Final

Framework and approach paper

Aurora Energy Pty Ltd

Regulatory control period commencing 1 July 2012

29 November 2010

AUSTRALIAN ENERGY REGULATOR

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Contents

Summary

Aurora Energy Pty Ltd (Aurora) operates as the distribution network service provider (DNSP) in mainland Tasmania. The electricity distribution systems on King and Flinders islands are owned by Hydro Tasmania and are not part of the inter-connected Tasmanian power system or the National Electricity Market (NEM). Aurora operates the King and Flinders island systems under an agreement with Hydro Tasmania.

The process that the AER must follow in making a distribution determination for mainland Tasmania for the next regulatory control period, commencing on 1 July 2012, will take place over the final two years of the current regulatory control period.

The AER's functions and powers are set out in the National Electricity Law (NEL) and the National Electricity Rules (NER).

In anticipation of every distribution determination, the AER is required to prepare and publish a framework and approach paper. The framework and approach paper assists a DNSP in preparing its regulatory proposal to the AER by:

- setting out the AER's likely approach (and its reasons for that likely approach) in the distribution determination to the classification of distribution services,
- stating the form (or forms) of the control mechanisms to be applied by the distribution determination and the AER's reasons for deciding on control mechanisms of the relevant form (or forms)
- providing a statement of the AER's likely approach to cost allocation based on the guidelines currently in force
- the application of schemes, and any other matters on which the AER thinks fit to give an indication of its likely approach.

The AER's likely approach to service classification, form of control and cost allocation is summarised in the sections below and discussed in detail in the chapters that follow.

Classification of services

In classifying distribution services the NER require that the AER must act on the basis that (unless a different classification is clearly more appropriate):

- there should be no departure from a previous classification (if the services have been previously classified), or
- if there has been no previous classification—the classification should be consistent with the previously applicable regulatory approach.[1]

The AER's likely approach is to classify:

[1] NER, cll. 6.2.1(d) and 6.2.2(d).

- certain declared distribution network services currently provided by Aurora as standard control services, with all of these services being grouped as network services
- connection services (excluding customer contributions) currently provided by Aurora as standard control services
- certain metering services, public lighting services (previously unregulated), fixed fee special distribution services and quoted services currently provided by Aurora as alternative control services, with these services categorised in the following way:
  - metering services
  - public lighting services (except new public lighting technology services)
  - fee based services
  - quoted services
- new public lighting technology services will likely be classified as negotiated distribution services

The AER's likely approach is not to classify certain other distribution services for the purposes of chapter 6 of the NER. This includes:

- pay-as-you-go (PAYG) metering services provided by Aurora Retail

Customer contributions for connections will remain unregulated. However, two bills have recently been introduced into South Australian parliament, which are part of the National Energy Customer Framework (NECF) package of bills.[2] The NECF will include an accessible framework for customers to arrange new connections to connect to electricity networks.[3]

Control mechanisms

The AER's approach is to apply a revenue cap form of control to Aurora's standard control services and connection services. Aurora's connection augmentation costs will also be recovered under a revenue cap, but the AER is not permitted under the NER to regulate the customer contributions component.

The AER's approach is to apply a price cap form of control to the services the AER is likely to classify as alternative control services. In particular, the AER's likely approach is to:

- continue a price cap for metering services, and for the reference set of special services

2 Ministerial Council on Energy, Standing Committee of Officials Bulletin No. 185, 5 November 2010.

3 Ministerial Council on Energy, Communiqué—23rd meeting of the MCE, Melbourne, 11 June 2010.

- incorporate other special services into the price cap form of control for the reference set of special services
- establish a price cap form of control on unit rates for quoted services
- establish a price cap control mechanism for public lighting services except for new technology public lighting services.

This paper does not deal with the form of control for negotiated distribution services that are regulated under the negotiate/arbitrate framework set out in Part D of chapter 6 of the NER. That is, under the NER negotiated distribution services are not subject to a specified form of control such as a price or revenue cap. DNSPs will negotiate with users in accordance with a negotiating framework approved by the AER, and negotiated distribution service criteria determined by the AER.[4] In the event of a dispute, the AER will arbitrate in accordance with the same criteria and with regard to the approved framework.[5]

Application of efficiency benefit sharing scheme

The AER's distribution efficiency benefit sharing scheme (EBSS) was released on 26 June 2008. Although Aurora is not currently subject to an EBSS, the AER's preliminary position is that the AER's EBSS will be applied to Aurora in the forthcoming regulatory control period. However, the scheme will not have a direct financial impact until the 2017–18 to 2021–22 regulatory control period, when Aurora will receive carryover benefits or penalties for efficiency gains or losses realised during the forthcoming regulatory control period.

The EBSS has been designed to provide an incentive for a DNSP to reveal its efficient level of expenditure through the retention of efficiency gains for five years after the year in which the gain is made. The scheme calculates revenue increments or decrements derived from the difference between a DNSP's actual operating expenditure and the forecast operating expenditure approved in its building block determination. It is these increments or decrements that provide for the fair sharing of gains and losses between a DNSP and network users.

The EBSS is symmetrical in nature, which allows a DNSP to retain the benefits of an efficiency gain (or bear the costs of an efficiency loss) for the length of the carryover period, regardless of the year of the regulatory control period in which the gain/loss was realised.

The nominal five-year carryover period assumed in the AER's EBSS results in a benefit-sharing ratio of approximately 30:70 between a DNSP and its customers.[6] This means that a DNSP will retain approximately 30 per cent of the benefits of efficiency gains and customers will retain approximately 70 per cent of the benefits.

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4 NER, cl. 6.7.2.

5 NER, cl. 6.22.2(c).

6 The EBSS assumes a nominal carryover period of five years, but allows a longer carryover period where the regulatory control period covered by the relevant distribution determination is longer than five years. The carryover period will not exceed 10 years. A 10-year carryover period results in a sharing ratio of approximately 50:50.

Carryover amounts are included as a building block element in the calculation of allowed revenue for the regulatory control period following the period in which the EBSS was applied.

Application of service target performance incentive scheme

The AER's distribution service target performance incentive scheme (STPIS) was released on 26 June 2008. The AER's likely approach is to apply a STPIS to Aurora, but to use the network segments developed by the Office of the Tasmanian Economic Regulator (OTTER) as they better reflect the reliability expectations of consumers.

The STPIS scheme states that the guaranteed service level (GSL) component of the STPIS will not apply where an existing jurisdictional GSL scheme applies. Under the Tasmanian Electricity Code (TEC) a GSL scheme currently exists. The TEC is currently managed by OTTER. OTTER has provisionally indicated in its submission that it intends to continue the application of the TEC GSL scheme in the forthcoming control period. As a result the GSL component of the STPIS will not apply to Aurora in forthcoming regulatory control period. The AER's likely approach is to apply the SAIDI and SAIFI s-factor parameters, and the call answering customer service parameter.

Application of demand management incentive scheme

This paper sets out the AER's likely approach on the application of a proposed demand management incentive scheme (DMIS) to Aurora for the forthcoming regulatory control period.

The AER proposes to apply a DMIS in the form of a demand management innovation allowance (DMIA) to Aurora. The AER's likely approach is to provide Aurora with a DMIA allowance of $400 000 on an annual basis.

The AER considers that this allowance will enable Aurora to carry out a number of small-scale demand management projects, or a single larger-scale demand management project during the regulatory control period. Under the AER's proposal, a total of $2 million would be allowed as DMIA expenditure by Aurora over the next regulatory control period.

The AER's likely approach is to apply a revenue cap to Aurora's standard control services. As revenue is not dependent on throughput, the AER considers that a forgone revenue component for the DMIA is not necessary.

Other matters

The AER must include in its framework and approach paper for Aurora a statement of its likely approach to cost allocation based on the guidelines then in force.

In accordance with clause 6.15.3 of the NER, the AER released cost allocation guidelines on 26 June 2008.[7]

Clause 6.15.4(b) of the NER stipulates that electricity distribution businesses must submit a Cost Allocation Method (CAM) to the AER six months after the commencement of the rules. Aurora submitted a CAM to the AER in December 2008. The AER approved Aurora's cost allocation method in June 2009.

Aurora's CAM will not be used to allocate actual costs until the forthcoming regulatory control period, however costs forecast for Aurora's forthcoming regulatory control period must be allocated in accordance with the CAM.

Clause 6.8.1(ca) of the NER requires that the framework and approach paper must include the AER's determination under clause 6.25(b) as to whether or not Part J of Chapter 6A is to be applied to determine the pricing of any transmission standard control services provided by any dual function assets owned, controlled or operated by Aurora. Aurora has advised the AER that it does not own any dual function assets.[8]

Next steps

This framework and approach paper completes the first stage of consultation on the distribution determination for Aurora for the next regulatory control period.

The next steps in the determination process are summarised in the table below:

Aurora to submit regulatory proposal to the AER	30 May 2011
AER to publish draft decision on distribution determination for Aurora	November 2011*
AER to publish final decision and distribution determination for Aurora	30 April 2012
Aurora to submit initial pricing proposal for AER approval	Mid May 2012
AER to publish approved pricing proposal	Mid June 2012
Distribution determination and approved pricing proposal to commence	1 July 2012

* The NER do not provide specific timeframes in relation to publishing the draft decision. Accordingly, this date is indicative only.

7 AER, *Electricity distribution network service providers—Cost allocation guidelines*, June 2008.
8 Aurora, *Information paper for AER: services, classifications and control mechanisms—Framework and approach process*, May 2010, p. 9.

1 Introduction

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

Under chapter 6 of the NER, the AER is able to make a decision to classify or not classify distribution services to be provided by a distribution network service provider (DNSP) and how they should be regulated, and must make distribution determinations for each DNSP.

Aurora Energy Pty Ltd (Aurora) operates as the DNSP on mainland Tasmania. The provision of distribution services by Aurora are currently regulated by the Office of the Tasmanian Economic Regulator (OTTER).[9] In January 2007, OTTER released a statement of reasons for the declaration of electricity supply services, consistent with the requirements of the Electricity Supply Industry (Price Control) Regulations 2003 (price control regulations) and the Tasmanian Electricity Code 1995 (TEC). This statement of reasons applies to Aurora for the regulatory control period 1 January 2008 to 30 June 2012.

The procedure to be followed by the AER in making a distribution determination is set out in Part E of chapter 6 of the NER. The first step in making a distribution determination is the preparation and publication of a framework and approach paper.

For the Aurora, this step in the process commenced on 25 June 2010 with the publication of the AER's preliminary positions on the framework and approach and is completed with the publication of this paper.

The AER received 7 submissions on its preliminary positions paper. Stakeholders that provided submissions on the preliminary positions paper are listed at Appendix B of this paper.

1.1 Nature of the framework and approach paper

In anticipation of every distribution determination, the AER is required to prepare and publish a framework and approach paper. The framework and approach paper assists DNSPs in preparing their regulatory proposals to the AER by:

- stating the form (or forms) of the control mechanisms to be applied in the distribution determination and the AER's reasons for deciding on the form of control[10]
- setting out the AER's likely approach (and its reasons for that likely approach) in the distribution determination to:
  1. the classification of distribution services
  2. the application of a service target performance incentive scheme (STPIS) or schemes

[9] Formerly the Office of the Tasmanian Energy Regulator.
[10] NER, cl. 6.8.1(c).

3. the application of an efficiency benefit sharing scheme (EBSS) or schemes
4. the application of a demand management incentive scheme (DMIS) or schemes, and
5. any other matters on which the AER thinks fit to give an indication of its likely approach[11]

- providing a statement of the AER's likely approach to cost allocation based on the guidelines currently in force.[12]

- a determination as to whether or not Part J of Chapter 6A is to be applied to determine the pricing of any transmission standard control services provided by any dual function assets owned, controlled or operated by Aurora.[13] If a DNSP owns, controls or operates dual function assets, it must advise the AER of the value of those assets 24 months prior to the end of the current regulatory control period to enable such a determination.[14] Aurora has advised the AER that it does not own any dual function assets.

The control mechanisms applied in the distribution determination must be as set out in the framework and approach paper.

In all other respects, the framework and approach paper is not binding on the AER or DNSPs, however:

- the classification of services in a distribution determination must be as set out in the framework and approach paper unless the AER considers that, in light of a DNSP's regulatory proposal and any submissions received in the determination process, there are good reasons for departing from the classification proposed in that paper

- where, in respect to classification of services or any other matter, a DNSP's regulatory proposal puts forward an approach different to that set out in the framework and approach paper, the AER will expect to see a fully supported argument explaining the difference in approach, and detailing how circumstances have changed such that a different approach would be more appropriate and necessary to satisfy the requirements of the NEL and NER.

The procedure to be followed by the AER in making a distribution determination is set out in chapter 6, Part E of the NER, and summarised in Table 1.1.

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11 NER, cl. 6.8.1(b).

12 NER, cl. 6.15.4(b).

13 NER, cl. 6.8.1(ca). A dual function asset means any part of a network owned, operated or controlled by a Distribution Network Service Provider which operates between 66 kV and 220 kV and which operates in parallel, and provides support, to the higher voltage transmission network which is deemed by clause 6.24.2(a) to be a dual function asset. For the avoidance of doubt:
(a) a dual function asset can only be an asset which forms part of a network that is predominantly a distribution network; and
(b) an asset which forms part of a network which is predominantly a transmission network cannot be characterised as a dual function asset, through the operation of clause 6.24.2(a).

14 NER, cl. 6.25.

Table 1.1 Procedures for making a distribution determination

1	**AER's framework and approach paper**	
	AER published preliminary positions paper for its framework and approach paper for Aurora	25 June 2010
	AER to publish framework and approach paper for Aurora	29 November 2010
2	**Regulatory proposal and distribution determination**	
	Aurora to submit regulatory proposal to the AER	30 May 2011
	AER to publish draft decision on distribution determination for Aurora	November 2011*
	AER to publish final decision and distribution determination for Aurora	30 April 2012
	Aurora to submit initial pricing proposals for AER approval	Mid May 2012
	AER to publish approved pricing proposal	Mid June 2012
	Distribution determination and approved pricing proposal to commence	**1 July 2012**

* The NER do not provide specific timeframes in relation to publishing the draft decision. Accordingly, this date is indicative only.

This framework and approach paper sets out the likely framework and approach for the AER's distribution determination for Aurora for the regulatory control period commencing 1 July 2012.

1.2 Components of the framework and approach paper

The detailed requirements guiding the AER's decision on each component of the framework and approach paper are discussed in the chapters that follow. To provide context to those chapters, this section outlines the relationships between the various components of the framework and approach paper.

The first issues to be addressed in the framework and approach paper are the AER's likely approach to classification of distribution services provided by Aurora and the control mechanism(s) that will apply to each class of services.

Service classification occurs at two levels:

1. the AER may choose to classify a distribution service as:
    i. a direct control service, or
    ii. a negotiated distribution service.[15]

The AER may also decide against classifying a distribution service. If the AER decides against classifying a distribution service, clause 6.2.1 of the NER provides that the service is not regulated under the NER.

2. where the AER classifies a distribution service as a direct control service it must further classify it as either:

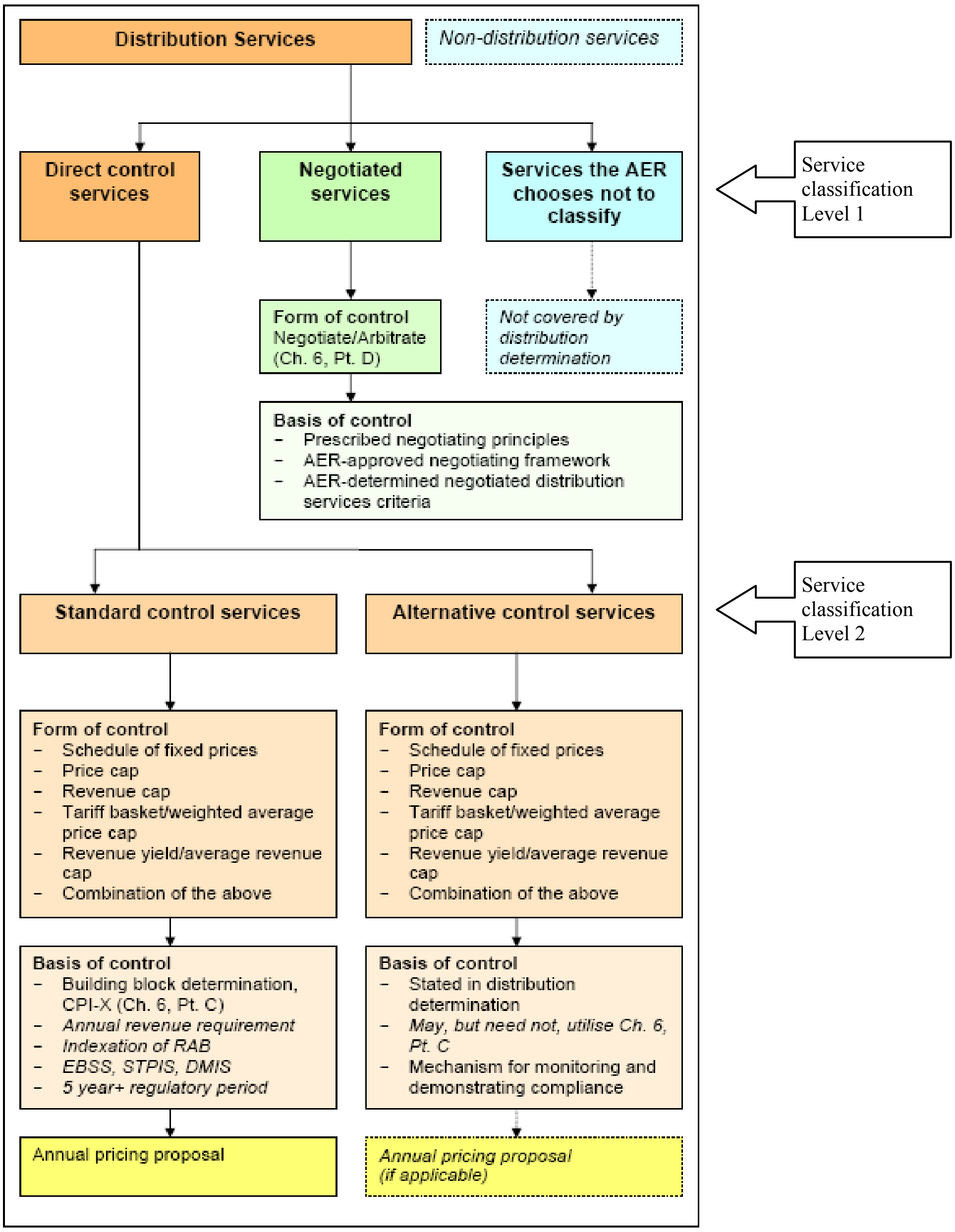
[15] NER, cl. 6.2.1(a).

i. a standard control service, or

ii. an alternative control service.[16]

The classification to which a service is assigned determines what control mechanism(s) can be applied to that service and what the basis for that control mechanism will be, and therefore how the service and costs associated with providing it are treated in a distribution determination. This is illustrated in Figure 1.1 below.

Figure 1.1 Service classification and control mechanisms



Source: NER, chapter 6.

Distribution services that are not classified will not be subject to the framework for economic regulation of distribution services in chapter 6 of the NER.[17] In addition, non-distribution services cannot be regulated under the NER.

[16] NER, cl. 6.2.2(a).

Terms and conditions of access to negotiated distribution services, including the price of those services, will be determined under the negotiate/arbitrate framework set out in Part D of chapter 6 of the NER. DNSPs will negotiate with users in accordance with a negotiating framework approved by the AER, and negotiated distribution service criteria determined by the AER.[18] In the event of a dispute, the AER will arbitrate in accordance with these criteria and with regard to the approved framework.[19]

The distribution determination must impose a control on the price of, and/or revenue derived from, direct control services.[20] The control mechanism may consist of:

1. a schedule of fixed prices
2. caps on the prices of individual services
3. caps on the revenue to be derived from a particular combination of services
4. tariff basket price control
5. revenue yield control
6. a combination of any of the above.[21]

For standard control services, the control mechanism must be of the prospective CPI minus X (CPI–X) form or an incentive-based variant. The basis of the control mechanism must be a building block determination made in accordance with Part C of chapter 6 of the NER.[22] The AER's distribution determination must include a decision on how compliance with the relevant control mechanism is to be demonstrated.[23]

The basis of the control mechanism for alternative control services may, but need not, be a building block determination, and can utilise elements of Part C of chapter 6 of the NER with or without modification.[24] The distribution determination must state the basis for the control mechanism applied to any alternative control services,[25] and must include a decision on how compliance with the control mechanism is to be demonstrated.[26]

For all direct control services, an annual pricing proposal must be submitted to, and approved by, the AER under Part I of chapter 6 of the NER.[27]

The incentive schemes developed by the AER under chapter 6 of the NER apply only to standard control services.[28]

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17 NER, cl. 6.2.1(a).
18 NER, cl. 6.7.2.
19 NER, cl. 6.22.2(c).
20 NER, cl. 6.2.5(a).
21 NER, cl. 6.2.5(b).
22 NER, cl. 6.2.5(a).
23 NER, cl. 6.12.1(13).
24 NER, cl. 6.2.6(c).
25 NER, cl. 6.2.6(b).
26 NER, cl. 6.12.1(13).
27 NER, cl. 6.18.2(a).
28 NER, cll. 6.5.8, 6.6.2 and 6.6.3.

As noted previously, the framework and approach paper for Aurora must also include a statement of the AER's likely approach to cost allocation based on the guidelines then in force and a determination in relation to any dual function assets owned, controlled or operated by Aurora.

1.3 Continuity between regulatory control periods

The AER recognises that the transition to the new national framework for the economic regulation of distribution services has the potential to impose administrative costs on Aurora, and to create short-term uncertainty for Aurora, its customers, and end-users. This is recognised in transitional provisions in the NER and in the jurisdictional legislation that applies, as well as in jurisdictional derogations in chapter 9 of the NER.

The AER has sought to minimise the impact of the transition to the new economic regulatory framework, both in regards to changes to current arrangements necessitated by the new requirements of the NEL and the NER, and in coordinating the AER's regulatory functions with those retained by jurisdictional regulators. The framework and approach paper is a key means by which greater certainty can be provided on how the new regulatory framework will apply to DNSPs.

1.4 Structure of this paper

This paper sets out the AER's likely framework and approach for Aurora for the regulatory control period commencing 1 July 2012:

- chapter 2 sets out the likely approach to the classification of distribution services
- chapter 3 states the form (or forms) of the control mechanisms to be applied to each class of services by the distribution determination
- chapter 4 sets out the likely approach to the application of the STPIS
- chapter 5 sets out the likely approach to the application of the EBSS
- chapter 6 sets out the likely approach to the application of the DMIS
- chapter 7 sets out the likely approach to a range of other issues, including cost allocation and dual function assets based on the guidelines currently in force.

2 Classification of distribution services

2.1 Introduction

This chapter sets out the AER's likely approach to the classification of Aurora's distribution services for the next regulatory control period. The AER may classify the distribution services as either direct control services or negotiated distribution services. The AER must further classify direct control services as either standard control services or alternative control services. Services not classified by the AER are not regulated under the NER.

Service classification effectively determines two key aspects of the distribution determination:

- whether the service should be under a direct price or revenue control, a 'negotiate-arbitrate' framework, or no price or revenue control—that is, the form of control that will apply to the service,[29]

- whether the costs of providing the service should be recovered by Aurora through distribution use of system (DUOS) tariffs paid by most customers, or through separate tariffs paid by the individual customer requesting the service.[30]

The AER's role in service classification only determines the manner in which a DNSP recovers the costs associated with the distribution services it provides—it does not determine the contestability of these services.[31] For example, the AER's classification of a distribution service as a direct control service does not make Aurora the exclusive monopoly provider of the service. Likewise, the AER's classification of a distribution service as a negotiated distribution service does not, of itself, make the service contestable and open to supply by providers other than Aurora. Contestability is determined by legislation, or other regulatory instruments, and is beyond the control of the AER. Contestability is, however, relevant to the AER's consideration of the form of regulation factors that the AER must consider in classifying services under section 2F of the NEL.[32]

29 The forms of control available for each service depend on the classification. The forms of control available for direct control services are listed under clause 6.2.5(b) of the NER and include revenue caps, average revenue caps, price caps, weighted average price caps, a schedule of fixed prices or a combination of the specified forms of control. Negotiated distribution services are regulated under the 'negotiate-arbitrate' framework set out in Part D of chapter 6 of the NER. The forms of control are discussed in greater detail in chapter 3 of this paper.

30 In general, the costs of providing standard control services would be expected to be recovered through DUOS tariffs paid by all or most customers, whereas the costs of providing alternative control or negotiated distribution services would be expected to be recovered from the individual customers who are the recipients of such services.

31 Contestability concerns whether or not a service is permitted by the laws or other regulatory instruments of the relevant jurisdiction to be provided by a party other than the DNSP.

32 NER, cl. 6.2.1(c).

2.2 Regulatory requirements

A distribution determination must include a decision on the classification of the distribution services to be provided by the DNSP during the course of the relevant regulatory control period.[33] Only services within the definition of 'distribution services' in chapter 10 of the NER can be classified. The classification forms part of the distribution determination and operates only for the period for which the determination is made.[34] In the framework and approach paper, the AER must set out its likely approach to the classification of distribution services in a DNSP's forthcoming distribution determination, and its reasons for that approach.[35] If the AER decides against classifying a distribution service, the service is not regulated under the NER.[36]

The classification of services in the distribution determination must be as set out in this framework and approach paper unless the AER considers that, in light of the DNSP's regulatory proposal and submissions received, there are good reasons for departing from the classification.[37]

Distribution services may be grouped together for the purpose of classification. That is, distribution services may be grouped as direct control services or negotiated distribution services.[38] Similarly, direct control services may be grouped as standard control services or alternative control services.[39] In each case, a single classification applies to each service in the group.

Where the NER require that a particular classification be assigned to a specified kind of distribution service, the service is to be classified in accordance with that requirement.[40] In all other cases, the factors that will guide the AER's decision on service classification are discussed in the sections that follow. In classifying services that have previously been subject to regulation under the present or earlier legislation, clauses 6.2.1(d) and 6.2.2(d) of the NER state that the AER must act on the basis that, unless a different classification is clearly more appropriate:

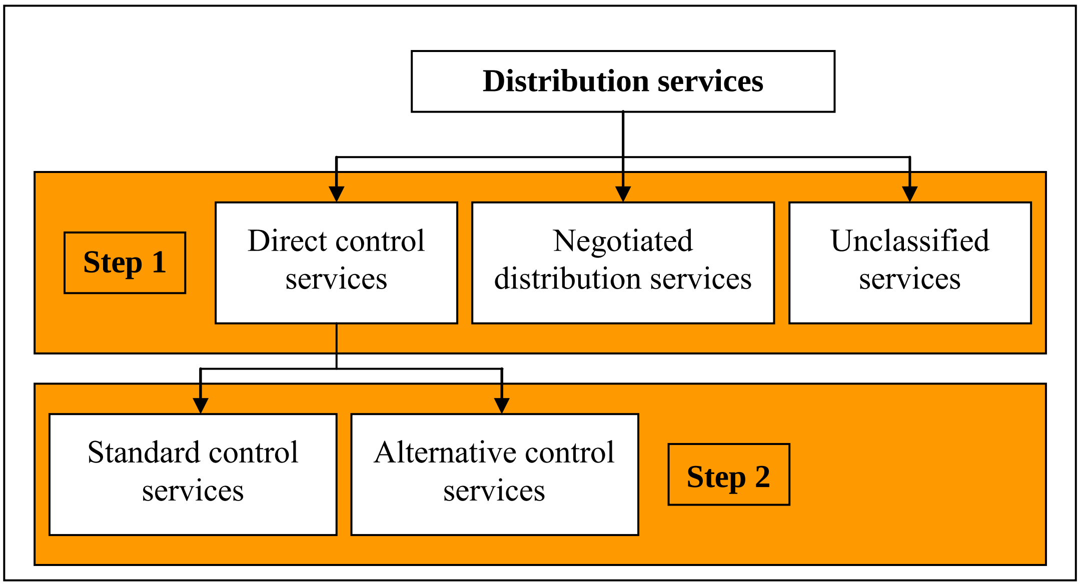
- there should be no departure from a previous classification (if the services have been previously classified), or
- if there has been no previous classification, the classification should be consistent with the previously applicable regulatory approach.[41]

Aurora's current service classifications are listed in Table 2.1 of this paper.

Figure 2.1 below outlines the steps in the distribution service classification process.

33 NER, cl. 6.12.1(1).
34 NER, cl. 6.2.3.
35 NER, cl. 6.8.1(b)(1).
36 Refer note at NER, cl. 6.2.1.
37 NER, cl. 6.12.3(b).
38 NER, cl. 6.2.1(b).
39 NER, cl. 6.2.2(b).
40 NER, cll. 6.2.1(e) and 6.2.2(e).
41 NER, cll. 6.2.1(d) and 6.2.2(d).

Figure 2.1 Distribution service classification process



Source: NER, chapter 6, part B.

2.2.1 Step 1: Division of distribution services into direct control, negotiated distribution and unregulated services

When classifying distribution services as either direct control services or negotiated distribution services, the AER must have regard to all of the four factors in clause 6.2.1(c) of the NER:

1) the form of regulation factors. These factors are specified in section 2F of the NEL:

   (a) the presence and extent of any barriers to entry in a market for electricity network services

   (b) the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other electricity network service provided by the network service provider

   (c) the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other service provided by the network service provider in any other market

   (d) the extent to which any market power possessed by a network service provider is, or is likely to be, mitigated by any countervailing market power possessed by a network service user or prospective network service user

   (e) the presence and extent of any substitute, and the elasticity of demand, in a market for an electricity network service in which a network service provider provides that service

   (f) the presence and extent of any substitute for, and the elasticity of demand in a market for, elasticity or gas (as the case may be), and

(g) the extent to which there is information available to a prospective network service user or network service user, and whether that information is adequate, to enable the prospective network service user or network service user to negotiate on an informed basis with a network service provider for the provision of an electricity network service to them by the network service provider.[42]

2) the form of regulation (if any) previously applicable to the relevant service or services and, in particular, any previous classification under the present system of classification or under the present regulatory system (as the case requires)
3) the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction), and
4) any other relevant factor.[43]

As mentioned above, in classifying distribution services that have previously been subject to regulation under the present or earlier legislation, the AER must also follow the requirements of clause 6.2.1(d).

2.2.2 Step 2: Division of direct control services into standard control and alternative control services

In classifying direct control services as either standard control services or alternative control services, the AER must have regard to all of the six factors in clause 6.2.2(c) of the NER:

1) the potential for development of competition in the relevant market and how the classification might influence that potential
2) the possible effects of the classification on administrative costs of the AER, the DNSP and users or potential users
3) the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made
4) the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)
5) the extent that costs of providing the relevant service are directly attributable to the customer to whom the service is provided, and
6) any other relevant factor.[44]

As mentioned above, in classifying direct control services that have previously been subject to regulation under the present or earlier legislation, the AER must also follow the requirements of clause 6.2.2(d).

2.3 Overview of current service classification arrangements in Tasmania

The *Electricity Supply Industry Act 1995* (ESI Act) was established in 1995 and is the principal Act governing the operation of the electricity supply industry in Tasmania.

[42] NEL, s. 2F.
[43] NER, cl. 6.2.1(c).
[44] NER, cl. 6.2.2(c).

Among other things, the ESI Act establishes OTTER's role as the economic regulator and provides OTTER with the role of administering the *Tasmanian Electricity Code* (TEC).

OTTER's obligations under the *Electricity Supply Industry (Price Control) Regulations 2003* (price control regulations) and the TEC form the basis of the framework in which pricing investigations and determinations must be conducted.

Regulation 19(2) of the price control regulations require that 'declared' services be subject to price regulation by OTTER. The price control regulations provide that OTTER can declare electricity distribution services if it is of the opinion that:

- the electricity entity has substantial market power in respect of that good or service
- the promotion of competition, efficiency or the public interest requires the making of the declaration.

Regulation 23(2) of the price control regulations also requires that OTTER, no later than six months before the expiration of a pricing determination, release a Declaration of Services issues paper inviting submissions on whether the existing declaration of current declared distribution services should be revoked.

The most recent Declaration of Services issues paper was released by OTTER in November 2006. OTTER considered submissions on the 2006 issues paper and finalised its views on the scope of the declaration in a Statement of Reasons paper, released in January 2007. In the 2007 Statement of Reasons paper, OTTER determined to retain (with amendments), the declaration of services that were subject of the 2006 issues paper. The current 'declared' services that apply to Aurora for the regulatory control period, 1 January 2008 to 30 June 2012 are discussed below.

2.3.1 Distribution services

In January 2007, OTTER determined the following services would be 'declared' services in accordance with the price control regulations for the purpose of determining maximum prices that would apply from 1 January 2008:

Distribution services encompassing:

- distribution network services
- metering services
- special services.[45]

Each of the three different elements of the distribution service is regulated in a different way.

[45] OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania—Final Report and Proposed Maximum Prices,* September 2007, p. v (OTTER, *Final report*, Sep 2007).

2.3.1.1 Distribution network services

OTTER defined distribution network services as follows:[46]

> Distribution network services, provided by Aurora Energy Pty Ltd, as the distribution network service provider, being the conveyance of electricity (from the connection point with the transmission system to the customer connection point including entry services, use of system services and exit services, excluding any connection assets owned and maintained by the customer) including:
>
> (a) the undertaking of works or the provision of maintenance or repairs for the purposes of carrying out conveyance of electricity; and
>
> (b) the provision, installation and maintenance or repairs of any, switchgear or other electrical plant essential to the transportation and delivery of electricity

This definition covers most 'standard' network services, and these services are currently regulated under a revenue cap.

2.3.1.2 Metering services

OTTER defined metering services as:[47]

> Metering services, being the provision, installation and maintenance of any Type 5, 6 or 7 meter and related meter data capture provided by Aurora Energy Pty Ltd, excluding the provision of integrated prepayment meters and the provision of metering to a standard in excess of that required for the billing of customer services, but including special meter readings and meter testing of Type 5, 6 or 7 meters.

Metering services are confined to the meter and do not include other connection assets such as current and voltage transformers, which are included within the definition of distribution network services under 'special services'.[48] They also do not include the special meters owned and operated by Aurora Retail to provide the 'pay as you go' (PAYG) service. Metering services are currently regulated under a price cap.

2.3.1.3 Special services

In its 2007 statement of reasons, OTTER defined special services as:[49]

> Special Services, including but not limited to connections, disconnections (including disconnections made at the request of the retailer) and reconnections.

However, in its 2008 special services determination, OTTER identified a number of categories of special services, based on a submission from Aurora.[50] Tables 2.4 and

46 OTTER, *Investigation of Maximum Prices for Electricity Distribution Services on Mainland Tasmania: 2007—Declaration of Distribution Services to be Investigated and Terms of Reference for the Price Investigation—Statement of Reasons,* January 2007, p. i, p. 15 (OTTER, *Statement of Reasons*, Jan 2007).

47 ibid. p. i, p. 16.

48 OTTER, *Final report*, Sep 2007, p. 262.

49 OTTER, *Statement of Reasons*, Jan 2007, p. i; p. 16 .

50 OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania—Supplementary Final Report and Statement of Reasons on Maximum Prices*

2.5 of the special services determination identify the following distribution special services:

- energisation, de-energisation and re-energisation
- meter alteration
- meter testing
- removal of meters and service connection
- renewable energy connection—including, installation of import / export metering equipment
- temporary connections for builders
- temporary connections for shows and carnivals
- disconnect service connection
- truck tee up
- open turret or cabinet for electrical contractor.

The first three categories (known as the reference set) are regulated under a weighted average price cap for special services, and are charged on a fixed fee basis. The other categories of special services do not form part of the weighted average price cap but OTTER determined that these special services and their prices must be provided to OTTER as part of the annual pricing process. OTTER elected to take such an approach on the basis that there appeared to be no real evidence that Aurora was abusing its monopoly power such that customers would benefit from including these in the reference set of special services and regulating them under a price cap.[51]

The following special services are currently not regulated and are generally subject to negotiation between Aurora and the customer:

- public lighting
- connection of a large embedded generator, including network augmentation required to receive energy
- moving mains, services or meters
- provision of electric plant (ie mobile generators) for top-up or stand-by electricity supplies
- temporary supply

for Special Services Provided by Aurora Energy, June 2008, pp. 12–17 (OTTER, *Maximum Prices for Special Services*, June 2008).

