interval metering	57.43	58.05	58.53	56.05	56.27
Site visit - late cancellation	–	–	–	–	–
Transfer of retailer	–	–	–	–	–
Meter alteration					
Tariff alteration – single phase	167.45	177.37	178.84	171.26	171.94
Tariff alteration – three phase	228.33	241.86	243.88	233.54	234.46
Adjust time clock	54.80	58.05	58.53	56.05	56.27
Install pulse outputs	152.22	161.24	162.59	155.69	156.31
Remove meter	251.13	270.00	271.44	257.32	256.72
Meter alteration – after hours visit	730.67	773.96	780.41	747.33	750.27
Meter alteration - late cancellation	–	–	–	–	–
Meter alteration Wasted visit	91.33	96.75	97.55	93.42	93.78
Meter test					
Meter test – single phase	274.00	290.24	292.65	280.25	281.35
Meter test – multi phase	548.00	580.47	585.31	560.50	562.70
Meter test – CT	608.89	644.97	650.34	622.77	625.22
Meter test – after hours	730.67	773.96	780.41	747.33	750.27
Meter test – late cancellation	–	–	–	–	–

Meter test – wasted visit	91.33	96.75	97.55	93.42	93.78
Supply establishment					
New connection – after hours	730.67	773.96	780.41	747.33	750.27
Install additional service span - single phase	411.48	438.70	444.22	429.53	430.78
Install additional service span - single phase - additional spans	311.03	330.70	335.64	326.60	328.09
Install additional service span - multi phase	586.47	624.32	632.98	614.17	616.52
Install additional service span - multi phase - additional spans	486.01	516.33	524.40	511.25	513.83
New connection - late cancellation	–	–	–	–	–
New connection – wasted visit	91.33	96.75	97.55	93.42	93.78
Supply abolishment					
Remove service & meters	251.13	270.00	271.44	257.32	256.72
Supply abolishment – after hours	730.67	773.96	780.41	747.33	750.27
Supply abolishment – late cancellation	–	–	–	–	–
Supply abolishment – wasted visit	150.68	162.00	162.87	154.39	154.03
Renewable energy connection					
Renewable energy connection	167.45	177.37	178.84	171.26	171.94
Renewable energy connection – after hours	1,305.87	1,403.99	1,411.50	1,338.04	1,334.96
Renewable energy connection – wasted visit	150.68	162.00	162.87	154.39	154.03
Renewable energy connection – late cancellation	–	–	–	–	–
Temporary builders connection					
Temporary supply underground – single phase - temporary position	182.67	193.49	195.10	186.83	187.57
Temporary supply underground – three phase - temporary position	281.67	296.61	301.62	295.38	297.89
Temporary supply underground – single phase - permanent position	281.67	296.61	301.62	295.38	297.89
Temporary supply underground – three phase - permanent position	281.67	296.61	301.62	295.38	297.89
Temporary supply overhead – single phase - temporary position	511.93	546.70	552.79	532.46	533.47
Temporary supply overhead – three phase - temporary position	686.92	732.32	741.56	717.10	719.21