51 ibid., p. 19.

- reserve or duplicate supply
- connection as required by a specific customer, above the least overall cost, technically acceptable asset
- metering to a standard in excess of that required.

Table 2.1 Aurora's current services and regulatory arrangements

Service category	Declared distribution or metering service	Unregulated service
Network services	'Standard' network services	Above standard network services
Metering services	Standard metering services for type 5–7 meters Special meter readings and meter testing of type 5–7 meters	Above standard metering services Metering services for type 1–4 remotely read meters Metering services for integrated prepayment meters used to provide PAYG services
Special services	Energisation, de-energisation and re-energisation (includes disconnections and reconnections) Meter alteration (adding and altering circuits) Meter testing (including for single phase, three phase and current transformer meters) Removal of meters and service connection Renewable energy connection – including installation of import/export metering equipment Temporary connections Disconnect service connection Truck tee up Open turret or cabinet for electrical contractor	Moving mains, services or meters forming part of the network to accommodate extension, redesign or redevelopment of any premises The provision of electric plant for the specific provision of top-up or stand-by supplies of electricity Temporary supply Reserve or duplicate supply Network services and system augmentation required to receive energy from an embedded generator; Public lighting Above standard connections

Source: AER analysis of OTTER's Final report (Sep 2007), Maximum prices for special services (Jun 2008) and the TEC.

2.4 Preliminary position on service classification

Having regard to the regulatory approach applicable to distribution services provided by Aurora in the current regulatory control period,[52] and the requirements of clauses 6.2.1 and 6.2.2 of the NER, the AER's preliminary position was that, in the next regulatory control period, the distribution services currently classified as:

[52] NER, cll. 6.2.1(c)(2) and 6.2.2(c)(3).

- standard network services should be classified as direct control services and further classified as standard control services

- connection services (standard connections and connections requiring augmentation) should be classified as direct control services and further classified as standard control services; and capital contributions made by customers should remain unregulated

- all type 5, 6 and 7 metering services, excluding PAYG metering services and non-standard metering services, should be classified as direct control services and further classified as alternative control services

- all PAYG metering services should remain unregulated

- non-standard metering services should be unregulated

- public lighting services should be classified as direct control services and further classified as alternative control services

- special services that fall into OTTER's reference set of special services should be classified as direct control services and further classified as alternative control services

- special services that fall outside of OTTER's reference set of special services should be classified as direct control services and further classified as alternative control services

- non-standard services (quoted services), including non-standard network services, should be unregulated.

Table 2.2 displays a summary of the AER's preliminary position on the classification of distribution services provided by Aurora.

Table 2.2 AER's preliminary position—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			Above standard network services
Metering services		Type 5–7 metering services, excluding PAYG metering services		PAYG metering services and non-standard metering services
Public lighting		All public lighting services		
Connection services	Standard connection services and connections requiring augmentation			Capital contributions component of connections requiring augmentation
Fee based services		All special services.		
Non-standard services				All non-standard (quoted) services

Source: AER analysis.

2.5 Issues and AER considerations

2.5.1 Distribution services

Under the NER, the AER must make a decision to classify a distribution service as either a direct control or negotiated distribution service[53], and, in relation to direct control services, as a standard control or alternative control service. This requires the AER, taking into account the matters contained in clauses 6.2.1 and 6.2.2 of the NER, to proceed on the basis that the service classification it adopts should be the same as that applied previously, unless another classification is clearly more appropriate. [54]

First, it is necessary to understand what a distribution service is. The NER defines a 'distribution service' as 'a service provided by means of, or in connection with, a distribution system'.[55] 'Distribution system' is defined in the NER as a 'distribution network, together with the connection assets associated with the distribution network,

[53] The AER can also decide against classifying a distribution service pursuant to clause 6.2.1 of the NER.
[54] NER, cl 6.2.1(d).
[55] This definition paraphrases the definition contained in chapter 10 of the NER. In the case of any inconsistency between the definition in this section and that in the NER, the definition in the NER prevails.

which is connected to another transmission or distribution system. Connection assets on their own do not constitute a distribution system'.[56]

Chapter 10 of the NER further provides that distribution services include services provided by means of, or in connection with, the apparatus, equipment, plant or buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail), where these assets are owned, controlled or operated by the DNSP, excluding services provided over a transmission network.

The AER considers that network services, connection services, metering services, public lighting services, fee based services, and quoted services are distribution services.

2.5.2 Considerations relevant to classification of services

Requirements to classify a service of specified kind in a particular way

Where the NER require a service of a specified kind to be classified as a direct control or negotiated distribution service, or as a standard control or alternative control service (as the case may be), then that service is to be classified in accordance with that requirement.[57] The AER is not aware of any requirement in the NER to this effect in relation to distribution services provided by Aurora.

Presumption in favour of prior classification consistent with previously applicable regulatory approach (as the case may be)

Where the NER do not require a service to be classified in a particular way, the classification process includes a presumption in favour of the prior classification, or classification consistent with the previously applicable regulatory approach (as the case may be).[58]

With this in mind, the AER must assess whether a different classification is clearly more appropriate, having regard to the factors it is required to consider in the NER. The AER's approach is that there are some distribution services provided by Aurora where a different classification is clearly more appropriate.

2.5.3 Classification of distribution services

Having regard to the presumption of the previous regulatory approach for the electricity distribution services provided by Aurora, this section considers whether the previous classifications should continue to apply or whether different classifications for each distribution service are clearly more appropriate.

2.5.3.1 Network services

The AER considers network services to predominantly relate to services provided over the shared network used to service all network users connected to it. Such services may include the construction, maintenance, operation, planning and design of the shared network. Network services are delivered through the provision and operation of apparatus, equipment, plant and / or buildings (excluding connection

[56] NER, chapter 10.
[57] NER, cll. 6.2.1(e) and 6.2.2(e).
[58] NER, cll. 6.2.1(d) and 6.2.2(d).

assets) used to convey, and control the conveyance of, electricity to customers. Such assets include poles, lines, cables, substations, communication and control systems, and involve activities such as inspection, testing, repairs, maintenance, vegetation clearing, asset replacement, asset refurbishment and asset construction services that are not connection services. Network services also include the provision of emergency response and administrative support for other network services.

The term 'network services', therefore, encompasses a significant proportion of a DNSP's distribution services. The AER considers that this view is consistent with how the NER defines a 'network service'.[59]

Current classifications

OTTER defined distribution network services in its 2007 statement of reasons for its declaration decision as:

> …the conveyance of electricity (from the connection point with the transmission system to the customer connection point including entry services, use of system services and exit services, excluding any connection assets owned and maintained by the customer) including:
>
> (a) the undertaking of works or the provision of maintenance or repairs for the purposes of carrying out conveyance of electricity, and
>
> (b) the provision, installation and maintenance or repairs of any switchgear or other electrical plant essential to the transportation and delivery of electricity.[60]

Network services are characteristically provided by Aurora on a 'standard' basis, with the 'non-standard' supply of these services generally dealt with on a fixed fee or quoted basis. The AER considers a non-standard network supply as being the provision of a higher standard of reliability or quality of supply, which enables greater reliability or quality of supply at a customer's premises. Non-standard network services are currently unregulated.

AER's preliminary position

The AER's preliminary position was that Aurora's network services should be classified in a manner consistent with the previously applicable regulatory approach, as no other classification was clearly more appropriate. This was supported by the AER's assessment against the factors in clause 6.2.1 and 6.2.2 of the NER.

On this basis, the AER considered standard network services should be classified as direct control services and, in turn, as standard control services. The AER considered that non-standard network services, which are currently unregulated, should remain unregulated.[61]

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59 NER, chapter 10. "Distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network."

60 OTTER, *Statement of Reasons*, Jan 2007, p. 15.

61 AER, *Preliminary positions–framework and approach paper, Aurora Energy Pty Ltd,* ***Regulatory control period commencing 1 July 2012***, June 2010, pp. 25–27.

Submissions

The AER received one submission from Aurora on the classification of network services. Aurora concurred with the AER's preliminary position on standard network services and non-standard network services.[62]

Issues and AER considerations

In determining the appropriate classification for the Aurora's standard network services, the AER has first had regard to all of the four factors in clause 6.2.1(c) of the NER, including the form of regulation factors contained in section 2F of the NEL.

Aurora holds an electricity distribution licence that was issued by OTTER—a copy of which is available on OTTER's website. The license is the only distribution license that is currently in place for mainland Tasmania. The AER notes that under section 17 of the ESI Act, a person is prevented from distributing and supplying electricity unless they hold a license authorising them to do so.

The AER considers that these arrangements together effectively amount to a regulatory barrier for the purposes of section 2F of the NEL. This is because Aurora, as the only holder of an electricity distribution license in Tasmania, is the only party that can provide these network services within each of the areas prescribed in its license.

Further, the significant capital costs of entry, and the economies of scale and scope available to Aurora, as the incumbent distribution network service provider, are highly likely to make duplication of the Aurora's shared network by an alternative service provider both commercially unviable and economically inefficient. For the purposes of sections 2F(b) and 2F(c) of the NEL, the economies of scale and scope available to Aurora are also likely to prevent augmentation of the network being competitively provided by an alternative service provider.

For the purposes of section 2F(e) of the NEL, substitutes for using these shared network services are few, and are likely to be limited to embedded generation or switching to an alternative energy source, such as natural gas. The AER considers that these are unlikely to be viable commercial options in most instances for most existing large and small customers, primarily as the natural gas distribution network is quite small in Tasmania and the cost of embedded generation can be prohibitive.

These factors contribute to the view that Aurora possesses significant market power in the provision of standard distribution network services, and that it is appropriate to subject these services to a direct form of control. In particular, having regard to the purpose of section 2F(g) of the NEL, even a high degree of information available to users would not neutralise the lack of countervailing market power caused by these other form of regulation factors.

The AER has also had regard to clauses 6.2.1(c)(2) and 6.2.1(c)(3) of the NER and notes that network services are currently subject to a control form of regulation in Tasmania. Other NEM jurisdictions apply the same classification.

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62 Aurora, *Framework and Approach Paper–Response to AER Preliminary Positions*, August 2010, pp. 5–7.

For the purposes of clause 6.2.1(d), the AER notes that standard network services are currently regulated as distribution services under a revenue cap form of control, which creates a presumption that they should be classified as direct control services.

Therefore, having regard for the requirements of clause 6.2.1 of the NER, the AER considers that network services should be classified as direct control services.

Once a service is classified as a direct control service, the AER must then apply all six factors in clause 6.2.2(c) of the NER to determine whether it should be classified as a standard or alternative control service.

Standard network services are currently regulated as distribution services under a revenue cap form of control, which, in accordance with clause 6.2.2(d) of the NER, creates a presumption that they should be classified as standard control services unless a different classification is clearly more appropriate. Having regard to all the factors in clause 6.2.2(c) of the NER, the AER considers that there is no basis to move away from this presumption, for the following reasons:

- As discussed above, there is little if any potential for the development of competition in the market for standard network services. The AER considers that its classification will not influence the potential for competition—rather, the absence of competition due to Aurora holding the only distribution license for mainland Tasmania and by the requirements of the ESI Act.

- There would be no material effect on administrative costs of the AER, DNSP or any other party. This is because classifying network services as standard control services would involve a similar regulatory approach to that which has been applied by the OTTER for the current regulatory control period.

- Standard network services are currently regulated in Tasmania, and all of the other jurisdictions in the NEM, under a control mechanism that incorporates a CPI–X framework (or variant thereof), where the X factor is determined according to a building block approach. Network tariffs are subject to the annual approval of the regulator.

- The nature of standard network services is that they are provided by a shared network and their costs cannot be directly attributed to individual customers.

- There do not appear to be any other factors that are relevant to the AER's proposed classification.

The AER's likely approach

The AER's likely approach is to classify Aurora's standard network services in a manner which is consistent with the previously applicable regulatory approach, as no other classification is clearly more appropriate. This is supported by the AER's assessment against the factors in clause 6.2.1 and 6.2.2 of the NER.

On this basis, the AER considers standard network services should be classified as direct control services and, in turn, as standard control services.

The AER's classification of non-standard network services, which are currently unregulated, is discussed in section 2.5.3.6 of this chapter under quoted services.

2.5.3.2 Metering services

Aurora provides a range of metering services to Tasmanian consumers. The AER considers that metering is limited to the costs of providing, installing and maintaining standard meters and services provided to non-contestable customers to support the customer billing system.

The AER notes that clause 7.2.3 of the NER provides for some types of meters to be contestable. Specifically, clause 7.2.3(a)(1) of the NER states:

> The *Local Network Service Provider* is the *responsible person* for:
>
> (1) a type 1, 2, 3 or 4 *metering installation* connected to, or proposed to be connected to, the *Local Network Service Provider's network* where the *Market Participant* has accepted the *Local Network Service Provider's* offer in accordance with paragraphs (b) and (c)

Thus, under this clause of the NER the installation of type 1 to 4 meters is contestable. As a consequence, metering classified by the AER relates to metering services for type 5, 6 and 7 meters, and type 1 to 4 meters should not be regulated.

Current classifications

Standard type 5, 6 and 7 metering services

OTTER's 2003 declaration decision provided that metering services were part of the overall revenue cap applied to network services.[63] In 2007, however, OTTER elected to separately declare type 5, 6 and 7 (but not type 1 to 4) metering services.[64] OTTER expected that type 1 to 4 meters would be contestable in future (which they are) and hence were not part of the declaration.

In particular, in its 2007 OTTER defined the metering services it declared in the following way:

> Metering services, being the provision, installation and maintenance of any Type 5, 6 or 7 meter and related meter data capture provided by Aurora Energy Pty Ltd, excluding the provision of integrated prepayment meters and the provision of metering to a standard in excess of that required for the billing of customer services, but including special meter readings and meter testing of Type 5, 6 or 7 meters.[65]

OTTER's 2007 declaration clarifies that metering services it decided to declare were confined to the meter and did not include other connection assets such as current and

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63 OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices*, September 2003.

64 Type 1 to 4 meters are remotely read meters, type 5 are manually read interval meters, type 6 are accumulation meters and type 7 are for unmetered supplies.

65 OTTER, *Investigation of Maximum Prices for Electricity Distribution Services on Mainland Tasmania: 2007 Declaration of Distribution Services to be Investigated and Terms of Reference for the Price Investigation Statement of Reasons,* January 2007, p. I

voltage transformers, which were included within the definition of distribution network services.[66]

The AER notes that there was no discussion of electronic metering in OTTER's 2007 declaration.

Aurora's approach to electronic metering services is detailed in OTTER's 2007 Electricity Pricing Investigation—Final Report, which stated that Aurora's intention is to replace all mechanical meters with electronic meters as they reach the end of their useful life and connect all new customers with electronic meters.[67]

PAYG metering services

Pay as you go metering is a product provided by Aurora in its capacity as a licensed retailer (Aurora Retail), whereby customers do not receive an electricity account, but instead utilise a recharge card to update the credit facility within the metering equipment. Aurora currently has just over 40,000 of its customers using this facility.[68]

The provision of metering services for the PAYG product can be split into two distinct types:[69]

- those where the metering service is provided by Aurora Retail; and
- those where the metering service is provided by Aurora (as a DNSP).

Where the service is provided by Aurora Retail, the meter encompasses the entire PAYG product, including the recording of energy consumption and the card reading facility and credit management. Where Aurora provides the metering service, the meter records the energy consumption, and a separate Payguard unit (provided by Aurora Retail) accommodates the card reading facility and credit management.[70] Approximately 500 of the 40,000 PAYG customers have standard electronic meters with the Payguard unit.[71]

As outlined above, integrated prepayment meters were excluded from the definition of metering services in OTTER's 2007 declaration decision and thus not regulated. While the AER expressed the view in its preliminary positions paper that all PAYG meters were not previously regulated by OTTER, OTTER has since clarified that older integrated prepayment meters were excluded from its calculations as those meters were owned by Aurora Retail, but did set charges for the electronic meters owned by Aurora Networks.[72]

OTTER decided not to regulate the integrated prepayment meters owned by Aurora Retail because the customer always had the option to revert back to the regulated alternative, but was also concerned that subjecting these meters to regulation would

66 OTTER, *Final report*, Sep 2007, p. 262.
67 OTTER, *Final report*, Sep 2007, p. XXVIII.
68 Aurora, *Response to AER preliminary positions paper*, 30 August 2010, p. 11.
69 ibid., p. 12.
70 ibid.
71 Aurora, *Information paper*, May 2010, p. 9.
72 OTTER, Response to information requested on 1 November 2010, submitted on 1 November 2010.

result in partial regulation of the PAYG retail product prices and may impede Aurora adopting better technology. Specifically, OTTER stated that it:

> …chose not to regulate any Aurora Pay As You Go (APAYG) charges, as customers are free to choose APAYG and to revert to the standard tariff if this product does not suit their needs in terms of service and/or price. To regulate maximum prices for integrated prepayment meters, by including these in the suite of regulated meters, would result in partial regulation of the APAYG product prices. Further, there will be changes in the type of meters used for the APAYG service and regulation of prices may be an impediment to Aurora adopting better emerging technology.[73]

AER's preliminary position

The AER's preliminary position was that Aurora's metering services—including PAYG metering—should be classified in a manner consistent with the previously applicable regulatory approach, as no other classification is clearly more appropriate. The AER considered that:

- metering services for all type 5, 6 and 7 meters should be classified as direct control services and, in turn, as alternative control services
- all PAYG metering services should be unregulated.

Submissions

The AER received a submission from Aurora on the classification of metering services.

While Aurora agreed with the AER's preliminary position on type 5, 6 and 7 metering services, and type 1 to 4 metering services, it did not agree with the AER's preliminary position to not classify PAYG metering services. [74] Aurora considered that by excluding all PAYG metering services, the AER had also excluded the electronic meters owned by Aurora Network which provided standard metering services. These electronic meters can be used to provide PAYG services by Aurora Retail through the addition of a Payguard unit.

In its submission, Aurora clarified that two types of meters were used to provide PAYG services — standard meters that could provide the PAYG product with the addition of a Payguard unit, and meters that were only able to provide the PAYG product as a complete unit.

Aurora noted that the metering services for the PAYG product provided by Aurora (as a DNSP) are in fact standard metering services (i.e. a standard meter is provided that is not linked to the PAYG product, but does include a Payguard unit).[75] Aurora noted that the standard meter is not removed if a customer chooses to move away from the PAYG product (which currently occurs with the Aurora Retail provided PAYG meter).[76] Aurora further noted that existing Aurora Retail PAYG meters that fail or do

[73] OTTER, *Final report*, Sep 2007, p. 262.
[74] ibid, pp. 8–12.
[75] ibid., p. 12.
[76] ibid.

not meet compliance are to be replaced with a standard meter and Payguard unit.[77] Aurora therefore proposed that PAYG metering services provided by Aurora be classified as direct control, alternative control services. Aurora agreed that all PAYG metering services provided by Aurora Retail should not be regulated because they are not standard metering services provided by Aurora in its capacity as a DNSP.[78]

The AER recognises this distinction, and has incorporated it into its classification of metering services.

Issues and AER considerations

Standard metering services

The AER notes that clause 7.2.3(a)(2) of the NER provides that a DNSP, as the local network service provider, is the responsible person[79] for all type 5, 6 and 7 metering installations. Aurora has confirmed that its electronic meters to which an Aurora Retail Payguard unit can be added are type 6 meters.

For the purpose of this analysis, the term 'standard metering services' includes metering services provided using type 5, type 6 and type 7 meters. For clarity, standard metering services includes those type 6 meters owned by Aurora to which a Payguard unit can be attached, but excludes those meters provided by Aurora Retail.

On this basis, and having regard to the factors in section 2F of the NEL, the AER considers that there is a regulatory barrier to any party other than Aurora providing standard metering services, given that Aurora is the only party that can provide them within each of the areas prescribed in its license. Furthermore, the economies of scale and scope available to Aurora, particularly in relation to its network services, are likely to prevent metering services being competitively provided by an alternative service provider. The AER also considers that there are no real substitutes for these services as all customers require metering services (regardless of whether they utilise the PAYG product to pay for their electricity usage).[80]

These factors contribute to the view that Aurora possesses significant market power in the provision of standard metering services.

The AER has also had specific regard to clauses 6.2.1(c)(2) and 6.2.1(c)(3) of the NER and notes that these standard metering services, are currently subject to a control form of regulation in Tasmania as well as in all other jurisdictions in the NEM. This is because clause 7.2.3(a)(2) of the NER applies to all DNSPs in the NEM.

Having regard to the requirements of clause 6.2.1 of the NER, the AER considers that all standard metering services should be classified as direct control services.

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77 ibid.

78 ibid.

79 The responsible person is the person who has responsibility for the provision of a metering installation for a particular connection point, being either the Local Network Service Provider or the Market Participant as described in Chapter 7 of the NER.

80 Aurora has indicated that it is planned that all PAYG customers will have a standard electronic meter installed by Aurora with an Aurora Retail Payguard unit. It follows that a customer will not be able to replace an Aurora meter with an Aurora Retail PAYG meter. Aurora, *Framework and Approach Paper–Response to AER Preliminary Positions*, August 2010, p. 12.

Once a service is classified as a direct control service, the AER must then have regard to all six factors in clause 6.2.2(c) to determine whether it should be classified as a standard or alternative control service.

Standard metering services, are currently regulated through a price cap on the maximum daily allowance for each class of meter. Having regard to clause 6.2.2(d) of the NER, this creates a presumption that they should be classified as alternative control services unless a different classification is clearly more appropriate. Having regard to all the factors in clause 6.2.2(c) of the NER, the AER considers that there is no basis to move away from this presumption, for the following reasons:

- As discussed above, there is little if any potential for the development of competition in the market for metering services. The AER considers that its classification will not influence the potential for competition—rather, the absence of competition is determined by the requirements of clause 7.2.3(a)(2) of the NER.

- There would be no material effect on administrative costs of the AER, DNSP or any other party. This is because classifying these metering services as alternative control services would involve a broadly similar regulatory approach to that which has been applied by OTTER for the current regulatory control period.

- Standard metering services are currently regulated in Tasmania through a maximum daily allowance for each class of meter, although this is not the case in all NEM jurisdictions.

- The nature of metering services is that the costs of providing the service can be directly attributed to individual customers.

- There do not appear to be any other factors that are relevant to the AER's proposed classification of standard metering services.

For these reasons, the AER considers that there is no basis to move away from the presumption that standard metering services should be classified as alternative control services.

The AER's likely approach

The AER's likely approach is to classify standard metering services as direct control services, and further classify them as alternative control services. Type 1 to 4 metering services, and meters provided by Aurora Retail to provide PAYG services will remain unregulated.

2.5.3.3 Public lighting services

Aurora operates and maintains the public lighting system throughout Tasmania on behalf of the 29 local councils and the Department of Industry, Energy and Resources (DIER). While DIER is responsible for providing public lighting on state roads and major highways, these assets are serviced and maintained by Aurora.

Aurora owns the majority of public lighting assets in Tasmania where approximately 75 per cent of public lights are supported on Aurora's electricity distribution poles.

The remaining 25 per cent are supported by dedicated public lighting poles which are mostly privately owned.[81]

In the majority of new housing developments, the provision of new public lighting services, such as the design, installation and connection of public lighting assets, is undertaken by Aurora.

Current classification

Public lighting services have not been previously regulated in Tasmania. However, the AER has been advised by Aurora that its public lighting services are split into the following five categories:

- the repair, replacement and maintenance of public lighting owned by Aurora, where the streetlight services are provided to third parties
- the repair, replacement and maintenance of public lighting owned by third parties where Aurora undertakes the service for a fee
- alteration and relocation of existing public lighting assets owned by Aurora at the request of a third party
- alteration and relocation of existing public lighting assets owned by a third party at the request of that third party
- the provision of new public lighting assets by Aurora to customers or third parties, on the request of that customer or third party.[82]

The AER's preliminary position

The AER’s preliminary position was to classify each of the above five categories of public lighting services provided by Aurora in Tasmania as direct control services, and further classify them as alternative control services.[83]

The AER proposed not to classify public lighting services for luminaires that are provided on a trial basis, such as trial LED street lights.[84]

Submissions

Aurora, StreetlightsLED, the Local Government Association of Tasmania (LGAT) and DIER all agreed with the AER's preliminary view to classify public lighting services as direct control services, and in turn, as alternative control services.[85]

Trans Tasman Energy Group (TTEG) cited concerns with the classification of public lighting services as alternative control services and raised issues arising from the AER's classification of these services in NSW and Victoria. TTEG's concerns were in

81 Aurora, Information paper, May 2010, p. 8; Aurora, Prices for the provision of Street Lights for the period 1 July 2010 until 30 June 2011, May 2010, p. 2.
82 Aurora, *Information paper*, May 2010, pp. 3-4.
83 AER, Preliminary positions paper, June 2010, p. 38.
84 ibid., p. 34.
85 Aurora, Information paper, May 2010; LGAT and DIER, Submission to the AER, August 2010; StreetlightsLED, Submission to the AER, August 2010.

relation to the lack of cost visibility in a DNSP's modelling in NSW and a decision to classify some new lighting technologies as negotiated services in Victoria. TTEG considered that public lighting services should instead be classified as negotiated distribution services.[86]

Notwithstanding this, all stakeholders agreed with the AER's classification based on the categories of the public lighting services currently provided by Aurora. TTEG's submission stated that:

> Aurora's services are consistent with the public lighting services required by customers and to the establishment of a tiered pricing structure.[87]

However, TTEG's support for the AER's approach to classification was conditional on the coupling of this categorisation with a tiered pricing structure.[88]

Transparency of tariffs and costs

LGAT and DIER suggested that there should be greater transparency in the AER's process of determining appropriate price caps, in particular, the AER's review of Aurora's building block model. Both parties considered that it was necessary for Aurora to provide unbundled billing of public lighting costs and more information regarding the specification for all lighting options. They reasoned that this would help them achieve emissions targets and cost efficiencies.[89]

TTEG noted that charges for public lighting services in Tasmania were not separately identified and that this was inconsistent with the level of information provided to public lighting customers in other jurisdictions. In particular, TTEG noted that:

> The current situation in Tasmania is quite different to other states as public lighting customers (councils and DIER) are currently billed by Aurora via a "bundled" tariff which includes energy charges (e.g. the energy rate, distribution and other charges) and the light cost (including asset and maintenance costs).[90]

Accordingly, TTEG expected that energy and light charges will be unbundled in the next regulatory period as is the case in all other NEM jurisdictions.[91]

TTEG also considered that a tiered pricing structure (Full, Customer Lighting Equipment Rate (CLER), and Energy Only) should be established for public lighting services.[92] It also stated that:

> The only way customers can have visibility to (actual) costs, and establish a service agreement that will provide for the effective development of the sector is via a classification of the public lighting service as a Negotiated Distribution Service.[93]

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86 TTEG, Aurora framework and approach paper submission, August 2010, p. 2.
87 ibid, p. 4.
88 TTEG, Aurora Framework and approach paper submission, August 2010, p. 4.
89 LGAT and DIER, Submission to the AER, August 2010, p. 4.
90 TTEG, Aurora Framework and approach paper submission, August 2010, p. 2.
91 ibid.
92 ibid, p. 4.
93 ibid, p. 2.

The AER considers that its classification of Aurora's public lighting services will increase the level of transparency provided to consumers of these services. Where these services are classified as alternative control services and regulated under price caps, the AER's revenue determination process will involve assessing the unbundled components of the costs of providing these services. That said, the AER is unable to place requirements on Aurora to itemise the bills sent to consumers of public lighting services.

Contestability of public lighting services

TTEG considered that public lighting services had the potential to be contestable, noting that:

> …Aurora does not have a legislative monopoly over the provision of public lighting assets, and it appears that Aurora could authorise others to provide services, even on their own assets.[94]

TTEG also requested that the AER clarify why it considered that these services could not be contestable. In contrast to the AER's view on the previous classification for public lighting services in Tasmania, TTEG considered that the previous classification for public lighting in Tasmania, one which would be consistent with the existing arrangements, was negotiation.[95]

Further, TTEG expressed concern that the AER's preliminary position to classify public lighting services as alternative control services would contribute to Aurora's position as a monopoly provider for public lighting services. In particular, it was noted that:

> …any perceived "market power" has been potentially derived from the historical provision of services by Aurora — an alternative that should be available to public lighting customers is to tender for the public lighting services or to negotiate directly with Aurora.
>
> The AER also needs to establish that by potentially ignoring the competitive option for customers the AER may effectively establish Aurora in a monopoly provider, even though the AER has recognised that Aurora has no legislative monopoly.[96]

While the AER appreciates TTEG's characterisation of the arrangements in which public lighting services are currently provided as involving elements of negotiation, it does not necessarily follow that these arrangements are reflective of the arrangements that would apply if they were classified as negotiated distribution services under the NER.

Negotiated distribution services are subject to Part D of Chapter 6 of the NER and must comply with a negotiating framework (approved by the AER), the AER's negotiated distribution service criteria and the regulatory framework under the NER. The negotiate/arbitrate framework that would be established by classifying a service as a negotiated service under the NER is significantly different from the possibility of negotiating with Aurora absent this framework.

94 ibid, p. 5.
95 ibid, p. 2.
96 ibid, pp. 6-7.

In addition, the AER does not consider that the decision to classify public lighting services as alternative control services under a price cap form of control will impact on the contestability of public lighting services in Tasmania. The AER's likely approach to the classification of distribution services as alternative control services only determines the manner in which a DNSP recovers the costs of those services.

Current arrangements enable third parties to provide public lighting services on greenfield sites[97] (although Aurora would continue to have TEC customer charter obligations in relation to those assets). However, the AER considers that there is no contestability for the provision of services in respect of Aurora's assets. As noted by LGAT and DIER:

> unless contestability is introduced during the regulatory period, there is little potential for the development of competition for the provision of public lighting services using Aurora's assets… Aurora in practice has monopoly control over public lighting distribution services.[98]

Aurora has also recently advised the AER that, at present, no third parties have been authorised by Aurora to provide any public lighting services in Tasmania. Further, Aurora has stated that it has no plans to engage third parties to provide public lighting services its behalf.[99]

Aurora advised that should a third party wish to enter the market and offer services in its own right, it will need to obtain the appropriate jurisdictional certifications and Aurora access approvals to enable it to provide the relevant services. Aurora confirmed that:

> Provided that the third party meets the jurisdictional licensing requirements and has undergone training by Aurora in Aurora's access arrangements, authorisation can be given.[100]

In response to TTEG's submission regarding the ownership of public lighting assets in Tasmania,[101] the AER notes that Aurora has confirmed that:

> Aurora owns the majority of the luminaires. Approximately 75 percent of street lighting is supported on distribution poles. The other 25 percent of street lighting is on dedicated poles and in most cases privately owned.[102]

Economies of scale and scope in the provision of public lighting services

In relation to economies of scale and scope that Aurora benefits from providing public lighting services, TTEG noted that 'others can also benefit from economies of scale e.g. companies can provide tree pruning and public lighting services'.[103] TTEG also raised concerns about the extent to which Aurora would benefit from the joint provision of retail and network services:

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97 For example, new housing developments.
98 LGAT and DIER, Submission on street lighting proposals, August 2010, p. 2.
99 Aurora, Response to information requested on 1 November 2010, submitted on 5 November 2010, p. 4.
100 ibid., p. 3.
101 TTEG, Aurora framework and approach paper submission, August 2010, p. 9.
102 Aurora, Information Paper for the AER: Services, Classifications and Control Mechanisms, May 2010, p. 2.
103 TTEG, Aurora framework and approach paper submission, August 2010, p. 6.

> As the retail market for energy in Tasmania is contestable, and the provision of retail energy to public lighting will also be contestable (once unbundled), we do not consider that any synergies with Aurora Retail can fairly be considered as it would not be fair on other retailers and may be seen as anti competitive behaviour.[104]

The AER considers that Aurora does benefit from the economies of scale and scope in providing public lighting services in Tasmania. Aurora itself acknowledged that in providing public lighting services, there were externalities from its provision of other services:

> In particular, Aurora can use the same assets, labour and materials to provide public lighting services on its own public lighting assets as for those owned by third parties.[105]

That said, noting the ring-fenced nature of Aurora Retail's retail and network operations,[106] the AER considers that Aurora's distribution network business is unlikely to benefit from economies of scale or scope from its provision of retail services in relation to public lighting services.

Classification of public lighting in other NEM jurisdictions

The AER notes that TTEG's submission stated that:

> the classification of public lighting services as a Direct Controlled Service has been extremely problematic in NSW, particularly with the (lack of) cost visibility of data included in the distributor's modeling.[107]

TTEG's submission also considered that:

> The Alternative Controlled Service approach and the modeling has proven significantly problematic in other jurisdictions.[108]

The AER considers that the classification of Aurora's repair, replacement and maintenance of public lighting as a direct and alternative control service may be less problematic. This is because Aurora has provided its public lighting model as a starting point for the AER to determine charges for these services.

The AER also considers that from its assessment of this model, there is sufficient visibility of the costs associated with provision of these public lighting services. These include costs for:

- Fittings and brackets
- Labour
- Travel

104 ibid.
105 Aurora, Response to AER preliminary positions, August 2010, p. 13.
106 OTTER, Electricity Distribution and Retail Accounting Ring fencing Guidelines–Electricity Industry Guideline No. 2.2 (Issue No. 4), July 2008.
107 TTEG, Aurora framework and approach paper submission, August 2010, p. 8.
108 Ibid, p. 10.

- Materials and tools
- Annuity (return on investment)
- NUoS charges.[109]

Energy efficiency options and externalities

StreetlightsLED submitted that the AER should regulate public lighting with regard to energy efficiency and other market externalities such as toxic waste.[110]

LGAT and DIER also raised concerns regarding the limited range of energy efficient pubic lighting options available to customers and the limited ability to influence Aurora's globe replacement regime. The joint submission noted:

> - end users have limited range of choices in the globes that Aurora will use for public lights;
> - end users have limited ability to determine the upgrade and replacement schedule for public lights; ie to replace with more efficient globes.[111]

The AER's role is limited to considering how the distribution services provided by Aurora should be classified, the control mechanism that is to apply to each service and, ultimately, to determine the charges to apply to each service. The AER is unable to compel Aurora to change the way it provides public lighting services — for example, providing consideration of energy efficient luminaires, or addressing the impact of other environmental externalities. This is a question of government policy and relevant environmental standards.

While LGAT and DIER raised concerns about the limited range of energy efficient public lighting options available to customers, Aurora's public lighting model shows that Aurora also provides some energy efficient T5 (2x14 watt) fluorescent lights (T5s) and 42 watt compact fluorescent lights (CFLs).[112]

Notwithstanding this, as detailed below, the provision of these assets either in new housing developments, or as a replacement of existing public lighting assets provided by Aurora would fall within the service of the provision of new public lighting assets.

Where these assets are provided as a replacement for an existing public lighting asset which has not yet reached its end of life, this would fall under the service of alteration or relocation of an existing public lighting asset, which is a quoted service. This is considered in more detail below.

Issues and AER considerations

Since releasing the preliminary positions paper, Aurora has provided the AER with its public lighting charges model and some further information on these public lighting

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109 Aurora, Public lighting model for the AER, July 2010.
110 StreetlightsLED, Submission to the AER, August 2010, pp. 1-2.
111 LGAT and DIER, Submission on street lighting proposals, August 2010, p. 2.
112 Aurora, Public lighting model for the AER, July 2010.

services and charges.[113] This has led the AER to revise its view on the public lighting services that Aurora is likely to provide during the forthcoming regulatory control period.

Repair, replacement and maintenance of existing public lighting assets

As outlined in table 2.3, Aurora offers a wide variety of luminaries in providing public lighting services. Aurora's public lighting model includes annual charges for the provision of ongoing repair, replacement and maintenance for all these luminaire types.[114]

Table 2.3 Current and new public lighting luminaires to be offered by Aurora

Standard luminaires	Energy efficient luminaires
80W Mercury Vapour	2x14W T5 Fluorescent
70W High Pressure Sodium Vapour	2x24W T5 Fluorescent
100W High Pressure Sodium Vapour	26W Compact Fluorescent
150W High Pressure Sodium Vapour	32W Compact Fluorescent
250W High Pressure Sodium Vapour	42W Compact Fluorescent
400W High Pressure Sodium Vapour	42W Compact Fluorescent - Top Entry Decorative
70W Metal Halide	42W Compact Fluorescent - Side Entry Decorative
100W Metal Halide	42W Compact Fluorescent - Bottom Entry Decorative
150W Metal Halide	
250W Metal Halide	
400W Metal Halide	
80W Mercury Vapour - Decorative	
70W Metal Halide - Decorative	
100W Metal Halide - Decorative	

Source: Aurora, Public lighting model for the AER, July 2010.

The model also includes annual charges for luminaires which are currently provided by Aurora, but have been deemed 'obsolete'. These obsolete fittings are to be gradually phased out by Aurora.[115]

[113] Aurora, Public lighting model for the AER, July 2010; Aurora, Response to information requested on 25 October 2010 and 1 November 2010, submitted on 5 November 2010.
[114] Aurora, Public lighting model for the AER, July 2010.
[115] These include: 1x40W, 2x20W, 2x40W, 4x20W, and 4x40W Fluorescent lights; 60W and 100W Incandescent lights; 50W, 125W, 250W and 400W Mercury Vapour lights; 18W, 90W and 600W Sodium Vapour lights. Aurora, Public lighting model for the AER, July 2010.

Aurora's public lighting model also includes annual charges for 'contract lights'. In practice, contract lights are brackets and luminaires owned by Aurora and provided under contract to meet that customer's needs.[116]

The AER has been advised by Aurora that at present:

> all costs associated with the provision and maintenance of the contract lighting, except those for globe replacement, are met through the contract rates. Globe replacement and the NUoS associated with the fitting are met through the Contract Lighting tariff.[117]

The AER intends to review all costs associated with the repair, replacement and maintenance of public lighting by Aurora for the purposes of making its upcoming revenue determination. These will include costs for both public lighting owned by third parties, and those owned by Aurora, including contract lights.

Further to this, the AER will determine the efficient costs of providing these services, and will publish the charges for each service for the 1 July 2012 to 30 June 2017 regulatory control period.

Alteration and relocation of existing public lighting assets

The AER considered the alteration and relocation of existing public lighting assets together with its consideration of public lighting services in its preliminary positions paper. However, for the purposes of this final framework and approach paper, these services are considered in section 2.5.3.6 under quoted services.

The AER notes that a customer may nominate for Aurora to replace an existing asset (for example, an 80W Mercury Vapour light) with a new energy efficient asset (for example, a 42W Compact Fluorescent light), prior to the end of life for the 80W Mercury Vapour light. Aurora has clarified that this service would fall under the category of the alteration and relocation of an existing public lighting asset.[118]

Provision of new public lighting assets

Aurora has clarified that it will install new public lighting assets during the forthcoming regulatory control period. This includes the installation of public lighting in new housing developments and greenfield sites.[119]

However, the AER notes that Aurora's model includes charges for a large variety of public lighting assets that it currently provides, as well as assets that it proposes to provide. Accordingly, the AER considers that the provision of 'new public lighting assets' should also extend to the situation where a customer wishes to change the public lighting luminaire type, once the existing asset reaches the end of its life.

Aurora has confirmed that where a customer decides to switch public lighting luminaires at the end of life of the original luminaire, the cost of this service will be identical to that for the repair, replacement and maintenance of public lighting (which

116 Aurora, Response to information requested on 25 October 2010, submitted on 5 November 2010.
117 ibid.
118 Aurora, Response to information requested on 1 November 2010, submitted on 5 November 2010, p. 3.
119 ibid, p. 2.

includes the initial installation cost). The current charges for these services are provided in Aurora's public lighting model.

New public lighting technologies

The AER notes that its preliminary position was to not classify public lights provided on a trial basis.[120]

The AER has been previously advised by Aurora that a small trial involving three LED light fittings is being conducted with the Kingborough Council to establish a benchmark for the potential future deployment of these lights within that council. This is a joint trial and is being funded by both Aurora and the Kingborough Council.[121]

The AER has reconsidered its position in relation to this issue. Taking into account LGAT and DIER's submission in relation to the limited range of energy efficient public lighting options currently available, and the potential for new technologies to be introduced during the forthcoming regulatory control period, the AER now considers that these services should be classified.

In particular, the AER considers that it should consider the classification of new public lighting technologies, not currently offered by Aurora (such as LEDs), as they may be provided by Aurora during the forthcoming regulatory control period.

Energy charges

All public lighting assets (including all street lights) in Tasmania are connected to Aurora’s electricity distribution network. However, the conveyance of electricity to public lighting assets is not a public lighting service. Instead, the NUOS charges fall within the definition of network services, discussed in section 2.5.3.1.

Classification of public lighting services as direct control services or negotiated distribution services

Under clause 6.2.1(b) of the NER, the AER's likely approach is to group the following services together as direct control services, for the purposes of classification:

- the repair, replacement and maintenance of public lighting owned by Aurora, where the streetlight services are provided to third parties
- the repair, replacement and maintenance of public lighting owned by third parties where Aurora undertakes the service for a fee
- the provision of new public lighting assets by Aurora to customers or third parties, on the request of that customer or third party.

As noted above, the classification for alteration and relocation of existing public lighting assets is considered in section 2.5.3.6 under quoted services.

As discussed below, the AER's likely approach is to classify new public lighting technology services as negotiated distribution services. Discussion of 'public lighting

[120] AER, Preliminary positions paper, June 2010, p. 34.
[121] Aurora, Information Paper for the AER: Services, Classifications and Control Mechanisms, May 2010, p. 8.

services' in this section therefore excludes those public lighting services relating to alteration and relocation of existing public lighting assets, and new public lighting technology.

In considering the form of regulation factors under section 2F of the NEL, the AER is of the view that with regard to section 2F(a), there are significant barriers to entry for the provision of public lighting services in Tasmania. Aurora does not have a legislative monopoly over the provision of public lighting services.

However, as noted by the AER in its preliminary positions paper, due to the requirements of the TEC and the ESI Act, only Aurora can provide services on its public lighting assets, which include 75 per cent of all street lights in Tasmania. As stated in clause 8.2.3 of the TEC:

> A Distribution Network Service Provider must repair or replace an item of public lighting within 7 business days of being notified by any person that such repair or replacement is necessary, unless the public lighting provider has contractual or other arrangements with another party.[122]

The AER notes that the definition of public lighting in this obligation refers to:

> Street lighting provided by a governmental body or agency in Tasmania.[123]

In addition, section 109(1) of the ESI Act states that unauthorised persons are prevented from interfering with Aurora's electricity infrastructure or electrical installations.

Further, Aurora's Electricity Distribution Customer charter provides a description of its service standards and outlines the penalties it may be subject to should it fail to meet those standards for all services provided by Aurora, including for public lighting services.[76] This customer charter is a requirement of section 8.3.1 of the TEC.

While there is some limited scope for other entities, such as private contractors, to provide some public lighting services, the AER notes that this only relates to a small number of public lighting assets that are owned by councils and other customers; this does not extend to the majority of public lighting assets, which are owned by Aurora.

With regards to Aurora's assets, any potential third party provider must approach Aurora and request that they be permitted to work on the network.[124] Aurora has also advised that:

> Provided that the third party meets the jurisdictional licensing requirements and has undergone training by Aurora in Aurora's access arrangements, authorisation can be given.[125]

However, Aurora is not currently engaged with any third parties for the provision of public lighting services. Further, Aurora has advised that, to date, no third parties have

122 Tasmanian Electricity Code, Version: Chapter 8 Revised Code, 26 May 2010, p. 8–2.
123 Tasmanian Electricity Code, Version: Chapter 14 Glossary Revised Code, 26 May 2010, p. 19.
124 Aurora, Response to information requested on 1 November 2010, submitted on 5 November 2010, p. 3.
125 ibid, p. 3.

been authorised to provide any of the public lighting services offered by Aurora.[126] The AER has also been advised that:

> Aurora has no plans to engage third parties to provide public lighting services on behalf of Aurora. Should a third party wish to enter the market and offer those services in their own right that party will need to obtain the appropriate jurisdictional certifications and Aurora access approvals to enable them to provide that service.[127]

Accordingly, in light of this advice and the reasoning provided above, the AER considers that there are indeed significant barriers to entry for the provision of public lighting services in Tasmania.

With regard to section 2F(b) and 2F(c) of the NEL, the AER considers Aurora would appear to benefit from the economies of scale and scope, derived from the provision of network services, in providing public lighting services. Aurora is able to use the same assets, labour and materials to provide public lighting services on its own assets as well as those assets owned by third parties.[128]

The retail market in Tasmania is somewhat contestable, with third party retailers (for example, ERM Power) able to provide some retail electricity services to Tasmanian councils. However, there is no contestability for the provision of public lighting services by third parties for assets owned by Aurora. Aurora is the sole DNSP in Tasmania, and therefore the only party capable of providing distribution services for its public lighting assets.

With regard to section 2F(d), the AER also considers that customers of Aurora's public lighting services do not have countervailing market power that would mitigate Aurora's market power in providing public lighting services.

With regard to section 2F(e) and (f) of the NEL, the AER considers that demand for public lighting is highly inelastic. There are also limited substitution possibilities for the provision of public lighting services by Aurora. Aurora has advised the AER that there are no real competitive or substitution possibilities for these public lighting services given that the market for the provision of public lighting services in Tasmania is underdeveloped.[129]

With regard to section 2F(g), the AER does not consider that consumers of public lighting services would have sufficient information to negotiate on an informed basis with Aurora. Indeed, there are concerns about the lack of transparency regarding the terms on which public lighting services are provided to consumers.[130] Further, Aurora has only recently provided the AER with a guideline that describes the basis on which it intends to provide public lighting services to consumers.[131]

In relation to clause 6.2.1(c)(2) of the NER, the AER notes that public lighting has not been previously declared by OTTER, and as a result, these services have not

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126 ibid., p. 4.
127 ibid., p. 4.
128 Aurora, Response to AER Preliminary Positions, August 2010, p. 2.
129 Aurora, Information paper, May 2010, p. 28.
130 LGAT and DIER, Submission on street lighting proposals, August 2010, p. 2.
131 Aurora, Public lighting model for the AER, July 2010.

previously been classified. Accordingly, under OTTER’s current and previous regulatory regimes, public lighting services were unregulated.

Clause 6.2.1(c)(3) of the NER requires the AER to have regard to the desirability of consistency in the regulatory approach and the form of regulation within and beyond NEM jurisdictions. The AER notes that public lighting services in most other NEM jurisdictions are regulated as direct (alternative) control services. While in some jurisdictions public lighting services are regulated as negotiated services, as is the case in South Australia, it is unusual for public lighting to be completely unregulated.

Clause 6.2.1(d)(2) of the NER requires the AER, where there has been no previous classification, to adopt an approach that is consistent with the previous applicable regulatory approach (unregulated), unless a different classification is clearly more appropriate. The AER’s view is that in having regard to the factors in clause 6.2.1(c) of the NER, it is clearly more appropriate to classify public lighting services.

The AER is inclined to classify public lighting services (excluding those relating to alteration and relocation of existing public lighting assets, and new public lighting technology) as direct control services rather than negotiated distribution services as it would appear that charges for these public lighting services can be determined upfront in the price determination stage, and this may be superior to the potential for a series of negotiated outcomes during the regulatory control period

New public lighting technologies

As outlined above, the difference between new public lighting technologies services, and the public lighting service classified above is that they relate to types of luminaires that Aurora does not currently provide. Therefore, the AER considers that its analysis of 6.2.1(c) above applies to the new public lighting technologies service. Similar to the public lighting services considered above this service has not been previously classified in Tasmania, but a similar service has recently been classified in Victoria.

For the purposes of 6.2.1(c)(4), the AER considers that a factor relevant to consideration of the classification of this service is the inability for charges for these services to be determined by the AER in making its distribution determination due to the uncertain nature of the costs of this service. The AER considers that the inability to determine charges for these services upfront means that classifying these services as direct control services is not practical.

As outlined above, this service was previously unregulated, which creates the presumption that this service should not be classified unless a different classification is clearly more appropriate. For the same reasons as for the public lighting services classified as direct control services, the AER considers that a different classification is clearly more appropriate. However, due to the uncertain nature of the costs of this service and the practical difficulties that this uncertainty creates for setting charges in the distribution determination, the AER considers that classifying this service as a direct control services is appropriate in this instance.

On this basis, the AER's likely approach to classifying new public lighting technologies is as a negotiated distribution service. Such a classification prevents Aurora from exercising its market power in the provision of these services while also accounting for the difficulty that the uncertainty of the costs of providing these services poses for the classification of these services as direct control services.

Classification of public lighting services as standard control services or alternative control services

Once a service is classified as a direct control service, the AER must then have regard to the six factors in clause 6.2.2(c) of the NER in deciding whether that service should be further classified as a standard or alternative control service. Having regard to the factors under clause 6.2.2(c) of the NER, the AER considers that it would be clearly more appropriate to depart from the previous regulatory approach (unregulated). The AER considers it appropriate to classify public lighting services as direct control services, and further classify them as alternative control services.

This is because the AER considers that:

- For the reasons noted above, unless contestability for these services is introduced during the regulatory control period, there will continue to be little if any potential for the development of competition for the provision of public lighting services using Aurora's assets. Classification of public lighting services as alternative control services would not impede the ability of third parties and new entrants to provide public lighting services on assets not owned by Aurora.

- The classification of public lighting services as alternative control services may encourage the entry of other potential service providers in the long term, as there would be a greater transparency of public lighting tariffs to be charged to customers (as the charges would be determined and published by the AER).

- Although there would be some impact on the administrative costs of the AER and Aurora in classifying the public lighting services as alternative control services since these services have not previously been regulated; Aurora has advised that it uses an internally based building block approach for setting its charges for public lighting services.[132]

- The existence of this model may enable the AER to analyse and refine this model to determine charges for public lighting services, rather than developing a new public lighting model.

- Public lighting services are currently regulated in New South Wales, Queensland and Victoria (for operation, maintenance and repair) as alternative control services.

- The costs of providing public lighting services can be directly attributed to a specific set of customers including local councils, DIER and other state and local government authorities. The AER considers it would therefore be more appropriate for these customers to incur the associated costs, rather than spread the costs across all electricity customers in Tasmania.

[132] Aurora, Information paper, May 2010, p. 8.

The AER's likely approach

The AER's likely approach is that Aurora's public lighting services should be classified in a manner which is consistent with the AER's consideration of the form of regulation factors under section 2F of the NEL and the relevant provision under section 6.2.1 and 6.2.2 of the NER.

On this basis, the AER's likely approach is to classify:

- the repair, replacement and maintenance of Aurora's public lighting assets as a direct control service, and in turn as an alternative control service, because of Aurora's monopoly position in the provision of these services.

- the repair, replacement and maintenance of public lighting owned by third parties (where Aurora undertakes the service for a fee) as a direct control service, and in turn as an alternative control service because of Aurora's monopoly position in the provision of these services.

- the provision of new public lighting assets (standard and non-standard provision) as a as a direct control service, and in turn as an alternative control service, because of Aurora's current monopoly position in the provision of these services.

- the provision of new public lighting technologies, as a negotiated distribution service due to the uncertain nature of the costs of this service and the practical difficulties that this uncertainty creates for setting charges in the distribution determination.

The classification of the alteration and relocation of public lighting assets is considered in section 2.5.3.6 under quoted services.

2.5.3.4 Fee based services

Aurora provides a range of fee based 'special services' and these services are, in general, provided for the benefit of a single customer rather than uniformly supplied to all network customers. Services of this type are generally, but not always, homogenous in nature and scope and therefore their costs can be estimated with reasonable certainty. This means that for many of these special services a fixed fee can be set in advance. In other jurisdictions, services of this type have typically been treated as excluded services under the NER[133] and are also usually charged on a fixed fee basis to customers.

Current classification

In its special services final determination, the special services provided by Aurora were separated by OTTER into two types: standard special services, also referred to as the reference set, and miscellaneous (or other distribution) special services.[134]

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[133] OTTER, *Maximum Prices for Special Services*, June 2008, p. 5.

[134] OTTER refers to these as miscellaneous special services in its special services determination, but Aurora refers to them as other distribution special services.

Reference set of special services

The reference set of special services contains the following categories of service for customers:

- energisation, de-energisation and re-energisation (see also section 2.5.3.5)
- meter alteration
- meter testing.

This reference set of special services was declared by OTTER and is regulated under a weighted average price cap. OTTER sets the maximum prices for these services and average price increases, which do not occur automatically, are determined each year as part of the annual pricing process. The AER notes that the increases in prices are to be no more than the increase in the Weighted Average Wage Index for the Electricity Gas and Water Supply Industry in the preceding calendar year.[135]

Other distribution special services

In addition to the reference set of special services discussed above, Aurora provides several special services that are not regulated by OTTER through a weighted average price cap. Rather, Aurora is required to submit for approval a list of all other distribution special services and their proposed prices for the following 12 months to OTTER as part of the annual tariff setting process. OTTER also requires Aurora to publish its charge out rates that will be used in pricing of all non-standard (quoted) services (see section 2.5.3.6).[136]

Other distribution special services are generally provided as a result of a customer or retailer request and are categorised by Aurora as:

- new connection—permanent supply
- supply abolishment—removal of meters and service connection
- renewable energy connection
- new connection—temporary and temporary ‘in perm’
- new connection—temporary show and carnival connection
- truck tee-up
- miscellaneous services.[137]

The AER notes that while new connections are listed by Aurora as a fee based service, Aurora provides this service at no up-front cost to the customer, and that the

135 Under the Tariff Customer Regulations, Aurora is required to seek approval for any change to its tariffs. Once approved, the fee for these services is approved for the relevant period, which is a usually a year.

136 OTTER, *Maximum Prices for Special Services*, June 2008, p. viii.

137 Aurora, *Information Paper*, May 2010.

costs associated with meter installation and service connection are recovered through DUOS charges.[138] Connection services are further discussed (below) in section 2.5.3.5.

OTTER determined, at the time of the 2008 special services determination, that there was no benefit in regulating other distribution special services under a price cap as:

- they had not previously been regulated
- there was no evidence of Aurora abusing its monopoly power.[139]

OTTER did, however, note that while it had chosen not to regulate these services, that decision was not a sufficient reason not to regulate them in future.[140] Specifically, OTTER noted that:

> ... the Special Services listed in Table 2.5 had not previously been regulated, but noted that this in itself was not a sufficient reason not to regulate them in future. The underlying issue was whether the benefits of regulation would outweigh the costs of regulation. Whilst Aurora is the monopoly provider of these services there is a prima facie case that regulation is appropriate. However, in the absence of any documented complaints that the charges had been excessive, there appeared to be no real evidence that Aurora was abusing its monopoly power such that customers would benefit from including these in the set of Special Services regulated by price cap.[141]

Further, OTTER's requirement that Aurora submit prices annually indicates that, in effect, other distribution special services are subject to a light-handed form of regulation (price monitoring) by OTTER.

The AER's preliminary position

The AER's preliminary position was that the reference set of fee based services should be classified as direct control services and, in turn, as alternative control services. The AER also considered that other distribution special services that fall outside of the reference set of services should also be classified as direct control services, and in turn, as alternative control services.

Submissions

The AER received a submission from Aurora on the classification of fee based services. Aurora concurred with the AER's preliminary position to classify all fee based services as alternative control services.[142]

Issues and AER considerations

Reference set of special services

Having regard to the requirements of clause 6.2.1(d) of the NER, the AER considers there is a presumption in relation to the reference set of special services that they

138 OTTER, Response to information requested on 24 May 2010, submitted on 24 May 2010.
139 OTTER, *Maximum Prices for Special Services*, June 2008, p. 19.
140 ibid.
141 ibid.
142 Aurora, *Response to AER preliminary positions paper*, 30 August 2010, pp. 14–16.

should be classified as direct control services in the forthcoming regulatory control period.

Fee based services provided by Aurora represent two different types of work—they either involve:

- work on, or in relation to, parts of Aurora's distribution network, and therefore only Aurora will be able to undertake these services
- work undertaken by Aurora for a retailer acting on behalf of a customer.

Having regard to the form of regulation factors in section 2F of the NEL, the AER considers that fee based services should be classified as direct control services. There are high barriers to entry for a third party competing with Aurora to provide fee based services on Aurora's assets within its existing supply area due to the licensing requirements and existing provisions of the ESI Act. The network services provided by Aurora (section 2.5.3.1) provide positive externalities in the supply of fee based services, on its own assets. Further, the economies of scale and scope available to Aurora, particularly in relation to its network services, are also likely to prevent fee based services being competitively provided by an alternative service provider

Aurora noted that there are no real opportunities for customers to exert countervailing market power for these services because although they can define the nature of the service provided, the service will still be provided by Aurora using Aurora's assets, in relation to Aurora's distribution network.[143] Customers will therefore not have negotiating power to determine the price and other terms and conditions on which these services are provided.

The AER also considers that there are no substitutes for these services. These factors contribute to the view that Aurora possesses significant market power in the provision of the reference set of fee based services.

The AER has also had regard to clauses 6.2.1(c)(2) and (3) of the NER and notes that the reference set of special services is currently subject to a control form of regulation in Tasmania (weighted average price cap), and that similar arrangements exist in several other jurisdictions in the NEM.

Having regard for the requirements of clause 6.2.1 of the NER, the AER considers that the reference set fee based services should be classified as direct control services.

Once a service is classified as a direct control service, the AER must then have regard to all six factors in clause 6.2.2(c) of the NER to determine whether the service should be classified as a standard or alternative control service.

As noted above, the reference set of special services are currently fee based distribution services, subject to a price cap. This creates the presumption under clause 6.2.2(d) of the NER that they should be classified as alternative control services unless there is a compelling reason not to. The AER considers that there is no basis to

143 ibid, p. 15.

move away from this presumption. Having regard to all the factors in clause 6.2.2(c), the AER considers that there is no basis to move away from this presumption because:

- As discussed above, there is little if any potential for the development of competition in the market for the reference set of special services. The AER considers that its classification will not influence the potential for competition—rather, the absence of competition due to Aurora holding the only distribution license for mainland Tasmania and by the requirements of the ESI Act.

- There would be no material effect on administrative costs of the AER, Aurora or any other party. This is because classifying fee based services as alternative control services would involve a broadly similar regulatory approach to that which has been applied by OTTER for the current regulatory control period. Aurora submitted that classifying these services as anything other than alternative control services would involve a change in administrative costs for Aurora as it would alter the way in which these services are provided.[144]

- Fee based services from the reference set of services are currently regulated in Tasmania, and in some NEM jurisdictions. Special services (or excluded services) in other NEM jurisdictions have operated in a range of market conditions, from no competition for the provision of services through to a competitive market. The AER notes, however, that energisation services and metering services are currently regulated in Victoria and in other NEM jurisdiction on a fixed fee basis.

- The costs of providing the service can be directly attributed to specific customers.

- There do not appear to be any other factors that are relevant to the AER's proposed classification.

For these reasons, the AER considers that there is no basis to move away from the presumption that the reference set of special services should be classified as alternative control services.

Other distribution special services

The AER considers, as per the earlier discussion on classification of services and having regard to the form of regulation factors in section 2F of the NEL, that there is a regulatory barrier to any party other than Aurora providing other distribution special services. Similar to the reference set of special services there are high barriers to entry for a third party competing with Aurora to provide fee based services on Aurora's assets within its existing supply area due to the licensing requirements and existing provisions of the ESI Act. Furthermore, the economies of scale and scope available to Aurora, particularly in relation to its network services, are also likely to prevent these fee based services being competitively provided by an alternative service provider. The AER also considers that there are no substitutes for these services. These factors contribute to the view that Aurora possesses significant market power in the provision of the other distribution special services.

OTTER's 2008 special services determination states an intention to not regulate other distribution special services, due to a lack of evidence that Aurora is abusing its

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144 Aurora, *Response to AER preliminary positions paper*, 30 August 2010, p. 15.

monopoly power such that customers would benefit from price cap regulation of these services.[145] That said, the AER notes that OTTER subjected these services to a light handed form of regulation that required Aurora to submit a list of charges for its other distribution special services at the same time it advised OTTER of the tariffs for the reference set of special services. Aurora is further obliged by OTTER to provide it with a list of charges in each year of the current regulatory control period, for approval.

The AER notes that for the purposes of clause 6.2.1(c)(3) of the NER, fee based services are subject to a direct form of control in other jurisdictions in the NEM.

The AER notes that clause 6.2.1(d) of the NER states that where a distribution service has been subject to regulation, there should be no departure from that classification unless another classification is clearly more appropriate.

Having regard to the requirements of clause 6.2.1(d) of the NER, the AER considers there is a degree of uncertainty in forming a view about the presumption in respect of other distribution special services because although they are classified by OTTER as unregulated, OTTER does subject these services to price monitoring. The AER notes that it is difficult to form a view on the presumption on the previous classification for these services in this instance as these services are currently subject to light handed regulation rather than unregulated.

However, the AER considers for the reasons discussed above in relation to the reference set of special services, for the purposes of clause 6.2.1(d) of the NER, other distribution special services should also be classified as direct control services.

Once a service is classified as a direct control service, the AER must then have regard to all six factors in clause 6.2.2(c) of the NER to determine whether the service should be classified as a standard or alternative control service.

As noted above, other distribution special services are currently unregulated fee based distribution services, subject to price monitoring. This creates a presumption under clause 6.2.2(d) of the NER that they should not be classified unless a different classification is clearly more appropriate. Having regard to the factors in clause 6.2.2 of the NER, the AER considers that it is clearly more appropriate to move away from this presumption and classify these services as alternative control services because:

- As discussed above, there is little if any potential for the development of competition in the market for other distribution special services. The AER considers that its classification will not influence the potential for competition—rather, the absence of competition due to Aurora holding the only distribution license for mainland Tasmania and by the requirements of the ESI Act.

- There would be a marginal material effect on administrative costs of the AER, the DNSP or any other party. This is because classifying other distribution special services as alternative control services would involve regulating them through a price cap, such as that which is applied to other distribution special services for

[145] ibid.

the current regulatory control period. Aurora would be required to continue to submit charges for each fee based service.

- The AER considers for the purposes of clause 6.2.2(c)(3) that although there is a discrepancy between OTTER's classification of other distribution special services (unregulated) and its treatment of them (price monitoring), OTTER can be considered to be in effect subjecting other distribution special services to a form of regulation. Specifically, Aurora is required to submit for approval a list of all the special services and their proposed prices for the following 12 months to OTTER each year as part of the tariff setting process.[146] This treatment creates a compelling argument to apply an alternative form of control.

- The AER also notes that other NEM jurisdictions including Queensland and Victoria regulate similar services charged on a fixed fee basis as alternative control services.[147]

- The costs of providing the service can be directly attributed to specific customers.

- There do not appear to be any other factors that are relevant to the AER's proposed classification.

The AER's likely approach

The AER's likely approach is to classify fee based services, which include the reference set of special services and other distribution special services, as direct control services, and further, to classify them as alternative control services.

2.5.3.5 Connection services

Chapter 10 of the NER effectively defines connection services as consisting of entry services and exit services. An entry service is a service provided to serve a generator or group of generators, or a network service provider or group of network service providers, at a single connection point. An exit service is a service provided to serve a distribution customer or a group of distribution customers, or a network service provider or group of network service providers, at a single connection point.

Section 26 of the ESI Act also places an obligation on Aurora to connect a customer unless there is scope that the connection would:

- be detrimental to the network

- be in contravention of its licence conditions

- increase the risk of fire or damage to life or property.

This section of the ESI Act also gives guidance as to when electricity supply can be interrupted. Once a customer has been connected, the connection point is energised by Aurora. This energisation service is generally undertaken by Aurora for a retailer acting on behalf of a customer. This is a new connection service within the meaning

146 OTTER, *Maximum Prices for Special Services*, June 2008, p. viii.

147 AER, *Queensland final distribution determination*, May 2010, pp. 378–384; AER, *Victorian draft distribution determination–Appendices*, June 2010, pp. 2–3.

of the Australian Energy Market Operator's *B2B Procedure - Service Order Process*, which means that this service is charged on a fixed fee basis under these procedures. The scope of these services is also uniform across customers.

The energisation component of connection services has been declared as a special service by OTTER and is discussed under fee based services (section 2.5.3.4).

Current classifications

Standard connections

OTTER, in its 2007 declaration, grouped new connections under special services. However, the AER notes that the 2008 special services determination does not include connection services in the reference set of special services. However, as mentioned in section 2.5.3.4, Aurora has advised the AER that:

- Although new connection services are listed as fee-based special services, the fee for the installation of the meter and service in normal business hours (a standard connection service) is zero ($0), as these costs are recovered by Aurora through DUOS charges. That is, a customer does not pay for this service through an up-front fee.[148]
- Where a standard connection is not viable due to the cost of the connection and the expected revenue from standard tariffs, a capital contribution is charged to the customer.[149]
- Standard connection services are currently provided within the broader offering of network services (section 2.5.3.1).[150]

Aurora's approach to recovering costs of standard connection (and connection augmentation) is based on Aurora's adaptation of the original Hydro-electric Commission service and installation by-laws of 1993. These by-laws only required customer contributions if the customer required more than two spans of service.[151] The costs of standard connections are currently recovered through DUOS charges.[152]

New connections requiring augmentation

Aurora has advised the AER that connection services requiring augmentation relate to:[153]

- building connection assets at the customer's premises;
- modifying the existing distribution network or building additional network; and
- connecting those connection assets to the augmented distribution network.

148 OTTER, Response to information requested on 24 May 2010, submitted on 24 May 2010
149 Aurora, *Information Paper*, p. 15.
150 Aurora, Response to AER preliminary positions paper, 30 August 2010, p. 16
151 OTTER, Response to information requested on 27 May 2010, submitted on 27 May 2010.
152 ibid.
153 Aurora, *Response to AER preliminary positions paper*, 30 August 2010, p. 17.

Aurora has also advised the AER that connection services requiring augmentation are currently provided within the broader offering of network services (section 2.5.3.1). The provision of connection services requiring augmentation therefore consists of standard connection services, and in most instances, standard network services.[154]

Capital works therefore need to be undertaken to provide the connection, and the associated costs cannot always be fully recovered by Aurora. In this situation, the customer is required to pay a capital contribution to Aurora.[155]

Aurora has a suite of internal guidelines relating to customer connections.[156] One of Aurora's policies is to connect customers at least cost unless otherwise agreed to by the customer.[157] Aurora is intending to revise its customer contribution guidelines prior to the commencement of the forthcoming regulatory control period.[158]

According to the current guidelines, Aurora will subsidise the costs of providing connections based on a set of predetermined subsidies. Where the subsidies do not cover the total cost of the connection, the customer pays the shortfall.[159] Subsidies provided by Aurora include a:

- metering subsidy
- service connection subsidy (includes services conductor or cable, service fusing equipment, service terminating equipment and service enclosure equipment)
- transformer installation subsidy
- public road extension subsidy (extension of up to two spans of overhead power line along a public road or street).[160]

This procedure has been established to ensure that, as far as reasonably practicable, all customers are treated equally, cross subsidies are limited, and costs related specifically to an individual customer are borne by that customer, and not the general customer base through DUOS charges.[161] Aurora recovers the cost of its subsidies through DUOS charges.[162]

The current arrangement for the recovery of capital contributions from customers is not regulated by OTTER as Aurora's guidelines are not subject to OTTER approval. The AER considers that this means that the capital contributions component of new connections requiring augmentation is effectively unregulated.

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154 ibid.
155 Aurora, *Information Paper*, p. 15.
156 These include: *Extension of the network when a customer(s) or developer is required to contribute to the cost,* 1 July 1998; Aurora, *Overhead electricity supply at low voltage*, 29 June 2004; and *Aurora network's customer capital contribution policy*, 11 May 2006.
157 Aurora, *Aurora network's customer capital contribution policy*, 11 May 2006, p. 5.
158 Aurora, Response to information requested on 25 May 2010, submitted on 25 May 2010.
159 Aurora, *Overhead electricity supply at low voltage*, p. 7.
160 ibid., p. 7.
161 ibid., pp. 7–8.
162 OTTER, Response to information requested on 27 May 2010, submitted on 27 May 2010.

As noted earlier, the standard connection service component of connections requiring augmentation (installation of meter and service) is recovered through DUOS charges. Some standard elements of connection augmentation (such as additional service spans) are charged by Aurora on a fixed fee basis, and these are price monitored by OTTER. Beyond this, the cost of connection augmentations are recovered from customers via a capital contribution, and the subsidies provided by Aurora are recovered through DUOS charges.

The AER's preliminary position

The AER's preliminary position was that standard connection services provided by Aurora and connections requiring augmentation should be classified as direct control services, and further classified as standard control services.

The AER considered that the capital contributions component of connections requiring augmentation paid for by the customer would remain unregulated. The customer connections policy in the National Energy Customer Framework (NECF), once finalised and implemented,[163] is likely to provide more guidance to Aurora and customers on the determination and allocation of connection augmentation costs.

Submissions

The AER received a submission from Aurora on the classification of connection services. Aurora concurred with the AER's preliminary position to classify all connection services as standard control services.[164]

Issues and AER considerations

Standard connections

In determining the appropriate classification for connection services the AER has first had regard to all of the four factors in clause 6.2.1(c) of the NER, including the form of regulation factors contained in section 2F of the NEL.

As detailed in the AER's consideration of network services, Aurora holds the only electricity distribution licence in Tasmania. The AER therefore considers that the Tasmanian arrangements effectively amount to a regulatory barrier to entry for the purposes of section 2F(a) of the NEL. Similarly, the AER considers that for the purposes of sections 2F(b) and 2F(c) of the NEL, the economies of scale and scope available to Aurora are also likely to prevent standard connection services being competitively provided through an alternative source. The AER therefore considers that Aurora possesses significant market power in the provision of standard connection services.

Under clause 6.2.1(d) of the NER, there is a presumption that the classification should be consistent with the previously applicable regulatory approach unless another approach is clearly more appropriate. However, in the case of standard connection services, the current regulatory approach is somewhat unclear. Despite OTTER previously classifying standard connection services as special services (regulated under a price cap) the costs of these are currently recovered through DUOS charges.

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163 NECF was introduced into the South Australian Parliament during the spring 2010 sitting and will be progressively introduced into other jurisdictions.

164 Aurora, *Response to AER preliminary positions paper*, 30 August 2010, pp. 17–18.

Aurora has also stated that standard connection services are provided within the broader offering of 'network services', which are standard control services.[165] For the purposes of clause 6.2.1(d), the AER considers a direct form of control is consistent with the current treatment of standard connection services.

Having regard for the requirements of clause 6.2.1 of the NER, the AER considers that connection services should be classified as direct control services.

Once a service is classified as a direct control service, the AER must then apply the factors in clause 6.2.2(c) of the NER to determine whether it should be classified as a standard or alternative control service.

- As discussed above, there is little if any potential for the development of competition in the market for connection services. The AER considers that its classification will not influence the potential for competition—rather, the absence of competition due to Aurora holding the only distribution license for mainland Tasmania and by the requirements of the ESI Act.

- There would be no material effect on administrative costs of the AER, DNSP or any other party if the services were classified as standard control services. However, there would be some administrative cost in classifying these services as alternative control services as Aurora would be required to submit charges for each standard connection service.

- As outlined above, the previous regulatory approach in Tasmania involved recovering the costs of standard connection services through DUOS charges. This means that the costs are spread across all electricity distribution customers.

- The nature of connection services is that the customer that requested the service will benefit from the provision of that service, and as such, the costs are directly attributable to specific customers.

- In Queensland and South Australia the costs of standard connection services are recovered through DUOS charges, while in Victoria, standard connection services are classified as alternative control services.

- There do not appear to be any other factors that are relevant to the AER's proposed classification.