Temporary supply overhead – single phase - permanent position	511.93	546.70	552.79	532.46	533.47
Temporary supply overhead – three phase - permanent position	686.92	732.32	741.56	717.10	719.21
Temporary supply – after hours	1,305.87	1,403.99	1,411.50	1,338.04	1,334.96
Temporary supply – Late cancellation	–	–	–	–	–
Temporary supply – wasted visit	150.68	162.00	162.87	154.39	154.03
Temporary show & carnival connection					
Temporary supply – underground	304.45	322.48	325.17	311.39	312.61
Temporary supply – overhead mains	390.59	413.35	419.49	407.30	409.32
Temporary supply – overhead service	789.31	846.86	854.36	816.40	815.53
Temporary supply – after hours	730.67	773.96	780.41	747.33	750.27
Temporary supply – late cancellation	–	–	–	–	–
Temporary supply – wasted visit	150.68	162.00	162.87	154.39	154.03
Truck tee-up					
Tee-up (initial 30 mins)	125.03	128.31	131.67	135.12	138.66
Tee-up (additional 15 min block)	51.38	52.73	54.11	55.53	56.98
Tee-up – after hours	1,369.92	1,467.33	1,479.91	1,415.49	1,415.57
Tee-up – no truck – after hours	1,205.42	1,295.99	1,302.92	1,235.12	1,232.27
Tee-up – late cancellation	–	–	–	–	–
Tee-up – wasted visit	150.68	162.00	162.87	154.39	154.03
Open turret	137.00	145.12	146.33	140.12	140.68
Addition/alteration to connection point	304.45	322.48	325.17	311.39	312.61
Connection of new mains to existing installation	213.11	225.74	227.62	217.97	218.83
Data download	304.45	322.48	325.17	311.39	312.61
Alteration to unmetered supply	228.33	241.86	243.88	233.54	234.46
Miscellaneous service	121.78	128.99	130.07	124.55	125.04
Miscellaneous service – after hours	730.67	773.96	780.41	747.33	750.27
Miscellaneous service – late cancellation	–	–	–	–	–
Miscellaneous service – wasted visit	150.68	162.00	162.87	154.39	154.03

Source: AER analysis.
Note: These prices exclude GST.

The AER's draft decision on the charge out rates for labour for Aurora's quoted services is set out in Table E.7.

Table E.7 AER draft decision for price caps for labour charge-out rates for quoted services (nominal)

	2012–13	2013–14	2014–15	2015–16	2016–17
Apprentice	79.11	75.93	73.32	71.14	73.63
Cable Joiner	60.84	60.67	60.82	60.63	60.45
CC Commercial Metering	68.23	68.02	67.87	67.77	67.72
CC Service Crew	61.43	61.25	61.13	61.05	61.01
Designer	76.43	76.30	76.24	76.24	76.30
Distribution Electrical Technician	61.20	61.03	60.87	60.75	60.67
Distribution Linesman	55.93	55.77	55.66	55.59	55.56
Distribution Linesman LL	61.00	60.83	60.70	60.61	60.56
Distribution Operator	66.05	65.56	65.66	66.13	65.76
Electrical Inspectors	65.13	65.03	65.13	64.81	65.04
Field Service Co-ordinator	85.33	85.01	85.12	84.36	84.11
Labourer OH	51.41	51.27	51.28	51.35	51.39
Meter Reader	46.84	46.80	46.76	46.78	46.85
Pole Tester	51.08	51.00	50.97	50.99	51.05
Project Manager	76.58	76.36	77.27	77.17	76.87

Source: AER analysis.

F Assigning customers to tariff classes

The AER is required to decide on the principles governing assignment or reassignment of customers to tariff classes.[1233] 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:[1234]

- 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:[1235]

1233 NER, Clause 6.12.1(17).
1234 Aurora, *Regulatory proposal,* May 2011, p. 230.
1235 NER, Clause 6.18.4(a)(i).

a. the nature and extent of the customer's usage

b. the nature of the customer's connection to the network[1236]

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[1237]

   b. customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.[1238]

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

[1236] The AER interprets 'nature' to include the installation of any technology capable of supporting time based tariffs.
[1237] NER, Clause 6.18.4(2).
[1238] NER, Clause 6.18.4(3).

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 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.

G Submissions

The AER received four submissions on Aurora's regulatory proposal from the following interested parties:

- Energy Users Association of Australia (EUAA) – received 12 August 2011
- The Tasmanian Council of Social Service (TasCOSS) – received 12 August 2011
- DA consulting – received 12 August 2011
- Transend Networks Pty Ltd (Transend) – received 28 October 2011.

The AER has not considered Transend's submission in making its draft distribution determination because the AER received it too late in the review process. The AER will consider Transend's submission in making its final determination. The AER has published the submissions on its website (www.aer.gov.au).