Clause 6.2.2(d) of the NER provides that the AER must act on the basis that there should be no departure from a previous regulatory approach unless another classification is clearly more appropriate. The AER is not inclined to depart from the previous regulatory approach because the AER considers that recovery of the costs of standard connection services through DUOS charges (ie spread across all customers and regulated under a revenue cap) is appropriate, due to the reasons discussed above.

Connections requiring augmentation

These connections require an augmentation or extension to the distribution network, in order to connect the customer. That is, capital works need to be undertaken in order

[165] Aurora, Response to AER preliminary positions paper, 30 August 2010, p. 16.

to provide the connection. The cost associated with these services cannot always be fully recovered through the customer's supply and usage tariff over the life of the new assets installed to facilitate that connection. In these circumstances, customers are required to pay an upfront financial capital contribution.

Part K of chapter 6 of the NER provides for the establishment of prudential requirements for connection services, which may include financial capital contributions and non-cash contributions. Part K regulates the treatment of capital contributions to a limited extent by preventing DNSPs from receiving income twice for the same assets through such prudential requirements and distribution service prices.

In addition, the dispute resolution procedures set out in Part L of Chapter 6 of the NER may also have application in respect of capital contributions where a dispute arises between the DNSP and the connection applicant in respect of new connection services.

However, because these capital contributions are 'works' they do not constitute a service, but a contribution to the costs of the connection service. It follows that capital contributions do not fall within the meaning of distribution service in chapter 10 of the NER and cannot be the subject of classification in clause 6.2.1 of the NER. As it is not possible for the AER to separately classify capital contributions as services under the NER, the AER may only regulate the actual connection requiring augmentation ‘service’.

Classification of connections requiring augmentation currently varies between jurisdictions, but is worth considering in the context of Tasmania.

In determining the appropriate classification for connections requiring augmentation the AER has first had regard to all of the four factors in clause 6.2.1(c) of the NER, including the form of regulation factors contained in section 2F of the NEL.

As detailed in the AER’s consideration of network services, Aurora holds the only electricity distribution licence in Tasmania. The AER therefore considers that the Tasmanian arrangements effectively amount to a regulatory barrier to entry for the purposes of section 2F(a) of the NEL. Similarly, the AER also considers that for the purposes of sections 2F(b) and 2F(c) of the NEL, the economies of scale and scope available to Aurora are also likely to prevent connections requiring augmentation being competitively provided through an alternative source.

In addition, as noted above, capital contributions for connections requiring augmentation are not regulated in Tasmania. There is no regulated guideline or arrangement to cover the quantum of capital contributions, or a dispute resolution mechanism like there is in other NEM jurisdictions. Aurora’s connection and capital contributions procedures and policies are not subject to OTTER approval. The AER therefore considers that Aurora possesses significant market power in the provision of connections requiring augmentation.

Under clause 6.2.1(d) of the NER, there is a presumption that the classification should be consistent with the previously applicable regulatory approach unless another approach is clearly more appropriate. As with standard connection services, the current regulatory approach for new connections requiring augmentation is somewhat unclear. Aurora has also stated that standard connection services are provided within the broader offering of 'network services', which are standard control services.[166] The AER considers a direct form of control is most appropriate given that Aurora currently recovers the cost of connection services and subsidies provided for augmentation through DUOS charges, despite connection services being special services subject to price monitoring.

The AER has also had regard to clauses 6.2.1(c)(2) and 6.2.1(c)(3) of the NER and notes that connections requiring augmentation are currently subject to a form of control regulation in Tasmania.

In Victoria, connections requiring augmentation are classified as standard control services, with capital contributions for augmentation works regulated by the Essential Service Commission's (ESCV) Guideline 14. This classification is consistent with the previous regulatory approach except that the ESCV classified capital contributions as an excluded service. Under the NER, the AER is not permitted to separately classify capital contributions for augmentation works because they are costs of the connection service.

In New South Wales, clause 6.2.3B of the transitional Chapter 6 rules specified the classification that the AER was required to apply in the prior regulatory control period. For customer funded connection services, the AER did not depart from the Independent Pricing and Regulatory Tribunal's 'unregulated' classification.[167]

In Queensland, the AER placed significant weight on the potential for competition to develop in relation to the design and construction of large connection assets (essentially connections requiring augmentation), and classified this as an alternative control service. The design and construction of small connection assets is a standard control service.[168] Both Queensland DNSPs have capital contribution policies approved by the Queensland Competition Authority.

In South Australia, new or upgraded connection services (to the extent the user is not required to make a financial contribution under the Essential Service Commission of South Australia's (ESCOSA) Electricity Distribution Code), are classified as standard control services. New or upgraded connection services (to the extent the user is required to make a financial contribution under the Electricity Distribution Code), are classified as negotiated services.[169] These classifications are consistent with the previous regulatory approach in South Australia.

Having regard to the factors in clause 6.2.1 of the NER, the AER considers that connections requiring augmentation should be classified as direct control services.

Once a service is classified as a direct control service, the AER must then apply the factors in clause 6.2.2 of the NER to determine whether it should be classified as a

166 Aurora, Response to AER preliminary positions paper, 30 August 2010, p. 16.

167 AER, *New South Wales draft distribution determination 2009–10 to 2013–14*, November 2008, pp. 17–p. 36.

168 AER, *Framework and approach paper—Classification of services and control mechanisms for Energex and Ergon 2010–15,* August 2008, p. 20.

169 AER, *Framework and approach paper—ETSA Utilities 2010–15 (final),* November 2008,, p. 20.

standard or alternative control service. Having regard to clause 6.2.2(d) and the factors in clause 6.2.2(c) of the NER, the AER does not consider that there is a need to move away from the current regulatory approach for the following reasons:

- As discussed above, there is little, if any, potential for the development of competition in the market for connections requiring augmentation. The AER considers that its classification will not influence the potential for competition—rather, the absence of competition due to Aurora holding the only distribution license for mainland Tasmania and by the requirements of the ESI Act.

- There would be a marginal effect on administrative costs of the AER, DNSP or any other party. This is because classifying connections requiring augmentation as standard control services would involve regulation under a revenue cap. However, the AER notes that although this is a change in regulatory approach, Aurora's current practice is to recover costs through DUOS charges.

- Although classification of connections requiring augmentation varies across jurisdictions, classification as a standard control service is largely consistent with the Victorian draft distribution determination, albeit that in Victoria, capital contributions are regulated under Guideline 14 in Victoria, but not regulated in Tasmania.

- The nature of connections requiring augmentation is that the service can be attributed to a specific customer (or group of customers).

- There do no appear to be any other factors that are relevant to the AER's proposed classification.

The AER therefore considers that, having regard to clauses 6.2.1 and 6.2.2 of the NER, the most appropriate classification for new connections requiring augmentation is direct control services, and further, standard control services.

As discussed above, the prudential requirements in Part K of chapter 6 of the NER provide that Aurora will not be entitled to a return of, or return on, capital contributions for augmentation works paid for by the customer in addition to that received from distribution service prices.

Further, as there is no regulatory instrument in Tasmania that governs capital contributions, and the NER prevents the AER from regulating augmentation works as a service, capital contributions for augmentation works paid for by the customer will remain unregulated. However, since the release of the AER's preliminary positions paper, two bills were introduced into the South Australian Parliament in October, as part of the NECF package of bills.[170]

The NECF will contain provisions for customer connections (although these are still in development), and provide for greater competition, strong protections for energy customers and at the same time reduce regulatory burdens on energy businesses.[171]

170 Ministerial Council on Energy, Standing Committee of Officials Bulletin No. 185, 5 November 2010.

171 ibid.

The AER expects that the transition from the Tasmanian jurisdictional framework to the NECF and the associated transfer of functions to the AER will occur during the forthcoming regulatory control period.

The AER's likely approach

The AER’s likely approach is to classify all connection services as direct control services, and further classify them as standard control services. Consistent with the AER's preliminary position, the AER considers that the capital contributions component of connections requiring augmentation paid for by the customer will remain unregulated. The customer connections policy in the NECF, once finalised and implemented,[172] is likely to provide more guidance to Aurora and customers on the determination and allocation of connection augmentation costs.

2.5.3.6 Quoted (non-standard) services

As noted in the discussion on other distribution special services (section 2.5.3.4), Aurora provides a range of non-standard services on a quoted basis. Examples of these services include, but are not limited to:

- removal or relocation of Aurora’s assets at a customer’s (for example, the Tasmanian Government’s) request
- services that are provided:
  - at a higher standard than the standard service, due to a customer’s request for Aurora to do so
  - through a non-standard process at a customer’s request (for example, where more frequent meter reading is required).[173]

The nature and scope of these services are specific to individual customers’ needs, and as a result variable from customer to customer. Therefore, the cost of providing the services cannot be estimated without first understanding the customer’s specific requirements. It is not appropriate to set a generic total fixed fee in advance for these services.[174]

In its preliminary positions paper, the AER referred to these services as non-standard services.[175]

Current classifications

As noted in the discussion for other distribution special services (section 2.5.3.4), OTTER recognised that in some circumstances the specification of a fixed price is not always feasible. Consequently, OTTER determined that Aurora should publish its

[172] Two NECF bills were introduced into the South Australian Parliament in October 2010 and if passed will be progressively introduced into other jurisdictions.
[173] Aurora, *Information paper*, May 2010, p. 18.
[174] Aurora, *Response to AER preliminary positions paper*, 30 August 2010, p. 7.
[175] AER, *Preliminary positions–framework and approach paper, Aurora Energy Pty Ltd, Regulatory control period commencing 1 July 2012*, June 2010, pp. 52-53.

charge out rates used to calculate the requisite charge for all quoted services.[176] Specifically, OTTER stated that:

> Given this, the Regulator considers that transparency would best be promoted by means of Aurora publishing its charge out rates. That is, Aurora should be able to publish the call out and hourly charge out rate for a service truck with qualified technician to attend a customer's premise.[177]

OTTER therefore determined that it would:

> …require Aurora to publish its fees and charges for all Special Services, including its charge out rates used to calculate the requisite charge for all non-standard services. [178]

The AER notes that the actual unit price is not assessed or approved by OTTER; Aurora is only required to publish this information. That is, these services are effectively 'unregulated'. This is distinguished from fee-based services, where OTTER assesses and approves the prices.

The AER's preliminary position

The AER's preliminary position was that Aurora's quoted services should be classified in a manner which is consistent with the previously applicable regulatory approach, and indicated that they would be unregulated.

Submissions

The AER received a submission from Aurora on the classification of these services. Aurora concurred with the AER's preliminary position to not classify quoted services.[179]

Issues and AER considerations

As indicated in section 2.5.3.3 above, the AER now considers that it is appropriate to consider the classification of the following services together with other quoted services as they are similar in nature:

- alteration and relocation of existing public lighting assets owned by Aurora at the request of a third party; and
- alteration and relocation of existing public lighting assets owned by a third party at the request of that customer or third party.

In classifying services as direct control services, negotiated services or unregulated services under the NER, the AER must consider:

- the form of regulation factors set out at section 2F of the NEL
- the form of regulation previously applicable to the service(s) – particularly the classification under the previous regulatory regime

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[176] OTTER, *Maximum Prices for Special Services*, June 2008, p. 20.
[177] ibid., p. 23.
[178] ibid, p. 20.
[179] Aurora, *Response to AER preliminary positions paper*, 30 August 2010, pp. 17–18.

- the desirability of consistency in the form of regulation for similar services in other jurisdictions.[180]

As detailed in the AER's consideration of other services, Aurora holds the only electricity distribution licence in Tasmania. The AER therefore considers that the Tasmanian arrangements effectively amount to a regulatory barrier to entry for the purposes of section 2F(a) of the NEL.

Similarly, the AER considers that for the purposes of sections 2F(b) and 2F(c) of the NEL, the economies of scale and scope available to Aurora, particularly in relation to non-standard network services are also likely to prevent quoted services being competitively provided through an alternative source. Although Aurora is currently required to publish its charge out rates, the AER considers that in itself, this is not sufficient information to neutralise the lack of countervailing market power caused by these other form of regulation factors.

As noted in the discussion for other distribution special services (section 2.5.3.4), OTTER has recognised the existence of quoted services, and has indicated that in some circumstances the specification of a fixed price is not always feasible. Consequently, OTTER determined that Aurora should publish its charge out rates used to calculate the requisite charge for all quoted services.[181]

The actual unit price is not assessed or approved by OTTER; Aurora is only required to publish this information. That is, these services are effectively 'unregulated'.

Clause 6.2.1(d) of the NER states that where a distribution service has been subject to regulation, there should be no departure from that classification unless another classification is clearly more appropriate.

Having regard to the requirements of clause 6.2.1(d) of the NER, the AER considers there is a degree of uncertainty in forming a view about the presumption in respect of quoted services because they are not currently subject to any substantive form of regulation by OTTER. OTTER does require that Aurora publish its charge out rates, but does not require Aurora to submit them for approval by OTTER. The AER considers that it was not OTTER's explicit intention for these services to be regulated, given the uncertain nature of the service to be provided, and the absence of any evidence of Aurora abusing its monopoly power.

However, despite not explicitly regulating quoted services, the AER does consider it was OTTER's intention that the charge out rates be publicly available so that electricity customers are able to view these rates. The AER also considers that quoted services are very similar to fee based services, except that rather than being charged at a fixed rate, customers are charged based on a quote, because the service required is not standard.

Services of this nature are provided in other NEM jurisdictions. These have been previously considered, and classified by the AER in recent distribution determinations as direct control services (alternative control services):

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180 NER, cl. 6.2.1 (c)

181 OTTER, *Maximum Prices for Special Services*, June 2008, p. 20.

- in Victoria - rearrangement of network assets at customer request, and elective undergrounding
- in South Australia – asset relocation, temporary disconnection and temporary line insulation
- in Queensland – removal or relocation of assets at customer request, and moving the point of attachment at customer request.[182]

These are currently being provided on a 'quoted service' basis. Common characteristics of these services are:

- they can only be provided by the DNSP in that state (or area) – the customer cannot seek the service from another party
- they incur costs that can be attributed to one customer
- the cost of providing the service is variable, depending on the individual customer. As such, a fee cannot be discerned in advance.

For Tasmania, the AER has considered the form of regulation factors and the treatment of these services in other jurisdictions. On balance, the AER considers that these services should be classified and regulated under the NER, despite the fact that they were not directly regulated by OTTER. The AER also notes that:

- Aurora is the only party that can provide these services at present
- there is nothing to indicate that other parties are willing, or able to provide this service in the forthcoming regulatory control period, given that Aurora has monopoly ownership distribution infrastructure in Tasmania
- there are no real substitutes for these services
- demand for these services is relatively inelastic.

On this basis, these services should be classified as direct control services, rather than negotiated services.[183]

In undertaking this assessment, the precise nature of these services is still somewhat uncertain. The AER has sought further information from Aurora on the scope of these services since releasing its preliminary positions paper. In response, Aurora provided further clarity:

> The customer may require a dedicated supply route with no shared use of network assets. The customer is effectively given a dedicated feeder that for

[182] AER, *Victorian distribution determination 2011-2015, Final decision*, October 2010, appendix B; AER, *South Australian distribution determination 2010-2015, Final decision*, May 2010, appendix A; AER, *South Australian distribution determination 2010-2015, Final decision*, May 2010, appendix A.

[183] This classification occurs through cl. 6.2.2 of the NER.

> all intents and purposes becomes a dedicated connection asset for that customer.
>
> The customer may require enhanced security of supply via alternative network connection points. The customer will be provided with automatic 'cut-over' switches that will transfer loads in the event of normal operating conditions failing.
>
> The customer may require 'emergency' capacity to meet 'peaky' loadings. The outcomes will be provided with connection assets that are rated higher than 'normal' operating conditions.[184]

Aurora also indicated that it did frequently undertake services that would fall within the alteration and relocation of assets service. Aurora had performed a minimum of 417 of these services since 1 January 2008.[185] Further, Aurora noted that:

> Asset removals or relocations typically involves the relocation of existing overhead infrastructure i.e. poles and wires, and are typically undertaken in conjunction with road works by government authorities. The customer (road authority) is charged for Aurora's costs to remove the existing assets and replace that infrastructure with a like-for-like construction in an alternate location. Each of these relocations is separately calculated and the charge is therefore individual to each customer.[186]

The AER expects that Aurora will provide a break down of these services as part of its regulatory proposal.[187] Based on the information currently before the AER, it appears that these services are analogous to similar services in other jurisdictions – such as the services listed for Queensland, South Australia and Victoria above.

The AER considers that following services are direct control services;

- removal or relocation of Aurora's assets at a customer's (for example, the Tasmanian Government's) request
- services that are provided:
  - at a higher standard than the standard service, due to a customer's request for Aurora to do so
  - through a non-standard process at a customer's request (for example, where more frequent meter reading is required).[188]

Once a service has been classified as a direct control service, the AER must further classify it as a standard control service or an alternative control service. This sub classification is undertaken under cl. 6.2.2 of the NER. The AER's consideration of cl. 6.2.2 is set out below:

- There is little if any potential for the development of competition in the market for quoted services. The AER considers that its classification will not influence the

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184 Aurora Energy, *Correspondence regarding non-standard services*, 5 November 2010, p .2.
185 ibid.
186 ibid, p. 2-3.
187 Aurora Energy's regulatory proposal is due in May 2011.
188 Aurora, *Information paper*, May 2010, p. 18.

potential for competition—rather, the absence of competition due to Aurora holding the only distribution license for mainland Tasmania and by the requirements of the ESI Act.

- There would be some additional effect on administrative costs of the AER, the DNSP or any other party. This is because classifying quoted services as alternative control services would involve regulating the costs of inputs (charge out rates), which has not previously been conducted (although Aurora has determined charges for these services during the regulatory period).

- For the purposes of clause 6.2.2(c)(3), although there is a discrepancy between OTTER's classification of other distribution special services (unregulated) and its treatment of them (a form of price monitoring), the AER considers that while OTTER's intention may not be to explicitly regulate quoted services, OTTER does intend for electricity customers to be able to view Aurora's charge out rates.

- The AER also notes that other NEM jurisdictions including Queensland and Victoria regulate similar services charged on a quoted basis as alternative control services.[189]

- The costs of providing a quoted service can be directly attributed to specific customers.

- The AER does not consider there are any other factors relevant to the AER's proposed classification.

On this basis, the AER will classify these as quoted alternative control services for the forthcoming regulatory control period. That is, the AER will not approve a charge for these services as part of the distribution determination. Rather, the AER will set price caps on the individual cost inputs for these services – namely, labour and materials.

The AER's likely approach

The AER's likely approach is to classify quoted services as standard control services, and further classify them as alternative control services.

2.6 AER's likely approach to service classification

Except where the NER require that a service of a specified kind be classified in a particular way, in classifying distribution services that have previously been subject to regulation under the present or earlier legislation, the NER require the AER to act on the basis that, unless a different classification is clearly more appropriate:

- there should be no departure from a previous classification if the services have been previously classified

- if there has been no previous classification—the classification should be consistent with the previously applicable regulatory approach.[190]

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[189] AER, *Queensland final distribution determination*, May 2010, pp. 378–384; AER, *Victorian draft distribution determination–Appendices*, June 2010, pp. 2–3.

Having regard to the requirements of the NER and NEL, and the regulatory approach applicable to distribution services provided by Aurora in the current regulatory control period, the AER's likely approach is that distribution services currently classified as:

- standard network services will be classified as direct control services and further classified as standard control services
- connection services (standard connections and connections requiring augmentation) will be classified as direct control services and further classified as standard control services; and capital contributions made by customers will remain unregulated
- type 5, 6 and 7 metering services will be classified as direct control services and further classified as alternative control services
- PAYG metering services provided by Aurora Retail will remain unregulated
- public lighting services (except for new public lighting technology services and alteration and relocation of public lighting assets) will be classified as direct control services and further classified as alternative control services
- new public lighting technology services will be classified as negotiated distribution services
- fee based services (special services) will be classified as direct control services and further classified as alternative control services
- quoted (non-standard) services, including non-standard network and metering services, and alteration and relocation of public lighting assets, will be classified as direct control services and further classified as alternative control services

The AER's likely approach is that having considered and assessed the classifications currently in place for all services against the factors in clauses 6.2.1 and 6.2.2 of the NER, there is nothing to suggest that classifying the services differently to that detailed above is appropriate.

The NER also require the AER to have regard to the desirability of consistency in the regulatory approach and form of regulation within and beyond specific NEM jurisdictions. The AER's likely approach set out in this paper aims to achieve consistency with the previous treatment of services in Tasmania where appropriate. However, consistency between NEM jurisdictions may not be achieved in the first round of regulatory determinations given that the NER require the maintenance of consistency with previous regulatory approaches, which may differ across jurisdictions. That said, the AER considers greater consistency in how similar services are classified across jurisdictions is a medium to long term objective to the extent possible. The AER considers that different classifications for similar services may continue to be appropriate given differing circumstances (such as different legislative barriers to contestability that apply to similar services) between jurisdictions.

[190] NER, cll. 6.2.1(d) and 6.2.2(d).

The AER has considered the cost implications of the transition to the new regulatory framework in chapter 6 of the NER, and the need to ensure that this transition does not impose unjustified costs on DNSPs and users. In the context of the presumption in favour of the previous classification, the AER is satisfied that the likely approach set out in this paper provides for a smooth transition to the benefit of both Aurora and electricity consumers, and does not impose unnecessary costs. Table 2.4 shows the AER's likely approach to classification for Aurora's distribution services.

Table 2.4 AER's likely approach—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		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		
Quoted services		All quoted (non-standard) services including above standard network and metering services Alteration and relocation of public lighting assets		

Source: AER analysis.

Table A.1 of Appendix A of this paper includes general descriptions of the types of activities that fall within each proposed service group, although it does not purport to provide a complete listing of the underlying services provided Aurora. Aurora can nominate additional services or propose changes to the AER's likely approach in its regulatory proposal but must justify any changes or additional services proposed.

3 Control mechanisms

3.1 Introduction

This chapter states the forms of the control mechanisms to be applied to Aurora's direct control services for the forthcoming regulatory control period. Direct control services consist of standard control services and alternative control services. Different control mechanisms may apply to each of these classifications, or to services of the same classification.

This chapter does not deal with the form of control for negotiated distribution services, which is regulated under the negotiate/arbitrate framework set out in Part D of chapter 6 of the NER.

3.2 Regulatory requirements

A distribution determination imposes controls over the prices of direct control services, and/or the revenue to be derived from direct control services.[191] The AER's framework and approach paper must state the form or forms of the control mechanisms to be applied by the distribution determination to direct control services and the AER's reasons for deciding on control mechanisms of the relevant form or forms.[192]

Unlike other elements of the framework and approach paper, the AER's statement of the form or forms of the control mechanisms in the framework and approach paper is binding on the AER and the DNSP for the relevant distribution determination—that is, the control mechanisms to apply in the distribution determination must be as set out in the framework and approach paper.[193]

3.2.1 Available control mechanisms

The NER limit the available control mechanisms that may be applied to direct control services. That is, these are the only available control mechanisms for both standard control and alternative control services. Control mechanisms in the NER comprise two parts:

- the form of control mechanism[194]
- the basis of the control mechanism.[195]

Clause 6.2.5(b) of the NER lists the available options for the form of control, which are:

- a schedule of fixed prices
- caps on the prices of individual services (for example a price cap or caps)

[191] NER, cl. 6.2.5(a).
[192] NER, cl. 6.8.1(c).
[193] NER, cl. 6.12.3(c).
[194] NER, cl. 6.2.5(b).
[195] NER, cl. 6.2.6(a).

- caps on the revenue to be derived from a particular combination of services (for example a revenue cap)
- tariff basket price control (for example a weighted average price cap)
- revenue yield control (i.e. an average revenue cap)
- a combination of any of the above.

The forms of control mechanism available for standard and alternative control services are the same. The basis for the control mechanism, however, can differ depending on which class of services it is to apply to. This is discussed in turn below in relation to standard control and alternative control services.

3.2.2 Standard control services

In deciding on a control mechanism to apply to standard control services, the AER must have regard to the following factors in clause 6.2.5(c) of the NER:

- the need for efficient tariff structures; and
- the possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

The basis of the control mechanism for standard control services must be the prospective CPI–X form or some incentive-based variant of the CPI–X form in accordance with Part C of chapter 6 of the NER.[196]

3.2.3 Alternative control services

The factors the AER must have regard to in deciding on a control mechanism for alternative control services are the same as those for standard control services in all but one respect. Whereas for standard control services the AER must have regard to the need for efficient tariff structures, for alternative control services the AER must instead have regard to the potential for development of competition in the relevant market, and how the control mechanism might influence that potential.[197]

The control mechanism must have a basis specified in the distribution determination.[198] This may, but need not, utilise elements of Part C of chapter 6 of the NER with or without modification. For example, the control mechanism may (but

[196] NER, cl. 6.2.6(a).
[197] NER, cl. 6.2.5(d)(1).
[198] NER, cl. 6.2.6(b).

need not) use a building block approach, and may (but need not) incorporate a pass-through mechanism.[199]

3.3 Form of control mechanism for standard control services

In its framework and approach paper the AER must state the form of the control mechanism or mechanisms that will apply to standard control services during the forthcoming regulatory control period.

This chapter should be read on the basis that the AER's positions relating to the classification of Aurora's distribution services in chapter 2 are applied.

3.3.1 Current regulatory arrangements for Aurora

3.3.1.1 Distribution network services

A detailed discussion of the characteristics of the control mechanism for Aurora's distribution network services was provided in the AER's preliminary positions paper. These characteristics are summarised as follows:

- The aggregate annual revenue requirement (AARR) is developed using a building block approach.
- Usage-based prices are calculated for specific services. These prices should be set such that at least avoidable cost, but no more than stand-alone cost is recovered for each service. Total recovered revenue from each usage-based service, plus daily or fixed charges should not exceed the AARR.
- Network tariffs are developed every year and are submitted to OTTER for approval, in accordance with any guidelines by OTTER.

This control mechanism is revenue cap, where the basis of control is an incentive based variant of CPI–X.

3.3.2 AER's preliminary position on standard control services

The AER's preliminary position proposed to apply a revenue cap to the services classified as standard control services in the forthcoming regulatory control period on the basis of a CPI–X form.

It stated that in preparing its final framework and approach paper, the AER will consider whether a different form of control is more appropriate in light of submissions received from stakeholders.

3.3.3 Summary of submissions

Aurora's submission was the only submission received which had regard to the form of control for standard control services. Aurora's submission agreed with the AER's preliminary assessment of standard control services. Further, the Aurora submission

199 NER, cl. 6.2.6(c).

supports the application of a revenue cap for the provision of standard control services in the forthcoming regulatory control period.

3.3.4 Issues and AER's considerations

In its framework and approach paper the AER must state the form of control mechanism or mechanisms that will apply to standard control services during the 2012–2017 regulatory control period.

In light of the AER's preliminary positions paper and submissions received from stakeholders, the following discussion addresses each of the factors that the AER must have regard to in selecting a form of control under clause 6.2.5(c) of the NER.

The regulatory arrangements applicable in the current regulatory control period

Clause 6.2.5(c)(3) of the NER requires that the AER must have regard to the regulatory arrangements applicable in the current regulatory control period when deciding on a control mechanism. As noted above, in the current regulatory control period, a fixed revenue cap control mechanism is applied to Aurora's prescribed distribution network services. The basis of the control mechanism for this revenue cap is an incentive based variant of CPI–X. As discussed in chapter 2, these prescribed distribution network services will be classified as standard control services in the forthcoming regulatory control period. In deciding on the appropriateness of the current control mechanism the AER has turned its attention to the incentives and risk properties of a revenue cap with regard to the other control mechanisms.

The AER specifically acknowledges the perverse incentive for DNSPs to exaggerate forecast costs, and notes that:

- Irrespective of the selected form of control, the AER under clauses 6.5.6 and 6.5.7 of the NER, will undertake a robust investigation into whether the total of Aurora's forecast costs during the upcoming determination process reasonably reflects the efficient costs and the costs that a prudent operator in the circumstances of Aurora would require.

- The AER's likely approach to apply an efficiency benefit sharing scheme (EBSS) will provide an incentive for Aurora to reveal its efficient operating expenditure during the forthcoming regulatory control period. Revealed costs in the forthcoming regulatory control period can be used in assessing forecast operating costs in future regulatory control periods.

- In regard to cuts in service quality, the AER notes that the Tasmanian Electricity Code (TEC) already places considerable boundaries on how Aurora operates, including an onus on the DNSP to adopt quality management and assurance procedures.[200] The AER also considers that the application of an incentive arrangement such as the service target performance incentive scheme (STPIS) will provide appropriate incentives for Aurora to maintain and improve service performance.

[200] TEC, clause 8.2.1

- Further, under the TEC a guaranteed service level scheme applies to Aurora. This scheme provides that Aurora must make penalty payments to customers should service performance fall below a certain standard. This incentive compliments the incentive under the STPIS to maintain and improve service levels.

- In regard to the risk in variations in factors that affect costs, whilst all forecast risks can not be negated, clause 6.6.1 of the NER makes available to Aurora the ability to apply for any cost pass throughs for events that materially increase or decrease the costs of providing direct control services.

The AER's final position is that the potential impacts on incentives and risks are not sufficient to support a change from the current control mechanism that applies to distribution network services in Tasmania in regulating standard control services.

The need for efficient prices

Clause 6.2.5(c)(1) of the NER requires the AER to have regard to the need for efficient tariff structures. In this context it is worth noting that the AER's application of a revenue cap control mechanism will be accompanied by:

- a robust approval process of prices for standard control services by the AER in accordance with the requirements of clauses 6.18.2 and 9.48.4B of the NER

- re-balancing side constraints under clause 6.18.6 of the NER that limit the tariff change that a DNSP can make each year, within the overall revenue cap constraint

- a requirement for Aurora to manage volume fluctuations, while requiring them to meet both the overall revenue cap constraint and side-constraint requirements on tariff class movements.

- These NER provisions and the management of volume fluctuations imposed under a revenue cap control mechanism provide a strong platform for the delivery of efficient tariffs.

- One possible incentive for a DNSP under a revenue cap is to set inefficient tariffs on demand sensitive services. By increasing prices on these services the DNSP will reduce the demand and therefore reduce the volume of the services it sells. This will reduce the overall costs of supplying these services whilst maintaining a similar level of return.

- That said, the AER notes that DNSPs may also face the incentive to set inefficient tariffs under other forms of control, such as a schedule of fixed prices, price caps, weighted average price caps and average revenue caps forms of control because they are highly dependent on out-turn electricity consumption. One possible perverse incentive for a DNSP under these forms of control is to set inefficient tariffs to maximise their revenue by increasing tariffs for market segments where demand is expected to grow, rather than set prices at cost reflective levels.

- The AER notes however, that it in approving prices for standard control services through Aurora's pricing proposals, the AER is bound by clause 6.18.8 of the NER. This approval requires the AER to be satisfied that the pricing principles in clause 6.18.5 of the NER have been met, which in turn requires the AER to be satisfied that, among other things, the revenue from tariff groups is within reasonable ranges and that tariffs reflect long run marginal costs.

- The AER does not propose, having regard to the need for efficient prices, to alter the current control mechanism for standard control services in Tasmania from a revenue cap.

The desirability of consistency

- Clause 6.2.5(c)(4) of the NER requires the AER to have regard to the desirability of consistency between regulatory arrangements for similar services, both within and beyond the relevant jurisdiction.

- As noted above, the current control mechanism for distribution network services in Tasmania is a revenue cap. The AER's approach to continue this control mechanism is therefore consistent with the previous approach.

- In relation to the consistency of mechanisms across jurisdictions, the AER notes that no single control mechanism is currently applied to standard control services in the NEM. Weighted average price caps, an average revenue cap and revenue caps are currently being applied in other NEM jurisdictions.

- The AER considers that as DNSPs transition from jurisdictional regulatory arrangements to the NER the pursuit of consistency in the control mechanisms between jurisdictions is a matter to be considered in the medium to longer term, and that consistency between jurisdictions should not be a driving consideration in selecting a control mechanism for Aurora at this time.

- The AER notes, that it is desirable for the control mechanism to be consistently applied to similar services within each NEM jurisdiction. For this reason, the AER's final position is that a sole control mechanism should be applied to standard control services provided by Aurora in the forthcoming regulatory control period.

Administrative costs

- Clause 6.2.5(c)(2) of the NER requires the AER to consider the possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users.

- Ideally, a control mechanism should minimise the complexity and administrative burden for the AER, the DNSP and the users, without compromising the effectiveness of the constraint. Simplicity in regulatory approaches brings the potential benefits of more timely regulatory determinations, greater certainty and transparency, and reduced compliance costs for a DNSP.

- The AER is required to base its control mechanism for standard control services on a building block approach. While there are unavoidable administrative and compliance costs associated with this basis of control, it is not practicable to quantify the administrative costs of one form of control relative to another. While the AER considers that a change in form of control would likely incur additional administrative costs in the short term it is not clear whether additional costs would be incurred thereafter. Based on this the AER considers there are no clear grounds for favouring one form of control over another on the basis of administrative costs in this instance.

- The AER considers that administrative costs are likely minimised in this instance by maintaining, with any necessary alterations, the current form of control.

Any other relevant factor

In addition to the matters set out above, in deciding on the form of control, clause 6.2.5(c)(5) of the NER requires the AER to have regard to any other relevant factor. The AER does not consider there are any other factors relevant to deciding the control mechanism to apply to Aurora's standard control services in the forthcoming regulatory control period.

Basis of a control mechanism for standard control services

As set out above, clause 6.2.6(a) of the NER requires that the basis of the control mechanism for standard control services be of the prospective CPI-X form, or some incentive-based variant of the prospective CPI minus X form, in accordance with Part C of the NER. Accordingly, the AER's draft and final distribution determinations (and the reasons for its draft and final distribution determinations) will set out, in specific terms, the basis of the control mechanism in accordance with these requirements.

3.4 Form of control mechanism for alternative control services

The AER's framework and approach paper must state the form, or forms, of the control mechanisms that will apply to alternative control services during the forthcoming regulatory control period.

This section should be read on the basis that the AER's positions relating to the classification of Aurora's distribution services in chapter 2 are applied.

3.4.1 Current regulatory arrangements for Aurora

A detailed discussion of the characteristics of the control mechanisms for Aurora's alternative control services was provided in the AER's preliminary positions paper. These characteristics are summarised as follows.

3.4.1.1 Metering services

- The charges for standard metering services are established using an annuity approach based on meter replacement cost, operating (predominately meter reading) and capital costs.

- The annuity model calculates a combined allowance for depreciation charges for the return of capital and applies a weighted average cost of capital (WACC) to the value of each meter class to calculate the return on capital.

- Operating expenditure is indexed by a fixed labour factor minus a productivity factor and added to the annual allowance over the regulatory control period.

- Capital expenditure is also added to the annual allowance but does not change over the regulatory control period as the growth in the cost of materials is assumed to be 0 per cent.

- Adding the operating and capital expenditures together sets a cap on the maximum daily meter allowance for each meter class.

This control mechanism is a price cap.

3.4.1.2 Public lighting

The AER identifies the public lighting services that Aurora performs as being grouped into the following service categories:

- The repair, replacement and maintenance of public lighting assets owned by Aurora where the public lighting service is provided to third parties; or where Aurora undertakes repair, replacement and maintenance of public lighting assets owned by third parties for a fee.

- The alteration and relocation of existing public lighting assets owned by Aurora at the request of a third party; or alteration and relocation of existing public lighting assets owned by a third party at the request of that third party by Aurora.

- Provision of new public lighting by Aurora to customers or third parties on request of that customer or third party.[201]

The AER decided to consider the alteration and relocation of public lighting assets services together with quoted services when classifying these services.

As there is a mixture of ownership arrangements for the provision of public lighting services in Tasmania, Aurora's calculation of public lighting charges is only based on public lighting assets that are owned by Aurora.[202] The charges are set as follows:

- The charges for public lighting services are established using an annuity approach based on the replacement costs for each light type.

- The annuity model calculates a combined allowance for depreciation charges for the return of capital and applies a WACC to the value of each light type to calculate the return on capital.

- The annuity calculation is then added to the estimated operation and maintenance costs for each light type to estimate a total annual charge.

- Through the revenue cap for distribution network services a street lighting DUOS charge is calculated which is applied to public lighting services.

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[201] Aurora, *Information paper for the AER: Services, Classifications and Control Mechanisms*, May 2010, p. 35.

[202] Aurora, *Information paper for the AER: Services, Classifications and Control Mechanisms*, May 2010, p. 8

- The annual DUOS and annuity charges are added to arrive at a total annual charge, which is then converted to a monthly fixed fee.

- These public lighting services are unregulated.

3.4.1.3 Special services

Special services are made up of two separate sets of services, a reference set of special services and other special services. The characteristics of the reference set of special services are as follows:

- A notional maximum revenue is set which may be earned from the reference set of special services.

- The notional maximum revenue is escalated by the ABS labour price index.

- A fixed 'weighting' is defined for each of the service types.

- The number of services likely to be provided, multiplied by the proposed charges, must not exceed the notional maximum revenue (there is no subsequent catch-up if actual revenue exceeds or falls short of the notional maximum).

- Aurora can amend or modify the list of the reference set of special services over time by advising OTTER as part of its annual pricing proposal. There are few formal limitations on services that can be added, other than they must comply with the definition of 'special distribution services' in OTTER's 2007 declaration decision.

The control mechanisms for the reference set of special services are price caps.

The other categories of special services do not form part of the price caps. Rather OTTER elected to require simply that these other special services and their prices be provided to OTTER as part of the annual pricing process. These other special services are therefore subject to a schedule of fixed prices.

3.4.1.4 Quoted services

The nature and scope of these services are specific to individual customers' needs, and the cost of providing the services cannot be estimated without first understanding the customer's specific requirements. Aurora sets individual prices for these services after they have been requested and after it has undertaken an assessment of the requested task. OTTER does require that Aurora publish its charge out rates, but does not require Aurora to submit them for approval by OTTER.

- These quoted services are unregulated.

3.4.2 AER's preliminary position on alternative control services

The AER's preliminary position proposed to apply price cap regulation in the forthcoming regulatory control period to the services classified as alternative control, namely:

- all type 5, 6 and 7 metering services, excluding PAYG metering and above standard metering services
- all public lighting services with repair, replacement and maintenance to be fee based services; and alterations, relocations and the provision of new public lighting services to be quoted services
- extend the application of a price cap to the reference set of special services to incorporate other special services to be regulated as fee based services.

In preparing its final framework and approach paper, the AER has considered whether a different form of control is more appropriate in light of submissions received from stakeholders.

3.4.3 Summary of submissions

Aurora's submission supports the forms of control proposed by the AER in its preliminary positions paper. Aurora agrees that public lighting services which are to be classified as alternative control services should have the following price cap forms of control:

- the repair, replacement and maintenance of public lighting to be subject to fee based regulation (fee based services)
- the alteration and relocation of existing public lighting assets to be provided on a quoted basis (quoted services)
- the provision of new public lighting to be provided on a quoted basis (quoted services).[203]

Aurora also initially proposed that price caps be applied to:

- the individual prices for fee based services
- the unit costs for quoted services.[204]

Aurora also submitted that standard network services, which includes the conveyance of electricity to public lighting and are classified as standard control services, should have a revenue cap form of control applied.[205]

LGAT and DIER's joint submission supports the AER's preliminary position to regulate all public lighting service prices. However, LGAT and DIER suggested there needs to be transparency in this process:

> …as with Aurora being a "monopoly" provider for energy distribution, combined with the fact there is no proposed commitment to unbundle costs,

[203] Aurora, *Response to AER preliminary positions*, August 2010, p. 24.
[204] Aurora, *Information paper for AER*, May 2010, p. 43.
[205] Aurora, Response to AER preliminary positions, August 2010, p. 24.

> there is no guarantee the pricing model will deliver preferable outcomes for Local Government and DIER.[206]

LGAT and DIER supported the unbundled billing for public lighting services, stating:

> …it is essential that unbundled billing occurs in order for to (sic) us to understand our energy use to try and achieve emissions and costs efficiencies.[207]

TTEG submission expected public lighting tariffs to be unbundled prior to the next regulatory control period:

> …as this would enable contestability of the energy component i.e. consistent with other NEM jurisdictions.[208]

TTEG contended that a tiered pricing structure for public lighting services must be established to provide options for customers. This tiered pricing structure would provide the following service choices for customers: full, customer lighting equipment rate (CLER), and energy only.[209]

StreetlightsLED's submission supported the AER's application of a price cap form of control for public lighting services.[210]

3.4.4 Issues and AER's considerations––alternative control services

In its framework and approach paper the AER must state the form of control mechanism or mechanisms that will apply to alternative control services during the 2012–2017 regulatory control period.

As set out in chapter 2, the AER has classified the following distribution services as alternative control services:

- standard metering services – all type 5, 6 and 7 metering services, excluding above standard metering services
- public lighting services – repair, replacement and maintenance; and the provision of new public lighting assets
- fee based services – all special services (reference set and other special services)
- quoted services – quoted services (including the alteration and relocation of public lighting services).

Chapter 2 classified the provision of new public lighting technology services (not to be confused with new public lighting assets) as negotiated distribution services. Therefore, the following does not deal with the form of control for these services as they are regulated under the negotiating framework set out in Part D of chapter 6 of the NER.

206 LGAT and DIER, Submission on street lighting proposals, August 2010, p. 4.
207 LGAT and DIER, Submission on street lighting proposals, August 2010, pp. 4-5.
208 TTEG, Aurora framework and approach paper submission, August 2010, p. 2.
209 TTEG, Aurora framework and approach paper submission, August 2010, p. 5.
210 StreetlightsLED, Submission to the AER, August 2010, p. 1.

In light of the AER's preliminary positions paper and submissions received from stakeholders, the following discussion addresses each of the factors that the AER must have regard to in selecting a form of control for each classification of alternative control services under clause 6.2.5(d) of the NER.

3.4.4.1 Standard metering services

The regulatory arrangements applicable in the current regulatory control period

Clause 6.2.5(d)(3) of the NER provides that, in deciding on the control mechanism to apply to alternative control services, the AER must have regard to the current regulatory arrangements applicable to Aurora.

Under the current regulatory arrangements, standard metering services are regulated under a price cap form of control. This approach utilises an annuity approach based on meter replacement cost, operating (predominately meter reading) and capital costs. The annuity revenue required from each meter class was then divided by the number of meters in the class to establish a maximum average daily metering allowance for each meter class.

The AER notes that the current regulatory arrangements are available under the NER and are similar to how these services are regulated in other jurisdictions.

Based on these current regulatory arrangements the AER can see no justification to depart from the current form of control.

The influence on the potential for development of competition

Clause 6.2.5(d)(1) of the NER requires the AER to have regard to the potential for competition for standard metering services and how the form of control might influence that potential.

As noted in chapter 2, the AER considers that there is a regulatory barrier to any party other than Aurora from providing metering services for type 5, 6 and 7 meters. Further the economies of scale and scope available to Aurora, particularly in relation to its network services, are likely to prevent standard metering services being competitively provided by an alternative service provider. The AER also considers there are no real substitutes for these services as all customers need to receive metering services for billing purposes.

These factors contribute to the view that Aurora possesses significant market power in the provision of these standard metering services.

Therefore AER considers that the continuation of the application of a price cap control mechanism for all standard metering services, will not have any material impact on the competition for alternative control services. The AER also considers that it will not impede the potential to develop competition for these services should it exist. The AER considers that by classifying these services as alternative control services and the application of a price cap control mechanism price signals are sent to the market regarding the provision of these services.

Administrative costs

Clause 6.2.5(d)(2) of the NER requires the AER to have regard to the possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users.

Given the AER's proposed control mechanism for all standard metering services is the same as that which currently applies, the AER's final position is that administrative costs of the AER, the DNSP and users or potential users are likely minimised in this instance by maintaining, with any necessary alterations, the current form of control.

The desirability of consistency

Clause 6.2.5(d)(4) of the NER requires the AER to have regard to the desirability of consistency between regulatory arrangements for similar services, both within and beyond the relevant jurisdiction.

Different forms of control are applied across the NEM jurisdictions to excluded or special distribution services, which are most likely to be classified as alternative control services. For example, in Victoria, alternative control services are regulated through a price cap. In New South Wales and Queensland, a variant of a schedule of fixed prices is applied to alternative control services. Whilst different forms of control are applied across the NEM jurisdictions, the AER notes that in each jurisdiction these respective forms of control are applied consistently to similar services within the regulatory control period.

While consistency is generally desirable, the AER considers the pursuit of consistency in forms of control across jurisdictions should not be the primary consideration in the selection of a control mechanism to apply to Aurora's alternative control services. However, the AER does consider that a form of control should be applied consistently for similar services within a jurisdiction.

Finally, the AER notes that regard should be had for the consistent application of a form of control between regulatory arrangements for similar services within the jurisdiction. The AER considers that departure from the current regulatory control period form of control should only occur where it has been proven that it is appropriate to do so. There is no evidence that it would be appropriate in this case.

Given the above considerations, the AER's final position is consistent with the current regulatory arrangements in Tasmania for these services and proposes to continue the use of the annuity approach as the basis of control to setting the price caps in the forthcoming regulatory control period.

Any other relevant factor

In addition to the matters set out above, in deciding on the form of control, clause 6.2.5(d)(5) of the NER requires the AER to have regard to any other relevant factor. The AER does not consider there are any other factors relevant to deciding on the control mechanism to apply to Aurora's standard metering services in the forthcoming regulatory control period.

Basis of a control mechanism for alternative control services

Clause 6.2.6(b) of the NER states that for alternative control services, the control mechanism must have a basis stated in the distribution determination.

As stated above, 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.

3.4.4.2 Public lighting services – repair, replacement and maintenance and the provision of new public lighting assets

The regulatory arrangements applicable in the current regulatory control period

Clause 6.2.5(d)(3) of the NER provides that, in deciding on the control mechanism to apply to alternative control services, the AER must have regard to the current regulatory arrangements applicable to Aurora.

As stated in chapter 2, public lighting in Tasmania in the current regulatory control period does not fall under the definition of any of the declared services and hence is not regulated by OTTER. As the AER has classified these services as alternative control services in chapter 2, the AER is required under clause 6.2.5 of the NER to impose a price control mechanism.

The AER's preliminary position was to apply a price cap control mechanism to these services.

The influence on the potential for development of competition

Clause 6.2.5(d)(1) of the NER requires the AER to have regard to the potential for competition for the public lighting services and the provision of new public lighting assets and how the form of control might influence that potential.

As noted in chapter 2 and consistent with its analysis of the majority of other alternative control services, the AER considers that Aurora possesses significant market power in the provision of repair, replacement and maintenance of public lighting services and the provision of new public lighting assets. The AER considers that there is a regulatory barrier to any party other than Aurora providing these services. Furthermore, the economies of scale and scope available to Aurora, particularly in relation to its network services, are also likely to prevent fee base services being competitively provided by an alternative service provider.

Therefore the AER considers that the application of any of the control mechanisms for the repair, replacement and maintenance of public lighting services and the provision of new public lighting assets is unlikely to have any material impact on the competition for these alternative control services, or impede the potential to develop competition for these services.

Administrative costs

Clause 6.2.5(d)(2) of the NER requires the AER to have regard to the possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users.

With respect to the classification of the repair, replacement and maintenance of public lighting services and the provision of new public lighting assets as alternative control services, the AER notes that the change from being unregulated will potentially result in some additional administrative costs to Aurora. Such an increase is expected to be largely transitional in nature, so that administrative costs are likely to reduce over time.

As noted above, the AER considers that there will be initial increases in administrative costs in the transition from being unregulated services to alternative control services. However the AER notes that this would occur under the application of any of the control mechanisms available under clause 6.2.5(b) of the NER.

The desirability of consistency

Clause 6.2.5(d)(4) of the NER requires the AER to have regard to the desirability of consistency between regulatory arrangements for similar services, both within and beyond the relevant jurisdiction.

As stated above, the AER notes that different forms of control are applied across the NEM jurisdictions to alternative control services. Whilst different forms of control are applied across the NEM jurisdictions, the AER notes that in each jurisdiction these respective forms of control are applied consistently to similar services within the current regulatory control period.

While consistency is generally desirable, the AER considers the pursuit of consistency in forms of control across jurisdictions should not be the primary consideration in the selection of a control mechanism to apply to Aurora’s alternative control services. However, the AER does consider that a form of control should be applied consistently for similar services within a jurisdiction.

Finally, the AER notes that regard should be had for the consistent application of a form of control between regulatory arrangements for similar services within the jurisdiction. The AER considers that departure from the current regulatory control period form of control should only occur where it has been proven that it is appropriate to do so.

The repair, replacement and maintenance of public lighting services and the provision of new public lighting assets are currently unregulated and therefore are not subject to a control mechanism. Therefore the AER has no ability to have consistency across regulatory control periods as these services are subject to a control mechanism in forthcoming regulatory control period. However, the AER has the ability to apply a consistent control mechanism to all services classified as repair, replacement and maintenance public lighting services and the provision of new public lighting assets. The AER considers this type of consistency is desirable for these services.

Given the above considerations, the AER considers it appropriate for the repair, replacement and maintenance of public lighting services and the provision of new public lighting assets to be regulated under price caps.

Any other relevant factor

In addition to the matters set out above, in deciding on the form of control, clause 6.2.5(d)(5) of the NER requires the AER to have regard to any other relevant factor. The AER considers the unbundling of public lighting services charges is a relevant factor in deciding on the control mechanism to apply to Aurora's repair, replacement and maintenance public lighting services and the provision of new public lighting assets in the forthcoming regulatory control period.

The AER noted above that the LGAT and DIER; and the TTEG submissions requested that the form of control for public lighting services facilitate the unbundling of public lighting charges. These submissions noted that public lighting services tend to make up a significant proportion of a councils total energy costs. As stated above, the AER notes that presently these services are bundled together and provided as a monthly charge.

The AER's preliminary positions paper proposed to apply price caps to the repair, replacement and maintenance of public lighting services and the provision of new public lighting assets. The AER's preliminary positions paper also proposed to draw on and develop the annuity model currently used by Aurora for the calculation of these charges. Through this process the AER would assess the cost inputs into the model to ensure that revenue would be reflective of efficient costs. Further, by applying a price cap to these services the AER considers it would be able to increase the transparency in the calculation of public lighting services.

Therefore consistent with the AER's preliminary positions paper, the application of price caps to the repair, replacement and maintenance of public lighting services and the provision of new public lighting assets is considered an appropriate control mechanism for these services in the forthcoming regulatory control period.

Basis of a control mechanism for alternative control services

Clause 6.2.6(b) of the NER states that for alternative control services, the control mechanism must have a basis stated in the distribution determination.

As stated above, the AER's starting position is the current application of an annuity model as the basis of control for repair, replacement and maintenance public lighting services and the provision of new public lighting assets. Through the distribution determination process the AER will further investigate and confirm whether a more appropriate basis of control (for example, the use of a regulatory asset base) for repair, replacement and maintenance public lighting services and the provision of new public lighting assets is required in the forthcoming regulatory control period.

3.4.4.3 Fee based services

The regulatory arrangements applicable in the current regulatory control period

Clause 6.2.5(d)(3) of the NER provides that, in deciding on the control mechanism to apply to alternative control services, the AER must have regard to the current regulatory arrangements applicable to Aurora.

Under the current regulatory arrangements these fee based services are two separate sets of services. The reference set of services (energisation, de–energisation and re–energisation; meter alteration and meter testing) are currently fee based distribution services, subject to a price cap. The other categories of special services are not regulated by a price cap. For these other special services OTTER determined that these special services and their prices must be provided to OTTER as part of the annual pricing process.

As noted in chapter 2 and further discussed below, the AER considers that Aurora possesses significant market power in the provision of these services. Further noted in chapter 2, the AER considers that both of these sets of services should be classified as alternative control services in the forthcoming regulatory control period. Consequently, the AER must decide on an appropriate form of control to apply to these services.

The AER notes that the current form of control is available under the NER. As stated in the AER's preliminary position paper, the AER considers that the current form of control will assist in the facilitation of cost reflective pricing for these services. Cost reflective pricing and a move to more transparent user-pays fee system and to better define these services was a view held by OTTER and supported by the AER for the regulation of these services in the forthcoming regulatory control period.

Based on the current regulatory arrangements for the reference set of special services the AER can see no justification to depart from the current form of control. However, as the other categories of special services are not currently subject to a control mechanism the AER must decide on an appropriate form of control for these services in the forthcoming regulatory control period.

As discussed further below, the AER considers that all fee based services should be regulated by the same control mechanism. Based on the regulatory arrangements for the reference set of special services in the current regulatory control period and similarities in grouping the other categories of special services with them, the AER considers that a price cap would be an appropriate form of control for fee based services.

The influence on the potential for development of competition

Clause 6.2.5(d)(1) of the NER requires the AER to have regard to the potential for competition for all fee based services and how the form of control might influence that potential.

As noted in chapter 2 and consistent with its analysis of the other alternative control services, the AER considers that Aurora possesses significant market power in the provision of the fee based services. The AER considers that there is a regulatory barrier to any party other than Aurora providing these services. Furthermore, the economies of scale and scope available to Aurora, particularly in relation to its network services, are also likely to prevent fee base services being competitively provided by an alternative service provider.

Therefore the AER considers that the application of a price cap control mechanism for all fee based services will not have any material impact on the competition for alternative control services, or impede the potential to develop competition for these services.

Administrative costs

Clause 6.2.5(d)(2) of the NER requires the AER to have regard to the possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users.

Price caps are currently applied to the reference set of special services. However, as discussed in the AER's preliminary positions paper, with the grouping of other special services, the AER proposed to modify the basis of control for setting the price caps for these fee based services in the forthcoming regulatory control period.

The AER recognises that this change in basis of control will potentially result in some additional administrative costs to Aurora. Such an increase is expected to be largely transitional in nature, so that administrative costs are likely to reduce over time. However, the AER considers the change in basis of control will not only create greater cost reflectivity for the charges of these services but more appropriate charges to end users in a user-pays environment. The AER considers a short term increase in administrative costs for the DNSP, users or potential users is justified in these circumstances.

The AER considers that a change in the basis of control is not likely to have a material effect on administration costs for the AER in regulating these services.

For these reasons, the AER considers that, with regard to administrative costs, applying price caps form of regulation for all fee based services is warranted.

The desirability of consistency

Clause 6.2.5(d)(4) of the NER requires the AER to have regard to the desirability of consistency between regulatory arrangements for similar services, both within and beyond the relevant jurisdiction.

As stated above, different forms of control are applied across the NEM jurisdictions to alternative control services. Whilst different forms of control are applied across the NEM jurisdictions, the AER notes that in each jurisdiction these respective forms of control are applied consistently to similar services within the current regulatory period.

While consistency is generally desirable, the AER considers the pursuit of consistency in forms of control across jurisdictions should not be the primary consideration in the selection of a control mechanism to apply to Aurora's alternative control services. However, the AER does consider that a form of control should be applied consistently for similar services within a jurisdiction.

Finally, the AER notes that regard should be had for the consistent application of a form of control between regulatory arrangements for similar services within the jurisdiction. The AER considers that departure from the current regulatory control period form of control should only occur where it has been proven that it is appropriate to do so.

Given the above considerations, the AER considers it appropriate for the reference set and other categories of special services classified as fee based services to be regulated under price caps in the forthcoming regulatory control period.

Any other relevant factor

In addition to the matters set out above, in deciding on the form of control, clause 6.2.5(d)(5) of the NER requires the AER to have regard to any other relevant factor. The AER considers that the basis of control to be applied to the fee based services to be a relevant factor in determining the appropriate control mechanism in the forthcoming regulatory control period.

The AER's preliminary positions paper stated that the current basis of control for the reference set of special services utilises a formula based approach using a notional revenue cap combined with fixed weightings of services. Through this approach Aurora can, at an aggregate level, earn total revenues to recover the total cost of providing these services. This approach allows setting and rebalancing individual charges as long as they meet the notional maximum revenue. However, the AER considers that this approach may not promote cost reflective charges as the ability exists for Aurora to cross–subsidise among the reference set of special services. OTTER had previously acknowledged this point and noted:

> …if some Services have been provided at less than the cost of provision this has been off-set by those Services where the charges are currently in excess of their cost.[211]

The AER considers that consistent with OTTER's 2007 decision that the regulation of these services should be better defined over time and should move to a more transparent user-pays fee system.[212] This is further in line with OTTER's statement that:

> Special Services generally represent those services that are provided for the benefit of a single customer rather than uniformly supplied to all network customers.[213]

Based on this the AER considers that not only should the basis of control allow for more transparent and cost reflective prices but also the control mechanism should also assist in the facilitation of this. The AER considers that price caps on individual services will not only create greater transparency but also provide for more cost reflective prices.

On this basis, the AER considers that, with regard to other relevant factors, a price cap form of regulation for all fee based services is warranted.

Basis of a control mechanism for alternative control services

Clause 6.2.6(b) of the NER states that for alternative control services, the control mechanism must have a basis stated in the distribution determination.

211 OTTER, *Maximum prices for special services*, June 2008, p. 22.
212 OTTER, *Maximum prices for special services*, June 2008, p. 1.
213 OTTER, *Maximum prices for special services*, June 2008, p. 1.

Through the distribution determination process the AER will confirm a basis of control for all fee based services which will enable more transparent and cost reflective prices for fee based services.

3.4.4.4 Quoted services

The regulatory arrangements applicable in the current regulatory control period

Clause 6.2.5(d)(3) of the NER provides that, in deciding on the control mechanism to apply to alternative control services, the AER must have regard to the current regulatory arrangements applicable to Aurora.

As stated in chapter 2, Aurora's quoted services are effectively unregulated in the current regulatory control period. For all quoted services, aside from the alteration and relocation of public lighting assets, Aurora is required to publish unit prices for these services however these unit prices are neither assessed nor approved by OTTER. As these quoted services have been classified as alternative control services in chapter 2, the AER is required under clause 6.2.5 of the NER to impose a price control mechanism. As no current control mechanism exists the AER must investigate the other factors in 6.2.5(d) of the NER to inform its decision.

The influence on the potential for development of competition

Clause 6.2.5(d)(1) of the NER requires the AER to have regard to the potential for competition for quoted services and how the form of control might influence that potential.

Consistent with the other alternative control services, the AER considers that Aurora possesses significant market power in the provision of the quoted services. The AER considers that there is a regulatory barrier to any party other than Aurora providing these services. Furthermore, the economies of scale and scope available to Aurora, particularly in relation to its network services, are also likely to prevent non-standard services being competitively provided by an alternative service provider.

Therefore the AER considers that the application of any of the control mechanisms for non-standard services is unlikely to have any material impact on the competition for alternative control services, or impede the potential to develop competition for these services.

Administrative costs

Clause 6.2.5(d)(2) of the NER requires the AER to have regard to the possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users.

With respect to the classification of non-standard services as alternative control services, the AER notes that the change in classification from unregulated services will potentially result in some additional administrative costs to Aurora. Such an increase is expected to be largely transitional in nature, so that administrative costs are likely to reduce over time.

The AER and users and potential users may incur some additional costs as a by-product of this change in basis of control. However, this too should be largely transitional in nature and these costs are likely to reduce over time.

The AER considers that these initial increases in administrative costs would occur under the application of any of the control mechanisms available under clause 6.2.5(b) of the NER.

The desirability of consistency

Clause 6.2.5(d)(4) of the NER requires the AER to have regard to the desirability of consistency between regulatory arrangements for similar services, both within and beyond the relevant jurisdiction.

As stated above, the AER notes that different forms of control are applied across the NEM jurisdictions to alternative control services. Whilst different forms of control are applied across the NEM jurisdictions, the AER notes that in each jurisdiction these respective forms of control are applied consistently to similar services within the current regulatory control period.

While consistency is generally desirable, the AER considers the pursuit of consistency in forms of control across jurisdictions should not be the primary consideration in the selection of a control mechanism to apply to Aurora's alternative control services. However, the AER does consider that a form of control should be applied consistently for similar services within a jurisdiction.

Finally, the AER notes that regard should be had for the consistent application of a form of control between regulatory arrangements for similar services within the jurisdiction. The AER considers that departure from the current regulatory control period form of control should only occur where it has been proven that it is appropriate to do so.

The non-standard control services are currently unregulated and therefore are not subject to a control mechanism. Therefore, the AER has no ability to have consistency across regulatory control periods as these services are subject to a control mechanism in forthcoming regulatory control period. However, the AER has the ability to apply a consistent control mechanism to all services classified as quoted services. The AER considers this type of consistency is desirable for these services.

Given the above considerations, the AER considers it appropriate for the quoted services classified as alternative control services to be regulated under a consistent control mechanism in the forthcoming regulatory control period.

Any other relevant factor

In addition to the matters set out above, in deciding on the form of control, clause 6.2.5(d)(5) of the NER requires the AER to have regard to any other relevant factor. The AER considers that relevant factors are the cost inputs and the prices of these services.

The costs inputs in providing the same service may be greatly affected by the circumstances resulting in significantly large variations in the charge because the service requested is not standard. As such it would be inappropriate to classify these services as fee based services and apply a fixed charge.

Consistent with its approach to the other alternative control services, the AER considers the control mechanism to apply to these services should where possible deliver transparent and cost reflective prices.

Based on the above, the AER considers a schedule of fixed prices or price caps are more appropriate than the other control mechanisms. Under either of these approaches the unit costs of inputs can be capped but not the overall individual service. This creates greater cost reflective prices. Further, unit costs inputs (usually labour rates) can be reviewed through the annual pricing proposal and be published publicly to assist in greater transparency.

The AER considers that by themselves the other control mechanisms would not provide the same level of transparency or cost reflectivity as they are more reliant on the frequency of services. For example a revenue cap could see large charges for services when their demand is low but see a dramatic fall in charges when the demand is high. This would result in lower cost reflective prices as the charge for the service is closely linked to the frequency of the service and not the cost inputs. This example demonstrates the possibility of price variation that could occur through the application of a revenue cap for these services.

The AER notes that the price variation in the example above could be mitigated as clause 6.5.6(b) of the NER allows a combination of control mechanisms to be used. However, the AER considers that even a combination of control mechanisms would be influenced by variability of cost inputs and frequency of services and would be undesirable in this instance.

Therefore the AER considers that a schedule of fixed prices or price caps are the most appropriate control mechanisms for quoted services. While both of these approaches can deliver transparent and cost reflective prices, price caps provide for greater flexibility to Aurora, so the AER considers that price caps are preferable. As noted above, the regulatory barriers and the economies of scale and scope available to Aurora, particularly in relation to its network services, are also likely to prevent quoted services being competitively provided by an alternative service provider. However, should competition develop through the provision of greater transparent and cost reflective pricing, price caps would allow Aurora to charge below the capped price to compete for these services.

On this basis, the AER considers that, with regard to other relevant factors, a price cap form of regulation for quoted services is warranted.

Basis of a control mechanism for alternative control services

Clause 6.2.6(b) of the NER states that for alternative control services, the control mechanism must have a basis stated in the distribution determination.

Through the distribution determination process the AER will confirm a basis of control for quoted services.

3.5 Form of control mechanisms to be applied in the distribution determination

3.5.1 Standard control services

The AER will apply a revenue cap to the services classified in chapter 2 as standard control services in the forthcoming regulatory control period with a basis of the CPI–X form. In summary, the AER's approach is based on the following considerations, which the AER has had regard to in accordance with clause 6.2.5(c) of the NER:

- A revenue cap is the current control mechanism for Aurora's distribution network services[214] and is one of the control mechanisms listed in clause 6.2.5(b) of the NER that can be applied in the forthcoming regulatory control period.[215]

- The incentives and risks of this control mechanism are widely recognised. However, requirements of the NER, the TEC, appropriate incentives imposed by the incentive schemes and Aurora's history of operating under a revenue cap is considered by the AER to manage these risks and promote positive incentives.[216]

- The AER notes there are provisions in place under clause 6.18 of the NER that require the AER to carefully examine tariff structures for efficiency as part of the pricing proposal process.[217] These NER provisions and the management of volume fluctuations imposed under a revenue cap control mechanism provides a strong platform for the delivery of efficient tariffs.

- Retaining the current form of control for standard control services maintains consistency in the regulation of those services across Tasmania.[218] The AER considers that consistency of regulatory approaches within jurisdictions is an important initial goal, while noting that achieving consistency across jurisdictions is a medium to longer term objective.

- Transition to a completely new form of control mechanism will not guarantee a reduction in administrative costs, and may itself create undesirable administrative costs.[219]

3.5.2 Alternative control services

The AER's final position is to 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

[214] NER, cl 6.2.5(c)(3)
[215] NER cl. 6.2.5(b)(3)
[216] NER, cl 6.2.5(c)(5)
[217] NER, cl 6.2.5(c)(1)
[218] NER, cl. 6.2.5(c)(4)
[219] NER, cl. 6.2.5(c)(2)

- all fee based services
- quoted services.

In summary, the AER's approach is based on the following considerations it has had regard to in accordance with clause 6.2.5(d) of the NER:

- A price cap is the current control mechanism for reference set special services and metering services and is one of the control mechanisms listed in 6.2.5(b) of the NER that can be applied in the forthcoming regulatory control period.[220] A price cap or price caps will be applied to all alternative control services in the forthcoming regulatory control period.

- It is considered unlikely that there will be any impact on the development of competition in the market for these services as a result of applying a price cap control mechanism.[221] However if competition exists a price cap can promote greater cost reflective prices and provide more accurate price signals to the market enabling competitors to assess prices and decide whether or not to enter the market.

- Retaining the current form of regulation (price cap) for the reference set of special services and all standard metering services maintains consistency in the regulation of those services across Tasmania and over regulatory periods, and is also consistent with the form of regulation applied in some other NEM jurisdictions.[222] The other special services, public lighting services and quoted services are currently unregulated and therefore are not currently subject to a control mechanism. Although the application of a price cap is not consistent with the previous approach, the application of price caps to all alternative control services will result in consistency in the control mechanism applied to these services.

- The AER considers that retaining the current form of regulation (price cap) for the all standard metering services and the fee based services will have limited if any effect on the administrative costs to the AER, Aurora and users or potential users in the forthcoming regulatory control period. With respect to the unregulated services in the current regulatory control period and not currently subject to a control mechanism, the AER considers that the regulation of these services will result in some additional administrative costs. However the AER considers that these are expected to be largely transitional in nature and are expected to reduce over time. [223]

- For all the alternative control public lighting services, the fee based services and quoted services the AER has had regard to all relevant factors, as discussed above.[224] Additional relevant factors have contributed to the AER's decision to apply a price cap or price caps to these services.

220 NER, cl. 6.2.5(b)(2)
221 NER, cl. 6.2.5(d)(1)
222 NER cl. 6.2.5(d)(4)
223 NER, cl. 6.2.5(d)(2)
224 NER, cl. 6.2.5(d)(5)

4 Application of the service target performance incentive scheme

4.1 Introduction

This chapter set outs the AER's likely approach to the application of a service target performance incentive scheme (STPIS) to Aurora for the forthcoming regulatory control period, and its reasons for that approach.

The STPIS provides financial incentives for DNSPs to maintain and improve service performance. This balances the incentive in the regulatory framework for DNSPs to reduce costs at the expense of service quality. Cost reductions are beneficial to both DNSPs and their customers when service performance is maintained or improved. However, cost efficiencies achieved at the expense of service performance are not always desirable.

The STPIS works as part of the building block determination. Through the s-factor component of the STPIS, DNSPs are penalised (or rewarded) for diminished (or improved) service compared to predetermined targets. These penalties or rewards are an adjustment to the annual revenue that DNSPs earn under the control mechanism. In addition to the s-factor, the STPIS may also include a guaranteed service level (GSL) component, which sets threshold levels of service and provides for direct payments to customers who experience service worse than the predetermined level.

4.2 Regulatory requirements

The AER's distribution determination for Aurora in the forthcoming regulatory control period will specify how the STPIS is to be applied to the DNSP in that period.[225] In its framework and approach paper, the AER must set out its likely approach, together with its reasons for the likely approach, to the application of a STPIS in the determination.[226]

4.3 AER's national distribution STPIS

As part of the national framework for the economic regulation of distribution services, the AER is required to develop and publish an incentive scheme to ensure that DNSPs maintain and improve upon, agreed levels of service.[227] The AER developed the STPIS in accordance with this requirement.[228] The AER's STPIS is available on the AER's website: www.aer.gov.au .

4.4 Implementing the STPIS

The national STPIS is designed to facilitate the consistent application of a service performance incentive framework across the NEM, but can be implemented taking into account the circumstances of each DNSP.

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225 NER, cl. 6.3.2(a)(3).
226 NER, cl. 6.8.1(b)(2).
227 NER, cl. 6.6.2(a).
228 The latest version of the STPIS was published in November 2009. It's full reference is: AER, *Electricity distribution network service providers: Service target performance incentive scheme*, November 2009 (AER, *STPIS*, Nov 2009)

The objectives of the scheme are to ensure consistency with the national electricity objective in section 7 of the National Electricity Law.[229]

In implementing the national STPIS, 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 penalty or reward under the scheme
- any current regulatory requirements to which the relevant DNSP is currently subject
- the past performance of the distribution network
- any other incentives available to the DNSP under the NER or the relevant distribution determination
- the need to ensure that the incentives are sufficient to offset any financial incentives the DNSP may have to reduce costs at the expense of service levels
- the willingness of the customer or end user to pay for improved performance in the delivery of services, and
- the possible effects of the scheme on incentives for the implementation of non-network incentives. [230]

In implementing the notional STPIS, the AER must also:

- consult with the authorities responsible for the administration of relevant jurisdictional electricity legislation[231]
- ensure that service standards and service targets (including GSLs) set by the scheme do not put at risk the DNSP's ability to comply with relevant service standards and service targets (including GSLs) as specified in jurisdictional electricity legislation.[232]

The STPIS was developed with consideration of each of these individual requirements. As such, the STPIS was designed so that in its implementation it gives effect to and is consistent with the NER requirements.

By basing the STPIS on existing jurisdictional schemes, including the previous Tasmanian performance incentive scheme, the scheme has been developed with regard to past and current industry and community expectations. The scheme has also been designed to provide a degree of flexibility that may be exercised in its application to take account of transitional issues and the circumstances of DNSPs given their particular operating environments.

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229 Clause 1.5 of the STPIS
230 NER, cl. 6.6.2(3).
231 NER, cl. 6.6.2(b)(1).
232 NER, cl. 6.6.2(b)(2). The STPIS implemented by the AER must operate concurrently with any average or minimum service standards and GSL schemes that apply to the DNSP under jurisdictional electricity legislation.

Through the design of the STPIS and the operation of the framework and approach and distribution determination processes in the NER, the STPIS and its supporting regulatory arrangements provide for some flexibility in the application of the scheme. This is to accommodate, as appropriate, the individual circumstances of a DNSP, for example, where the DNSP has previously operated under an equivalent jurisdictional scheme and where there are differences between DNSP operating environments (for example, specific service performance issues that may arise in a jurisdiction or DNSP service area).

Notwithstanding this, where a DNSP proposes that the AER adopt a flexible approach to the application of the STPIS, as provided for in the scheme (for example, by adopting a different overall cap on the revenue at risk to that specified in the scheme), then it will need to satisfy the AER that such modifications satisfy the objectives of the scheme.

As the scheme's targets are based upon average performance over the most recent available five years of audited performance data, the scheme takes into consideration the historical performance of networks. GSL payments have been based upon existing jurisdictional arrangements and will only apply when an existing jurisdictional scheme does not exist. In developing the STPIS, the AER has taken into account incentives provided under the CPI−X regulatory framework and the EBSS as set out in the NER and the relevant schemes promulgated by the AER.

The rate at which rewards and penalties are assigned is based on customer willingness to pay, which has been derived from customer surveys and previous economic studies. The rationale for this approach is based on the economic assumption that the schedule of rewards and penalties should mimic customers' marginal willingness to pay for improved service performance. This allows a DNSP to change its service performance up to the point where the optimal level of service performance is attained; where the marginal cost of improving performance equals the reward for doing so.

In practice this means that where a DNSP's cost of undertaking works to improve service performance is less than the reward provided through the scheme the DNSP has an incentive to carry out the works and achieve the desired performance level. In this way the scheme can act as an additional cost-recovery mechanism for service performance improvements, where these improvements are over and above those being funded through the revenue allowed in a distribution determination. As the scheme is symmetrical, that is, penalties are accrued at the same rate as rewards, there is also an incentive under the scheme for a DNSP to maintain its service performance.

Though the penalties and rewards under the scheme are capped at ±5 per cent of revenue these incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels. Five per cent of revenue is a significant proportion of a DNSP's total revenue.

The AER has taken into account the possible effects of the STPIS on incentives for the implementation of non-network alternatives. The AER intends that the STPIS be as neutral as possible regarding the level of reliability provided by network solutions vis-à-vis non network alternatives.

4.5 Overview of the current and previous service incentive arrangements in Tasmania

4.5.1 Previous regulatory control period 2003–07

As part of its 2003 regulatory determination for Aurora, OTTER implemented a service incentive scheme that penalised Aurora for failing to meet predetermined SAIDI and SAIFI targets for service performance. Conversely the scheme rewarded Aurora for bettering the targets. This was the first financial performance incentive scheme implemented in Tasmania.

The service incentive scheme was similar to the s-factor component of the STPIS as Aurora's revenue was increased if it outperformed the targets and decreased it if failed to achieve the targets. Like the national STPIS, the Tasmanian scheme applied a cap on revenue at risk and excluded the effects of MED days.[233] The scheme differed from the national STPIS in that it set performance targets for SAIDI and SAIFI parameters for the entire State-wide network. Under the national STPIS, individual targets are set for separate geographical areas.

SAIDI and SAIFI targets were set based on input by Aurora, and analysis from OTTER's consultants, PB Associates. A baseline for 2003–07 was set using a historic 24 month rolling average, with explicit adjustments made to future year targets as a result of network upgrades.[234]

Table 4.1 outlines the outcomes of the service incentive scheme. In total Aurora was penalized $4.7 million ($2002) under the scheme. Under the scheme, Aurora failed to meet the targets and was penalized in each year of the 2003–07 regulatory control period. OTTER noted that there was significant variability in Aurora's performance results, even when the impact of major storms was excluded. Most of this variation was attributable to weather events.[235]

In the 2003–07 regulatory control period a GSL scheme also applied to Aurora. Aurora was required to make GSL payments to customers when the length of an interruption or frequency of interruptions exceeded a threshold. The penalty payment to customers was $80 for all breaches. The threshold for duration of an interruption was 12 hours and the threshold for the number of interruptions was 9 interruptions for urban customers and 12 interruptions for rural customers.[236]

Table 4.2 outlines the payments under the Tasmanian GSL scheme in that control period.

[233] OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices,* September 2003, p. 126. (OTTER, *Final Report*, Sep 2003)

[234] ibid., p. 116.

[235] OTTER, *Draft Position Paper Service Incentive Scheme*, May 2007, p. 32.

[236] ibid., p. 126.

Table 4.1 Outcomes of the Tasmanian service incentive scheme, 2002–2007

Indicator		**2002/03**	**2003/04**	**2004/05**	**2005/06**	**2006/07**
SAIFI	Target	2.15	2.12	2.02	1.91	1.82
(no of interruptions)	Actual	2.22	2.45	2.09	1.96	1.90
	Difference	-0.07	-0.33	-0.08	-0.05	-0.08
	Penalty ($2002)	$174 200	$850 200	$195 000	$130 000	$215 800
SAIDI	Target	185.00	181.00	165.50	154.00	144.40
(minutes)	Actual	193.00	216.00	170.00	182.00	188.00
	Difference	-8.00	-35.00	-4.50	-28.00	-43.60
	Penalty ($2002)	$208 000	$910 000	$117 000	$728 000	$1 133 600

Source: OTTER, May 2007, p. 32

Table 4.2 Payments under the Tasmanian GSL scheme 2003–07

	2003/04		**2004/05**		**2005/06**		
Indicator	No.	Value ($2002)	No.	Value ($2002)	No.	Value ($2002)	No.
12 hour outages	2 015	161 200	1 149	91 290	2 102	168 160	588
Urban reliability	98	7 840	806	64 480	4 291	343 280	1 334
	4 957	396 560	6 842	547 360			
February 2005 storms			17 390	1 391 200			
Total	**7 070**	**565 600**	**26 187**	**2 094 960**	**6 393**	**511 440**	**1 949**

Source: OTTER, Tasmanian Energy Supply Industry Performance Report 2004/05, p. 86, p. 79-80; OTTER, Tasmanian Energy Supply Industry Performance Report 2006/07, p. 98.

In addition to the network reliability payments Aurora makes under the GSL scheme, Aurora makes payments for customer service performance in accordance with its customer service charter. Aurora is required to publish a customer service charter under clause 8.3.1 of the Tasmanian Electricity Code (TEC). The charter must state the services and level of standard of such services that a customer is entitled to receive. Under clause 8.3.1 of the TEC the customer charter must be approved by the

Tasmanian regulator. Aurora published a customer service charter with GSLs and payments for failing to meet the GSLs. Generally, if Aurora does not adhere to the GSLs in the customer service charter, Aurora will make a payment to customers of $30. The payments made by Aurora under the customer charter are outlined in Table 4.3 below.

Table 4.3 Customer service, minimum service level payments in Aurora's customer service charter

Category	Payment
Meeting appointments for alterations to metering equipment on time	$30 per day up to $150
Four days notice of planned interruptions	$30
Arriving more than fifteen minutes late for an appointment	$30
Replacement of streetlights within 7 days	$30 per day up to $150
Not damaging a property while conducting vegetation clearing works	$30
Resolving electricity account mistakes and providing a written response within 10 days	$30

Source: Aurora, Tasmanian Electricity Customer Charter, March 2010.

4.5.2 Current regulatory control period 2008–12

In May 2007, OTTER released a Draft Position Paper on the service incentive arrangements to apply to Aurora in the 2008–12 regulatory period.[237] Subsequently, OTTER released a draft[238] and final report on the proposed maximum prices Aurora can charge for its services. The final report on the maximum prices that Aurora can charge for its distribution services set out the service incentive arrangements that would apply to Aurora in the 2008–12 regulatory control period.[239]

In the Draft Position Paper OTTER reviewed the performance incentive arrangements that it established for Aurora in the previous regulatory control period. This review covered the GSL scheme as well as the services incentive scheme. The positions adopted in the Draft Position Paper on the maximum prices that Aurora can charge for its services were broadly applied in OTTER's draft report and final report.

In its final decision OTTER decided not to apply a service incentive scheme. The Draft Position Paper identified a number of general concerns involved in setting a service incentive scheme based upon the standard measures of SAIDI, SAIFI and MAIFI. These concerns included:[240]

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[237] ibid.

[238] OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Draft Report and Proposed Maximum Prices*, July 2007 (OTTER, *Draft report*, July 2007)

[239] OTTER, *Final Report*, Sep 2007, p. 225.

[240] OTTER, *Draft Position Paper Service Incentive Scheme*, May 2007, p. 61.

- the lack of consistent historical data, especially for SAIDI and MAIFI, on which to establish a starting point for such a scheme
- the high degree of variability in SAIDI and SAIFI, mostly related to aspects of performance (mostly the weather) over which the distributor has limited influence
- the difficulty in establishing the impact of past reliability improvement programs, leading to uncertainty about the actual current performance levels, and thus the starting point for such a scheme
- the difficulty in forecasting the impact of future reliability improvement programs, leading to potentially unachievable or too easily attainable targets with the consequent financial implications
- the risk of incorrectly matching performance targets to capital expenditure forecasts

OTTER concluded that:

> [T]o establish a scheme based on inadequate data leading to an 'incorrect' starting point and unrealistic future performance targets, potentially exposes customers to the risk of rewarding Aurora for performance improvement arising from benign weather conditions and exposes Aurora to the risk of significant penalties against which it cannot mitigate. However, not to provide Aurora with any incentive to maintain average performance exposes Tasmanian electricity consumers to the risk that Aurora may reduce network maintenance, putting customers at risk of deteriorating reliability, with consequential economic losses.[241]

OTTER considered that this risk, given the facts at the time, could be counteracted by publicly reporting on service performance, which would provide Aurora with an incentive to maintain and improve performance. Those facts were that Aurora was cobadged with a publicly-owned retailer which was about to enter a competitive environment. OTTER considered that these factors made it "a viable option"[242] to report on network reliability standards rather than apply a service incentive scheme to Aurora in the 2008–12 control period.[243]

In its final report, consistent with the Draft Position Paper, OTTER decided to continue the existing GSL scheme, with a number of amendments. Firstly, it was decided that regional performance targets, rather than average feeder performance targets, would provide more appropriate targets tailored to the characteristics of individual sections of Aurora's network.[244]

The Draft Position Paper proposed to apply individual GSL payment obligations based upon community categories developed in a joint working group of OTTER, Aurora and the Office of Energy Planning and Conservation (OEPC).[245] The working group developed the reliability standards with the intention of using them as the basis

241 OTTER, *Draft Position Paper Service Incentive Scheme*, May 2007, pp. 61-62.
242 ibid., p. 62.
243 ibid., p. 64.
244 OTTER, *Final Report*, Sep 2007, p. 223.
245 ibid., p. 195.

of a service incentive scheme. The network communities grouping developed by the joint working group differed from the standard grouping of customers adopted by most economic regulators in Australia. In developing the reliability standards the working group applied the principle that standards should be appropriately matched to the nature of individual communities, their value of supply reliability, and the cost to provide electricity to that particular community.[246]

The working group found that the supply area category previously applied tended to mask poor performance. This was because averages of feeder SAIFI and SAIDI tended to fall well within the average reliability targets, while the percentage of individual feeders not meeting the lower bound of reliability in each category was often in excess of 5 per cent. Further, applying supply area categories to feeders precluded differentiation of varying types of loads on a single feeder; for example a feeder classified as rural may also supply regional centres or urban fringes as well as a significant rural load.[247]

In its final decision, OTTER applied individual GSL thresholds to the community classifications developed by the joint working group. The metrics proposed for measuring reliability of service in these communities was frequency of disconnections from supply per year and total time that customers were without electricity.[248]

These supply reliability standard and community categorisations were incorporated into the TEC. Clause 8.6.11 Interruptions to supply of the TEC outlined the minimum supply reliability standards that apply to communities within Tasmania. Table 4.4 below outlines the minimum service standards in the TEC.

Table 4.4 TEC Supply Reliability Standards

Supply reliability category	Annual number of supply interruptions (on average)		Annual duration of supply interruptions (on average)	
	Category A	**Area B**	**Category C**	**Area D**
Critical Infrastructure	0.2	0.2	30 mins	30 mins
High Density Commercial	1	2	60 mins	120 mins
Urban and Regional Centres	2	4	120 mins	240 mins
High Density Rural	4	6	480 mins	600 mins
Lower Density Rural	6	8	600 mins	720 mins

Source: Tasmanian Electricity Code.

OTTER decided that an uncapped GSL scheme would not be symmetrical for Aurora as it could potentially be exposed to unlimited payments, particularly in the event of a series of severe and widespread events. OTTER originally proposed that a cap of 2.5

246 OTTER, Aurora, OEPC, *Joint Working Group Final Report, Distribution Network Reliability Standards, Volume I – Summary of Recommendations and Overview*, Feb 2007, p. 2.
247 ibid., p. 7.
248 OTTER, *Draft Position Paper Service Incentive Scheme*, May 2007, p. 21-22.

times the GSL allowance would be appropriate,[249] but in response to a submission from Aurora, OTTER agreed in its final decision to a cap of 2 times the GSL allowance.[250]

The Draft Position Paper proposed that Aurora would be compensated in part for payments above a certain level when the impact of a single event exceeded a threshold.[251] The intent was to recognise that in some limited circumstances such as widespread storms, Aurora could not reasonably be expected to restore power to customers within the target time.[252] In its final report OTTER determined that the threshold for GSL payments for single supply interruption events changes depending on the number of people affected by these events. Aurora is still required to make GSL payments to customers for outages that are longer than the standard GSL threshold. However, Aurora can recover half of the total value of the payments that are above the standard threshold but below the adjusted threshold through an adjustment to tariffs in the next year.[253]

OTTER implemented a further risk sharing mechanism for Aurora under the GSL scheme. Under the scheme Aurora is required to make payments to customers when customers experience an outage that exceeds a certain duration specified in Table 4.4. The threshold to determine whether a payment is required is calculated after the event. If the event results in more than 34 000 customers experiencing an outage in a 24 hour period then the adjusted thresholds will be the threshold in Table 4.4 multiplied by the number of customers affected divided by 34 000. Aurora must continue to make payments based on the unadjusted thresholds, but can recover half the payments made to customers below the adjusted threshold recoverable through tariffs in the following year.[254]

OTTER increased the first year GSL payment allowance for Aurora under the new GSL scheme, as under the new scheme payments were expected to increase. OTTER scaled down this allowance by 33 per cent across the regulatory period, recognising:

- Aurora's view that with better management of outages 20 per cent of duration payments could be avoided

- OTTER's view that up to 50 per cent of frequency related payments were avoidable.[255]

OTTER agreed that the existing list of exemptions under the GSL scheme should continue.[256] The GSL payments under the new scheme are outlined in Table 4.5 and Table 4.6. The thresholds are tailored to the various communities as specified in the TEC reflecting the costs of servicing those areas. A single GSL threshold applies to the frequency of outages GSL payments for each community. A penalty payment to customers of $80 applies if the frequency of outages GSL is breached. Two thresholds

249 OTTER, *Draft Report*, July 2007, p. 196.
250 OTTER, *Final Report*, Sep 2007, p. 234-235.
251 OTTER, *Draft Report*, July 2007, p. 196.
252 OTTER, *Final Report,* Sep 2007, p. 235.
253 ibid., p. 235.
254 OTTER, *Final Report*, Sep 2007, p. 235.
255 ibid., p. 232.
256 ibid., p. 234.

are applied to single outage durations for each community with penalty payments of $80 for the first threshold and $160 for the second threshold.[257]

Table 4.5 Frequency of Outages GSL payments

Category	Threshold (number)
Urban, High Density Commercial, Critical Infrastructure	10
Higher Density Rural	13
Lower Density Rural	16
Frequency of Outage GSL payment	$80

Source: OTTER, Guaranteed Service Level (GSL) Scheme, Dec 2007, p.6.

Table 4.6 Single Outage Duration GSL payments

Category	Threshold (hours)	
Urban, High Density Commercial, Critical Infrastructure	8	16
Higher Density Rural	8	16
Lower Density Rural	12	24
Single Outage Duration GSL payment	$80	$160

Source: OTTER, Guideline Guaranteed Service Level (GSL) Scheme, Dec 2007, p.6

The GSL scheme applies exemptions for the following events:

- load shedding at Ministerial direction
- momentary interruptions
- interruptions of unmetered supply
- interruptions requested by the customer
- interruptions at installation covered by a curtailage arrangement
- disconnection for non-payment
- disconnection for safety reasons
- widespread interruptions due to rare events to be determined by OTTER after considering the factors giving rise to the interruptions
- interruptions for testing and maintenance of services wires, service fuses and meters.[258]

257 OTTER, *Guaranteed Service Level (GSL) Scheme*, Dec 2007, p. 6.

Total GSL payments are capped at two times the cumulative allowance in Table 4.7 below.

Table 4.7 GSL allowance in the current regulatory control period

	June 2008	2008/09	2009/10	2010/11	2011/12
Allowance ($ million 2006)	0.924	1.740	1.603	1.475	1.344

Source: OTTER, Sep 2007, p.234

Table 4.8 Aurora's GSL payments in the 2007–12 regulatory control period ($nominal)

	2007-08		2008-09	
	No.	Value	No.	Value
Timely restoration	3 055	$259 360	8 435	$766 880
Reliability	3 410	$272 800	2 050	$164 000
Total	**6 465**	**$532 160**	**10 485**	**$930 880**

Source: OTTER, Tasmanian energy supply industry performance report 2008–09, p. 107.

4.6 AER's preliminary position on the application of the STPIS

In the preliminary positions paper for Aurora,[259] the AER proposed to apply the supply reliability and customer service components of the STPIS to Aurora. The AER stated that it would not apply the STPIS GSL scheme as there is currently an existing GSL scheme in Tasmania.

The AER proposed to apply the SAIDI and SAIFI reliability performance components of the STPIS with separate SAIDI and SAIFI targets set for network segments in accordance with the existing network segments under the TEC minimum supply reliability standards. Targets would reflect the available data on average performance over the previous five years, with adjustments as necessary under the STPIS. The incentive rate to apply to the critical infrastructure and high density commercial sections of Aurora's network would be the same as for CBD network sections under the STPIS. All other sections would have the standard incentive rate applied to them.

For the reliability of supply component of the STPIS the AER proposed to apply the standard revenue of risk of ±5 per cent The AER would calculate a MED boundary based upon the 2.5 beta method as specified in the STPIS.

For the customer service component the AER proposed to apply the telephone answering customer service parameter. The default level of revenue at risk of

258 ibid, p. 234.

259 AER, *Preliminary positions Framework and approach paper Aurora Energy Pty Ltd Regulatory control period commencing 1 July 2012*, June 2010

± 0.5 per cent is proposed to be applied to the call answering parameter. The AER's preliminary positions are available on the AER's website: www.aer.gov.au.

4.7 Summary of submissions

Of the seven submissions received in response to the AER's preliminary positions paper, three of those submissions commented on the proposed application of the STPIS. These submissions included two from Aurora and OTTER's submission.

Aurora accepted the basic tenets of the AER proposed STPIS. This included the AER's decision to apply the TEC community categories as the network categories under the supply reliability component of the STPIS.[260] Aurora supported the 2.5 beta approach used to calculate the MED day exclusions.[261] Aurora agreed with the AER's proposed measures of VCR and the proposed application of the customer service parameter.[262] Aurora also agreed with the AER's proposal for setting performance targets under the STPIS.[263]

The following summary focuses on critical aspects of the scheme or areas where interested parties proposed that the AER should deviate from its preliminary positions. Full submissions are available on the AER's website.[264]

4.7.1 Aurora's first submission

In its first submission Aurora made the following comments:

- the application of both the STPIS and the TEC GSL scheme may apply conflicting costs and objectives. [265]
- the 5 per cent revenue at risk threshold is larger than necessary to drive maintained and improved performance. Aurora proposes a 2.5 per cent level of revenue at risk instead.
- the AER should adopt the connected KVA weighting for the STPIS parameters used in the TEC GSL scheme.[266]
- third party outages excluded the TEC should also be excluded from the STPSI.[267]
- the benefit sharing scheme applying to outages that affect more than 34 000 customers specified in OTTER's 2007 should apply in the forthcoming regulatory period.[268]

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260 Aurora, Service Target Performance Incentive Scheme Submission to AER Preliminary Positions, October 2010, (Aurora, STPIS submission, Oct 2010) p.20.
261 ibid., p. 22.
262 ibid., p. 23.
263 Aurora, *Framework and approach paper, response to AER preliminary positions*, August 2010 (*Aurora, Response to AER preliminary positions, August 2010*), p. 28.
264 www.aer.gov.au
265 Aurora, Response to AER preliminary positions, August 2010, p. 4.
266 ibid., p. 28.
267 ibid., p. 29.
268 ibid., p. 30.

- the TEC GSL scheme does not exclude events that are excluded from the financial effects of the STPIS s-factor, including most transmission exclusions.[269]

4.7.2 OTTER's submission

In its submission OTTER agreed in principle to continue the application of its existing GSL scheme. As this GSL scheme will continue to apply, the AER's STPIS GSL scheme will not apply in the next regulatory period. OTTER's key reason for retaining the Tasmania's GSL scheme is its linkage to Tasmania's supply reliability standards which are not feeder based, unlike the STPIS GSL schemes.[270]

4.7.3 Aurora's second submission

In its second submission, Aurora made the following comments:

- the customer number data it possesses for the purposes of calculating SAIDI and SAIFI targets may not be robust. As such the AER should adopt an embedded capacity weighting to calculate targets. It would be inappropriate to place any of Aurora's annual revenue at risk in a scheme that has "poorly set" targets.[271]
- Aurora considers that the following events should be excluded from the scheme:
  - high fire danger days, when Aurora's auto-reclosers are set to lock-out immediately rather than the standard "trip three times then lock-out"
  - outages at the direction of emergency personnel
  - unplanned outages caused by vegetation originating from outside Aurora's statutory clearance zones
  - unplanned outages due to most wildlife interactions with Aurora's infrastructure
  - outages due to customer installation faults & overloaded service fuses.[272]
- the proposed revenue at risk of ± 5 per cent is greater than necessary.[273] The revenue at risk should be set with consideration for the revenue at risk under the TEC GSL scheme.[274] The revenue at risk should be set at maximum of ±2.5 per cent.[275]

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[269] ibid., p. 30.
[270] OTTER, *Tasmanian GSl requirements*, August 2010, pp. 1–2.
[271] Aurora, *STPIS submission*, Oct 2010, p. 21.
[272] ibid., p. 23.
[273] ibid., p. 24.
[274] ibid., p. 25.
[275] ibid., p. 25.

4.8 Issues and AER considerations

4.8.1 Exclusions

In the AER's Preliminary Positions Paper, the AER proposed that exclusions provided under clause 3.3 of the STPIS would apply to Aurora.[276]

Aurora made two submissions to the AER concerning exclusions. In its first submission Aurora contended that third party outages excluded under the TEC should also be excluded under the STPIS.[277] In its later submission Aurora also recommended that the AER exclude events captured under section 26 of the ESI Act.[278]

Aurora notes that the exclusions under the TEC GSL scheme differ from the exclusion criteria that apply to service standards under the TEC.[279] The AER notes that these exclusions also differ from exemptions from the obligation to supply under Part 26 of the ESI Act.

Clause 3.3(a) of the STPIS provides that certain events may be excluded when calculating the revenue increment or decrement under the scheme. It is important to note that this allows the AER discretion to choose whether certain events should be excluded from the financial effects of the scheme. The AER is not obliged by this clause to exclude any events. Under the scheme Aurora may propose annually to exclude events from the financial effects of the scheme in accordance with clause 3.3 of the STPIS and the AER will then determine whether these effects should be excluded.

When considering exclusions, it is necessary for the AER to outline which events it intends to exclude under clause 3.3 of the STPIS, as performance targets must be set to ensure that they reflect events excluded under clause 3.3 of the STPIS.[280]

4.8.1.1 ESI Act

Aurora contends that the interaction between clause 3.3(a)(7) and section 26 of the ESI Act dictates that events outside the effective control of Aurora should be excluded from the scheme. With reference to s 26(2) Aurora contends that the following outages should be considered to be "outside of the consideration of the STPIS":

- high fire danger days, when Aurora's auto-reclosers are set to lock-out immediately rather than the standard "trip three times then lock-out" by the combination of STPIS Clause 3.3(a)(7) and ESI 26(2)(c);
- 3rd party outages by the combination of STPIS Clause 3.3(a)(7) and ESI 26(2)(d)(ii)
- outages at the direction of emergency personnel by the combination of STPIS Clause 3.3(a)(7) and ESI 26(2)(d)(i);

276 AER's Preliminary Positions Paper, p. 99.
277 Aurora, Response to AER preliminary positions, August 2010, p. 29.
278 Aurora, *STPIS submission*, Oct 2010, p. 23.
279 Aurora, Response to AER preliminary positions, August 2010, p. 30.
280 AER, *STPIS*, Nov 2009, clause 3.2.1(a)(1).

- unplanned outages caused by vegetation originating from outside Aurora's statutory clearance zones by the combination of STPIS Clause 3.3(a)(7) and ESI 26(2)(d)(ii); party outages by the combination of AER #6 and ESI 26(2)(d)(ii);
- unplanned outages due to most wildlife interactions with Aurora's infrastructure by the combination of STPIS Clause 3.3(a)(7) and ESI 26(2)(d)(ii); and
- outages due to customer installation faults & overloaded service fuses by the combination of STPIS Clause 3.3(a)(7) and ESI 26(2)(d)(ii).[281]

Section 26 of the ESI Act provides the following circumstances where Aurora is not obliged to supply electricity:

> 26. Obligation to supply
>
> (2) an electricity entity is not obliged to supply electricity to a customer if–
>
> (a) the supply would overload the power system or prejudice in some other way the supply of electricity to other customers; or
>
> (b) the supply would result in contravention of the conditions of the electricity entity's licence; or
>
> (c) the supply would result in risk of fire or some other risk to life or property; or
>
> (d) the supply is or needs to be interrupted–
>
> (i) in an emergency; or
>
> (ii) in circumstances beyond the electricity entity's control; or
>
> (iii) for carrying out work on electricity infrastructure; or
>
> (iv) to comply with a direction to the electricity entity under this Act; or
>
> (e) the electricity entity is exempted from the obligation by regulation.

Clause 3.3(a)(7) of the STIPS concerns "load interruptions" that result from "the exercise of an obligation, right or discretion imposed upon or provided for under." Under clause 3.3(a)(7) such interruptions must be "caused by the exercise of any obligation, right or discretion imposed upon or provided for" under the relevant jurisdictional legislation. As such, Aurora must:

a. hold an obligation, right or discretion, and
b. actively put into action or use that obligation, right or discretion to cause the load interruption.

Aurora appears to base its position on the premise that section 26 of the ESI Act provides for the exercise of such an obligation, right or discretion and that each outage it seeks to be excluded is caused by the exercise of that obligation, right or discretion. This is considered below.

281 Aurora, *STPIS submission*, Oct 2010, p.23

Section 26 of the ESI Act specifies when Aurora is not obliged to supply electricity. Section 26 appears to release Aurora from its obligation to supply if certain events occur. Once these events occur, it appears to provide a right not to supply or a discretion not to supply. Where load interruptions are "caused by the exercise" of that "right" or "discretion" to choose not to supply electricity, such interruptions would fall within the ambit of clause 3.3(a)(7) of the STPIS.

To ascertain whether Aurora is provided with a "right" or "discretion" not to supply each of the proposed excluded outages is examined further below:

- **High fire days** when Aurora's auto-reclosers are set to lock-out. On such days Aurora has the option, when a momentary outage occurs, to set auto-reclosers to trip and return electricity supply. Aurora may choose not to exercise this option as the supply would result in risk of fire or some other risk to life or property. The exercise of Aurora's right or discretion would be in accordance with s 26(2)(c) of the ESI Act. The interruption to supply would be caused by the exercise of the right or discretion to interrupt the supply of electricity and would fall within clause 3.3(a)(7) of the STPIS.

  The AER notes that Aurora has not specified when it considers that a day would be of 'high fire risk'. The AER will consider the appropriate definition of 'high fire risk days' as part of its final determination for Aurora.

- **3rd party outages** when another party is responsible for causing an interruption to the supply of electricity. Such outages are not caused by Aurora exercising a right or discretion to interrupt supply under s 26 of the ESI Act. These outages are caused by a party other than Aurora.

- **Outages at the direction of emergency personnel** where the supply needs to be interrupted in an emergency. Aurora would be acting in accordance with section 26(2)(d)(i) of the ESI Act and the exercise of its right or discretion would fall within clause 3.3(a)(7) of the STPIS. As such, the AER considers that these interruptions may be excluded from the financial effects of the scheme.

- **Outages caused by vegetation originating outside of Aurora's clearance zone.** Such outages are not caused by Aurora exercising a right or discretion to interrupt supply under s 26 of the ESI Act.

- **Unplanned outages caused by wildlife interaction**. Such outages are not caused by Aurora exercising a right or discretion to interrupt supply under s 26 of the ESI Act.

- **Outages due to customer installation faults & overloaded service fuses**. Where the outage is caused by the customer installation or overloading of service fuses by the customer, Aurora would not have exercised a right or discretion to interrupt supply in accordance with s 26 of the ESI Act. However, if Aurora did exercise its right or discretion to interrupt supply due to such problems, its action could possibly fall within the scope of s 26 of the ESI Act (such as under s 26(2)(a)). It would then also fall within clause 3.3(a)(7) of the STPIS. The Tasmanian Electricity Code is also relevant to these types of outages and is discussed below.

4.8.1.2 The Tasmanian Electricity Code

Under clause 8.6.11(c) of the TEC[282], Aurora may interrupt the supply of electricity to a Customer's electrical installation at any time for reasons including:

> Despite clause 8.6.11(a) and subject to Part 7 of the Electricity Supply Industry (Tariff Customers) Regulations 1998 and a requirement that the Distribution Network Service Provider must use its reasonable endeavours to act in accordance with the needs of Customers who have notified their Electricity Retailer that a person at their address is reliant upon life support equipment under Part 7 of the Electricity Supply Industry (Tariff Customers) Regulations 1998 and/or are classified as sensitive loads, the Distribution Network Service Provider may interrupt the supply of electricity to a Customer's electrical installation at any time for reasons including:
>
> (1) planned maintenance or repair of the Distribution Network Service Provider's distribution system;
>
> (2) unplanned maintenance or repair of the Distribution Network Service Provider's distribution system in circumstances where, in the opinion of the Distribution Network Service Provider, the connection of the Distribution Network Service Provider's distribution system to the Customer's electrical installation poses an immediate threat of injury or material damage to any person or to the Distribution Network Service Provider's distribution system;
>
> (3) the need to shed load in respect of the Customer’s electrical installation because the total demand for electricity in Tasmania at the relevant time exceeds the total supply available; or
>
> (4) the need to eliminate the risk of fire.

As Aurora has the right or discretion under clause 8.6.11(c) to interrupt supply, the AER considers that these interruptions may fall within the scope of clause 3.3(a)(7) of the STPIS and accordingly, the AER could exercise its discretion to exclude such events when calculating the revenue increment or decrement under the STPIS in accordance with clause 3.3(a).

On reviewing the events listed in clause 8.6.11(2), (3) and (4) of the TEC, the AER considers that such interruptions are captured by STPIS clause 3.3(a)(7). Further, the events specified under clause 8.6.11(c)(3) of the TEC are of the kind that would fall within clauses 3.3(a)(2)–(4) of the STPIS.

The AER therefore has decided that such events as set out in clause 8.6.11(2), (3) and (4) should be excluded from the revenue calculations under the STPIS in accordance with clause 3.3(a).

Interruptions captured under 8.6.11(c)(1) require further examination. At the outset it is important to reiterate that Clause 3.3(a) of the STPIS provides that certain events may be excluded when calculating the revenue increment or decrement under the

[282] subject to Part 7 of the Electricity Supply Industry (Tariff Customers) Regulations 1998 and a requirement that the Aurora must use its reasonable endeavours to act in accordance with the needs of Customers who have notified their Electricity Retailer that a person at their address is reliant upon life support equipment under Part 7 of the Electricity Supply Industry (Tariff Customers) Regulations 1998 and/or are classified as sensitive loads.

scheme. It is important to note that this allows the AER discretion to choose whether certain events should be excluded from the financial effects of the scheme.

The STPIS only applies to unplanned outages. In its initial decision the AER decided not to incorporate planned outages into the STPIS as:

> "The AER recognises planned interruptions are necessary to carry out required works on the network such as maintenance and new connections. The reason for including planned interruptions in the s-factor component of the proposed scheme was to provide incentives to improve the efficiency of undertaking planned works.
>
> However, the AER acknowledges that there are already cost efficiency incentives available in the regulatory framework applicable to DNSPs (through the CPI-X form of regulation and the operation of the EBSS) which are designed to improve the efficiency of a DNSP's performance, including planned works. Given that this suite of operational efficiency incentives will be in place for the national regulation of DNSPs the AER has decided not to include planned interruptions in the scheme at this time. The AER intends to report publicly on the level of planned interruptions in the future to ensure that this aspect of service performance can be monitored."[283]

Clause 8.6.11(c)(1) of the TEC concerns "planned maintenance or repair". There is no definition in the TEC of this phrase. The ordinary meaning of "planned" is "intended". Thus, "planned maintenance or repair" is of a kind where the DSNP has prior knowledge of what will occur. This understanding is supported by clause 8.6.11(e) of the TEC which requires that a DSNP give notice to a customer whose electrical installation will not receive a supply of electricity due to planned maintenance or repair of the DNSP's distribution system.

The AER notes that under the STPIS, an "unplanned interruption" is "an interruption due to an unplanned event". An "unplanned event" is "an event that causes an interruption where the customer has not been given the required notice of the interruption or where the customer has not requested the outage."

Therefore, where the customer has been given notice, as is required under the TEC, it will be a planned event and one to which, given that the STPIS only applies to unplanned outages, the STPIS does not apply. It may be that there are circumstances where, mistakenly or otherwise, no notice is given to the customer but the DNSP has still planned or intended the outage. However, in the AER's view, as notice should have been given in accordance with clause 8.6.11(e) of the TEC so as to allow the customer(s) to prepare for interruptions and mitigate the negative effects of those interruptions, a failure to provide notice does not mean that the event itself was unintended. For this reason, the AER considers that such events, if they do occur, should not be excluded from the STPIS under clause 3.3(a).

Accordingly, the AER will not exclude planned maintenance and repair under clause 8.6.11(c)(1) of the TEC from the financial effects of the scheme.

In summary, subject to the chapeau to clause 8.6.11(c), the AER will exclude from the financial effects under the scheme those events listed in clause 8.6.11(c)(2), (3), and

283 AER, *Final decision: Electricity distribution network service providers Service target performance incentive scheme*, June 2008, p.13

(4) of the TEC. The AER will not exclude planned maintenance and repair under clause 8.6.11(c)(1) of the TEC. The AER notes that the events listed in clause 8.6.11(c) of the TEC are not exhaustive. The AER's assessment, however, is limited to the events listed as it is not possible to evaluate unknown events that may fall within the scope of clause 8.6.11(c) of the TEC.

4.8.1.3 Exclusions under the TEC GSL scheme

Under the objectives of the STPIS the AER, consistent with clause 6.6.2(3) of the NER, must take into account any regulatory obligation or requirement to which Aurora is currently subject.[284]

Clause 2.6(b) of the STPIS further provides that the AER will give consideration to an arrangement proposed under the STPIS that reduces the impact of any transitional issues. In discussions with OTTER it was considered to be appropriate to streamline the exclusions under the STPIS and TEC GSL schemes. This would also mitigate any differing incentives under the schemes which could be caused by different exclusion criteria. Aurora noted that the events excluded from the schemes are different.[285] This addresses one difference between the two schemes addressing Aurora's concern that there may be differing incentives under the schemes. The AER recognises that such transitional issues may arise in moving to the national scheme and may need to be addressed at that time.[286]

Clause 2.6(d) of the STPIS states that [t]he AER shall decide on the appropriateness of the arrangement to address a transitional issue on the basis of:

1. materiality of the issue
2. reasonableness and fairness to the DNSP and customers
3. consistency with the objectives as set out in clause 1.5

The exclusions in the TEC GSL scheme and the STPIS are set out below. Following a review of these exclusions, the AER considers that most exclusions applied under the TEC GSL are replicated in the STIPS. Some events which may be excluded under the STPIS can not be excluded under the TEC GSL scheme.

Excluded events under the TEC GSL scheme are as follows:

(a) outages approved by the Regulator on application from a Distributor in relation to:

- load shedding due to a short fall in generation capacity; or
- an emergency restriction order made by the Minister under section 67 of the ESI Act; or
- widespread interruptions to supply due to rare events;

(b) a planned outage requested by a Customer;

[284] Clause 1.5(b)(2) of the STPIS

[285] Aurora, Response to AER preliminary positions, August 2010, p30

[286] AER, *Final Decision, Electricity Distribution Network Service Providers, Service Target Performance Incentive Scheme*, June 2008

(c) an outage caused by customer installation faults;

(d) an outage affecting the Customer's electrical installation that receives supply of electricity as a type 7 metering installation;

(e) an outage for the reason of testing and/or maintenance of service wires, service fuses and meters; or

(f) an outage arisen from disconnection:

- under section 42 of the ESI Act because of a Customer's failure to pay the relevant electricity account; or
- for reasons of safety under section 66, 67 or 70 of the Electricity Industry Safety and Administration Act 1997; or
- under section 22 (b) to (e) of the Electricity Supply Industry (Tariff Customers) Regulations 1998; or
- under section 90 of the ESI Act because of electricity having been supplied or consumed in contravention to the ESI Act.[287]

Each of these outages is examined within Table 4.9 against the exclusions provided for in the STPIS.

[287] OTTER, *Guaranteed Service Level Scheme* (version 2), December 2007, p.1–2

Table 4.9 Exclusions under the TEC GSL scheme and the STPIS

TEC GSL scheme exclusion	AER STPIS
(a) outages approved by the Regulator on application from a Distributor in relation to: load shedding due to a short fall in generation capacity; or an emergency restriction order made by the Minister under section 67 of the ESI Act; or widespread interruptions to supply due to rare events;	Load shedding due to a shortfall in generation capacity corresponds to the AER's exclusion 3.3(a)(2): load shedding due to a generation shortfall. An emergency restriction order made by the minister under section 67 of the ESI Act would be captured under clause 3.3(a)(7) as it constitutes an obligation for Aurora to interrupt electricity supply. Widespread interruptions to supply due to rare events are analogous to the major event day threshold by the STPIS. The AER notes that under the TEC GSL scheme OTTER has the choice to determine whether an event constitutes a rare event. As such, whether OTTER considers that the AER MED days should be excluded is a matter for its consideration.
(b) a planned outage requested by a customer;	Such events are not considered to be unplanned events under the definition of unplanned interruptions under the STPIS.[288] As such these events do not influence the financial effects of the scheme.
(c) an outage caused by customer installation faults;	The TEC GSL scheme defines customer installation faults as being a fault caused by the failure of the customer's service fuse for no apparent reason or due to overloaded circuits.[289] In correspondence with OTTER it was revealed that customer installation faults are faults in the customer's installation that cause loss of supply to that customer.[290] The AER notes that Aurora has requested that unplanned outages due to customer installation faults be excluded due to the interaction of s 26 of the ESI act and clause 3.3(a)(7) of the STPIS. The AER does not accept that in all instances concerning customer installation faults would fall within the scope of clause 3.3(a)(7). Under the STPIS outages caused by customer installation faults appear to be unplanned interruptions included in the s-factor calculation. However, the AER considers that there would be benefits in exercising the transitional arrangements of the scheme to exclude such outages. This would streamline the incentives under the STPIS and TEC GSL scheme and minimise the administrative costs of the two schemes. This is discussed further below.

288 See the definition on page 43 of the STPIS

289 TEC GSL scheme, p. 1.

290 OTTER, Response to Information Requested on 29 September 2010, Submitted on 7 September 2010

(d) an outage affecting the customer's electrical installation that receives supply of electricity as a type 7 metering installation;	Type 7 metered installations are unmetered supplies, comprising of telephone boxes, street lights, electric fences, and railway crossings. In Appendix A of the STPIS definitions of performance incentive scheme parameters are provided. The definition for the reliability of supply parameters in this section provides that "Unmetered street lighting supplies are excluded. Other unmetered supplied can either be included or excluded from the calculation of reliability measures."[291] Consequently the AER considers that that Type 7 metered installations that feed street lights should not be recorded as part of the scheme. The AER does not consider it appropriate to exempt other outages to type 7 metered installations as these supply assets of importance, and interruption of electricity supply to these assets could have significant negative welfare effects.
(e) an outage for the reason of testing and/or maintenance of service wires, service fuses and meters	Where customers are provided the required notice of the interruption such outages would not be considered to be unplanned outages, and would not influence the s-factor calculation.
(f) an outage arisen from disconnection: under section 42 of the ESI Act because of a customer's failure to pay the relevant electricity account; or for reasons of safety under section 66, 67 or 70 of the Electricity Industry Safety and Administration Act 1997; or under section 22 (b) to (e) of the Electricity Supply Industry (Tariff Customers) Regulations 1998; or under section 90 of the ESI Act because of electricity having been supplied or consumed in contravention to the ESI Act.	All of these outages constitute interruptions caused by the exercise of an obligation, right, or discretion imposed upon Aurora under jurisdictional legislation. As such these would be captured by clause 3.3(a)(7) of the STPIS.

Source: TEC GSL Scheme

The AER considers that the most of these outages provided for in the TEC GSL are captured under clause 3.3(a) of the STPIS. There are some exceptions, however, including some outages to type 7 metered installations.

Drawing on the analysis above, the AER considers that under the transitional provisions of the STPIS, it is appropriate to alter the exclusion criteria to capture customer installation faults. Exclusions due to a customer's electrical installation were not specifically included in the STPIS on the basis that it is often difficult to determine whether a customer's installation has caused a service interruption or whether the interruption is due to a distribution network protection system not

[291] See page 22 of the STPIS

responding appropriately to a customer fault.[292] However, the AER has been informed by OTTER that Aurora defines customer installation faults as being both house fires and outages due to a fault originating inside a customer's installation. Aurora tracks the effects of these outages.[293]

In correspondence with OTTER it was revealed that customer installation faults (as defined by Aurora above) would have a material financial impact on Aurora's performance.[294] The AER's calculation based upon data provided by OTTER is that these events would contribute 1.7 SAIDI minutes a year. More importantly, the standard deviation of the SAIDI effects between 2005-06 and 2009-10 was 2.1 minutes. This could lead to significant changes in Aurora's SAIDI performance from year to year and would have a material impact on the financial implications of the s-factor of Aurora and its customers.

Furthermore, it would also be reasonable and fair to Aurora to continue to exclude the impacts of customer installation faults as these faults do not relate to Aurora's network, and are outside Aurora's control. For these reasons the AER considers it appropriate to adopt clause 8.6.11(c) of the TEC GSL scheme for the STPIS, and accordingly, will exclude outages caused by customer installation faults. Excluding these events would also be consistent with the objectives of the scheme as:

- This will streamline of the incentives under the STPIS and TEC GSL schemes and help minimise the costs of administering both schemes. This is in line with the second objective of the scheme by taking into account the other regulatory obligations to which Aurora is subject.

- Further, as the customer installation faults are outside of Aurora's control and Aurora does not provide customer installation services, excluding these events will not affect Aurora's incentives to provide good service.

The AER notes that it cannot alter the TEC GSL scheme. The AER will continue to consult with OTTER regarding the interaction between the two schemes.

4.8.2 Revenue at risk

In the AER's Preliminary Positions Paper, the AER proposed not to deviate from the default maximum ± 5 per cent revenue[295].

Clause 2.5(b) of the STPIS provides that a DNSP may propose a different level of revenue at risk where this would satisfy the objectives of the scheme. The objectives of the scheme are specified in section 1.5 of the STPIS.

In both of its submissions Aurora contended that the 5 per cent revenue at risk threshold is too great and that it considers a 2.5 per cent revenue at risk threshold is more appropriate. In its first submission Aurora set out its proposal:

[292] AER, *Final decision: Electricity distribution network service providers Service target performance incentive scheme*, June 2008, p.21
[293] OTTER, Response to Information Requested on 29 September 2010, Submitted on 7 September 2010.
[294] ibid.
[295] AER's Preliminary Positions Paper, p. 96.

> [T]he 5 per cent revenue at risk threshold is larger than necessary to drive maintained and improved performance. As an alternative Aurora proposes a 2.5 per cent level of revenue at risk as providing an appropriate incentive. Aurora notes that the current GSL scheme is designed to implement a $1 million incentive and that the previous GSL scheme only effectively placed 1.25 per cent of revenue at risk[296]

In its second submission Aurora noted:

> The AER has proposed that the maximum revenue at risk be applied to Aurora in the STPIS, with 0.5% of annual revenue attached to the Customer Service Component and 4.5% of annual revenue attached to the S-factor.
>
> Aurora notes that this proportion of annual revenue is significantly larger than previously applied in respect of a Service Incentive Scheme. The Regulator placed 1.25% of Aurora's revenue at risk in the regulatory control period from 1 January 2004 to 31 December 2007, and a similar amount of total revenue over the current regulatory control period. Aurora contends that such an increase of such magnitude does not adequately consider established jurisdictional regulatory precedent, especially given that the Regulator was aware of the AER's considerations of the appropriate revenue at risk when the Regulator made the 2007 Determination and the Regulator's observation that reporting of category and community performance was sufficient to ensure no loss of reliability
>
> Aurora notes that the current GSL scheme that the AER proposes to partially implement was designed as a stand-alone Service Incentive Scheme, with an appropriate revenue at risk component. The removal of the single outage safety net and the risk sharing mechanism (see section 4.3) renders the revenue at risk greater than intended. Aurora proposes, therefore, that to recognise the regulatory intent, the revenue at risk associated with the GSL scheme be considered when setting the maximum revenue at risk for the S-factor components of the STPIS.
>
> In particular, Aurora proposes that the revenue at risk be 0.5% of annual revenue attached to the Customer Service Component and that the annual revenue attached to the S-factor be adjusted downwards to account for the historical impact of GSL payments under the scheme that was designed as a stand-alone Service Incentive Scheme and set at a value of a maximum of 2.5%.[297]

In its submissions, Aurora made a number of points concerning the threshold for revenue at risk. These are addressed below.

As provided above, in both of its submissions Aurora refers to the level of revenue at risk under the TEC GSL scheme and the previous Tasmanian services incentive scheme. Aurora contends that the AER should consider regulatory precedent when determining the revenue at risk. It is important to note that regulatory precedent differs across different jurisdictions within the NEM. In the development of the STPIS regulatory precedent was taken into consideration. The most recent regulatory precedent was established in the AER's Victorian determination, where all of the DNSPs were given a cap on revenue at risk of equal to or greater than ±5 per cent. This differs from the approach adopted by the AER in other NEM jurisdictions. In the Victorian determination, the AER was cognisant of material issues that necessitated a

296 Aurora, Response to AER preliminary positions, August 2010, p.27
297 Aurora, *STPIS submission*, No 2, p.24–25

different level of revenue at risk when determining the application of the STPIS in these jurisdictions.

In its second submission Aurora notes that the GSL scheme was developed as a stand alone incentive scheme, and should be taken into consideration when determining the appropriate level of revenue at risk. In the previous period, revenue at risk under the GSL scheme was capped at twice the revenue allowance for the GSL scheme.[298] However, the AER does not consider that it is necessary for a cap on GSL schemes to be applied. This matter is discussed further in section 4.8.3.

The revenue at risk mitigates the risk to customers and Aurora of significant fluctuations in prices over the course of a regulatory control period. A lower level of revenue at risk reduces the size of the incentive on Aurora to improve reliability. The AER considers that the size of the incentive and the volatility of the scheme are appropriately balanced with a 5 per cent cap on revenue at risk. The AER considers that in this instance, a 2.5 per cent cap is not appropriate as it results in a reduction to the size of the incentive that the scheme provides Aurora to maintain and improve network reliability. The AER is satisfied that a 5 per cent cap on revenue at risk represents an appropriate balance between providing incentives for reliability improvements and the risks on DNSPs and customers.

Further, unlike the STPIS, the TEC GSL scheme does not influence the tariffs that Aurora's customers are charged for electricity. The GSL scheme only presents a financial risk to Aurora. This risk is mitigated by the component of the revenue allowance Aurora is provided to cover the expected cost of the scheme.

Aurora's GSL scheme aligns with the TEC minimum service standards. As illustrated in Table 4.10, in the majority of cases, the TEC service standards are significantly more stringent than the GSL payment thresholds.

A comparison between the TEC supply reliability standards and the thresholds for GSL payments is provided in Table 4.10.

298 Aurora, *STPIS submission*, No 2, p.24–25

Table 4.10 Thresholds under the TEC supply reliability standards and GSL scheme

	Interruptions to supply			Duration of interruptions		
	TEC service standards		GSL threshold	TEC service standards		GSL threshold
	Category A	Area B		Category C	Area D	
Critical Infrastructure	0.2	0.2	10	30 mins	30 mins	480 mins
High Density Commercial	1	2	10	60 mins	60 mins	480 mins
Urban and Regional Centres	2	4	10	120 mins	120 mins	480 mins
High Density Rural	4	6	13	480 mins	600 mins	480 mins
Lower Density Rural	6	8	16	600 mins	720 mins	720 mins

Source: TEC and TEC GSL scheme

The AER notes that Aurora sought funding in its 2007 regulatory proposal (which was approved by OTTER) to meet the TEC reliability standards.[299] At the time it may have been appropriate for a cap to be placed on the revenue at risk under the scheme, given that areas of Aurora's network did not adhere to these standards.[300] Since that time, Aurora has been provided with funding during the last regulatory period to meet these standards and consequently, the AER considers that such a cap is not appropriate in this regulatory period.

As the scheme was developed as a stand alone incentive scheme it is important to consider the financial effects of the scheme on Aurora. It would appear that Aurora does not face significant financial risk as a result of the application of the GSL scheme. Aurora's actual performance under the GSL scheme is illustrated in Table 4.11. Table 4.11 indicates that Aurora bettered the forecast number of GSL payments in 2008 and 2009, however performed worse than forecast in 2010. The total effect of the scheme on Aurora's revenues (once Aurora's allowance for GSL payments is taken into consideration) is minimal, being in aggregate -0.24 per cent of revenue over the three year period. Given that the total effect of the GSL scheme to Aurora is not substantial the AER does not consider it necessary to reduce the level of revenue at risk under the STPIS for Aurora.

299 OTTER, *Final Report,* Sep 2007, p105

300 ibid., p.104

Table 4.11 Financial effects of the TEC GSL scheme (nominal$)

	Revenue allowance[a]	GSL payments[b]	GSL allowance[a]	penalty/reward under the scheme	% of revenue
1st half 2008	$99,314,124	$263,200	$971,308	$708,108	0.71%
2008-09	$208,891,043	$930,880	$1,871,938	$941,058	0.45%
2009-10	$220,385,152	$4,697,120	$1,790,570	($2,906,550)	-1.32%
Totals	$528,590,320	$5,891,200	$4,633,816	($1,257,384)	-0.24%

Source: Aurora, STPIS submission No.2, October 2010, p.16
[a] actual GSL payments – Aurora, STPIS submission, Oct 2010, p.16
[b] Revenue allowance and GSL allowance OTTER, 2007 Electricity pricing investigation – Final report, p234. The revenue and GSL allowance has been inflated from real 2006$ to nominal$.

Given that Aurora's actual penalties under the current GSL scheme do not appear to be substantial and OTTER's 2007 determination funded Aurora to improve its network performance to meet the TEC service standards, the AER does not consider it necessary to adjust the revenue at risk under the STPIS to accommodate risk under the GSL scheme. Further, no other GSL scheme in the NEM has a cap on its financial risk.

Based on the above analysis, the AER considers that the appropriate threshold for revenue at risk should be ± 5 per cent.

4.8.2.2 Calculation of revenue at risk

In Aurora's second submission Aurora states that the five per cent cap at risk is made up of a ±0.5 per cent cap on the customer service component, and a ±4.5 per cent cap on the supply reliability component. This is an incorrect interpretation of the ±5 per cent cap on revenue at risk under the STPIS. Clause 2.5(a) of the STPIS provides that the maximum revenue at risk for the scheme components in aggregate for each regulatory year within the regulatory control period shall be 5%, that is, the sum of the s-factors associated with all parameters must lie between +5% (the upper limit) and –5% (the lower limit). As specified in Appendix C of the STPIS the s-factor calculation includes the customer service and supply reliability parameters.

The total revenue at risk under the supply reliability component would only be capped at ±4.5 per cent if the total cap on the telephone answering parameter was reached (being ±0.5 per cent of revenue). If Aurora's performance under the telephone answering parameter is a gain of 0.25 per cent to revenue then a further increase in revenue of 4.75 per cent would be allowable under the supply reliability component.

4.8.3 Interaction between the TEC GSL scheme and the STPIS

The interaction between the STPIS and the TEC GSL scheme was commented on by both Aurora and OTTER. These comments concern three separate matters, which are individually addressed below.

At the outset it is important to note that the TEC GSL scheme is outside of the AER's jurisdiction. OTTER is the regulator responsible for the TEC and hence is responsible for the administration of the TEC GSL scheme. The AER will consult with OTTER should any further issues be identified relating to the interaction between the STPIS and TEC GSL scheme as part of the 2012 distribution determination for Aurora.

4.8.3.1 Application of the TEC GSL scheme

In its submission, OTTER provisionally indicated that the TEC GSL scheme would continue to apply in the forthcoming regulatory control period.[301] Under clause 6.1 of the STPIS, where jurisdictional electricity legislation imposes an obligation on a DNSP to operate a guaranteed service level scheme the GSL scheme specified in the STPIS will not apply. Consequently the STPIS GSL scheme will not apply to Aurora in the forthcoming regulatory control period.

4.8.3.2 Financial risk mitigation mechanisms for the TEC GSL scheme

Aurora, in its first submission, notes that OTTER's 2007 determination specifies mechanisms, the single event safety net and the risk sharing mechanism, which limit the financial risk to Aurora of the GSL scheme.[302] These mechanisms will cease to have effect at the end of the current regulatory period. When these mechanisms cease to have effect, the financial risk to Aurora under the scheme will increase.

The TEC GSL scheme falls outside of the AER's jurisdiction so the AER does not have the ability to modify the application of the scheme. Should OTTER consider it appropriate, OTTER has the ability to develop mechanisms in the scheme which limit the financial risk to Aurora.

The AER does not consider that this is necessary however. The actual financial consequences to Aurora of the current GSL scheme are minimal (as examined in section 4.8.2). Further, as the GSL payment criteria are less stringent than the TEC service standards to which Aurora must adhere as a licence condition, the GSL payments could be viewed as a penalty to Aurora for not adhering to its license conditions. Finally, the AER notes that no other GSL schemes within Australia have financial risk mitigation features. This includes the AER's GSL scheme specified in the STPIS.

4.8.3.3 Differing objectives under the schemes

Aurora, in its submissions, states its concern that the interaction between the TEC GSL scheme and the STPIS may create conflicting costs and objectives. [303] Aurora did not demonstrate how this might occur or what the conflicting costs and objectives might be. Aurora does comment that to meet the regulatory intent in the design of the scheme Aurora's GSL liability should be considered when determining the appropriate level of revenue at risk under the s-factor.[304] This is considered in section 4.8.2.

The AER considers that, though one scheme provides an incentive to improve minimum supply reliability performance and the other provides an incentive to improve average supply reliability over various network sections, the objectives of the

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301 OTTER, *Tasmanian GSL requirements*, August 2010, p.1–2

302 Aurora, Response to AER preliminary positions, August 2010, p.29–30 and Aurora, *STPIS submission*, No 2, p.24

303 Aurora, Response to AER preliminary positions, August 2010, Aug 2010 p.4

304 Aurora, *STPIS submission*, No.2, p.24

schemes are not conflicting. Under both schemes Aurora is rewarded for improving reliability performance. Indeed the increased financial incentive to improve performance could lead to Aurora improving its STPIS performance and its GSL performance.

Further, through the AER's determination Aurora will receive funding to deliver on its licence obligations, which include the provision of a minimal level of service for the TEC communities. The TEC supply reliability standards and GSL scheme are outlined in section 4.5. The TEC licence conditions are significantly more stringent than the GSL obligations as demonstrated in Table 4.11 above.

4.8.4 Calculation of SAIDI and SAIFI

In the preliminary positions paper the AER proposed to adopt the TEC community classifications. For the purposes of calculating SAIDI and SAIFI, the AER proposed to weight these by customer numbers rather than the installed distribution transformer capacity, which is the weighting applied under the TEC for service standards and the GSL scheme.

Aurora, in its submissions, proposed that the AER should adopt the connected installed transformer capacity for the STPIS parameters used in the TEC GSL scheme as opposed to the customer numbers weighting applied in the STPIS.

Aurora noted that that the reliability of supply data used to calculate GSL payments is inadequate to set SAIDI and SAIFI targets and monitor performance. The GSL system uses the Aurora "customer to asset link", whereby installations are "linked" to transformers. The customer to asset link is incomplete, being currently between 90% and 95% complete. At the beginning of the five year period required to set performance standards, the customer to asset link project had only just commenced, and was estimated to be 80% complete three years ago. In consequence, any targets set using this data will be wrong to a greater or lesser extent. Aurora contends that it is inappropriate to place any of its annual revenue at risk in a scheme that has poorly set targets.[305]

Aurora expressed concern that it could not accurately reconcile the geographical customer data provided in its customer to asset link. Aurora maintains that the customer data recorded in the "customer to asset project" is accurate but incomplete. Aurora notes that the data has not been audited by a third party and only used by Aurora for its own purposes.[306] In email correspondence Aurora indicated that for the 2007-08, 2008-09 and 2009-10 regulatory years the customer to asset link project was 85, 90 and 95 per cent complete respectively.

Given that Aurora's customer location database is incomplete and the accuracy of the database has not been reviewed by an external party, the AER considers that it may be inappropriate to weight the supply reliability measures in Aurora's proposal in accordance with customer numbers. However the AER requires further information concerning the customer data that Aurora possesses in order to make its final judgement on the appropriate weighting to be applied to the supply reliability parameters. It may well be the case that based upon currently available data Aurora

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[305] Aurora, *STPIS submission*, p.21

[306] Aurora, Response to Information Requested on 27 October 2010, Submitted on 29 October 2010

can provide a reliable approximation of historical customer numbers upon which historical SAIDI and SAIFI performance can be derived.

However if it is not possible to develop a reliable estimation of historical customer numbers in each of the network areas then it would be appropriate to apply an installed transformer capacity weighting.

The AER notes that the embedded capacity of Aurora's network will change over time depending on how Aurora undertakes its network investment. The AER recognizes that this could potentially affect the financial outcomes of the STPIS. If supply reliability targets for Aurora are weighted by installed transformer capacity, the AER will need consider the changes in historical and forecast installed transformer capacity, and the effect that changes in the embedded capacity can have on reliability performance.

Under clause 2.6(d) of the STPIS the AER shall decide on the appropriateness of the arrangement to address a transitional issue on the basis of:

- The materiality of the issue
- Reasonableness and fairness to the DNSP and customers
- Consistency with the objectives as set out in clause 1.5

The AER considers that in this instance it may appropriate to adopt the installed transformer capacity weighting if accurate customer data is not available. Should the customer data that Aurora possesses not be appropriate for the calculation of performance targets it would be better to apply the installed transformer as:

- An incorrect customer number weighting could materially affect the prices charged for electricity
- It is reasonable and fair on Aurora and its customers to apply the installed transformer capacity weighting. The incentives placed upon Aurora to improve performance will not be altered depending upon how the SAIDI and SAIFI parameters are weighted. Aurora will still be provided with an incentive to maintain and improve reliability performance. Further it would be unreasonable for Aurora or its customers to be rewarded or penalised under the STPIS caused by incorrect customer number data.
- Applying the installed transformer capacity will not alter the objectives under clause 1.5 of the STPIS. Provided that the AER correctly accounts for changes in the embedded capacity, the incentive placed upon Aurora will be to improve reliability performance regardless of the weighting.

If the AER determines that it is appropriate to base targets upon the installed transformer capacity, the AER will require Aurora to report supply reliability data both weighted by customer numbers and by installed transformer capacity. This is required for the application of the STPIS in the future. Further, the SAIDI and SAIFI data weighted by customers could be publically reported to facilitate comparison of performance between networks.

4.9 Consideration of NER criteria

4.9.1 NER criteria 6.6.2(b)(2) compliance with relevant service standards and service targets

Clause 6.6.2(b)(2) provides that in developing and implementing a STPIS, the AER must ensure that service standards and service targets (including GSLs) set by the scheme do not put at risk Aurora's ability to comply with relevant service standards and service targets (including GSLs) as specified in jurisdictional electricity legislation.

Service standards and service targets as specified in jurisdictional legislation will be funded through the capital and operating expenditure requirements of Aurora. The impact of these improvements will be considered when setting targets under the STPIS. The STPIS does not therefore put at risk Aurora's ability to comply with relevant service standards and service targets specified in jurisdictional electricity legislation. The GSL component of the scheme will not apply to Aurora as a TEC GSL scheme currently applies.

4.9.2 NER criteria 6.6.2(b)(3)(i) the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs

Incentive rates for reliability parameters under the STPIS are set on the basis of an economic study of the VCR, which estimates the value of service reliability as a value per kilowatt hour of lost load for supply interruptions. Weightings for each parameter are also based on the value that customers place on them.[307] Therefore, the potential penalty or reward available to Aurora reflects the potential benefit to consumers, and how they value performance under the parameter in question.

4.9.3 NER criteria 6.6.2(b)(3)(ii) any regulatory obligation or requirement to which DNSPs are subject

The AER's preliminary position was not to apply the GSL component of the STPIS to Aurora. Aurora is already subject to a GSL scheme administered by OTTER under the TEC.

In reaching this position, the AER had regard to the regulatory obligations to which Aurora is subject. These included the supply reliability standards under the TEC and the TEC GSL scheme. The AER proposed to apply s-factor supply reliability targets that align with the current TEC supply reliability standards and supply reliability categories. This would allow Aurora to collect and report a single set of supply reliability data. Further, the s-factor supply reliability targets will provide incentives to improve performance in each of the supply reliability categories specified in the TEC supply reliability standards.

[307] The scheme draws on the study of VCR by Charles River Associates (CRA) (CRA, Assessment of the Value of Customer Reliability – report prepared for VENCorp, 2002), and its application in the ESCV's EDPR, in setting a default VCR to be applied under the scheme. A discussion of the VCR applied within the STPIS is provided in the AER's Explanatory Statement and discussion paper: Proposed electricity distribution network service providers service target performance incentive scheme, April 2008, p. 20. This document can be found at www.aer.gov.au. The STPIS permits DNSPs to propose different values where new analysis is available.

4.9.4 NER criteria 6.6.2(b)(3)(iii) the past performance of the distribution network

Under the STPIS, performance targets are based upon an average of performance in the previous five years. The benefit of using an average of performance instead of recent performance is that it limits the effect of the variability in performance that occurs due to factors that are not within the control of the DNSP. If the DNSP's performance is poor in the year upon which targets are based for whatever reason, the DNSP's performance targets for the STPIS would be less onerous on the DNSP. Moreover, using the average rather than the most recent performance removes any incentive that the DNSP may have to underperform in the final year of a regulatory control period to make future targets easier.

4.9.5 NER criteria 6.6.2(b)(3)(iv) any other incentives available to the DNSP under the Rules or a relevant distribution determination

Other incentive schemes applicable to Aurora as part of the distribution determination are the efficiency benefit sharing scheme (EBSS), the demand management incentive scheme (DMIS) and the TEC GSL scheme.

The STPIS works as a 'counterbalance' to the EBSS. The EBSS creates incentives to realise operational efficiency gains. The STPIS serves to maintain or, where efficient, improve service levels (where customers are willing to pay for improved service) so that the incentive to minimise operating expenditure does not result in lower levels of service for customers.

In relation to the DMIS, the STPIS is essentially neutral regarding the level of reliability of network and non network solutions, neither encouraging nor discouraging non-network alternatives to augmentation. However, as discussed below, the AER recognises that there may be a perceived disincentive to implement non-network alternatives to network augmentation created by the reliability performance measures in the STPIS.

The AER has taken the TEC GSL scheme into consideration in determining its likely position as to how the STPIS will apply to Aurora. The AER has adopted the TEC community categories, aligning the network segments adopted under the STPIS with that of the TEC GSL scheme. The AER has also considered the exemptions under the schemes and aligned the exemptions where appropriate.

4.9.6 NER criteria 6.6.2(b)(3)(v) the need to ensure that the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels

Under the current regulatory framework for electricity DNSPs there is a strong financial incentive to reduce costs. While the incentive to reduce costs is beneficial to both businesses and customers, it is only beneficial to the extent that cost reductions are not achieved at the expense of service quality. There are a number of ways in which to provide an incentive for DNSPs to improve performance including:

- An s-factor incentive scheme that links the revenue that network businesses earn with the service that businesses provide, such as the STPIS s-factor. An s-factor scheme provides an incentive to improve performance in each individual section of the network.

- A GSL scheme that requires a network business to compensate customers when they breach guaranteed service level thresholds. These thresholds reflect the minimum level of service that is expected that customers should receive. A GSL scheme generally provides incentive to improve performance for the worst served customers within a network.

- Performance reporting. Publicly reporting on the performance of electricity network businesses can provide transparency and accountability motivating businesses to improve performance.

- Legislative requirements mandating minimum acceptable performance standards.

The incentive to improve performance created by public reporting depends upon the value upon which the electricity distribution business places on public perception of the operation of its business. The power of the other financial incentives depends on the rewards or penalties applied for changes in the level of service. The TEC specifies minimum service standards that Aurora must adhere to. In Tasmania, the penalty for not adhering to these standards would be the revocation of Aurora's licence to provide distribution services. Revoking a licence is an extreme penalty and is unlikely to be acted out in practice.

As discussed above, in the previous regulatory period OTTER did not apply a s-factor incentive scheme in Aurora's current regulatory control period. Instead OTTER decided to publically report on Aurora's service performance. Though public reporting may provide an incentive to improve performance, it is difficult to quantify this incentive. It is not clear that the incentive created by performance reporting is sufficient to offset any financial incentive to reduce costs at the expense of service performance.

Overall performance of electricity distribution networks is affected by a number of factors such as asset failure, weather effects and animal interference. DNSPs can manage these factors by investing in their networks, and deploying maintenance crews to mitigate the effects of interruptions. The AER grants DNSPs a revenue allowance to maintain quality, reliability and security of supply of their networks.

Once a distribution determination has been made, a DNSP's revenue allowance is locked in for duration of the regulatory control period. In the absence of an STPIS, under an incentive regulatory framework there is no obligation to spend the revenue allowance other than to maintain legislated standards of reliability. There is a strong incentive under the regulatory framework to underspend against the allowance, as cost reductions can be retained as profits. The s-factor scheme of the STPIS was developed to counteract this incentive to reduce costs when the cost reductions are achieved at the expense of service performance.

Additionally, the STPIS provides a DNSP with a financial incentive to improve service performance, which under the current regulatory framework would not exist otherwise. The application of a GSL scheme provides a mild incentive to improve service for the worst served customers, however does not provide an incentive to improve general network performance. As the STPIS s-factor targets are based upon average performance over the most recent five years of available data, the STPIS provides a financial incentive to improve on historical performance. As the penalties and rewards under the s-factor are weighted by the value customers place on network reliability, the s-factor only provides an incentive to improve performance where the cost of the investment to improve performance is less than the benefit to customers of the performance improvement.

4.9.7 NER criteria 6.6.2(b)(3)(vi) the willingness of the customer or end user to pay for improved performance in the delivery of services

The willingness of the Aurora's customers to pay for improved levels of service is factored into the incentive rates for each component. These incentive rates reflect the VCR, so that the weighting attached to each parameter, and therefore the amount of any reward or penalty, reflects the value customers place on it.

By segmenting the network for the purposes of determining targets for the reliability of supply component of the STPIS, the AER is able to set targets, and distribute revenue at risk (and therefore the amount of any reward or penalty available), in a way that reflects customers' priorities and their willingness to pay for improvements.

4.9.8 NER criteria 6.6.2(b)(3)(vii) the possible effects of the scheme on incentives for the implementation of non-network alternatives

The STPIS encourages a DNSP to maintain and improve service levels. The incentive created by the AER's proposed DMIS is for a DNSP to implement innovative and/or broad-based demand management that can result in improved network utilisation. The STPIS does not necessarily counteract the incentives created by the DMIS.

However, the AER is aware of the perceived disincentive to implement non-network alternatives to network augmentation created by the reliability performance measures in its STPIS, such that incentives to undertake demand side management may be diminished in the absence of, for example, an adjustment to performance targets or an exclusion to recognise what is seen as a greater risk that targets will not be met.

4.10 AER's likely approach to the application of the STPIS to Aurora

The factors that the AER will determine in specifying how the STPIS will apply to Aurora are specified in clause 2.1(d) of the STPIS. Each of these factors, together with the AER's likely approach to applying these factors, is set out below. In developing this likely approach the AER considered the relevant NER criteria (as outlined in section 4.9 above).

STPIS factor	AER's likely approach
1) each applicable parameter and component to apply including the method of network segmentation for the reliability of supply component	The AER will apply the SAIDI, SAIFI reliability of supply parameters and the telephone answering customer service parameter Separate SAIDI and SAIFI targets will be set for network areas in accordance with the TEC community classifications The SAIDI and SAIFI calculations will be weighted by customer numbers within each network segment, unless the data on customer numbers proves to be an unsuitable basis for calculating targets. The GSL component of the STPIS parameter will not apply to Aurora in the forthcoming period as the TEC GSL scheme will continue to apply.
2) The revenue at risk to apply to each particular parameter	The revenue at risk for the entire s-factor will be capped at ± 5 per cent of the maximum allowable revenue for each year of the regulatory control period. The level of revenue at risk for the telephone answering parameter will be capped at ± 0.5 per cent of the total maximum allowable revenue for each year of the regulatory control period.
3) The incentive rate for each parameter	The incentive rates will be calculated in accordance with the methodology specified in the STPIS
4) The performance target to apply to each applicable parameter	The performance targets for each parameter will be calculated in accordance with the methodology specified in the STPIS. Separate targets will be developed for each community category as specified in the TEC.
5) Any decision with respect to the transitional arrangements set out in clause 2.6	Under the transitional arrangements specified in clause 2.6 of the scheme, the AER will exclude outages caused by customer installation faults, defined as being customer installation faults as being both house fires and outages due to a fault originating inside a customer's installation from the financial effects of the scheme
6) The threshold to apply to any particular GSL parameter	As the existing TEC GSL scheme will continue to apply, the AER's GSL scheme will not apply. Thresholds for GSL payments are specified in the TEC GSL scheme.
7) The payment amount to apply to the applicable GSL parameter	As the existing TEC GSL scheme will continue to apply, the AER's GSL scheme will not apply. Payment amounts are specified in the TEC GSL scheme.
8) The Major event day boundary to apply to Aurora	The AER will calculate the MED day boundary in accordance with the approach specified in the STPIS.

5 Application of the efficiency benefit sharing scheme

5.1 Introduction

As part of the AER's distribution determination, the building block determination for Aurora for the forthcoming regulatory control period must specify how any applicable efficiency benefit sharing scheme (EBSS) will apply to it.[308]

This chapter sets out the AER's likely approach to the application of an EBSS to Aurora in the forthcoming regulatory control period, and its reasons for that likely approach.

An EBSS provides for a fair sharing of efficiency gains and losses between DNSPs and their customers. These gains and losses result from underspends or overspends in a DNSP's forecast operating expenditure for a regulatory control period.[309]

In the absence of an EBSS, there is an incentive for DNSPs to realise efficiency gains early in the regulatory control period because these benefits can only be retained for the remainder of the period. The DNSPs may also have an incentive to increase their actual operating expenditure in the third or fourth year of the regulatory control period (beyond the efficient level), as amounts from these years are typically the basis of operating expenditure forecasts for the next regulatory control period. The consequent effect is that the incentive for DNSPs to improve the efficiency of their operating expenditure declines throughout the regulatory control period. One of the objectives of an EBSS is to create a continuous incentive for DNSPs to seek economically efficient ways to reduce their operating expenditure in each year of the regulatory control period.

5.2 Regulatory requirements

Clauses 6.3.2(a)(3) and 6.12.1(9) of the NER require the AER's distribution determination for Aurora for the forthcoming regulatory control period to specify how the EBSS will be applied. Clause 6.8.1(b)(3) requires the AER's framework and approach paper to set out its likely approach, and reasons for that approach, to the application of the EBSS in that determination.

5.2.1 AER distribution EBSS

The AER is required to develop and publish a scheme or schemes that provide for a fair sharing between DNSPs and users, of:

- the efficiency gains derived from the operating expenditure of DNSPs for a regulatory control period being less than; and
- the efficiency losses derived from the operating expenditure of DNSPs for a regulatory control period being more than;

[308] NER, cl. 6.3.2(a)(3) and constituent decision cl. 6.12.1(9).
[309] NER, cl. 6.5.8(a).

the forecast benchmark operating expenditure accepted or substituted by the AER for that regulatory control period.[310]

In April 2008, the AER released its proposed EBSS to apply to DNSPs. The proposed scheme was the subject of public consultation and submissions were received from interested parties. Issues raised in those submissions were taken into account in preparing the AER's final EBSS and accompanying explanatory statement, released on 26 June 2008. The AER's final EBSS is available on the AER's website at http://www.aer.gov.au.

5.2.2 Implementing the EBSS

In implementing the EBSS, the AER must have regard to:

- the need to ensure that benefits to consumers likely to result from the EBSS are sufficient to warrant any reward or penalty under the scheme for DNSPs
- the need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure
- the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses
- any incentives the DNSP may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.[311]

The AER's distribution EBSS was developed, and will be applied to Aurora, having regard to these factors.

The AER's likely approach to the application of the EBSS to Aurora in the forthcoming regulatory control period is set out in the sections below.

5.3 Overview of current arrangements for Aurora

Aurora is not currently subject to an EBSS.

OTTER applied an EBSS to Aurora's operating expenditure for the 2003 regulatory period.[312] However, Aurora's expenditure during the 2003 regulatory period was significantly higher than forecast. A strict application of the EBSS would have resulted in a negative carryover of $36.34 million into the 2007 regulatory period.[313] In its 2007 decision, OTTER elected to set the carryover amount for that period to zero, noting that:

[310] NER, cl. 6.5.8(a).
[311] NER, cl. 6.5.8(c).
[312] OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania—Final Report and Proposed Maximum Prices*, September 2003, pp. 88–92.
[313] OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania—Final Report and Proposed Maximum Prices*, September 2007, p. 221.

- Clause 6.5.2 of the *Tasmanian Electricity Code* (TEC) requires that OTTER's decision provides for 'a sustainable commercial revenue stream'. OTTER was concerned that applying a negative carryover may breach this requirement[314]

- OTTER's 2003 decision provided no guidance as to the treatment of any negative efficiency carryovers[315]

- There are inherent difficulties in distinguishing between types of expenditure when applying a mechanism such as the EBSS, and there may be incentives to apply an ex-ante reclassification of expenditures so that savings appear in particular categories.[316]

In its 2007 final decision, OTTER elected not to apply an EBSS to Aurora in the 2007 regulatory control period. Although OTTER recognised that 'the incentives to pursue efficiency are weakened without a benefit-sharing scheme', it was concerned about an incentive scheme that is dependent on forecasts made many years in advance.[317] OTTER expressed concern that any forecasting errors were magnified under the EBSS, and the impacts of such errors could be carried forward for a number of years. OTTER considered that carrying forward the negative efficiencies into the next regulatory control period could act as a disincentive to the DNSP to make efficiency gains in the next regulatory control period.[318]

OTTER also noted the difficulty in determining whether Aurora's over-spending in the 2003 regulatory period was due to management decisions or to external factors beyond the control of the DNSP.[319] OTTER determined that the zero carryover would ensure that the maximum revenue determined for the 2007 regulatory control period would not be less than that required for an efficient DNSP to earn a commercial rate of return.[320]

OTTER suggested that its decision was not inconsistent with the design of the EBSS in the draft NER, noting that at the time no AER proposal for an EBSS was not yet available.[321]

5.4 AER preliminary position on the implementation of the EBSS

In the AER's Preliminary Positions paper, the AER noted that it is required to apply an EBSS to Aurora in the forthcoming regulatory control period.[322] In developing an EBSS to be applied to Aurora, the AER had regard to the factors in clause 6.5.8(c) of the NER.

314 ibid., p. 222.
315 ibid., p. 221.
316 ibid., p. 91.
317 ibid., p. 224.
318 ibid., p. 223.
319 ibid., p. 223.
320 ibid., p. 223.
321 ibid., p. 224.
322 AER, Preliminary positions—Framework and approach paper Aurora Energy Pty Ltd, June 2010, p. 109.

5.5 Summary of submissions

In response to its preliminary positions paper, the AER received one submission that addressed the application of an EBSS to Aurora.[323] That submission was the first submission made by Aurora.

In that submission, Aurora agreed with the AER's position to apply its national EBSS to Aurora for the forthcoming regulatory control period.[324] Aurora noted that it had argued against the introduction of an OTTER EBSS during the current regulatory period because, in its view, it 'would have resulted in the immediate imposition of efficiency penalties that Aurora believed it had little control over or ability to mitigate.'[325] Aurora stated that:

> Whilst the AER's proposed EBSS will apply from the commencement of the next regulatory control period, the financial impacts of the scheme will not commence until 2017. This will allow Aurora to gain an understanding of the operation of the EBSS during the 2012–2017 regulatory control period and to make expenditure decisions in the knowledge that those decisions will have revenue impacts in future periods.
>
> Aurora therefore agrees with the AER position in relation to the introduction of the EBSS and looks forward to working with the AER on the introduction of the mechanisms that will underpin Aurora's EBSS.[326]

5.6 Issues and AER considerations

The AER has developed an EBSS in accordance with the requirements of the NER, which it intends to apply to Aurora in the forthcoming regulatory control period. The AER had regard to the factors in clause 6.5.8(c) of the NER in the development of the EBSS. More detail is provided in the AER's final decision for its EBSS.[327]

5.6.1 Consideration of the NER factors

The AER's view on the implementation of the EBSS has not changed from its preliminary positions paper. As noted above, the AER must have regard to a number of factors in implementing the EBSS. These factors are discussed in turn below

5.6.1.1 The need to ensure that benefits to consumers likely to result from the EBSS are sufficient to warrant any reward or penalty under the EBSS for Aurora

In developing the EBSS, the AER selected a five year carryover period (the length of a standard regulatory control period). This results in a sharing ratio between Aurora and its customers of 30:70.[328] Where an efficiency gain is realised and a subsequent operating expenditure underspend occurs, Aurora will retain the benefit of the efficiency gain for the duration of the carryover period, after which time the price reductions as a result of the efficiency gain are passed on to customers in perpetuity. In this way, Aurora will retain 30 per cent of the total benefits of the efficiency gain,

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323 Aurora, *Framework and Approach paper response to AER Preliminary Positions*, August 2010, p. 31.
324 ibid., p. 32.
325 ibid., p. 32.
326 ibid., p. 32.
327 AER, *Electricity distribution network service providers efficiency benefit sharing scheme final decision*, June 2008.
328 AER, *Final decision efficiency benefit sharing scheme*, June 2008, pp. 17–18.

and the remaining 70 per cent is passed on to customers. The carryover period may extend into the following regulatory control period (if the efficiency was realised in year two or after).

Due to the symmetrical nature of the scheme, consumers are still subject to the 70 per cent sharing ratio allocation where a loss is made. Therefore, while Aurora must share the benefits of any gains, the costs of any losses are also borne by consumers in the form of increased prices. However, the risk that customers incur higher prices due to efficiency losses is mitigated by the continuous incentive for Aurora to strive for efficiency gains created by the EBSS.

The EBSS will provide greater certainty for Aurora on how actual operating expenditure will be used to set forecasts in future regulatory control periods. Without an EBSS, the incentive to improve efficiency decreases as the period progresses and there can be uncertainty as to how operating expenditure will be forecast in future regulatory control periods. The EBSS therefore provides a constant incentive to improve efficiency. The EBSS will encourage efficient and timely expenditure throughout the regulatory control period, removing the incentive to only seek efficiency gains in the first half of, or early in, the period. This encourages Aurora to reveal its efficient operating expenditure. Consequently, the AER will be better placed to determine efficient forecasts going forward, and in time, these benefits will be passed on to consumers.

5.6.1.2 The need to provide Aurora with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure

The EBSS is designed to ensure that a DNSP facing a potential efficiency gain does not perceive a material advantage in either deferring or advancing an efficiency gain or loss, but rather that it faces an essentially constant benefit or cost from implementing a gain or loss as it arises. The measurement of gains and losses should not be artificially affected by, for example, shifting costs between years. Rather, it should represent genuine business outcomes that have arisen in the ordinary course of conducting the business in a prudent and diligent manner.

Under an economic regulation incentive framework, efficiencies are normally only retained until the end of the regulatory control period. In the absence of an EBSS this may create a natural incentive for Aurora to realise operating expenditure efficiencies early in the regulatory control period, so that the benefit of that efficiency can be retained for a longer time. By allowing Aurora to retain the benefit of an efficiency gain for the length of the carryover period regardless of the regulatory year in which it is achieved, the EBSS will provide a continuous incentive to reduce operating expenditure.

There may also be a perceived incentive for Aurora to increase operating expenditure in the later years of the regulatory control period, as the third or fourth year of the regulatory control period is commonly used in regulatory proposals as the starting point in forecasting operating expenditure requirements for the following regulatory control period.

The incentive to increase operating expenditure for the regulatory control period in the base year is at least partly counteracted by the symmetrical nature of the scheme. In the absence of an EBSS, Aurora may be inclined to strategically defer operating expenditure until the base year to increase operating expenditure forecasts for following regulatory control periods. However, the symmetrical nature of the EBSS means that any overspend in that year will be penalised for the length of the carryover period. Any potential gains to Aurora from increasing operating expenditure in the base year will have to be weighed up against the penalties that will be incurred for five years after the overspend.

The AER's EBSS will thus provide Aurora with a continuous incentive to achieve efficiency gains (and minimise efficiency losses) in each year of the regulatory control period.

The AER's EBSS does not extend to capital expenditure, and deals only with operating expenditure. This decision is explained in detail in the AER's final decision for its EBSS.[329] The AER does not propose to extend the EBSS to Aurora's capital expenditure.

5.6.1.3 The desirability of both rewarding Aurora for efficiency gains and penalising Aurora for efficiency losses

As outlined above, although OTTER applied an EBSS to Aurora during the 2003 regulatory control period, OTTER reversed this position in its 2007 decision. One of the reasons for that decision was the lack of clarity in its 2003 decision about the treatment of negative carryover amounts. [330]

The AER notes that the TEC contains no explicit requirement that any incentive based regulatory scheme such as the EBSS be applied in a symmetrical manner. Clause 6.5.8(c)(3) of the NER, however, requires the AER, when implementing and developing the EBSS, to have regard to '…the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses.'

In developing the current EBSS, the AER's modelling demonstrated that application of positive and negative carryovers was important for the continuity of incentives to improve efficiency. Without symmetrical carryovers, there is a perceived incentive to shift operating expenditure into the base year on the expectation that this will increase forecasts for the forthcoming regulatory control period. The AER concluded that symmetry in the EBSS was therefore appropriate.[331]

Under the EBSS, any negative or positive carryover amount will be included as a building block element in the calculation of the Aurora's allowed revenue for the subsequent regulatory control period. Negative and positive gains are treated equally to ensure that the incentives created by the EBSS are not skewed in favour of realising operating expenditure efficiencies only during the early years of the regulatory control period.

5.6.1.4 Any incentives that Aurora may have to capitalise expenditure

An important outcome of the EBSS is that it will provide a constant incentive to Aurora to improve the efficiency of operating expenditure throughout the regulatory

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329 AER, *Final decision efficiency benefit sharing scheme*, June 2008, p. 6.

330 OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania—Final Report and Proposed Maximum Prices*, September 2007, p. 222, 223.

331 AER, *Final decision efficiency benefit sharing scheme*, June 2008, p. 5.

control period. Because the EBSS will only apply to operating expenditure and not capital expenditure, Aurora may have an incentive to reallocate operating expenditure to capital expenditure, thereby creating an artificial efficiency improvement. This incentive will be mitigated by the AER's requirement that Aurora provide the AER with a detailed description of any changes to its capitalisation policy and a calculation of the impact of those changes on forecast and actual operating expenditure. To negate any incentive to capitalise operating expenditure where it is not efficient to do so, the AER will adjust the forecast and actual operating expenditure figures used to determine the carryover amounts to account for any changes in capitalisation policy.

5.6.1.5 Possible effects of the EBSS on incentives for implementation of non-network alternatives

Expenditure on non-network alternatives generally takes the form of operating expenditure, rather than capital expenditure. Because the EBSS is not applied to capital expenditure, the incentive later on in the regulatory control period to reduce capital expenditure is less than the incentive to reduce operating expenditure. Therefore, where expenditure for non-network alternatives is operational, Aurora may have a greater incentive to augment networks later in the period than to implement non-network alternatives. The proposed EBSS excludes all costs associated with non-network alternatives. This will remove the potential impact of the EBSS on such decisions, which may otherwise discourage Aurora from considering demand side management.

5.7 AER's likely approach to the implementation of the EBSS

The AER's likely approach is that the AER's EBSS will be applied to Aurora for the forthcoming regulatory control period in accordance with clause 6.3.2(a)(3) and 6.12.1(9) of the NER. In forming this position, the AER has had regard to the factors in clause 6.5.8(c) of the NER and considers that:

- The benefits to Tasmanian consumers derived from the EBSS are sufficient to warrant any financial reward or penalty that Aurora may incur, because Aurora customers would receive 70 per cent of the efficiency gains realised by Aurora under the EBSS.[332] Because the EBSS is symmetrical, any efficiency losses would also be shared between customers and Aurora, so that the potential for financial penalty is balanced. [333] The symmetry of the scheme also provides balance so that incentives are not skewed in favour of realising efficiencies only during the first years of the regulatory control period. This will also remove the perceived tendency towards strategic deferral of operating expenditure to the final years of the regulatory control period in order to create an artificially high base year for further forecasts.

- The EBSS will provide a continuous incentive for Aurora to achieve operating expenditure efficiencies throughout the regulatory control period, as any efficiency gains or losses realised within the regulatory control period are retained

[332] NER, cl.6.5.8(c)(1)
[333] NER, cl.6.5.8(c)(3)

by Aurora for the length of the carryover period, regardless of the year in which the gain or loss is realised.[334]

- The EBSS will counter any artificial incentive to capitalise expenditure by requiring Aurora to report any changes to its capitalisation policy to the AER. The AER will adjust the forecast and outturn operating expenditure figures used to determine the carryover amounts to account for any changes in capitalisation policy.[335]

- The exclusion of costs associated with demand side management from consideration under the EBSS will remove any deterrents to the use on non-network alternatives that might otherwise arise under the EBSS.[336]

The AER notes the concerns raised by OTTER in its 2007 decision regarding the impact that forecasting accuracy and distinguishing between types of expenditure had on the application of an EBSS. The AER also considers that these issues are important considerations in the application of an EBSS. That said, the AER considers that up-front certainty that a symmetrical scheme will be applied during the regulatory period prior to the lodgement of the regulatory proposal, combined with additional information on Aurora's historical expenditure will assist the AER in making reasonable and accurate forecasts for the purpose of the EBSS.

The EBSS allows Aurora to propose 'uncontrollable' cost categories for exclusion from the scheme.[337] These categories must be proposed by Aurora in its regulatory proposal for consideration in the AER's distribution determination.

When making a decision on whether or not to approve an uncontrollable cost category, the AER will have regard to whether the cost category is genuinely beyond the control of Aurora. Aurora, in proposing uncontrollable operating expenditure categories will be required to maintain and provide disaggregated operating expenditure figures in support of any proposed uncontrollable operating expenditure categories to allow proper administration of the EBSS. The AER notes that outturn operating expenditure for uncontrollable cost categories will not be assumed to be efficient for the purposes of forecasting costs for future regulatory control periods; therefore, the efficiency of base year costs for these categories will need to be established in Aurora's regulatory proposal.

[334] NER, cl.6.5.8(c)(2)
[335] NER, cl.6.5.8(c)(4)
[336] NER, cl.6.5.8(c)(5)
[337] AER, *Final decision efficiency benefit sharing scheme*, June 2008, p. 6.

6 Application of a demand management incentive scheme

This chapter sets out the AER's likely approach to the application of a demand management incentive scheme (DMIS) to Aurora for the forthcoming regulatory control period and its reasons for that approach.

The objective of a DMIS is to provide incentives for DNSPs to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way.[338] The DMIS operates in conjunction with existing incentives in the regulatory framework to achieve these objectives.

Demand management refers to the implementation of any strategy to address growth in demand or peak demand. Network owners can seek to undertake demand management through a variety of mechanisms, such as incentives for customers to change their demand patterns, operational efficiency programs or load control technologies. Demand management can provide efficient alternatives to network investments by deferring the need for augmentations to relieve network constraints.

This can have positive impacts by reducing inefficient peaks and encouraging more efficient use of existing network assets, resulting in lower prices for network users.

6.1 Regulatory requirements

In developing and applying a DMIS, the AER must have regard to the factors set out in cl. 6.6.3 (b) of the NER:

1. the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for Distribution Network Service Providers;
2. the effect of a particular control mechanism (i.e. price – as distinct from revenue – regulation) on a Distribution Network Service Provider's incentives to adopt or implement efficient non-network alternatives;
3. the extent the Distribution Network Service Provider is able to offer efficient pricing structures;
4. the possible interaction between a demand management incentive scheme and other incentive schemes; and
5. the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.[339]

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.[340] The AER published its proposed DMIS to apply to Aurora on 25 June 2010. The final version of the DMIS was published by the AER on 15 October 2010.

338 NER, cl. 6.6.3 (a)
339 NER, cl. 6.6.3 (b)
340 Distribution consultation procedures, cl. 6.16 of the NER.

That final decision considered several issues raised in submissions in relation to the design of the DMIS. These submissions came from Aurora and from the Total Environment Centre (TEC).[341] Other issues, including those relevant to the application of the DMIS to Aurora are discussed in this framework and approach paper.

The AER's likely approach is that it will apply a DMIS composed of a demand management innovation allowance (DMIA) to Aurora for the forthcoming regulatory control period.

6.2 Structure of the DMIS

The DMIS allows for the recovery of costs for demand management projects and programs undertaken throughout the regulatory control period, subject to the satisfaction of a defined criterion. The DMIA is provided as a capped, annual ex ante allowance and is subject to a single adjustment in the subsequent regulatory control period to return to customers any expenditure not approved or not spent. The AER notes that although these amounts are allocated annually through the building block mechanism, the DNSP can use these funds at any point in the regulatory control period to pursue initiatives under the DMIS. Funds not used (as at the end of the regulatory control period) are 'clawed back' through in the opex allowances for the subsequent regulatory control period.

Annual reporting requirements create transparency in the operation of the DMIA, and allow the AER, DNSPs, end-users and other stakeholders to monitor the effectiveness and outcomes of the scheme.

6.3 Submissions

As mentioned, the AER received two submissions on the DMIS, from:

- Aurora
- TEC

Relevant to the AER's decision on the application of the schemes, those submissions expressed views on the size of the DMIA for Aurora.

Aurora stated:

> Aurora supports the introduction of a DMIS within the Tasmanian jurisdiction. However, investment in innovation is not a scale issue and Aurora believes that an annual DMIS of $1 000 000 would be more appropriate.[342]

In proposing an allowance of $1 million per year, ($5 million over the regulatory control period), Aurora further noted that:

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[341] Party submissions and the final DMIS and accompanying final decision on that DMIS can be found on the AER's website: www.aer.gov.au

[342] Aurora Energy, Framework and approach paper: response to AER preliminary positions, August 2010, p. 4, p. 33.

- it recognised significant advantages in introducing demand management practices, to manage existing winter peak loads and future load increases

- it will focus on feasibility studies and trials during the early phase of the regulatory control period. During the latter stages, Aurora suggests that higher implementation costs will be required in the introduction of technology for trials and programs that reflect appropriate peak and base demand management

- it will undertake trials that are consistent and comparable with any other Australian distributor, irrespective of the comparison in size to Aurora's operations.[343]

In its submission, TEC noted that the proposed DMIA will be below 0.1 per cent of total spending over the five year regulatory control period.[344] TEC submitted that this was in contrast with the untapped potential for demand management in the National Electricity Market (NEM).[345] It particularly noted the current capex spends of Aurora in the current regulatory period, stating:

> It is clear, for example, that DM has not been properly considered by Aurora Energy, as evidenced by its most recent reports into major upgrades of the Hobart Eastern Shore Region ($49m), the Launceston Area ($47m) and the Kingston Area ($40.6m). [346]

TEC further disagreed with the cap of the DMIA, stating that:

> the DMIA should be set at the level of DM potential that the AER has failed to capture through its regulatory determinations. An assessment of the level of DM potential has clearly never been considered by the AER.[347]

TEC also noted the current level of demand management expenditure provided by the Essential Services Commission of South Australia (ESCOSA) in its last price review for ETSA Utilities ($20.5 million), and stated that this had resulted in a 19 - 35% reduction in peak load.[348]

6.4 Issues and AER considerations

6.4.1 Amount of the DMIA

As part of the proposed DMIS the AER suggested an amount it considered appropriate for the DMIA. In developing the DMIA, the AER has traditionally provided a modest allowance. This is because the initiatives that the DMIA is designed to fund are largely untested or innovative in nature. It is these types of new innovative programs (opportunities for which may arise throughout the regulatory control period and as such are not provided for through the opex and capex allowances) that the AER is promoting through the DMIS. The AER may allow other forms of demand management through the DNSP's opex and capex allowances.

343 ibid., p. 33.
344 TEC, *Submission to the AER, proposed demand management incentive scheme and framework and approach paper for Aurora Energy*, August 2010, p.1.
345 ibid.
346 ibid.
347 ibid., p.2.
348 ibid.

The AER proposed a DMIA amount of $400,000 per annum, having had regard to the relative size of Aurora's network. In response, Aurora proposed an annual DMIA of $1,000,000. Aurora submitted that it would need to undertake feasibility studies and trials comparable with any other Australian DNSP despite the size of Aurora's operations. The AER notes that Aurora's proposed DMIA is similar to those provided to other Australian DNSPs.[349]

In deciding on an appropriate amount for the DMIA, the AER must have regard to the willingness of customers to pay for this scheme.[350] Little is known about customer willingness to pay for schemes that effectively fund research and development or trial untested initiatives. The AER must balance the incentives to undertake demand management projects with the associated costs. The AER must also be cognisant that some of these trials may prove unsuccessful and may not yield results for customers.

In light of these considerations, as well as the other factors in clause 6.6.3 of the NER (as discussed below), the AER's approach to the DMIA has been, and will continue to be, the provision of a modest allowance. As a result, the AER considers that the appropriate allowance for Aurora is $400 000 per year of the regulatory control period.

6.4.2 Capex and opex over the regulatory control period

The AER notes that the DMIA is not the only source of funding for demand management under the NER. In its submission TEC noted the lack of current demand management expenditure commenced by Aurora, citing several capex projects undertaken in the current regulatory control period.[351]

In arguing that the AER's DMIA was not large enough, TEC noted the allowances provided to ETSA Utilities by ESCOSA in 2005 for demand management. The AER notes that this allowance was provided as part of the distribution determination, in response to submissions and proposals put forward by ETSA Utilities. The AER notes it will not receive responses to the regulatory proposal from Aurora until May 2011. Therefore, the AER cannot assess the full scope of Aurora's proposed demand management projects at this time.

In assessing Aurora's opex and capex proposals ahead of making its final determination, the AER must have regard to the extent to which Aurora has considered, and made provision for, efficient non-network alternatives.[352] The AER must also have regard to the substitution possibilities between opex and capex.[353] The AER can consider demand management opex that defers or reduces the need for capex over the regulatory control period.

The AER has, as part of previous distribution determinations, provided allowances for several demand management projects through the opex and capex programs

349 Aurora, *Submission to the AER,* August 2010, p. 33.
The AER's distribution determinations for Victorian DNSPs for 2011-2015, provided allowances of $200 000 (for JEN and CitiPower), $400 000 (for United Energy) and $600 000 (for SP AusNet and Powercor).

350 NER, cl. 6.6.3 (b)

351 TEC, *Submission to the AER,* August 2010, pp. 1-2.

352 NER, clause 6.5.6 (e) (10) and 6.5.7 (e) (10).

353 NER, clause, 6.5.6 (e) (7) and 6.5.7 (e) (7).

undertaken in the regulatory control period. For example, the AER in its recent distribution determination for Victorian DNSPs provided an opex allowance of $3.0 million to United Energy for demand management initiatives, and $8.2m for SP AusNet.[354] SP AusNet was also provided with a capex allowance of $3.18m for energy storage trials. Some of these projects included:

- Energy storage trials
- Establishment of demand management teams
- Implementation of TOU tariffs and critical peak demand pricing
- The AER also permitted opex demand management spending which seeks to defer capex.

However, such expenditure can only be analysed subsequent to the regulatory proposals having been received — that is, as part of the regulatory determination process.

For the reasons set out above, the AER disagrees with TEC's view that the AER does not adequately consider demand management. The AER also does not consider that in limiting the DMIA, it is preventing the uptake of demand management. As the AER has previously stated, the DMIA is not the sole source of funding for demand management based on non network alternatives generally.

6.5 Consistency with the NER

In applying a DMIS to Aurora, the AER must have regard to the factors in clause 6.6.3 of the NER. These factors are addressed below.

6.5.1 The need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs

The rewards and penalties payable under a DMIS must be set at a level that ensures that the costs to consumers resulting from the associated adjustment to regulated revenues do not exceed the benefits expected to result from the implementation of the DMIS. In striking the appropriate balance, it must be recognised that the operation of such a scheme may result in cost impacts within a regulatory control period where benefits are unlikely to be revealed until later periods. The AER must consider the potential cost impacts arising from the implementation of a DMIS. The AER's DMIS is a modest scheme of $400 000, with allowances provided on a use-it-or-lose-it basis so that it is not recovered unless it is used for demand management initiatives under the DMIS. The AER considers that $400 000 per annum, funded from the operational expenditure of Aurora, is not an overly large sum and is likely to provide a benefit to consumers which would warrant any reward or penalty under the scheme for DNSPs.

Implementation of the scheme will allow Aurora to investigate and undertake demand management initiatives which will provide long term benefits to consumers that will outweigh the short-term costs of implementing the scheme. Once the AER has

[354] AER, *Victorian distribution determination, final decision*, 29 October 2010, Appendix L, p.367.

collected more information and data on the types of trials and projects the DNSPs are undertaking through the DMIA, a more robust assessment of the broader role of demand management in the NEM can be undertaken.

The AER's final DMIS for Aurora is designed to encourage the implementation of demand management initiatives which provide long term efficiency gains to energy users that are expected to outweigh any short term price increases. The allowance is designed to provide incentives for Aurora to conduct efficient, broad-based and/or innovative demand management programs.

The AER considers that the scheme's expenditure allowance will allow Aurora to carry out a number of small-scale demand management projects, or a single larger-scale demand management project during the regulatory control period.

The AER's DMIS encourages the implementation of demand management initiatives which provide long–term efficiency gains to energy users that may outweigh any short term price increases. The allowance is designed to provide incentives for DNSPs to conduct efficient, broad-based and/or innovative demand management programs, and should coordinate well with both existing and potential demand management initiatives being carried out by Aurora.

Given that peak demand is a key driver of network capital expenditure, a demand management innovation allowance could also be used for initiatives which result in a more efficient use of existing infrastructure and a lower level of investment in new infrastructure through either deferral of, or removal of the need for, network augmentation or expansion expenditures.

6.5.2 The effect of a particular control mechanism on a DNSP's incentives to adopt or implement efficient non-network alternatives

In proposing the application of a DMIS, the AER has had regard to the effects that particular control mechanisms may have on the incentives or disincentives for DNSPs to undertake demand management. The AER accepts that in some instances the incentives for demand management may be affected by the control mechanism applied to a DNSP's standard control services.

Under forms of control where revenue is at least partially dependent on the quantity of electricity sold (for example, a price cap or a weighted average price cap), a successful demand management program that causes a reduction in demand may result in less revenue to a DNSP. The AER notes that its likely approach is to apply a revenue cap to Aurora. Under a revenue cap, revenue is not dependant on the DNSP's throughput. Therefore, there are no inherent disincentives for Aurora to reduce its output through implementation of the DMIS.

For this reason, the AER considers that the form of control does not provide a disincentive to undertake demand management. The AER has not included a forgone revenue component in the Aurora DMIS as it has for DNSPs in other jurisdictions which are subject to a weighted average price cap form of control.

6.5.3 The extent the DNSP is able to offer efficient pricing structures

In applying a DMIS to Aurora, the AER must have regard to the extent that it it are able to offer efficient pricing structures.

Ideally, efficient pricing structures exist where the price of electricity at a particular point in the network reflects the true costs of its supply at that location at a particular point in time. For instance, efficient pricing structures should reflect increases in costs of supplying electricity in times of peak demand.

The AER considers that efficient pricing structures can assist the effectiveness of demand management programs, and that the availability of a DMIA will provide capacity for Aurora to conduct tariff-based demand management programs which will provide further information on mechanisms for efficient pricing.

6.5.4 The possible interaction between a DMIS and other incentive schemes

In applying a DMIS to Aurora the AER must have regard to the interaction of that scheme with other incentive schemes. The AER's view is that both an EBSS and STPIS will be applied to the Aurora DNSPs in the upcoming regulatory control period.

Increased expenditure on demand management within the regulatory control period may increase operating expenditure above the levels forecast in the distribution determination. This could lead to a corresponding and unintended penalty under the EBSS. To minimise the impact of the EBSS on the incentives to undertake efficient demand management programs, the EBSS excludes all costs associated with non-network alternatives, including operating expenditure on demand management and expenditure under the DMIS, from the calculation of operating expenditure overspends and underspends. This removes the potential impact of the EBSS on a decision to implement demand management or non-network alternatives, which may otherwise discourage Aurora from doing so.

The AER is aware of the perceived disincentive to implement non-network alternatives to augmentation created by the reliability performance measures in its STPIS, such that incentives to undertake demand side management may be diminished by what is seen as a greater risk that performance targets will not be met. The DMIS is designed to facilitate improved demand management capability and capacity, and to promote innovative and new developments in the area of demand management so that demand management projects may increasingly be identified as viable alternatives to network augmentation. This feature of the DMIA is designed to break down the barriers to implementation of demand management solutions, arising from claims that such options remain largely unproven and reflect a higher risk to DNSPs than network-based solutions.

The AER considers that the application of the DMIS to Aurora will not negatively interact with the incentives created by other schemes or send conflicting signals in terms of desired expenditure outcomes.

6.5.5 The willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.

The AER considers that the application of a modest, low cost and administratively streamlined scheme, such as the DMIS to be applied to Aurora (under which the cost increases experienced by customers and end users will be minimal) is appropriate at this time. The AER must also consider whether or not customers are willing to pay for demand management initiatives in the forthcoming regulatory period. The AER has no evidence that customers are willing to pay for large scale, untested demand management projects.

6.6 AER's likely approach to the application of the DMIS

Having had regard to the requirements of the NER, the AER will likely apply the final DMIS (published by the AER on 15 October 2010) to Aurora in the forthcoming regulatory control period. This DMIS comprises of the DMIA component as discussed above.

In determining the appropriate amount of the DMIA for Aurora, the AER has had regard to the relative size of the average annual revenue allowance in the current regulatory control period. This was also the approach taken by the AER in determining the DMIA for the South Australian, Queensland and Victorian DNSPs.

The AER proposes an annual DMIA amount of $400,000 for Aurora. This equates to $2 million over the regulatory control period.

The AER considers that this allowance will enable Aurora to carry out a number of small-scale demand management projects, or a single larger-scale demand management project during the regulatory control period.

7 Other matters

7.1 Cost allocation method

The cost allocation guidelines set out arrangements to manage the attribution of direct costs and the allocation of shared costs by DNSPs between different categories of distribution services. The categories of distribution services are:

- standard control services
- alternative control services
- negotiated distribution services
- unregulated services

Clause 6.15.4(b) of the NER stipulates that electricity distribution businesses must submit a Cost Allocation Method (CAM) to the AER six months after the commencement of the rules. Aurora submitted a CAM to the AER in December 2008. The AER approved Aurora's cost allocation method in June 2009. Aurora's CAM will not be used to allocate actual costs until the forthcoming regulatory control period, however costs forecast for Aurora's forthcoming regulatory control period must be allocated in accordance with the CAM.

The cost allocation guidelines require that DNSPs provide a specification of the categories of distribution services that they provide. To satisfy this requirement of the cost allocation guidelines Aurora provided the following classification of services:

- all distribution services currently provided by Aurora that are regulated by OTTER, will be standard control services
- all special services currently provided by Aurora that are regulated by OTTER, will be alternative control services
- all streetlighting services currently provided by Aurora that are not regulated by OTTER, will be unclassified

Aurora also noted that 'the general assumption that distribution services currently regulated by OTTER are classified as standard control services does not necessarily represent Aurora's view on the appropriate classification of services to apply in the next Regulatory Control Period'. Aurora proposed to amend the CAM should the classification of services in the method differ from the AER's final classification of services.

Clause 4.3 of the cost allocation guidelines states that The AER, in consultation with the DNSP, will review the DNSP's CAM as part of each distribution determination for the relevant DNSP. As part of the distribution determination for Aurora, the AER will review Aurora's CAM.

7.2 Dual function assets

Clause 6.8.1(ca) of the NER requires that the framework and approach paper must include the AER's determination under clause 6.25(b) as to whether or not Part J of Chapter 6A is to be applied to determine the pricing of any transmission standard control services provided by any dual function assets owned, controlled or operated by Aurora.

The AER has been advised by Aurora that it does not have any dual function assets.

A AER's proposed service groups and classifications

Table A.1 of this appendix sets out the AER's proposed distribution service groups, the applicable classifications and the current OTTER classifications. For guidance, the table includes general descriptions of the type of activities that fall within each service group. It is not a complete listing of the underlying services provided by Aurora.

Table A.1 AER's likely service groups and classifications

AER service group	OTTER current classification	AER proposed classification	Service/activity
Network services	Declared distribution services	Standard control services	Constructing the distribution network
			Maintaining the distribution network and connection assets
			Operating the distribution network and connection assets for DNSP purposes
			Planning and designing the distribution network
			Emergency response
			Administrative support (e.g. call centre, network billing)
Metering services	Declared distribution services	Alternative control services	Standard metering services for type 5–7 meters
			Special meter readings and meter testing of type 5–7 meters
	Unregulated	Unregulated	PAYG metering services provided by Aurora Retail
Public lighting services	Unregulated	Alternative control services	Repair, replacement and maintenance of public lighting
			Provision of new public lighting assets
	Unregulated	Negotiated Services	New public lighting technology services
Connection services	Standard control services	Standard control services	Standard connection services
	Standard control services	Standard control services	Connections requiring augmentation
	Unregulated	Unregulated	Customer contributions for connection augmentation

Fee based services	Declared special services	Alternative control services	Energisation, de-energisation and re-energisation (includes disconnections and reconnections) Meter alteration (adding and altering circuits) Meter testing (including for single phase, three phase and current transformer meters) Removal of meters and service connection Renewable energy connection – including installation of import/export metering equipment Temporary connections Disconnect service connection Truck tee up Open turret or cabinet for electrical contractor
Quoted (non-standard) services	Unregulated	Alternative control services	Moving mains, services or meters forming part of the network to accommodate extension, redesign or redevelopment of any premises The provision of electric plant for the specific provision of top-up or stand-by supplies of electricity Temporary supply Reserve or duplicate supply Network services and system augmentation required to receive energy from an embedded generator Alteration and relocation of existing public lighting assets

Source: AER analysis.

B Submissions received on preliminary positions paper

Submissions were received by the AER on its preliminary positions paper from the following stakeholders:

- Aurora Energy Pty Ltd (two submissions)
- Local Government Association of Tasmania and the Department of Infrastructure, Energy and Resources (joint submission)
- Office of the Tasmanian Economic Regulator
- StreetlightsLED Pty Ltd
- Total Environment Centre Inc
- Trans Tasman Energy Group

Glossary

AARR	Aggregate annual revenue requirement
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Aurora	Aurora Energy Pty Ltd (ABN 85 082 464 622).
CAM	Cost Allocation Method
cl. / cll.	clause / clauses
CPI	Consumer price index
CPI–X	Consumer Price Index minus X
DMIA	Demand management incentive allowance
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
DUOS	distribution use of system
EBSS	Efficiency benefit sharing scheme
ESCV	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
ESI Act	Electricity Supply Industry Act 1995 (Tas)
GSL	Guaranteed service level
m	million
MAIFI	Momentary average interruption frequency index
MCE	Ministerial Council on Energy
MWh	Megawatt hours
NEC	National Electricity Code
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
PAYG	Pay-as-you-go

PTRM	Post-tax revenue model
OTTER	Office of the Tasmanian Economic Regulator
RAB	Regulatory asset base
RFM	Roll-forward model
ROLR	Retailer of last resort
s.	section
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCONRRR	Steering Committee on National Regulatory Reporting Requirements
STPIS	Service target performance incentive scheme
TEC	Tasmanian Electricity Code 1995
TFP	Total factor productivity
VCR	Value customer reliability
WACC	Weighted average cost of capital